
Section 5 Attachments

Section 5 Attachments

Attachment 5-1: Redacted

Attachment 5-2: Financial Reports – Shell

Attachment 5-3: Financial Reports EDPR

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Financial Reports - Shell



Annual Report

and Form 20-F for the year ended
December 31, 2018, Royal Dutch Shell plc



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Shining a light on our energy solutions. Showing the extensive range of our activities; from Upstream and Integrated Gas to Downstream. Demonstrating the importance it has on our day-to-day lives through a simple and direct iconographic approach.

Cover: Conran Design Group
Typesetting: DFIN
Printer: Tuijtel under ISO 14001



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Terms and abbreviations

Currencies

\$	US dollar
€	euro
£	sterling

Units of measurement

acre	approximately 0.004 square kilometres
b(/d)	barrels (per day)
boe(/d)	barrels of oil equivalent (per day); natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel
kboe(/d)	thousand barrels of oil equivalent (per day); natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel
MMBtu	million British thermal units
megajoule	a unit of energy equal to one million joules
mtpa	million tonnes per annum
per day	volumes are converted into a daily basis using a calendar year
scf(/d)	standard cubic feet (per day)

Products

GTL	gas to liquids
LNG	liquefied natural gas
LPG	liquefied petroleum gas
NGL	natural gas liquids

Miscellaneous

ADS	American Depositary Share
AGM	Annual General Meeting
API	American Petroleum Institute
CCS	carbon capture and storage
CCS earnings	earnings on a current cost of supplies basis
CO ₂	carbon dioxide
EMTN	Euro medium-term note
EPS	earnings per share
FCF	free cash flow
FID	final investment decision
GAAP	generally accepted accounting principles
GHG	greenhouse gas
HSSE	health, safety, security and environment
IAS	International Accounting Standard
IEA	International Energy Agency
IFRS	International Financial Reporting Standard(s)
IOGP	International Association of Oil & Gas Producers
IPIECA	International Petroleum Industry Environmental Conservation Association (global oil and gas industry association for environmental and social issues)
LTIP	Long-term Incentive Plan
OECD	Organisation for Economic Co-operation and Development
OML	oil mining lease
OPEC	Organization of the Petroleum Exporting Countries
OPL	oil prospecting licence
PSC	production-sharing contract
PSP	Performance Share Plan
REMCO	Remuneration Committee
SEC	US Securities and Exchange Commission
TRCF	total recordable case frequency
TSR	total shareholder return
WTI	West Texas Intermediate

About this Report

The Royal Dutch Shell plc Annual Report and Form 20-F (this Report) serves as the Annual Report and Accounts in accordance with UK requirements and as the Annual Report on Form 20-F as filed with the US Securities and Exchange Commission (SEC) for the year ended December 31, 2018, for Royal Dutch Shell plc (the Company) and its subsidiaries (collectively referred to as Shell). This Report presents the Consolidated Financial Statements of Shell (pages 167-214), the Parent Company Financial Statements of Shell (pages 237-246) and the Financial Statements of the Royal Dutch Shell Dividend Access Trust (pages 251-255). Except for these Financial Statements, the numbers presented throughout this Report may not sum precisely to the totals provided and percentages may not precisely reflect the absolute figures, due to rounding. Cross references to Form 20-F are set out on pages 02-03 of this Report.

Financial reporting terms used in this Report are in accordance with International Financial Reporting Standards (IFRS). The Consolidated Financial Statements comprise the financial statements of the Company and its subsidiaries. "Subsidiaries" and "Shell subsidiaries" refer to those entities over which the Company has control, either directly or indirectly. Entities and unincorporated arrangements over which Shell has joint control are generally referred to as "joint ventures" and "joint operations", respectively. Entities over which Shell has significant influence but neither control nor joint control are referred to as "associates". "Joint ventures" and "joint operations" are collectively referred to as "joint arrangements".

This Report contains certain following forward-looking Non-GAAP measures such as free cash flow, capital investment and divestments. We are unable to provide a reconciliation of these forward-looking Non-GAAP measures to the most comparable GAAP financial measures, because certain information needed to reconcile those Non-GAAP measures to the most comparable GAAP financial measures is dependent on future events some of which are outside the control of the company, such as oil and gas prices, interest rates and exchange rates. Moreover, estimating such GAAP measures with the required precision necessary to provide a meaningful reconciliation is extremely difficult and could not be accomplished without unreasonable effort. Non-GAAP measures in respect of future periods which cannot be reconciled to the most comparable GAAP financial measure are calculated in a manner which is consistent with the accounting policies applied in Royal Dutch Shell plc's financial statements. All outlooks on financial metrics and/or alternative performance measures exclude the effect of the implementation of IFRS 16 *Leases*, which will take place effective as of January 1, 2019.

In addition to the term "Shell", in this Report "Shell Group", "we", "us" and "our" are also used to refer to the Company and its subsidiaries in general or to those who work for them. These terms are also used where no useful purpose is served by identifying the particular entity or entities. The term "Shell interest" is used for convenience to indicate the direct and/or indirect ownership interest held by Shell in an entity or unincorporated joint arrangement. The companies in which Royal Dutch Shell plc directly or indirectly own investments are separate legal entities. Shell subsidiaries' data include their interests in joint operations.

This Report contains data and analysis from Shell's new Sky scenario. Unlike Shell's previously published Mountains and Oceans exploratory scenarios, the Sky scenario is based on the assumption that society reaches the Paris Agreement's goal of holding the rise in global average temperatures this century to well below two degrees Celsius (2°C) above pre-industrial levels. Unlike Shell's Mountains and Oceans scenarios which unfolded in an open-ended way based upon plausible assumptions and quantifications, the Sky scenario was specifically designed to reach the Paris Agreement's goal in a technically possible manner. These scenarios are a part of an ongoing process used in Shell for over 40 years to challenge executives' perspectives on the future business environment. They are designed to stretch management

to consider even events that may only be remotely possible. Scenarios, therefore, are not intended to be predictions of likely future events or outcomes and investors should not rely on them when making an investment decision with regard to Royal Dutch Shell plc securities.

Additionally, it is important to note that Shell's existing portfolio has been decades in development. While we believe our portfolio is resilient under a wide range of outlooks, including the IEA's 450 scenario (World Energy Outlook 2016), it includes assets across a spectrum of energy intensities including some with above-average intensity. While we seek to enhance our operations' average energy intensity through both the development of new projects and divestments, we have no immediate plans to move to a net-zero emissions portfolio over our investment horizon of 10-20 years. Although, we have no immediate plans to move to a net-zero emissions portfolio, in November of 2017, we announced our ambition to reduce the Net Carbon Footprint of our energy products in accordance with society's implementation of the Paris Agreement's goal of holding global average temperature to well below 2°C above pre-industrial levels. Accordingly, assuming society aligns itself with the Paris Agreement's goals, we aim to reduce the Net Carbon Footprint of our energy products, which includes not only our direct and indirect carbon emissions, associated with producing the energy products which we sell, but also our customers' emissions from their use of the energy products that we sell, by around 20% in 2035 and by around 50% in 2050.

We also refer to "Shell's Net Carbon Footprint" in this Report. This includes Shell's carbon emissions from the production of our energy products, our suppliers' carbon emissions in supplying energy for that production, and our customers' carbon emissions associated with their use of the energy products we sell. Shell only controls its own emissions but, to support society in achieving the Paris Agreement goals, we aim to help and influence such suppliers and consumers to likewise lower their emissions. The use of the terminology "Shell's Net Carbon Footprint" is for convenience only and not intended to suggest these emissions are those of Shell or its subsidiaries.

Except where indicated, the figures shown in the tables in this Report are in respect of subsidiaries only, without deduction of any non-controlling interest. However, the term "Shell share" is used for convenience to refer to the volumes of hydrocarbons that are produced, processed or sold through subsidiaries, joint ventures and associates. All of a subsidiary's production, processing or sales volumes (including the share of joint operations) are included in the Shell share, even if Shell owns less than 100% of the subsidiary. In the case of joint ventures and associates, however, Shell-share figures are limited only to Shell's entitlement. In all cases, royalty payments in kind are deducted from the Shell share.

The financial statements contained in this Report have been prepared in accordance with the provisions of the Companies Act 2006 and with IFRS as adopted by the European Union. As applied to the financial statements, there are no material differences from IFRS as issued by the International Accounting Standards Board (IASB); therefore, the financial statements have been prepared in accordance with IFRS as issued by the IASB. IFRS as defined above includes interpretations issued by the IFRS Interpretations Committee.

Except where indicated, the figures shown in this Report are stated in US dollars. As used herein all references to "dollars" or "\$" are to the US currency.

This Report contains forward-looking statements (within the meaning of the US Private Securities Litigation Reform Act of 1995) concerning the financial condition, results of operations and businesses of Shell. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. Forward-looking statements are statements of future

About this Report Continued

expectations that are based on management's current expectations and assumptions and involve known and unknown risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied in these statements. Forward-looking statements include, among other things, statements concerning the potential exposure of Shell to market risks and statements expressing management's expectations, beliefs, estimates, forecasts, projections and assumptions. These forward-looking statements are identified by their use of terms and phrases such as "aim", "ambition", "anticipate", "believe", "could", "estimate", "expect", "goals", "intend", "may", "objectives", "outlook", "plan", "probably", "project", "risks", "schedule", "seek", "should", "target", "will" and similar terms and phrases. There are a number of factors that could affect the future operations of Shell and could cause those results to differ materially from those expressed in the forward-looking statements included in this Report, including (without limitation): (a) price fluctuations in crude oil and natural gas; (b) changes in demand for Shell's products; (c) currency fluctuations; (d) drilling and production results; (e) reserves estimates; (f) loss of market share and industry competition; (g) environmental and physical risks; (h) risks associated with the identification of suitable potential acquisition properties and targets, and successful negotiation and completion of such transactions; (i) the risk of doing business in developing countries and countries subject to international sanctions; (j) legislative, fiscal and regulatory developments including regulatory measures addressing climate change; (k) economic and financial market conditions in various countries and regions; (l) political risks, including the risks of expropriation and renegotiation of the terms of contracts with governmental entities, delays or advancements in the approval of projects and delays in the reimbursement for shared costs; and (m) changes in trading conditions. Also see "Risk factors" on pages 15-20 for additional risks and further discussion. No assurance is provided that future dividend payments will match or exceed previous dividend payments. All forward-looking statements contained in this Report are expressly qualified in their entirety by the cautionary statements contained or referred to in this section. Readers should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of this Report. Neither the Company nor any of its subsidiaries undertake any obligation to publicly update or revise any forward-looking statement as a result of new information, future events or other information. In light of these risks, results could differ materially from those stated, implied or inferred from the forward-looking statements contained in this Report.

This Report contains references to Shell's website and to the Shell Sustainability Report. These references are for the readers' convenience only. Shell is not incorporating by reference any information posted on www.shell.com or in the Shell Sustainability Report.

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DOCUMENTS ON DISPLAY

The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. All of the SEC filings made electronically by Shell are available to the public on the SEC website at www.sec.gov (commission file number 001-32575). This Report is also available, free of charge, at www.shell.com/annualreport or at the offices of Shell in The Hague, the Netherlands and London, United Kingdom. Copies of this Report also may be obtained, free of charge, by mail.

Strategic Report

Chair's message: Building trust in Shell

We are making good progress in shaping Shell into one of the best investment options for shareholders globally, while positioning it to thrive in the transition to a lower-carbon world. This progress is described in Ben's CEO review.

Our ongoing work to provide more and cleaner energy should increase recognition of the positive contributions that Shell can make to society over the decades ahead.

But our success in achieving these goals will depend largely on whether society trusts us.

Investors invest in companies they trust, governments allow trusted companies to operate and consumers buy things from people they trust. Trusted companies are also likely to attract and retain the brightest minds, helping to ensure the lasting vitality of the business.

Trust is clearly a virtuous circle. The question is, how can companies create and keep it? I believe this can only be achieved by everybody demonstrating unquestionable integrity – every day, in every way and everywhere we work.

Unquestionable integrity is essential for earning and maintaining the trust of customers, investors and wider society.

PUBLIC TRUST

According to our independent research, Shell still enjoys high levels of public trust in many Asian countries, including China and India. But trust in the oil and gas industry has declined in some parts of the world, particularly in western Europe, over the last few decades. Shell is no exception.

Shell lost the trust of many investors in 2004, when senior executives misrepresented the size of the company's oil reserves. The company has been working to restore that trust ever since.

Earning trust takes time. Losing it takes no time at all.

That is why we invest a lot of time in raising ethical standards and underscoring the importance of absolute integrity for all our employees. We can never stop working to ensure that the highest ethical standards are always followed by all Shell staff around the world.

And, because we strongly believe that all leaders must set an example, in 2018 we introduced mandatory ethical leadership workshops for senior executives across our global operations. I took part in one such workshop in December 2018, together with fellow Board member Sir Nigel Sheinwald and several senior managers. It was a great opportunity to learn from each other about the challenges facing leaders at Shell.

Ethical considerations are a key part of discussions in the Shell boardroom. Over the last year or more, we have made a concerted effort to use the experiences of our Board members, gained from working in a variety of countries and industries, to identify ethical dilemmas that could arise from business opportunities.

Each member of our diverse Board brings invaluable perspectives to these discussions, blending experience from both the public and private sectors. To highlight the contributions of our three newest members, Roberto Setubal brings insights from Brazil, a major developing country. Ann Godbehere brings extensive mining, insurance and financial sector experience, and Catherine Hughes brings decades of experience in the oil and gas industry. The Board must scrutinise Shell's plans and actions from different points of view.

Unfortunately, as a result of a settlement agreement Shell entered into in 2011 in Nigeria for an oil block called OPL 245, we have seen Shell's name in news headlines around the world. This is a stark reminder that building trust requires more than just complying with the law. Trust is also about perception. If people perceive you as not sharing their values, concerns or hopes for the future, they are unlikely to trust you.

This has been a difficult learning experience for us, particularly in terms of how our behaviour is perceived. We are using this experience to remind all our employees that even the perception of wrongdoing can result in a loss of trust.

To gain and maintain trust across more than 70 countries in which we operate, we also need to ensure we always work safely, without hurting people or the environment, while rectifying problems that arise.

We are making good progress on improving the safety of our operations. For example, our process safety incidents were reduced by more than a quarter in 2018, compared to 2017. Our personal injury rate was our second-lowest on record, following a record low in 2017. But two people still tragically died while working for Shell in 2018. Our safety goal is zero injuries and incidents.

TRANSPARENCY

Trust can only be earned and kept if people see that we share their concerns and hopes for the future. They can only see that if we are transparent about what we do and why we do it. Transparency goes beyond publishing financial results and executive pay figures. It is about being as open as we can with governments, customers and partners. On tax, for example, Shell has signed up to The B Team Responsible Tax Principles. These include being open about the entities the Company owns around the world, and why we own them.

The more transparent we are about our activities, the better equipped our investors, customers and wider society are to decide whether we are worthy of their trust.

Ultimately, we need to give them lots of reasons to trust us and no reasons to distrust us. Perhaps nowhere is this more important than for the 30 million daily retail customers who trust Shell to provide products they can rely on. We must live up to that trust every day.

Chair's message: Building trust in Shell Continued

We want all our retail customers to strongly believe that, when they are filling up or charging their vehicles, we are providing all the products and services they need safely, efficiently and ethically. We want all our business customers to be equally sure of Shell. By constantly demonstrating the unquestionable integrity of our businesses, people and partnerships, we believe we can earn and keep their trust over the long term.

Chad Holliday

Chair



The Board: Charles O. Holliday, Euleen Goh, Roberto Setubal, Jessica Uhl, Gerard Kleisterlee, Ann Godbehere, Sir Nigel Sheinwald, Linda G. Stuntz, Gerrit Zalm, Catherine J. Hughes, Ben van Beurden and Linda M. Szymanski (Company Secretary).

Chief Executive Officer's review: Delivering on our promises

Shell delivered a very strong financial performance in 2018. We are continuing to make good progress in building a world-class investment case.

Higher oil and gas prices, combined with our ongoing work to improve the performance and competitiveness of our businesses, contributed to a sharp increase in cash flow from operating activities to \$53 billion in 2018. We are on track with our outlook of annual free cash flow of between \$30 billion and \$35 billion by 2020, at a Brent crude oil price of \$60 a barrel (real terms 2016).

We delivered on our promises for the year, including completing our \$30-billion divestment programme and starting up key growth projects, while maintaining discipline on capital investment. We paid our entire dividend in cash, further reduced our debt and launched our share buyback programme.

But 2018 was not all good news for us. Tragically, a contractor died at our Rheinland refinery in Germany and another died at an onshore well in the USA. I am deeply unhappy about these incidents and call on all Shell employees, contractors and suppliers to redouble their focus on safety.

RESULTS

Income for the period was \$23.9 billion in 2018, compared with \$13.4 billion in 2017. Earnings on a current cost of supplies basis increased to \$24.4 billion, compared with \$12.5 billion in 2017. We distributed \$15.7 billion to shareholders in dividends in 2018.

After cancelling the Scrip Dividend Programme with effect from the fourth quarter 2017 dividend, our healthy free cash flow outlook and stronger balance sheet gave us the confidence to start our share buyback programme in mid-2018. We intend to buy back at least \$25 billion of shares by the end of 2020, subject to further progress with debt reduction and oil price conditions.

With the continued strengthening of our balance sheet, cash flows and our ongoing focus on capital efficiency, I am confident that we will do this while continuing to grow our portfolio.

We continued to deliver new projects, including the completion of an important chemical plant expansion in China and starting production from a deep-water development in the US Gulf of Mexico a year ahead of schedule. Overall, our production averaged 3.7 million barrels of oil equivalent a day in 2018, unchanged from 2017. Increased production from new field start-ups and ramp-ups, as well as lower maintenance activity, was offset by the impact of divestments and field declines.

Stronger crude oil and gas prices contributed to sharp increases in our Upstream and Integrated Gas earnings, while Downstream earnings fell slightly.

We continued to streamline our business – including the sale of our Downstream business in Argentina; Upstream interests in Iraq, Ireland, Norway and Oman; and Integrated Gas interests in Malaysia, New Zealand and Thailand.

The progress of our divestments has helped us to reduce net debt, with gearing standing at 20.3% at the end of 2018, down from 25.0% in 2017.

Although our \$30 billion divestment programme for 2016-18 has been successfully completed, we expect to continue divestments at an average rate of more than \$5 billion a year until at least 2020. This will help us to further strengthen the balance sheet, reduce debt and increase focus on our strategic priorities.

Capital investment in 2018 was slightly below \$25 billion, reflecting our disciplined capital investment approach. Our capital investment outlook remains between \$25 billion and \$30 billion a year until 2020. We see \$30 billion as a ceiling, even in a high oil price environment. Our continued focus on capital efficiency and streamlining our portfolio will make us more resilient and competitive.

We will continue to carefully control our costs and investment levels, but we are still investing in strong commercial opportunities for growth. For example, we added deep-water exploration acreage in both the Mexican and US parts of the Gulf of Mexico, off the coast of Brazil, and off the coast of Mauritania in 2018. We also announced two large deep-water discoveries in the US Gulf of Mexico.

Natural gas will play a key role in the transition to a lower-carbon global energy system over the next few decades, with liquefied natural gas (LNG) shipments playing an increasingly important part. This is one of the driving forces behind our taking the final investment decision in 2018 on LNG Canada, a major project in which Shell has a 40% interest.

LNG Canada is well positioned to help Shell meet some of the world's growing gas needs. We expect the cash flow it generates to be significant and resilient. Sustainable development was considered in every aspect of the project. For example, it has been designed to achieve the lowest carbon intensity of any LNG project in operation today, aided by the partial use of hydropower.

In December, Shell announced plans to set short-term targets for reducing the Net Carbon Footprint of the energy products it sells – a carbon intensity measure that includes our customers' emissions when they use these products – and to link these targets to executive remuneration. This is an industry first.

Shell's Remuneration Committee will include a new performance condition linked to the transition to lower-carbon energy for the Long-term Incentive Plan grant starting in 2019, one year earlier than planned. Further details are in the Directors' Remuneration Report.

In 2018, I also announced our ambition to provide a reliable electricity supply to 100 million people in the developing world by 2030. Economic and social progress are being hindered in many countries by a lack of reliable energy supplies that are essential to providing basic medical services and clean water, for example. Better access to energy improves people's lives.

I am proud of Shell's success in 2018. We will continue to focus on delivering on our strategy in 2019, maintaining our disciplined approach to capital investment while working to grow our cash flow and returns. Our strategy to deliver a world-class investment case is working.

Ben van Beurden
Chief Executive Officer

Strategy and outlook

STRATEGY

Shell's purpose is to power progress together by providing more and cleaner energy solutions. Our strategy is to strengthen our position as a leading energy company by providing oil, gas and low-carbon energy as the world's energy system transforms. Safety and social responsibility are fundamental to our business approach. Shell will only succeed by working collaboratively with customers, governments, business partners, investors and other stakeholders.

Our strategy is founded on our outlook for the energy sector and the chance to grasp the opportunities arising from the substantial changes in the world around us. The rising standard of living of a growing global population is likely to continue to drive demand for energy, including oil and gas, for years to come. At the same time, technology changes and the need to tackle climate change means there is a transition under way to a lower-carbon, multi-source energy system with increasing customer choice. We recognise that the pace and path forward are uncertain and require agile decision-making.

STRATEGIC AMBITIONS

Against this backdrop, we have the following strategic ambitions to guide us in pursuing our purpose:

- to provide a world-class investment case. This involves growing free cash flow and increasing returns, all built upon a strong financial framework and resilient portfolio;
- to thrive in the energy transition by responding to society's desire for more and cleaner, convenient and competitive energy; and
- to sustain a strong societal licence to operate and make a positive contribution to society through our activities.

The execution of our strategy is founded on becoming a more customer-centric and simpler, more streamlined organisation, focused on growing returns and free cash flow. By investing in competitive projects, driving down costs and selling non-core businesses, we are continuously reshaping our portfolio to become a more resilient and focused company.

Our ability to achieve our strategic ambitions depends on how we respond to competitive forces. We continuously assess the external environment – the markets as well as the underlying economic, political, social and environmental drivers that shape them – to evaluate changes in competitive forces and business models. We use multiple future scenarios to assess the resilience of our strategy. We undertake regular reviews of the markets we operate in and analyse trends and uncertainties, as well as our traditional and non-traditional competitors' strengths and weaknesses, to understand our competitive position. We maintain business strategies and plans that focus on actions and capabilities to create and sustain competitive advantage. We maintain a risk management framework that regularly assesses our response to, and risk appetite for, identified risk factors (see "Risk factors" on page 15).

Our Executive Directors' remuneration is linked to the successful delivery of our strategy, based on performance indicators that are aligned with shareholder interests. Long-term incentives form the majority of the Executive Directors' remuneration for above-target performance. In 2018, the Long-term Incentive Plan (LTIP) included cash generation, capital discipline, and value created for shareholders metrics. See the "Directors' Remuneration Report" on page 142.

STRATEGIC THEMES

As part of our strategy, we divide our portfolio into strategic themes, each with distinctive capabilities, growth strategies, risk management, capital allocation and expected returns:

- Cash engines are strategic themes that are expected to provide strong and resilient returns and free cash flow, funding shareholder returns and strengthening the balance sheet. Shell continues to invest in selective growth opportunities for cash engines. Our cash engines are Conventional Oil and Gas in Upstream, Integrated Gas, and Oil Products in Downstream.
- Growth priorities are the cash engines of the future. Shell seeks to invest in affordable growth in advantaged positions with a pathway to free cash flow and returns in the near future. Our growth priorities currently are Deep water in Upstream and Chemicals in Downstream.
- Emerging opportunities are strategic themes that are expected to become growth priorities after further development. These businesses should provide us with material growth in free cash flow in the next decade or beyond. We seek to manage our exposure to these businesses while establishing scale. Our emerging opportunities currently are Shales in Upstream and New Energies, which is part of the Integrated Gas organisation.

For more details on how the strategic themes are embedded into our businesses, see "Business Overview" on page 13.

Our intention is to have an advantaged and resilient position in each strategic theme to drive an optimal free cash flow and returns profile over multiple timelines. When we set our plans and goals, we do so on the basis of delivering sustained returns over decades.

OUTLOOK FOR 2019 AND BEYOND

We continuously seek to improve our operating performance and maximise sustainable free cash flow, with an emphasis on health, safety, security, environment and asset performance, as well as our ethics and compliance principles. In order to achieve that, we strive for highly qualified and motivated employees.

We are on track with our outlook of annual free cash flow of between \$30 billion and \$35 billion by 2020, at a Brent crude oil price of \$60 a barrel (real terms 2016).

Our capital investment outlook remains between \$25 billion and \$30 billion a year until 2020. We see \$30 billion as a ceiling, even in a high oil price environment.

Following the successful delivery of our \$30 billion divestment programme during 2016-18, we will continue with an annual average outlook of at least \$5 billion of divestments in 2019 and 2020.

Following the delivery of an additional \$10 billion of cash flow from operations between 2014 and 2018, key project start-ups and ramp-ups are expected to generate an additional \$5 billion cash flow from operations between 2018 and 2020, assuming \$60 per barrel (real terms 2016) and mid-cycle Downstream industry conditions. We will remain highly selective on new investment decisions throughout 2019 and beyond.

We launched our share buyback programme in 2018. Our intention remains to buy back at least \$25 billion of our shares by the end of 2020, subject to further progress with debt reduction and oil price conditions.

We fully support the Paris Agreement's goal to keep the rise in global average temperature this century to well below two degrees Celsius above pre-industrial levels and to pursue efforts to limit temperature increase even further to 1.5 degrees Celsius. We have set a long-term ambition to reduce the Net Carbon Footprint of our energy products, measured in grams of carbon-dioxide equivalent per megajoule consumed, by around 20% by 2035 and by around 50% by 2050, in pace with society. To operationalise this long-term ambition, we will start setting specific Net Carbon Footprint targets for shorter-term periods. The first target has been set for a three-year period and is detailed in the Climate Change section on page 77. The target and other measures will be linked to our executive remuneration and we have introduced an additional performance condition in our Long-term Incentive Plan (LTIP) in 2019 linked to the transition to lower-carbon energy. Further details can be found in the Directors' Remuneration Report on page 124.

The statements in this "Strategy and outlook" section, including those related to our growth strategies and our expected or potential future cash flow from operations, free cash flow, share buybacks, capital investment, divestments, production and Net Carbon Footprint are based on management's current expectations and certain material assumptions and, accordingly, involve risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied herein. See "About this Report" on pages 05-06 and "Risk factors" on pages 15-20.

This outlook does not include the impact of the application of the new standard IFRS 16 Leases, which is effective as of January 1, 2019.

Business overview

HISTORY

From 1907 until 2005, Royal Dutch Petroleum Company and The "Shell" Transport and Trading Company, p.l.c. were the two public parent companies of a group of companies known collectively as the "Royal Dutch/Shell Group". Operating activities were conducted through the subsidiaries of these parent companies. In 2005, Royal Dutch Shell plc became the single parent company of Royal Dutch Petroleum Company and of The "Shell" Transport and Trading Company, p.l.c., now The Shell Transport and Trading Company Limited.

Royal Dutch Shell plc (the Company) is a public limited company registered in England and Wales and headquartered in The Hague, the Netherlands.

BUSINESS MODEL

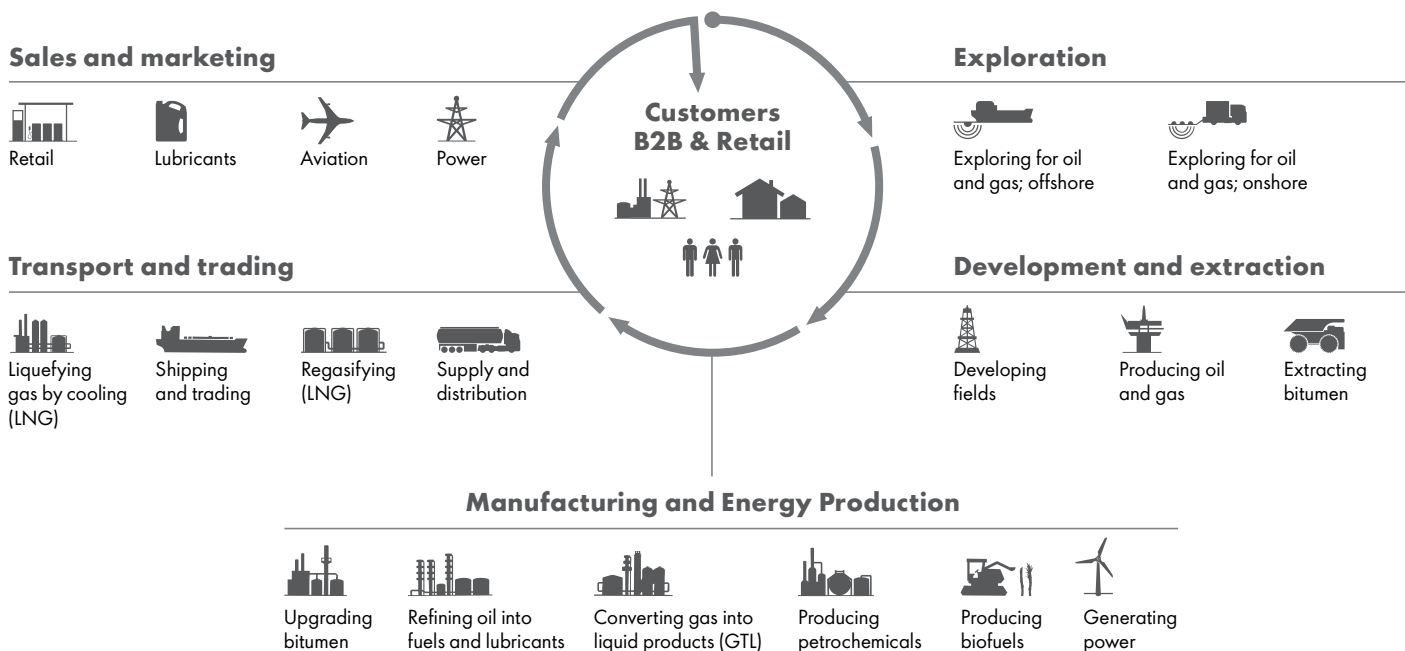
Shell is an international energy company with expertise in the exploration, development, production, refining and marketing of oil and natural gas, as well as in the manufacturing and marketing of chemicals. We are one of the world's largest independent energy companies in terms of market capitalisation, cash flow from operating activities, and production levels.

We seek to create shareholder value through the following activities:

- We explore for crude oil and natural gas worldwide, both in conventional fields and from sources such as tight rock, shale and coal formations. We work to develop new crude oil and natural gas supplies from major fields. We also extract bitumen from oil sands, which we convert into synthetic crude oil.

- We cool natural gas to produce liquefied natural gas (LNG) that can be safely shipped to markets around the world, and we convert gas into liquids (GTL).
- We transport and trade oil, gas and other energy-related products, such as electricity and carbon-emissions rights.
- We have a portfolio of refineries and chemical plants which enables us to capture value from oil and gas production, turning them into a range of refined and petrochemical products which are moved and marketed around the world for domestic, industrial and transport use. The products we sell include gasoline, diesel, heating oil, aviation fuel, marine fuel, LNG for transport, lubricants, bitumen and sulphur. We also produce and sell ethanol from sugar cane in Brazil, through our Raízen joint venture.
- We invest in low-carbon energy solutions such as biofuels, hydrogen, wind and solar power, and in other opportunities linked to the energy transition.

The integration of our businesses is one of our competitive advantages, allowing for optimisations across our global portfolio. Our key strengths include the development and application of innovation and technology, the financial and project management skills that allow us to safely develop large and integrated projects, the management of integrated value chains and the marketing of energy products. The distinctive Shell pecten, a trademark in use since the early part of the 20th century, and trademarks in which the word Shell appears, help raise the profile of our brand globally.



ORGANISATION

We describe below how our activities are organised. Integrated Gas, Upstream and Downstream focus on our seven strategic themes (see “Strategy and outlook” on page 10). Our Projects & Technology organisation manages the delivery of Shell’s major projects and drives research and innovation to develop new technology solutions.

INTEGRATED GAS (INCLUDING NEW ENERGIES)

This organisation covers two strategic themes: Integrated Gas, which is a cash engine; and New Energies, which is an emerging opportunity.

Integrated Gas manages LNG activities and the conversion of natural gas into GTL fuels and other products. It includes natural gas exploration and extraction, and the operation of upstream and midstream infrastructure necessary to deliver gas to market. It markets and trades natural gas, LNG, electricity and carbon-emission rights and also markets and sells LNG as a fuel for heavy-duty vehicles and marine vessels.

In New Energies, we are exploring emerging opportunities and investing in those where we believe sufficient commercial value is available. We focus on new fuels for transport, such as advanced biofuels, hydrogen and charging for battery-electric vehicles; and power, including from low-carbon sources such as wind and solar as well as natural gas.

UPSTREAM

Our Upstream organisation covers three strategic themes: Conventional Oil and Gas, which is a cash engine; Deep water, which is a growth priority; and Shales, which is an emerging opportunity.

It manages the exploration for and extraction of crude oil, natural gas and natural gas liquids. It also markets and transports oil and gas, and operates infrastructure necessary to deliver them to market.

DOWNSTREAM

Our Downstream organisation comprises two strategic themes: Oil Products, which is a cash engine; and Chemicals, which is a growth priority.

It manages different Oil Products and Chemicals activities as part of an integrated value chain, that trades and refines crude oil, and other feedstocks into a range of products which are moved and marketed around the world for domestic, industrial and transport use. The products we sell include gasoline, diesel, heating oil, aviation fuel, marine fuel, biofuel, lubricants, bitumen and sulphur. In addition, we produce and sell petrochemicals for industrial use worldwide. Our Downstream organisation also manages Oil Sands activities (the extraction of bitumen from mined oil sands and its conversion into synthetic crude oil).

PROJECTS & TECHNOLOGY

Our Projects & Technology organisation manages the delivery of our major projects and drives research and innovation to develop new technology solutions. It provides technical services and technology capability for our Integrated Gas, Upstream and Downstream activities. It is also responsible for providing functional leadership across Shell in the areas of safety and environment, contracting and procurement, wells activities and greenhouse gas management.

Our future hydrocarbon production depends on the delivery of large and integrated projects (see “Risk factors” on page 15). Systematic management of

life-cycle technical and non-technical risks is in place for each opportunity, with assurance and control activities embedded throughout the project life cycle. We focus on the cost-effective delivery of projects through commercial agreements, supply-chain management, and construction and engineering productivity through effective planning and simplification of delivery processes. Development of our employees’ project management competencies is underpinned by project principles, standards and processes. A dedicated competence framework, training, standards and processes exist for various technical disciplines. In addition, we provide governance support for our non-Shell-operated ventures or projects.

SEGMENTAL REPORTING

Our reporting segments are Integrated Gas, Upstream, Downstream and Corporate. Upstream combines the operating segments Upstream (managed by our Upstream organisation) and Oil Sands (managed by our Downstream organisation), which have similar economic characteristics. Integrated Gas, Upstream and Downstream include their respective elements of our Projects & Technology organisation. The Corporate segment comprises our holdings and treasury organisation, self-insurance activities, and headquarters and central functions. See Note 4 to the “Consolidated Financial Statements” on pages 181-184.

Revenue by business segment (including inter-segment sales)

	\$ million		
	2018	2017	2016
Integrated Gas			
Third parties	43,764	32,674	25,282
Inter-segment	4,853	3,978	3,908
Total	48,617	36,652	29,190
Upstream			
Third parties	9,892	7,723	6,412
Inter-segment	37,841	32,469	26,524
Total	47,733	40,192	32,936
Downstream			
Third parties	334,680	264,731	201,823
Inter-segment	5,358	4,248	1,727
Total	340,038	268,979	203,550
Corporate			
Third parties	43	51	74
Total	43	51	74

Revenue by geographical area (excluding inter-segment sales)

	2018	2017	\$ million 2016
Europe	118,960	100,609	81,573
Asia, Oceania, Africa	153,716	114,683	87,635
USA	89,876	66,854	44,615
Other Americas	25,827	23,033	19,768
Total	388,379	305,179	233,591

TECHNOLOGY AND INNOVATION

Technology and innovation are essential to our efforts to meet the world's energy needs in a competitive way. If we do not develop the right technology, do not have access to it or do not deploy it effectively, this could have a material adverse effect on the delivery of our strategy and our licence to operate (see "Risk factors" on pages 17-18). We continuously look for technologies and innovations of potential relevance to our business. Our Chief Technology Officer oversees the development and deployment of new and differentiating technologies and innovations across Shell, seeking to align business and technology requirements throughout our technology maturation process.

In 2018, research and development expenses were \$986 million, compared with \$922 million in 2017, and \$1,014 million in 2016. Our main technology centres are in India, the Netherlands and the USA, with other centres in Brazil, China, Germany, Oman and Qatar. A strong patent portfolio underlies the technology that we employ in our various businesses. In total, we have around 10,325 granted patents and pending patent applications.

Risk factors

The risks discussed below could have a material adverse effect separately, or in combination, on our earnings, cash flows and financial condition. Accordingly, investors should carefully consider these risks.

Measures that we use to manage or mitigate our various risks are set out in the relevant sections of this Report, indicated by way of cross references under each risk factor. The Board's responsibility for identifying, evaluating and managing our significant risks is discussed in "Corporate governance" on pages 103-104.

We are exposed to fluctuating prices of crude oil, natural gas, oil products and chemicals.

The prices of crude oil, natural gas, oil products and chemicals are affected by supply and demand, both globally and regionally. Government actions may also affect the prices of crude oil, natural gas, oil products and chemicals. For example, if a government were to ban diesel automobiles from entering a city or provide tax deductions for the purchase of renewable automobiles. Moreover, prices for oil and gas can move independently of each other. Factors that influence supply and demand include operational issues, natural disasters, weather, political instability, conflicts, economic conditions and actions by major oil and gas producing countries. Additionally, in a low oil and gas price environment, we would generate less revenue from our Upstream and Integrated Gas businesses, and, as a result, parts of those businesses could become less profitable, or could incur losses. Additionally, low oil and gas prices have resulted, and could continue to result, in the debooking of proved oil or gas reserves, if they become uneconomic in this type of price environment. Prolonged periods of low oil and gas prices, or rising costs, have resulted and could continue to result in projects being delayed or cancelled. In addition, assets have been impaired in the past, and there could be impairments in the future. Low oil and gas prices could also affect our ability to maintain our long-term capital investment programme and dividend payments. Prolonged periods of low oil and gas prices could adversely affect the financial, fiscal, legal, political and social stability of countries that rely significantly on oil and gas revenue. In a high oil and gas price environment, we could experience sharp increases in costs, and, under some production-sharing contracts, our entitlement to proved reserves would be reduced. Higher prices could also reduce demand for our products, which could result in lower profitability, particularly in our Downstream business. Accordingly, price fluctuations could have a material adverse effect on our earnings, cash flows and financial condition.

See "Market overview" on page 21.

Our ability to deliver competitive returns and pursue commercial opportunities depends in part on the accuracy of our price assumptions.

We use a range of oil and gas price assumptions, which we review on a periodic basis, to evaluate projects and commercial opportunities. If our assumptions prove to be incorrect, it could have a material adverse effect on our earnings, cash flows and financial condition.

See "Market overview" on page 22.

Our ability to achieve strategic objectives depends on how we react to competitive forces.

We face competition in each of our businesses. We seek to differentiate our products; however, many of them are competing in commodity-type

markets. Accordingly, failure to manage our costs as well as our operational performance could result in a material adverse effect on our earnings, cash flows and financial condition. We also compete with state-owned oil and gas entities with vast access to financial resources. State-owned entities could be motivated by political or other factors in making their business decisions. Accordingly, when bidding on new leases or projects, we could find ourselves at a competitive disadvantage as these state-owned entities may not require a competitive return. If we are unable to obtain competitive returns when bidding on new leases or projects, it could have a material adverse effect on our earnings, cash flows and financial condition.

See "Strategy and outlook" on page 10.

We seek to execute divestments in the pursuit of our strategy. We may not be able to successfully divest these assets in line with our strategy.

We may not be able to successfully divest assets at acceptable prices or within the timeline envisaged due to market conditions or credit risk, resulting in increased pressure on our cash position and potential impairments. Additionally, in some cases, we have retained certain liabilities following a divestment. Moreover, even in cases where we have not expressly retained certain liabilities, we may be held liable for past acts, failures to act or liabilities that are different from those foreseen. We may also face liabilities if a purchaser fails to honour its commitments. Accordingly, if we are unable to divest assets at acceptable prices or within our envisaged timeframe, this could have a material adverse effect on our earnings, cash flows and financial condition.

See "Strategy and outlook" on pages 10-11.

Our future hydrocarbon production depends on the delivery of large and integrated projects, as well as on our ability to replace proved oil and gas reserves.

We face numerous challenges in developing capital projects, especially those which are large and integrated. Challenges include uncertain geology, frontier conditions, the existence and availability of necessary technology and engineering resources, the availability of skilled labour, the existence of transportation infrastructure, project delays, the expiration of licences and potential cost overruns, as well as technical, fiscal, regulatory, political and other conditions. These challenges are particularly relevant in certain developing and emerging-market countries, in frontier areas and in deep-water fields, such as off the coast of Brazil. We may fail to assess or manage these and other risks properly. Such potential obstacles could impair our delivery of these projects, our ability to fulfil the value potential at the time of the project investment approval, and/or our ability to fulfil related contractual commitments. These could lead to impairments and could have a material adverse effect on our earnings, cash flows and financial condition.

Future oil and gas production will depend on our access to new proved reserves through exploration, negotiations with governments and other owners of proved reserves and acquisitions, as well as on developing and applying new technologies and recovery processes to existing fields. Failure to replace proved reserves could result in lower future production, potentially having a material adverse effect on our earnings, cash flows and financial condition.

See "Business overview" on page 13.

Oil and gas production available for sale		Million boe [A]	
	2018	2017	2016
Shell subsidiaries	1,179	1,168	1,158
Shell share of joint ventures and associates	159	170	184
Total	1,338	1,338	1,342

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

Proved developed and undeveloped oil and gas reserves [A][B] (at December 31)		Million boe [C]	
	2018	2017	2016
Shell subsidiaries	10,294	10,177	11,040
Shell share of joint ventures and associates	1,285	2,056	2,208
Total	11,578	12,233	13,248

Attributable to non-controlling interest in			
Shell subsidiaries	331	325	5

[A] We manage our total proved reserves base without distinguishing between proved reserves from subsidiaries and those from joint ventures and associates.

[B] Includes proved reserves associated with future production that will be consumed in operations.

[C] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

The estimation of proved oil and gas reserves involves subjective judgements based on available information and the application of complex rules; therefore, subsequent downward adjustments are possible.

The estimation of proved oil and gas reserves involves subjective judgements and determinations based on available geological, technical, contractual and economic information. Estimates could change because of new information from production or drilling activities, or changes in economic factors, including changes in the price of oil or gas and changes in the regulatory policies of host governments, or other events. Estimates could also be altered by acquisitions and divestments, new discoveries, and extensions of existing fields and mines, as well as the application of improved recovery techniques. Published proved oil and gas reserves estimates could also be subject to correction due to errors in the application of published rules and changes in guidance. Downward adjustments could indicate lower future production volumes and could also lead to impairment of assets. This could have a material adverse effect on our earnings, cash flows and financial condition.

See "Supplementary information – oil and gas (unaudited)" on page 215.

Rising climate change concerns have led and could lead to additional legal and/or regulatory measures which could result in project delays or cancellations, a decrease in demand for fossil fuels, potential litigation and additional compliance obligations.

In December 2015, 195 nations adopted the Paris Agreement, which we fully support. The Paris Agreement aims to limit increases in global temperatures to well below two degrees Celsius. As a result, we expect continued and increased attention to climate change from all sectors of society. This attention has led, and we expect it to continue to lead, to additional regulations designed to reduce greenhouse gas (GHG) emissions.

We expect that a growing share of our GHG emissions will be subject to regulation, resulting in increased compliance costs and operational restrictions. If our GHG emissions rise alongside our ambitions to increase the scale of our business, our regulatory burden will increase proportionally. We also expect that GHG regulation, as well as emission reduction actions by customers, will continue to focus more on suppressing demand for fossil

fuels, either through taxes, fees, incentives to promote the sale of electric vehicles or even through the future prohibition of sales of new diesel or gasoline vehicles. This could result in lower revenue and, in the long term, potential impairment of certain assets.

Additionally, some groups are pressuring certain investors to divest their investments in fossil fuel companies. If this were to continue, it could have a material adverse effect on the price of our securities and our ability to access equity capital markets. The World Bank has also announced plans to stop financing upstream oil and gas projects in 2019. Similarly, according to press reports, other financial institutions also appear to be considering limiting their exposure to certain fossil fuel projects. Accordingly, our ability to use financing for future projects may be adversely impacted. This could also adversely impact our potential partners' ability to finance their portion of costs, either through equity or debt.

Further, in some countries, governments, regulators, organisations and individuals have filed lawsuits seeking to hold fossil fuel companies liable for costs associated with climate change. While we believe these lawsuits to be without merit, losing any of these lawsuits could have a material adverse effect on our earnings, cash flows and financial condition.

In addition, physical effects of climate change such as, but not limited to, rise in temperature, sea-level rise and fluctuations in water levels could adversely impact both our operations and supply chains.

If we are unable to find economically viable, as well as publicly acceptable, solutions that reduce our GHG emissions and/or GHG intensity for new and existing projects or for the products we sell, we could experience additional costs or financial penalties, delayed or cancelled projects, and/or reduced production and reduced demand for hydrocarbons, which could have a material adverse effect on our earnings, cash flows and financial condition.

Also, if we are unable to keep pace with society's energy transition or we are unable to provide the desired low GHG emissions products needed to facilitate society's energy transition, it could have a material adverse effect on our earnings, cash flows and financial condition.

See "Climate change and energy transition" on page 73.

Our operations expose us to social instability, criminality, civil unrest, terrorism, piracy, cyber-disruption, acts of war and risks of pandemic diseases that could have a material adverse effect on our business.

As seen in recent years in Nigeria, North Africa, the Middle East, South America and South-East Asia, social and civil unrest, both in the countries in which we operate and elsewhere, can and do affect us. Such potential developments that could have a material adverse effect on our earnings, cash flows and financial condition include: acts of political or economic terrorism; acts of maritime piracy; cyber-espionage or disruptive cyber-attacks; conflicts including war and civil unrest (including disruptions by non-governmental and political organisations); and local security concerns that threaten the safe operation of our facilities, transport of our products and the well-being of our people. Pandemic diseases can also affect our operations directly and indirectly. If such risks materialise, they could result in injuries, loss of life, environmental harm and disruption to business activities, which in turn could have a material adverse effect on our earnings, cash flows and financial condition.

See “Environment and society” on page 70.

We operate in more than 70 countries that have differing degrees of political, legal and fiscal stability. This exposes us to a wide range of political developments that could result in changes to contractual terms, laws and regulations. In addition, we and our joint arrangements and associates face the risk of litigation and disputes worldwide.

Developments in politics, laws and regulations can and do affect our operations. Potential impacts include: forced divestment of assets; expropriation of property; cancellation or forced renegotiation of contract rights; additional taxes including windfall taxes, restrictions on deductions and retroactive tax claims; antitrust claims; changes to trade compliance regulations; price controls; local content requirements; foreign exchange controls; changes to environmental regulations; changes to regulatory interpretations and enforcement; and changes to disclosure requirements. Any of these, individually or in aggregate, could have a material adverse effect on our earnings, cash flows and financial condition.

In addition to the above risks, the United Kingdom is expected to leave the European Union (EU) in March 2019. As a result of this decision, it is possible that we may experience delays in moving our products and employees between the UK and EU. Also, additional tariffs and taxes could impact the demand for some of our products. This potential delay and reduced demand for our products, combined with the potential adverse changes in macroeconomic conditions in both the EU and UK, could have a material adverse effect on our earnings and cash flows.

From time to time, social and political factors play a role in unprecedented and unanticipated judicial outcomes that could adversely affect Shell. Non-compliance with policies and regulations could result in regulatory investigations, litigation and, ultimately, sanctions. Certain governments and regulatory bodies have, in Shell’s opinion, exceeded their constitutional authority by: attempting unilaterally to amend or cancel existing agreements or arrangements; failing to honour existing contractual commitments; and seeking to adjudicate disputes between private litigants. Additionally, certain governments have adopted laws and regulations that could potentially conflict with other countries’ laws and regulations, potentially subjecting us to both criminal and civil sanctions. Such developments and outcomes could have a material adverse effect on our earnings, cash flows and financial condition.

See “Corporate governance” on page 104.

The nature of our operations exposes us, and the communities in which we work, to a wide range of health, safety, security and environment risks.

The health, safety, security and environment (HSSE) risks to which we, and the communities in which we work, are potentially exposed cover a wide spectrum, given the geographic range, operational diversity and technical complexity of our operations. These risks include the effects of natural disasters (including weather events), earthquakes, social unrest, personal health and safety lapses, and crime. If a major risk materialises, such as an explosion or hydrocarbon spill, this could result in injuries, loss of life, environmental harm, disruption of business activities, and loss or suspension of our licence to operate or ability to bid on mineral rights. Accordingly, this would have a material adverse effect on our earnings, cash flows and financial condition.

Our operations are subject to extensive HSSE regulatory requirements that often change and are likely to become more stringent over time. Governments could require operators to adjust their future production plans, as has been done in the Netherlands, affecting production and costs. We could incur significant additional costs in the future due to compliance with these requirements or as a result of violations of, or liabilities under, laws and regulations, such as fines, penalties, clean-up costs and third-party claims. Therefore, HSSE risks, should they materialise, could have a material adverse effect on our earnings, cash flows and financial condition.

See “Environment and society” on page 66.

A further erosion of the business and operating environment in Nigeria could have a material adverse effect on us.

In our Nigerian operations, we face various risks and adverse conditions. These include: security issues surrounding the safety of our people, host communities and operations; sabotage and theft; our ability to enforce existing contractual rights; litigation; limited infrastructure; potential legislation that could increase our taxes or costs of operations; the effect of lower oil and gas prices on the government budget; and regional instability created by militant activities. Any of these risks or adverse conditions could have a material adverse effect on our earnings, cash flows and financial condition.

See “Upstream” on page 41.

Production from the Groningen field in the Netherlands causes earthquakes that affect local communities.

Shell and ExxonMobil are 50:50 shareholders in Nederlandse Aardolie Maatschappij B.V. (NAM). An important part of NAM’s gas production comes from the onshore Groningen gas field, in which EBN, a Dutch government entity, has a 40% interest and NAM a 60% interest. Since 1995, production from the Groningen field has caused earthquakes. Some of these earthquakes have caused damage to houses and other structures in the region, resulting in complaints and lawsuits from the local community. Following the Dutch cabinet’s decision to reduce NAM’s production from the Groningen field to zero by 2030, NAM’s shareholders and the Dutch State signed a heads of agreement in June 2018. This agreement supports the ramp-down of production from the Groningen field, includes measures to ensure the financial robustness of NAM, and determines the split of legal responsibilities between the Dutch government and the Groningen field partners. Shell’s proved reserves were reduced by 0.63 billion boe as a result in 2018. Additional earthquakes, lawsuits and any acceleration of the current plan to cease production from the Groningen field by 2030 could have further adverse effects on NAM and therefore could impact our earnings, cash flows and financial condition.

See “Upstream” on page 39.

Our future performance depends on the successful development and deployment of new technologies and new products.

Technology and innovation are essential to our efforts to meet the world’s energy demands in a competitive way. If we do not develop the right technology and products, do not have access to such technology and products or do not deploy these effectively, there could be a material adverse effect on the delivery of our strategy and our licence to operate. We operate in environments where advanced technologies are utilised. In developing new technologies and new products, unknown or unforeseeable technological failures or environmental and health effects

could harm our reputation and licence to operate or expose us to litigation or sanctions. The associated costs of new technology are sometimes underestimated, or delays occur. If we are unable to develop the right technologies and products in a timely and cost-effective manner, or if we develop technologies and products that adversely impact the environment or health of individuals, there could be a material adverse effect on our earnings, cash flows and financial condition.

See "Business overview" on page 14.

We are exposed to treasury and trading risks, including liquidity risk, interest rate risk, foreign exchange risk, commodity price risk and credit risk. We are affected by the global macroeconomic environment as well as financial and commodity market conditions.

Our subsidiaries, joint arrangements and associates are subject to differing economic and financial market conditions around the world. Political or economic instability affects such markets.

We use debt instruments, such as bonds and commercial paper, to raise significant amounts of capital. Should our access to debt markets become more difficult, the potential impact on our liquidity could have a material adverse effect on our operations. Our financing costs could also be affected by interest rate fluctuations or any credit rating deterioration.

We are exposed to changes in currency values and to exchange controls as a result of our substantial international operations. Our reporting currency is the dollar. However, to a material extent, we hold assets and are exposed to liabilities in other currencies. Commodity trading is an important component of our Upstream, Integrated Gas and Downstream businesses and is integrated with our supply business. While we undertake some foreign exchange and commodity hedging, we do not do so for all our activities. Furthermore, even where hedging is in place, it may not function as expected.

We are exposed to credit risk; our counterparties could fail or could be unable to meet their payment and/or performance obligations under contractual arrangements. Although we do not have significant direct exposure to sovereign debt, it is possible that our partners and customers may have exposure which could impair their ability to meet their obligations. In addition, our pension plans may invest in government bonds, and therefore could be affected by a sovereign debt downgrade or other default.

If any of the risks set out above materialise, they could have a material adverse effect on our earnings, cash flows and financial condition.

See "Liquidity and capital resources" on page 62 and Note 19 to the "Consolidated Financial Statements" on pages 202-207.

We have substantial pension commitments, funding of which is subject to capital market risks.

Liabilities associated with defined benefit pension plans can be significant, as can the cash funding requirement of such plans; both depend on various assumptions. Volatility in capital markets or government policies, and the resulting consequences for investment performance and interest rates, as well as changes in assumptions for mortality, retirement age or pensionable remuneration at retirement, could result in significant changes to the funding level of future liabilities. We operate a number of defined benefit pension plans and, in case of a shortfall, we could be required to make substantial cash contributions (depending on the applicable local regulations) resulting in a material adverse effect on our earnings, cash flows and financial condition.

See "Liquidity and capital resources" on page 62.

We mainly self-insure our risk exposure. We could incur significant losses from different types of risks that are not covered by insurance from third-party insurers.

Our insurance subsidiaries provide hazard insurance coverage to other Shell entities and only reinsure a portion of their risk exposures. Such reinsurance would not provide any material coverage in the event of a large-scale safety and environmental incident. Similarly, in the event of a material safety and environmental incident, there would be no material proceeds available from third-party insurance companies to meet our obligations. Therefore, we may incur significant losses from different types of risks that are not covered by insurance from third-party insurers, potentially resulting in a material adverse effect on our earnings, cash flows and financial condition.

See "Corporate" on page 61.

An erosion of our business reputation could have a material adverse effect on our brand, our ability to secure new resources or access capital markets, and on our licence to operate.

Our reputation is an important asset. The Shell General Business Principles (Principles) govern how Shell and its individual companies conduct their affairs, and the Shell Code of Conduct instructs employees and contract staff on how to behave in line with the Principles. Our challenge is to ensure that all employees and contract staff, more than 100,000 in total, comply with the Principles and the Code of Conduct. Real or perceived failures of governance or regulatory compliance could harm our reputation. This could impact our licence to operate, damage our brand, reduce consumer demand for our branded products, harm our ability to secure new resources and contracts, and limit our ability to access capital markets and attract staff. Many other factors, including the materialisation of the risks discussed in several of the other risk factors, could negatively impact our reputation and could have a material adverse effect on our earnings, cash flows and financial condition.

See "Corporate governance" on pages 96-97.

Many of our major projects and operations are conducted in joint arrangements or associates. This could reduce our degree of control, as well as our ability to identify and manage risks.

In cases where we are not the operator, we have limited influence over, and control of, the behaviour, performance and costs of operation of such joint arrangements or associates. Despite not having control, we could still be exposed to the risks associated with these operations, including reputational, litigation (where joint and several liability could apply) and government sanction risks. For example, our partners or members of a joint arrangement or an associate (particularly local partners in developing countries) may not be able to meet their financial or other obligations to the projects, threatening the viability of a given project. Where we are the operator of a joint arrangement, the other partner(s) could still be able to veto or block certain decisions, which could be to our overall detriment. Accordingly, where we have limited influence, we are exposed to operational risks that could have a material adverse effect on our earnings, cash flows and financial condition.

See "Corporate governance" on page 104.

We rely heavily on information technology systems for our operations.

The operation of many of our business processes depends on reliable information technology (IT) systems. Our IT systems are increasingly dependent on key contractors supporting the delivery of IT services, and continue to expand in terms of the number of systems. Shell, like many other multinational companies, is the target of attempts to gain unauthorised access to our IT systems and our data through various channels, including more sophisticated and coordinated attempts often referred to as advanced persistent threats. While our IT systems have been breached in the past, we believe that to date, no significant breach has occurred. Timely detection is becoming increasingly complex but we seek to detect and investigate all such security incidents, aiming to prevent their recurrence. Disruption of critical IT services, or breaches of information security, could harm our reputation and have a material adverse effect on our earnings, cash flows and financial condition.

See "Corporate" on page 61.

Violations of antitrust and competition laws carry fines and expose us and/or our employees to criminal sanctions and civil suits.

Antitrust and competition laws apply to Shell and its joint ventures and associates in the vast majority of countries in which we do business. Shell and its joint ventures and associates have been fined for violations of antitrust and competition laws in the past. These include a number of fines by the European Commission Directorate-General for Competition (DG COMP). Due to DG COMP's fining guidelines, any future conviction of Shell or any of its joint ventures or associates for violation of EU competition law could result in significantly larger fines and have a material adverse effect on us. Violation of antitrust laws is a criminal offence in many countries, and individuals can be imprisoned or fined. In certain circumstances, directors may receive director disqualification orders. Furthermore, it is now common for persons or corporations allegedly injured by antitrust violations to sue for damages. Any violation of these laws can harm our reputation and could have a material adverse effect on our earnings, cash flows and financial condition.

See "Corporate governance" on pages 96-97.

Violations of anti-bribery, tax-evasion and anti-money laundering laws carry fines and expose us and/or our employees to criminal sanctions, civil suits and ancillary consequences (such as debarment and the revocation of licences).

Anti-bribery, tax-evasion and anti-money laundering laws apply to Shell, its joint ventures and associates in all countries in which we do business. Shell and its joint ventures and associates in the past have been fined for violations of the US Foreign Corrupt Practices Act. Any violation of anti-bribery, tax-evasion or anti-money laundering laws, including those potential violations associated with Shell Nigeria Exploration and Production Company Ltd.'s (SNEPCO's) investment in Nigerian oil block OPL 245 and the 2011 settlement of litigation pertaining to that block, could have a material adverse effect on our earnings, cash flows and financial condition.

See "Our people" on pages 79-81, "Corporate governance" on pages 96-97 and Note 25 to the "Consolidated Financial Statements" on pages 211-213.

Violations of data protection laws carry fines and expose us and/or our employees to criminal sanctions and civil suits.

Data protection laws apply to Shell and its joint ventures and associates in the vast majority of countries in which we do business. Most of the countries we operate in have data protection laws and regulations. Additionally, the EU General Data Protection Regulation (GDPR) came into effect in May 2018, which increased penalties up to a maximum of 4% of global annual turnover for breach of the regulation. The GDPR requires mandatory breach notification, the standard for which is also followed outside the EU (particularly in Asia). Non-compliance with data protection laws could expose us to regulatory investigations, which could result in fines and penalties as well as harm our reputation. In addition to imposing fines, regulators may also issue orders to stop processing personal data, which could disrupt operations. We could also be subject to litigation from persons or corporations allegedly affected by data protection violations. Violation of data protection laws is a criminal offence in some countries, and individuals can be imprisoned or fined. Any violation of these laws or harm to our reputation could have a material adverse effect on our earnings, cash flows and financial condition.

See "Corporate governance" on pages 96-97.

Violations of trade compliance laws and regulations, including sanctions, carry fines and expose us and our employees to criminal sanctions and civil suits.

We use "trade compliance" as an umbrella term for various national and international laws designed to regulate the movement of items across national boundaries and restrict or prohibit trade and other dealings with certain parties. The number and breadth of such laws continue to expand. For example, the EU and the USA continue to impose restrictions and prohibitions on certain transactions involving Syria. In addition, the USA continues to have comprehensive sanctions in place against Iran, while the EU and other nations continue to maintain targeted sanctions. Additional restrictions and controls directed at defined oil and gas activities in Russia, which were imposed by the EU and the USA in 2014, are still in force. Further restrictions regarding Russia were introduced by the USA in 2017 and expanded in 2018. Both the EU and the USA introduced sectorial sanctions against Venezuela in 2017, which the USA expanded in 2018 and 2019. The US sanctions primarily target the government of Venezuela and the oil industry. In addition to the significant trade-control programmes

Risk factors Continued

administered by the EU and the USA, many other nations are also adopting such programmes. This expansion of sanctions, including the frequent additions of prohibited parties, combined with the number of markets in which we operate and the large number of transactions we process, makes ensuring compliance with all sanctions complex and at times challenging. Any violation of one or more of these regimes could lead to loss of import or export privileges, significant penalties on or prosecution of Shell or its employees, and could harm our reputation and have a material adverse effect on our earnings, cash flows and financial condition.

See "Corporate governance" on pages 96-97.

Investors should also consider the following, which could limit shareholder remedies.

The Company's Articles of Association determine the jurisdiction for shareholder disputes. This could limit shareholder remedies.

Our Articles of Association generally require that all disputes between our shareholders in such capacity and the Company or our subsidiaries (or our Directors or former Directors), or between the Company and our Directors or former Directors, be exclusively resolved by arbitration in The Hague, the Netherlands, under the Rules of Arbitration of the International Chamber of Commerce. Our Articles of Association also provide that, if this provision is to be determined invalid or unenforceable for any reason, the dispute could only be brought before the courts of England and Wales. Accordingly, the ability of shareholders to obtain monetary or other relief, including in respect of securities law claims, could be determined in accordance with these provisions.

Market overview

We maintain a large business portfolio across an integrated value chain and are exposed to crude oil, natural gas, oil product and chemical prices (see "Risk factors" on page 15). This diversified portfolio helps us mitigate the impact of price volatility. Our annual planning cycle and periodic portfolio reviews aim to ensure that our levels of capital investment and operating expenses are appropriate in the context of a volatile price environment. We test the resilience of our projects and other opportunities against a range of crude oil, natural gas, oil product and chemical prices and costs. We also aim to maintain a strong balance sheet to provide resilience against weak market prices.

GLOBAL ECONOMIC GROWTH

One of the key drivers of oil, natural gas and oil product demand growth is economic growth. According to the *World Economic Outlook* released by the International Monetary Fund (IMF) in January 2019, global economic growth for 2018 is estimated at 3.7%, 0.1% lower than in 2017. Economic growth moderated in some large advanced economies in the second half of the year, after strong growth in 2017, while the group of emerging-market economies continued to expand at broadly the same pace as in 2017.

According to the IMF's latest estimate, economic growth accelerated in the USA to 2.9% in 2018 from 2.2% in 2017, with private sector activity partly supported by sizable tax cuts and higher defense expenditures. But growth slowed in the eurozone and in the United Kingdom due to weaker export growth, higher energy prices and increased political uncertainty, such as the prospect of the UK leaving the European Union (Brexit). Growth in emerging-market economies showed a divergent picture. In China, growth slowed from 6.9% in 2017 to an estimated 6.6% in 2018, due to weaker credit growth and additional US tariffs on imports from China. Argentina and Turkey slid into recession as financial conditions deteriorated and investors became increasingly concerned about financial risks and political uncertainty. In contrast, economic recovery continued in Brazil and India. Higher oil and gas prices lifted growth among fuel-exporting economies, such as some in sub-Saharan Africa (e.g. Nigeria), the Middle East and Russia.

For 2019, the IMF expects the weaker economic conditions seen towards the end of 2018 to continue as many countries face headwinds from rising trade barriers, geopolitical tensions, and tightening financing conditions.

GLOBAL PRICES, DEMAND AND SUPPLY

The following table provides an overview of the main crude oil and natural gas price markers that we are exposed to:

Oil and gas average industry prices [A]

	2018	2017	2016
Brent (\$/b)	71	54	44
West Texas Intermediate (\$/b)	65	51	43
Henry Hub (\$/MMBtu)	3.1	3.0	2.5
UK National Balancing Point (pence/therm)	60	45	35
Japan Customs-cleared Crude (\$/b)	74	54	42

[A] Yearly average prices are based on daily spot prices. The 2018 average price for Japan Customs-cleared Crude excludes December data.

CRUDE OIL

Brent crude oil, an international benchmark, traded between \$51 per barrel (/b) and \$86/b in 2018, ending the year at the lower price of \$51/b. It averaged \$71/b for the year, \$17/b higher than in 2017, and \$27/b higher than in 2016 when the average price was at its lowest average level since 2004.

On a yearly average basis, West Texas Intermediate crude oil traded at a \$6/b discount to Brent in 2018, compared with \$3/b in 2017. The discount widened from 2017, reflecting constrained pipeline capacity from the landlocked Cushing storage hub to the US Gulf Coast. US oil exports increased from 2017, which helped to limit further widening of the price differential.

Reflecting the economic conditions described above, global oil demand grew by 1.2 million barrels per day (b/d), or 1.2%, to 99.2 million b/d, according to the International Energy Agency's (IEA) *Oil Market Report* published in January 2019 (Oil Market Report). This growth was driven by emerging economies, where demand grew by 0.9 million b/d. In advanced economies, demand grew by 0.3 million b/d. Oil demand growth in 2018 was 0.4 million b/d lower than in 2017, when it rose by 1.6 million b/d.

Oil supply in 2018 is estimated in the Oil Market Report at 99.9 million b/d, an increase of 2.5 million b/d compared with 2017. Because growth in oil supply outpaced growth in demand, the trend of falling global crude oil and oil products inventory levels, which started in mid-2016, began to reverse in the middle of 2018. Average commercial inventory levels for OECD countries in November 2018 were estimated at 2,850 million barrels in the Oil Market Report, around 50 million barrels less than in November 2017 and about 150 million barrels above the year average levels seen in 2014 when the Brent price was around \$100/b before starting to fall in late 2014.

Due to falling inventory levels, oil prices strengthened to a peak of \$86/b in October 2018. Oil prices fell in November to below \$60/b, driven by market expectations of higher supply growth and lower demand growth. The outlook for supply growth became more bullish due to the US government waiving some export sanctions on Iran and record production levels in the USA and Saudi Arabia. At the same time, the outlook for demand growth weakened as macroeconomic indicators deteriorated.

On the non-OPEC supply side, the US Energy Information Administration reported another year of supply growth. US production is estimated to have averaged 10.8 million b/d in 2018, 1.4 million b/d higher than in 2017, and 2.0 million b/d higher than in 2016. Like 2017, higher oil prices in 2018 reflected an attractive environment for US production to grow and for drilling activity to increase, as indicated by a higher onshore oil rig count for the year. Production from other non-OPEC countries increased by 1.2 million b/d in 2018 and averaged 56.6 million b/d.

To support oil prices, OPEC members agreed in November 2017 to extend an agreement to reduce overall production by 1.2 million b/d, relative to production levels in October 2016. In December 2018, in response to a 40% fall in oil prices from the peak levels seen in October, OPEC and other non-OPEC resource holders, most notably Russia, agreed to reduce production by 1.2 million b/d from October levels. OPEC production averaged 32.5 million b/d in 2018, a similar level to 2017 and about 0.5 million b/d less than in 2016.

Looking ahead, the IMF's global economic outlook indicates a slightly lower outlook for global economic growth. Additionally, according to the IEA, moderate oil price levels at the beginning of 2019 could create around 1.4 million b/d of additional demand growth in 2019. If OPEC members and co-operating non-OPEC resource holders, such as Russia, successfully implement the December 2018 agreement, then demand growth and production declines from existing operations would have to be balanced by production growth from non-OPEC countries, mostly from the USA. As a consequence, markets could tighten, and prices could rise if supply growth from the USA moderates. Postponements and cancellations of new supply projects over the last few years could lead to further market tightening in the next few years, given the long lead time of many of these projects. In such a scenario, we believe that the average Brent crude oil price could be 10% to 40% higher in 2022 than the 2018 average.

On the other hand, we believe that the price environment could weaken if OPEC and the non-OPEC resource holders abandon their production cuts, global economic growth slows, or if other non-OPEC producers, such as US shale producers, effectively deliver more and cheaper oil to the market. In such a scenario, we believe that the average Brent crude oil price could be 10% to 30% lower in 2022 than the 2018 average.

NATURAL GAS

We estimate global gas demand to have grown by about 3.2% in 2018, which is higher than the average annual growth rate of 2.4% since the beginning of the century. A combination of weather conditions, implementation of new policies such as the partial substitution of coal by gas-fired power generation in China, and global economic growth led to an increase in demand in most regions.

Global liquefied natural gas (LNG) imports grew by 28 million tonnes (9.6%) in 2018. LNG demand growth was supported by weather conditions, lower nuclear power generation and the start-up of new regasification capacity in Asia. China and India alone increased their regasification capacity by 19% and 33% from 2017 respectively, equal to 21 million tonnes per annum, in total. Supply growth was primarily driven by the start-up of new projects in Australia, the USA and Russia. The majority of additional LNG supply was absorbed by Asia, offsetting declines in the Middle East and North Africa.

Natural gas prices can vary from region to region.

In the USA, the natural gas price at the Henry Hub averaged \$3.1 per million British thermal units (MMBtu) in 2018, 3% higher than in 2017, and traded in a range of \$2.5-4.9/MMBtu. There was some downward pressure on prices due to strong gas supply growth, which averaged 11% higher than in 2017, helped by higher oil prices and new gas pipeline capacity. However, gas prices were also supported by a range of other factors, such as below-normal storage inventory levels, and demand growth due to colder than normal weather in the second half of 2018, the completion of LNG liquefaction projects, increased exports to Mexico by pipeline and US industrial demand.

In Europe, natural gas prices were higher than in 2017. The average price at the UK National Balancing Point (NBP) was 33% higher in 2018. At the main continental gas trading hubs – in the Netherlands, Belgium and Germany – prices were also stronger, as reflected by stronger Dutch Title Transfer Facility (TTF) prices. European gas prices were supported by record prices for carbon dioxide (CO₂) allowances (EUAs) which averaged €16/tCO₂ in 2018

compared to €6/tCO₂ in 2017, resulting in higher preference for gas over coal in power generation. Gas prices were also supported by lower nuclear power output, particularly in Belgium and Spain, lower than normal temperatures early in the year, and competition from North-East Asian markets for LNG supplies for storage replenishment ahead of winter.

We also produce and sell natural gas in regions where supply, demand and regulatory circumstances differ markedly from those in the USA or Europe. Long-term contracted LNG prices in the Asia-Pacific region generally increased in 2018 as they are predominantly indexed to the price of Japan Customs-cleared Crude, which has increased in line with global oil prices. North Asia spot prices (reflected by the Japan Korea Marker) also increased due to relatively strong demand, particularly from China.

Looking ahead, we expect gas markets in North America, Europe and Asia Pacific to be well supplied over the next few years, despite our expectation of LNG demand growth in Asia. Price developments are very uncertain and dependent on many factors.

In the USA, Henry Hub gas prices may increase over the next few years due to increasing demand from LNG exports, exports to Mexico by pipeline, and US residential/industrial users. On the other hand, increasing availability of low-cost natural gas and oil, combined with technological improvements, could continue to place pressure on natural gas prices. Due to such uncertainty, we believe that average Henry Hub gas prices could be between 10% lower to 30% higher by 2022 than the 2018 average. In Europe, we believe gas prices will be increasingly influenced by the cost of LNG imports from the USA. We believe that the price at the UK NBP may average between 30% lower and 30% higher by 2022 than the 2018 average. In the Asia Pacific region, gas prices are expected to continue to be strongly influenced by oil prices, but also increasingly by Henry Hub gas prices. By 2022, we believe that the price of LNG delivered under contract to the Asia-Pacific market may average between 30% lower and 30% higher than the 2018 average.

CRUDE OIL AND NATURAL GAS PRICE ASSUMPTIONS

Our ability to deliver competitive returns and pursue commercial opportunities ultimately depends on the accuracy of our price assumptions (see "Risk factors" on page 15). The range of possible future crude oil and natural gas prices used in project and portfolio evaluations is determined after a rigorous assessment of short, medium and long-term market drivers. Historical analyses, trends and statistical volatility are considered in this assessment, as are analyses of market fundamentals such as possible future economic conditions, geopolitics, actions by OPEC and other major resource holders, production costs and the balance of supply and demand. Sensitivity analyses are used to test the impact of low-price drivers, such as economic weakness, and high-price drivers, such as strong economic growth and low investment in new production capacity. Short-term events, such as relatively warm winters or cool summers, affect demand. Supply disruptions, due to weather or political instability, contribute to price volatility. See also Note 8 to the "Consolidated Financial Statements" on page 188.

REFINING MARGINS

Refining marker average industry gross margins	\$/b		
	2018	2017	2016
US West Coast	11.5	14.0	12.9
US Gulf Coast Coking	7.0	9.9	9.1
Rotterdam Complex	2.5	4.3	2.5
Singapore	1.4	3.6	2.8

Industry gross refining margins were lower on average in 2018 than in 2017 in each of the key refining hubs of Europe, Singapore and the USA. Oil products demand growth has slowed in line with global economic growth. Periods of high crude prices led to reductions in oil products demand. Refinery capacity additions, especially in the Middle East and Asia, combined with tempered demand growth have led to generally lower refinery utilisations. Refinery activity continued to be low in Latin America.

Looking forward, we believe refinery margins may be impacted by the introduction of the new International Maritime Organization shipping fuel specification in 2020.

PETROCHEMICAL MARGINS

Cracker industry margins	\$/tonne		
	2018	2017	2016
North East/South East Asia naphtha	511	688	672
Western Europe naphtha	653	727	598
US ethane	332	471	450

Cracker industry margins fell in all three main regions in 2018. Asian naphtha cracker margins fell sharply in the fourth quarter, amid continuing concerns over the potential impact of US tariffs, while US ethane cracker margins came under pressure from new cracker unit start-ups. Supported by healthy European demand, European naphtha cracker margins decreased the least during 2018.

The outlook for petrochemical margins in 2019 and beyond depends on supply and demand balances and feedstock costs. Demand for petrochemicals is closely linked to economic growth. Product prices reflect prices of raw materials, which are closely linked to crude oil and natural gas prices. The balance of these factors will drive margins.

The statements in this "Market overview" section, including those related to our price forecasts, are forward-looking statements based on management's current expectations and certain material assumptions and, accordingly, involve risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied herein. See "About this Report" on pages 05-06 and "Risk factors" on pages 15-20.

Summary of results

Key statistics

	\$ million, except where indicated		
	2018	2017	2016
Income for the period	23,906	13,435	4,777
Current cost of supplies adjustment	458	(964)	(1,085)
Total segment earnings [A][B], of which:	24,364	12,471	3,692
Integrated Gas	11,444	5,078	2,529
Upstream	6,798	1,551	(3,674)
Downstream	7,601	8,258	6,588
Corporate	(1,479)	(2,416)	(1,751)
Capital investment [B]	24,779	24,006	79,877
Divestments [B]	7,102	17,340	4,984
Operating expenses [B]	39,316	38,083	41,549
Return on average capital employed [B]	9.4%	5.8%	3.0%
Gearing at December 31 [C]	20.3%	25.0%	29.1%
Oil and gas production (thousand boe/d)	3,666	3,664	3,668
Proved oil and gas reserves at December 31 (million boe)	11,578	12,233	13,248

[A] Segment earnings are presented on a current cost of supplies basis. See Note 4 to the "Consolidated Financial Statements" on pages 181-184.

[B] See "Non-GAAP measures reconciliations" on pages 263-264.

[C] With effect from 2018, the net debt calculation has been amended. See Note 14 to the "Consolidated Financial Statements" on page 191. Gearing as previously published at December 31, 2017, and at December 31, 2016, was 24.8% and 28.0% respectively.

EARNINGS 2018-2017

Income for the period was \$23,906 million in 2018, compared with \$13,435 million in 2017. After current cost of supplies adjustment, total segment earnings were \$24,364 million in 2018, compared with \$12,471 million in 2017.

Earnings on a current cost of supplies basis (CCS earnings) exclude the effect of changes in the oil price on inventory carrying amounts, after making allowance for the tax effect. The purchase price of volumes sold in the period is based on the current cost of supplies during the same period, rather than on the historic cost calculated on a first-in, first-out (FIFO) basis. Therefore, when oil prices are decreasing, CCS earnings are likely to be higher than earnings calculated on a FIFO basis and, when prices are increasing, CCS earnings are likely to be lower than earnings calculated on a FIFO basis.

Integrated Gas earnings in 2018 were \$11,444 million, compared with \$5,078 million in 2017. The increase was mainly driven by higher realised oil, gas, and liquefied natural gas (LNG) prices, higher gains on divestments, increased contributions from LNG trading, the impact of fair value accounting of commodity derivatives, and higher production. These effects were partly offset by the absence of a gain from the strengthening Australian dollar on a deferred tax position in 2017 and by higher operating expenses. See "Integrated Gas" on pages 29-30.

Upstream earnings in 2018 were \$6,798 million, compared with \$1,551 million in 2017. The increase was mainly driven by higher realised oil and gas prices, lower impairment charges, the absence of a charge as a result of US tax reform legislation in 2017, and lower well write-offs. This was partly offset by the movements in deferred tax positions, lower gains on divestments, lower production, and a charge related to the impact of the weakening Brazilian real on a deferred tax position. See "Upstream" on pages 36-37.

Downstream earnings in 2018 were \$7,601 million, compared with \$8,258 million in 2017. The decrease was mainly driven by higher operating expenses, unfavourable exchange rate effects, and lower realised base chemicals and refining margins. This was partly offset by higher realised marketing margins, lower charges related to provisions, the impact of fair value accounting of commodity derivatives and higher gains on divestments. There was also a charge in 2017 as a result of US tax reform legislation. See "Downstream" on pages 53-54.

Corporate earnings in 2018 were a loss of \$1,479 million, compared with a loss of \$2,416 million in 2017. The lower loss was mainly driven by lower net foreign exchange losses and net interest expense, partially offset by higher costs. There was also a charge in 2017 as a result of US tax reform legislation. See "Corporate" on page 61.

EARNINGS 2017-2016

Income for the period was \$13,435 million in 2017, compared with \$4,777 million in 2016. After current cost of supplies adjustment, total segment earnings were \$12,471 million in 2017, compared with \$3,692 million in 2016. BG Group plc (BG) was consolidated within Shell's results with effect from February 2016 following its acquisition.

Integrated Gas earnings in 2017 were \$5,078 million, compared with \$2,529 million in 2016. The increase was mainly driven by higher realised oil, gas, and LNG prices, as well as the impact of the strengthening Australian dollar on a deferred tax position, and lower impairment charges. These effects were partly offset by the impacts in 2017 of a charge for fair value accounting of commodity derivatives, a charge as a result of US tax reform legislation, and by lower liquids production partially offset by higher LNG liquefaction volumes.

Upstream earnings in 2017 were \$1,551 million, compared with a loss of \$3,674 million in 2016. The improvement was mainly driven by higher realised oil and gas prices. Higher gains on divestments and lower depreciation charges were partly offset by higher impairment charges. Overall, there were higher taxation charges. Beneficial movements in deferred tax positions were more than offset by a charge in 2017 as a result of US tax reform legislation and the absence of a gain related to the impact of a strengthening Brazilian real on a deferred tax position in 2016.

Downstream earnings in 2017 were \$8,258 million, compared with \$6,588 million in 2016. The increase was mainly driven by improved refining and chemicals industry conditions, the impact of fair value accounting of commodity derivatives, and lower taxation, redundancy and impairment charges. This was partly offset by lower gains on divestments and higher depreciation charges.

Corporate earnings in 2017 were a loss of \$2,416 million, compared with a loss of \$1,751 million in 2016. The higher loss was mainly driven by higher interest expense and net foreign exchange losses, partly offset by lower operating expenses. There was also a charge in 2017 as a result of US tax reform legislation.

PRODUCTION AVAILABLE FOR SALE

Oil and gas production available for sale in 2018 was 1,338 million barrels of oil equivalent (boe), or 3,666 thousand boe per day (boe/d), compared with 1,338 million boe, or 3,664 thousand boe/d, in 2017. In 2018, increased production from new field start-ups and ramp-ups, as well as lower maintenance activity was offset by the impact of divestments and field declines.

Oil and gas production available for sale [A]			
	Thousand boe/d		
	2018	2017	2016
Crude oil and natural gas liquids	1,749	1,730	1,679
Synthetic crude oil	53	91	146
Bitumen	—	4	13
Natural gas [B]	1,863	1,839	1,830
Total	3,666	3,664	3,668
Of which:			
Integrated Gas	957	887	884
Upstream	2,709	2,777	2,784

[A] See "Oil and gas information" on pages 49-50.

[B] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

PROVED RESERVES

The proved oil and gas reserves of Shell subsidiaries and the Shell share of the proved oil and gas reserves of joint ventures and associates are summarised in "Oil and gas information" on pages 44-46 and set out in more detail in "Supplementary information – oil and gas (unaudited)" on pages 215-226.

Before taking production into account, our proved reserves increased by 733 million boe in 2018. This comprised increases of 1,337 million boe from Shell subsidiaries and decreases of 604 million boe from the Shell share of joint ventures and associates, mainly related to the Groningen field. The increase from Shell subsidiaries included 997 million boe from revisions and reclassifications, 474 million boe from extensions and discoveries, and 42 million boe from improved recovery, partly offset by net sales of minerals in place of 175 million boe.

In 2018, total oil and gas production was 1,388 million boe, of which 1,338 million boe was available for sale and 50 million boe was consumed in operations. Production available for sale from subsidiaries was 1,179 million boe and 43 million boe was consumed in operations. The Shell share of the production available for sale of joint ventures and associates was 159 million boe and 7 million boe was consumed in operations.

Accordingly, after taking production into account, our proved reserves decreased by 655 million boe in 2018, to 11,578 million boe at December 31, 2018, with an increase of 117 million boe from subsidiaries and a decrease of 771 million boe from the Shell share of joint ventures and associates.

CAPITAL INVESTMENT AND OTHER INFORMATION

Capital investment was \$24.8 billion in 2018, compared with \$24.0 billion in 2017.

Divestments were \$7.1 billion in 2018, compared with \$17.3 billion in 2017. Operating expenses increased by \$1.2 billion in 2018, to \$39.3 billion.

Our return on average capital employed (ROACE) increased to 9.4%, compared with 5.8% in 2017, mainly driven by a higher income in 2018.

Gearing was 20.3% at the end of 2018, compared with 25.0% at the end of 2017, driven by debt repayments and an increased cash balance in 2018. With effect from 2018, the net debt calculation has been amended and the prior period comparative has been revised. See Note 14 to the "Consolidated Financial Statements" on page 191.

SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

See Note 2 to the "Consolidated Financial Statements" on pages 172-181.

LEGAL PROCEEDINGS

See Note 25 to the "Consolidated Financial Statements" on pages 211-213.

SELECTED FINANCIAL DATA

The selected financial data set out below are derived, in part, from the "Consolidated Financial Statements". This data should be read in conjunction with the "Consolidated Financial Statements" and related Notes, as well as with this Strategic Report.

Consolidated Statement of Income and of Comprehensive Income data					\$ million
	2018	2017	2016	2015	2014
Revenue	388,379	305,179	233,591	264,960	421,105
Income for the period	23,906	13,435	4,777	2,200	14,730
Income/(loss) attributable to non-controlling interest	554	458	202	261	(144)
Income attributable to Royal Dutch Shell plc shareholders	23,352	12,977	4,575	1,939	14,874
Comprehensive income/(loss) attributable to Royal Dutch Shell plc shareholders	24,475	18,828	(1,374)	(811)	2,692

Consolidated Balance Sheet data					\$ million
	2018	2017	2016	2015	2014
Total assets	399,194	407,097	411,275	340,157	353,116
Total debt	76,824	85,665	92,476	58,379	45,540
Share capital	685	696	683	546	540
Equity attributable to Royal Dutch Shell plc shareholders	198,646	194,356	186,646	162,876	171,966
Non-controlling interest	3,888	3,456	1,865	1,245	820

Earnings per share					\$
	2018	2017	2016	2015	2014
Basic earnings per €0.07 ordinary share	2.82	1.58	0.58	0.31	2.36
Diluted earnings per €0.07 ordinary share	2.80	1.56	0.58	0.30	2.36

Shares					Million
	2018	2017	2016	2015	2014
Basic weighted average number of A and B shares	8,282.8	8,223.4	7,833.7	6,320.3	6,311.5
Diluted weighted average number of A and B shares	8,348.7	8,299.0	7,891.7	6,393.8	6,311.6

Performance indicators

These indicators enable management to evaluate Shell's performance against its strategy and operating plans. Those which are used in the determination of Executive Directors' remuneration are asterisked below and on the following page. See "Directors' Remuneration Report" on pages 119-147.

FINANCIAL PERFORMANCE INDICATORS

Total shareholder return *

2018	(4.2)%	2017	30.0%
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Total shareholder return (TSR) is the difference between the share price at the beginning of the year and the share price at the end of the year (each averaged over 90 days), plus gross dividends delivered during the calendar year (reinvested quarterly), expressed as a percentage of the share price at the beginning of the year (averaged over 90 days). The data used are a weighted average in dollars for A and B shares. The TSRs of major publicly-traded oil and gas companies can be compared directly, providing a way to determine how we are performing in relation to our industry peers.

Cash flow from operating activities (\$ million) *

2018	53,085	2017	35,650
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Cash flow from operating activities is the total of all cash receipts and payments associated with our sales of oil, gas, chemicals and other products. The components that provide a reconciliation from income for the period are listed in the "Consolidated Statement of Cash Flows". This indicator reflects our ability to generate cash to service and reduce our debt and for distributions to shareholders and investments. See "Liquidity and capital resources" on page 63.

Free cash flow (\$ million) *

2018	39,426	2017	27,621
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Free cash flow is the sum of "Cash flow from operating activities" and "Cash flow from investing activities", which are listed in the "Consolidated Statement of Cash Flows". This indicator is used to evaluate cash available for financing activities, including dividend payments, after investment in maintaining and growing our business. See "Non-GAAP measures reconciliations" on page 264.

Return on average capital employed *

2018	9.4%	2017	5.8%
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Return on average capital employed (ROACE) is defined as income for the period, adjusted for after-tax interest expense, as a percentage of average capital employed during the year. Capital employed is the sum of total equity and total debt. ROACE measures the efficiency of our utilisation of the capital that we employ and is a common measure of business performance. See "Summary of results" on page 24 and "Non-GAAP measures reconciliations" on page 264.

Earnings on a current cost of supplies basis (\$ million)

2018	24,364	2017	12,471
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Earnings per share on a current cost of supplies basis (\$)

2018	2.85	2017	1.46
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Earnings on a current cost of supplies basis (CCS earnings) is the income for the period, adjusted for the after-tax effect of oil-price changes on inventory. Segment earnings presented on a current cost of supplies basis is the earnings measure used by the Chief Executive Officer for the purposes of making decisions about allocating resources and assessing performance. See "Summary of results" on page 24 and "Non-GAAP measures reconciliations" on page 263.

CCS earnings per share, which is on a diluted basis above, is calculated by dividing CCS earnings attributable to shareholders (see "Non-GAAP measures reconciliations" on page 263) by the average number of shares outstanding over the year, increased by the average number of dilutive shares related to share-based compensation plans.

Capital investment (\$ million)

2018	24,779	2017	24,006
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Capital investment is defined as capital expenditure and investments in joint ventures and associates, as reported in the "Consolidated Statement of Cash Flows", plus exploration expense, excluding exploration wells written off, new finance leases and investments in Integrated Gas, Upstream and Downstream equity securities, adjusted to an accruals basis. Capital investment is a measure used to make decisions about allocating resources and assessing performance. See "Liquidity and capital resources" on page 63 and "Non-GAAP measures reconciliations" on page 263.

Gearing

2018	20.3%	2017	25.0%
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Gearing is defined as net debt (total debt less cash and cash equivalents) as a percentage of total capital (net debt plus total equity) at December 31. With effect from 2018, the net debt calculation includes the fair value of derivative financial instruments used to hedge foreign exchange and interest rate risks relating to debt, and associated collateral balances. The inclusion of these debt-related derivative balances reduces the volatility of net debt caused by fluctuations in foreign exchange and interest rates, and eliminates the potential impact of related collateral payments or receipts. The prior period comparative has been revised to reflect the change in net debt calculation. Gearing is a measure of the degree to which our operations are financed by debt. See "Liquidity and capital resources" on page 62.

OTHER PERFORMANCE INDICATORS
Production available for sale (thousand boe/d) *

2018	3,666	2017	3,664
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Production is the sum of all average daily volumes of unrefined oil and natural gas produced for sale by Shell subsidiaries and Shell's share of those produced for sale by joint ventures and associates. The unrefined oil comprises crude oil, natural gas liquids, synthetic crude oil and bitumen. The gas volume is converted into equivalent barrels of oil to make the summation possible. See "Summary of results" on page 25.

LNG liquefaction volumes (million tonnes) *

2018	34.3	2017	33.2
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Liquefied natural gas (LNG) liquefaction volumes is a measure of the operational performance of our Integrated Gas business and LNG market demand. See "Integrated Gas" on page 29.

Refinery and chemical plant availability *

2018	91.9%	2017	90.7%
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Refinery and chemical plant availability is the weighted average of the actual uptime of plants as a percentage of their maximum possible uptime. The weighting is based on the capital employed, adjusted for cash and non-current liabilities. This indicator is a measure of the operational excellence of our Downstream manufacturing facilities. See "Downstream" on page 53.

Project delivery on schedule *

2018	75%	2017	86%
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Project delivery on budget *

2018	97%	2017	93%
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Project delivery reflects our capability to complete major projects on time and within budget on the basis of targets set in our annual Business Plan. Project delivery on schedule measures the percentage of projects delivered on schedule. Project delivery on budget reflects the aggregate cost against the aggregate budget for those projects.

Total recordable case frequency (injuries per million working hours) *

2018	0.9	2017	0.8
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Total recordable case frequency (TRCF) is the number of employees and contract staff injuries requiring medical treatment or time off for every million hours worked. It is a standard measure of occupational safety. See "Environment and society" on page 67.

Number of operational Tier 1 and 2 process safety events *

2018	121	2017	166
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A Tier 1 process safety event is an unplanned or uncontrolled release of any material, including non-toxic and non-flammable materials, from a process with the greatest actual consequence resulting in harm to employees and contract staff, or a neighbouring community, damage to equipment, or exceeding a threshold quantity as defined by the API Recommended Practice 754 and IOGP Standard 456. A Tier 2 process safety event is a release of lesser consequence. See "Environment and society" on page 67.

Upstream and Integrated Gas greenhouse gas intensity (tonnes of CO₂ equivalent/tonne of hydrocarbon production available for sale) *

2018	0.158	2017	0.166
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Upstream/midstream greenhouse gas (GHG) intensity is a measure of GHG emissions (direct and indirect GHG emissions associated with imported energy, excluding emissions from exported energy), expressed in metric tonnes of carbon dioxide (CO₂) equivalent, emitted into the atmosphere per metric tonne of hydrocarbon production available for sale. See "Climate change and energy transition" on pages 77-78.

Refining greenhouse gas intensity (tonnes of CO₂ equivalent/UEDC™) *

2018	1.05	2017	1.14
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Refining GHG intensity is a measure of GHG emissions (direct and indirect GHG emissions associated with imported energy, excluding emissions from exported energy), expressed in metric tonnes of CO₂ equivalent, emitted into the atmosphere per unit of Utilized Equivalent Distillation Capacity (UEDC™). UEDC™ is a proprietary metric of Solomon Associates. It is a complexity-weighted normalisation parameter that reflects the operating cost intensity of a refinery based on size and configuration of its particular mix of process and non-process facilities. See "Climate change and energy transition" on pages 77-78.

Chemicals greenhouse gas intensity (tonnes of CO₂ equivalent/tonne petrochemicals produced) *

2018	0.96	2017	0.95
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Chemicals GHG intensity is a measure of GHG emissions (direct and indirect GHG emissions associated with imported energy, excluding emissions from exported energy), expressed in metric tonnes of CO₂ equivalent, emitted into the atmosphere per metric tonne of steam cracker high value petrochemicals production. The 2017 comparative has been revised to align with the current definition (previously petrochemical production only). See "Climate change and energy transition" on pages 77-78.

Proved oil and gas reserves (million boe)

2018	11,578	2017	12,233
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Proved oil and gas reserves are the total estimated quantities of oil and gas from Shell subsidiaries and Shell's share from joint ventures and associates that geoscience and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs, at December 31, under existing economic conditions, operating methods and government regulations. Gas volumes are converted into barrels of oil equivalent (boe) using a factor of 5,800 standard cubic feet per barrel. Reserves are crucial to an oil and gas company, since they constitute the source of future production. Reserves estimates are subject to change due to a wide variety of factors, some of which are unpredictable. See "Risk factors" on pages 15-16, "Summary of results" on page 25, "Oil and gas information" on pages 44-46 and "Supplementary information – oil and gas (unaudited)" on pages 215-226.

Number of operational spills of more than 100 kilograms

2018	92	2017	104
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The operational spills indicator is the number of incidents in respect of activities where we are the operator in which 100 kilograms or more of oil or oil products were spilled as a result of those activities and reached the environment. The 2017 number was updated from 99 to reflect the completion of investigations into spills. See "Environment and society" on page 68.

Direct greenhouse gas emissions (million tonnes of CO₂ equivalent)

2018	71	2017	73
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Direct GHG emissions from facilities operated by Shell, expressed in CO₂ equivalent. See "Climate change and energy transition" on pages 77-78.

Integrated Gas

Key statistics

	\$ million, except where indicated		
	2018	2017	2016
Segment earnings	11,444	5,078	2,529
Including:			
Revenue (including inter-segment sales)	48,617	36,652	29,190
Share of profit of joint ventures and associates	2,273	1,714	1,116
Interest and other income	2,230	687	765
Operating expenses [A]	6,014	5,471	6,479
Exploration	208	141	494
Depreciation, depletion and amortisation	4,850	4,965	4,509
Taxation charge	2,795	790	1,254
Capital investment [A]	4,460	3,827	26,214
Divestments [A]	3,124	3,077	352
Oil and gas production available for sale (thousand boe/d)	957	887	884
LNG liquefaction volumes (million tonnes)	34.3	33.2	30.9

[A] See "Non-GAAP measures reconciliations" on pages 263-264

OVERVIEW

Our Integrated Gas business manages liquefied natural gas (LNG) activities and the conversion of natural gas into gas-to-liquids (GTL) fuels and other products, as well as our New Energies portfolio. It includes natural gas exploration and extraction, and the operation of upstream and midstream infrastructure necessary to deliver gas to market. It markets and trades natural gas, LNG, electricity and carbon-emission rights and also markets and sells LNG as a fuel for heavy-duty vehicles and marine vessels.

BUSINESS CONDITIONS

Global oil demand grew by 1.2% in 2018, according to the International Energy Agency's Oil Market Report published in January 2019, with the Brent crude oil price averaging \$71 per barrel (/b), up \$17/b from 2017.

Global gas demand is estimated to have grown by about 3.2% in 2018. A combination of weather conditions, implementation of new policies such as the partial substitution of coal by gas-fired power generation in China, and global economic growth led to an increase in demand in most regions.

Global LNG imports grew by 28 million tonnes (9.6%) in 2018. LNG demand growth was supported by weather conditions, lower nuclear power generation and the start-up of new regasification capacity in Asia. China and India alone increased their regasification capacity by 19% and 33% from 2017 respectively, equal to 21 million tonnes per annum, in total. Supply growth was primarily driven by the start-up of new projects in Australia, the USA and Russia. The majority of additional LNG supply was absorbed by Asia, offsetting declines in the Middle East and North Africa.

Natural gas prices can vary from region to region.

In the USA, the natural gas price at the Henry Hub averaged \$3.1 per million British thermal units (MMBtu) in 2018, 3% higher than in 2017, and traded in a range of \$2.5-4.9/MMBtu.

In Europe, natural gas prices were higher than in 2017. The average price at the UK National Balancing Point was \$7.9/MMBtu, compared with \$5.8/MMBtu in 2017. At the main continental European gas trading hubs – in the Netherlands, Belgium and Germany – prices were also stronger, as reflected by stronger Dutch Title Transfer Facility prices.

Long-term contracted LNG prices in the Asia-Pacific region generally increased in 2018 as they are predominantly indexed to the price of Japan Customs-cleared Crude, which has increased in line with global oil prices. North Asia spot prices (reflected by the Japan Korea Marker) also increased due to relatively strong demand, particularly from China.

See "Market overview" on pages 21-23.

PRODUCTION AVAILABLE FOR SALE

In 2018, production was 349 million barrels of oil equivalent (boe), or 957 thousand boe per day (boe/d), compared with 324 million boe, or 887 thousand boe/d in 2017. Natural gas production increased by 9% compared with 2017, mainly due to the stronger operational performance of our assets, namely higher availability at Pearl GTL in 2018, and improved performance combined with full year production of all three trains at Gorgon in Australia, partially offset by the divestment of Bongkot field in Thailand. Liquids production increased 5%, mainly due to higher availability at Pearl GTL in Qatar.

LNG LIQUEFACTION VOLUMES

LNG liquefaction volumes of 34.3 million tonnes in 2018 were 3% higher than in 2017, driven by increased feed gas availability in Atlantic LNG in Trinidad and Tobago, Queensland Curtis LNG (QCLNG) in Australia and Oman LNG; less maintenance mainly in Gorgon and QCLNG in Australia; and incremental volumes from Gorgon with all trains operational for a full year; partly offset by divestments of our interests in Woodside Petroleum limited (Woodside) in 2017 and Malaysia LNG in 2018.

LNG sales volumes of 71.21 million tonnes in 2018 were 8% higher than in 2017, driven by our increased LNG purchases from third parties and higher LNG liquefaction volumes.

EARNINGS 2018-2017

Segment earnings in 2018 were \$11,444 million, which included a net gain of \$2,045 million. The net gain primarily reflected gains of \$1,937 million on sale of assets, mainly related to the divestment of assets in Thailand, New Zealand and India. It also comprised a gain of \$481 million related to the fair value accounting of commodity derivatives and impairment charges of \$371 million related to investments in Trinidad and Tobago and Shell's investment in a joint venture.

Segment earnings in 2017 were \$5,078 million, which included a net charge of \$190 million. The net charge mainly reflected a charge of \$445 million on fair value accounting of commodity derivatives and a charge of \$412 million as a result of US tax reform legislation, partly offset by a gain of \$636 million from the strengthening Australian dollar on a deferred tax position.

Excluding the net gain and the net charge described above, segment earnings were \$9,399 million in 2018 compared with \$5,268 million in 2017. Earnings were positively impacted by increased contributions from trading and higher realised oil, gas and LNG prices (around \$4,200 million), increased LNG volumes from various assets across the portfolio (around \$615 million). Earnings were negatively impacted by higher operating expenses (around \$502 million of which \$246 million relates to growth of New Energy activities) and lower dividends due to divestments (around \$274 million).

In 2018, the impact of exchange rate movements of the Australian dollar on deferred tax balances was significantly reduced, as a result of the change in the fiscal functional currency of a number of Shell entities in Australia to the US dollar with effect from January 1, 2018.

EARNINGS 2017-2016

Segment earnings in 2017 were \$5,078 million, which included a net charge of \$190 million as described above.

Segment earnings in 2016 were \$2,529 million, which included a net charge of \$1,171 million. The net charge included impairments of \$451 million, reported mainly in share of profit of joint ventures and associates, the reassessment of a deferred tax asset in Australia of \$533 million, onerous contract provisions in Europe and the USA of \$390 million, and redundancy and restructuring charges of \$245 million, partly offset by gains on divestments of \$212 million and on the accounting reclassification of Shell's interest in Woodside in Australia of \$479 million (both reported in interest and other income).

Excluding the net charges described above, segment earnings were \$5,268 million in 2017 compared with \$3,700 million in 2016. Earnings were positively impacted by higher realised oil, gas and LNG prices (around \$1,620 million), lower operating expenses (around \$110 million), lower exploration charges (around \$170 million), and lower well write-offs (around \$100 million). Earnings were negatively impacted by a total of around \$230 million from lower liquids production, mainly as a result of the shutdown at Pearl, partially offset by higher LNG liquefaction volumes across the portfolio. Other items, which included lower contributions from trading and higher taxation, had a net negative impact of around \$200 million.

CAPITAL INVESTMENT AND DIVESTMENTS

Capital investment in 2018 was \$4.5 billion, compared with \$3.8 billion in 2017.

Divestments in 2018 were \$3.1 billion, in line with \$3.1 billion in 2017.

PORTFOLIO AND BUSINESS DEVELOPMENT

Key portfolio events in 2018 included the following:

- In February, we completed the acquisition of First Utility, a leading independent UK household energy and broadband provider.
- In March, we completed the acquisition of a 43.8% interest in Silicon Ranch Corporation, a developer, owner and operator of solar energy assets in the USA.
- In July, with our partners, we completed the dilution of interests in LNG Canada to Petronas. As a result, our interest in LNG Canada was reduced from 50% to 40%.
- In August, we acquired ENI's interest in the North Coast Marine Area (NCMA) block offshore Trinidad and Tobago, increasing our interest from 63.2% to 80.5%.
- In December, we acquired Total's 26% interest in the Hazira LNG and Port venture, increasing our interest from 74% to 100%.
- In December, we formed 50/50 joint ventures with EDF Renewables and EDP Renewables to build wind farms off the coast of New Jersey and Massachusetts, respectively, in the USA.

In February 2019, we acquired sonnen, a provider of smart energy storage systems and innovative energy services for households, and Limejump, a UK-based digital energy-technology company.

The following major milestones were reached in 2018:

- In June, the final investment decision was taken on the Borssele III and IV offshore wind farm projects in the Netherlands (Shell interest 20%).
- In October, the final investment decision was taken on LNG Canada (Shell interest 40%). Construction has started and first LNG is expected before the middle of the next decade.
- In December, wells were opened at the Prelude floating liquefied natural gas (FLNG) facility in Australia (Shell interest 67.5%). During this initial phase of production, gas and condensate are produced and moved through the facility. Once this has been completed, the facility will be prepared for reliable production of LNG and LPG.

We continued to divest selected assets during 2018, including:

- In Greece, we sold our 49% interests in Attiki Gas Supply Company S.A. and Attiki Natural Gas Distribution Company S.A.
- In India, we reduced our interest in Mahanagar Gas Limited from 32.5% to 10%.
- In Malaysia, we sold our 15% interest in Malaysia LNG Tiga Sdn Bhd to the Sarawak State Financial Secretary.
- In New Zealand, we sold our shares in Shell entities to OMV.
- In Thailand, we sold our 22.2% interest in the offshore Bongkot field and adjoining acreage to PTT Exploration & Production Public Company Limited.

In November 2018, we agreed to sell our interest in the undeveloped Sunrise gas field in the Timor Sea (Shell interest 26.6%) to the government of Timor-Leste. The transaction is pending regulatory approval and expected to close in the first half of 2019.

BUSINESS AND PROPERTY

Our Integrated Gas business is described below by country.

EUROPE

Gibraltar

We have a 51% interest in the first LNG regasification facility in Gibraltar, construction of which was completed in 2018.

Netherlands

We have access to import and storage capacity at the GATE LNG terminal in the Netherlands (Shell capacity rights 1.4 million tonnes per annum, mtpa), enabling us to supply LNG to marine and road transport customers in northwest Europe. We are also using the terminal to supply LNG to our growing truck-refuelling network in the Netherlands.

Norway

Gasnor AS (Shell interest 100%) provides LNG fuel for ships and industrial customers and has a natural gas pipeline network.

UK

We have a 50% interest in the Dragon LNG regasification terminal, with long-term arrangements in place governing the use of capacity rights.

Rest of Europe

We also have interests in Cyprus.

ASIA (INCLUDING THE MIDDLE EAST AND RUSSIA)

Brunei

We have a 25% interest in Brunei LNG Sendirian Berhad, which sells most of its LNG on long-term contracts to customers in Asia.

China

We jointly develop and produce from the onshore Changbei tight-gas field under a PSC with China National Petroleum Corporation (CNPC). In 2016, we completed the Changbei I development programme under the PSC and subsequently handed over the production operatorship to CNPC. In December 2017, we took the final investment decision on the Changbei II Phase 1 project, and we expect the drilling programme and construction of facilities to be completed in 2021. Shell remains the operator of Changbei II.

In 2018, we completed the handover of the Jinjia block in Sichuan to CNPC.

India

We have a 30% interest in the producing oil and gas field Panna/Mukta. We also have a 30% interest in the Mid Tapti and South Tapti fields, which ceased production in the first quarter of 2016.

We decreased our interest in the publicly-listed Mahanagar Gas Limited from 32.5% to 10%, a natural gas distribution company in Mumbai.

In December, we acquired Total's 26% interest in the Hazira LNG and Port venture, increasing our interest from 74% to 100%. The Hazira LNG and Port venture, located in the state of Gujarat on the west coast, comprises two companies: Hazira LNG Pvt Ltd, which operates a regasification terminal; and Hazira Port Pvt Ltd, which manages a cargo port at Hazira.

Indonesia

We have a 35% interest in the INPEX Masela Ltd joint venture which owns and operates the offshore Masela block. In April 2016, the joint venture received a notification from the Indonesian government authorities instructing it to re-propose a plan for the Abadi gas field based on an onshore LNG project. The partners are preparing a new Plan of Development for submission to the government of Indonesia in 2019.

Iran

Shell transactions with Iran are disclosed separately. See "Section 13(r) of the US Securities Exchange Act of 1934 Disclosure" on page 262.

Malaysia

We operate a GTL plant, Shell MDS (Shell interest 72%), adjacent to the Malaysia LNG facilities. Using Shell technology, the plant converts gas into high-quality middle distillates, drilling fluids, waxes and specialty products. In 2018, we sold our 15% interest in Malaysia LNG Tiga Sdn Bhd to the Sarawak State Financial Secretary.

Oman

We have a 30% interest in Oman LNG LLC, which mainly supplies Asian markets under long-term contracts. We also have an 11% interest in Qalhat LNG, which is part of the Oman LNG complex.

Qatar

We operate the Pearl GTL plant (Shell interest 100%) in Qatar under a development and PSC with the government. The fully-integrated facility has capacity for production, processing and transportation of 1.6 billion standard cubic feet per day (scf/d) of gas from Qatar's North Field. It has an installed capacity of about 140 thousand boe/d of high-quality liquid hydrocarbon products and 120 thousand boe/d of natural gas liquids (NGL) and ethane.

We have a 30% interest in Qatargas 4, which comprises integrated facilities to produce about 1.4 billion scf/d of gas from Qatar's North Field, an onshore gas-processing facility and one LNG train with a collective production capacity of 7.8 mtpa of LNG and 70 thousand boe/d of condensate and NGL.

Russia

We have a 27.5% interest in Sakhalin-2, the joint venture with Gazprom, an integrated oil and gas project located in a subarctic environment.

We have a 50% interest in Salym Petroleum Development N.V., the joint venture with GazpromNeft, developing the Salym fields in western Siberia, Khanty Mansiysk Autonomous District, where production was approximately 120 thousand boe/d in 2018.

We have a 50% interest in Khanty-Mansiysk Petroleum Alliance VOF partnership with GazpromNeft.

With effect from January 1, 2019, Salym and Khanty-Mansiysk Petroleum Alliance VOF partnership will be reported in the Upstream segment. Comparative information will not be adjusted.

As a result of European Union and US sanctions prohibiting certain defined oil and gas activities in Russia, we suspended our support to Salym and Khanty-Mansiysk Petroleum Alliance VOF partnership in relation to shale oil activities in 2014. Salym and Khanty-Mansiysk Petroleum Alliance VOF partnership also suspended any shale oil related activities in 2014.

Singapore

We have a 50% interest in a joint venture with KS Investments (the investment arm of Keppel Group) that holds a licence to supply LNG fuel for vessels in the Port of Singapore. We have aggregator licences to import LNG into Singapore.

Rest of Asia

We also have interests in Myanmar.

OCEANIA

Australia

We have interests in offshore production, LNG liquefaction and exploration licences in the North West Shelf (NWS) and Greater Gorgon areas of the Carnarvon Basin, as well as in the Browse Basin and Timor Sea. Woodside is the operator on behalf of the NWS joint venture, which produced more than 500 thousand boe/d of gas and condensates in 2018.

We have a 25% interest in the Gorgon LNG joint venture, which is operated by Chevron. The venture started operating in 2016, producing from the offshore Gorgon and Jansz-Io fields via a three train LNG plant on Barrow Island.

We are the operator of a permit in the Browse Basin in which two separate gas fields were found: Prelude and Concerto (Shell interest 67.5% in each). Our development concept for these fields is based on our floating liquified natural gas (FLNG) technology. The Prelude FLNG project, at its peak, is expected to produce about 130 thousand boe/d of gas and NGL, 3.6 mtpa of LNG, 1.3 mtpa of condensate and 0.4 mtpa of liquefied petroleum gas. During 2018, milestones included starting to commission the facilities and successful receipt of LNG and propane into the tanks. In December, wells were opened, entering the start-up phase. Our other interests in the basin include a joint arrangement, with Shell as the operator, for the Crux gas and condensate field (Shell interest 82%).

We are also a partner in the Browse joint arrangement (Shell interest 27%) covering the Brecknock, Calliance and Torosa gas fields, which is operated by Woodside. In November 2018, we agreed to sell our interest in the undeveloped Sunrise gas field in the Timor Sea (Shell interest 26.6%) to the government of Timor-Leste. We are a partner in both Shell-operated and other exploration joint arrangements in multiple basins, including Bonaparte, Browse, Exmouth Plateau, Greater Gorgon and Outer Canning.

We have a 50% interest in Arrow, a Queensland-based joint venture with CNPC. Arrow owns coalbed methane assets and a domestic power business.

We have a 50% interest in train one and a 97.5% interest in train two of the Shell-operated QCLNG venture. The two-train liquefaction plant has an installed capacity of 8.5 mtpa. We also operate the venture's natural gas operations, which include wells, compression stations and processing plants, in Queensland's Surat Basin. We have interests ranging from 44% to 74% in 24 field compression stations and six central processing plants. Our production of natural gas from the onshore Surat Basin supplies the liquefaction plant and the domestic gas market.

A gas sales agreement between Arrow and QCLNG has been signed, under which gas from Arrow's Surat Basin fields would flow to the QCLNG venture, that would then both sell gas to local customers and export it through its gas plant on Curtis Island.

AFRICA

Egypt

We have interests of 35.5% and 38%, respectively, in trains one and two of the Egyptian LNG (ELNG) plant. In January 2014, force majeure notices were issued under the LNG agreements as a result of domestic gas diversions severely restricting volumes available to ELNG. These notices remain in place. See "Oil and gas information" on page 45.

Mozambique

A feasibility study is ongoing for a potential GTL project, under a memorandum of understanding (MOU) signed with the government of Mozambique in 2017.

Nigeria

We have a 25.6% interest in Nigeria LNG Ltd, which operates six LNG trains located on Bonny Island.

Tanzania

We have a 60% interest in, and are the operator of, Blocks 1 and 4 offshore southern Tanzania. The blocks cover approximately 4,000 square kilometres of the Mafia Deep Offshore Basin and the northern part of the Rovuma Basin. We continue to develop a potential LNG project with partners in Block 2 in line with the Block 1 and 4 appraisal programme agreed with the Tanzanian government. We are engaging with the government to extend the Block 4 licence. The government has confirmed that the Block 4 licence, due to initially expire on October 31, 2017, remains in full force pending the grant of the licence extension.

Rest of Africa

We have a 17.9% share in the West African Gas Pipeline Company Limited which owns and operates a 678-kilometre pipeline that transports gas from Nigeria to Ghana, Benin and Togo. We also have interests in Gabon and Morocco.

NORTH AMERICA

Canada

In 2018, we took the final investment decision on LNG Canada, a liquified natural gas project in Kitimat, British Columbia. We also completed the dilution of interest from 50% to 40% in LNG Canada to Petronas. With LNG Canada's other joint venture partners also having taken final investment decisions, construction started in October 2018. First LNG is expected before the middle of the next decade.

USA

We have offtake rights to 100% of the capacity (2.5 mtpa) of the Kinder Morgan-owned Elba Island liquefaction plant, which is under construction. Elba Island also has a regasification terminal in which we have contracted capacity of 11.6 mtpa.

We have 13.1 mtpa of contracted capacity in the Lake Charles regasification terminal in Louisiana. We are also evaluating a project to convert the existing regasification facility owned by Energy Transfer into a liquefaction plant in which we would have capacity rights.

SOUTH AMERICA

Bolivia

We have a 100% interest in the La Vertiente, Los Suris and Tarija XX East blocks and the La Vertiente gas processing plant. We have a 37.5% interest in the Caipipendi block, where we mainly produce from the Margarita field. We are also exploring in Caipipendi block. We also have a 25% interest in the Tarija XX West block where we produce from the Itaú field. We have the rights to explore and further develop the onshore Huacareta block (Shell interest 100%) and we are exploring there.

Peru

We have a non-Shell-operated 20% interest in the Peru LNG liquefaction plant.

Trinidad and Tobago

We are the largest shareholder in all four trains at Atlantic LNG. We also have an interest in three concessions with producing fields – Central Block, East Coast Marine Area (ECMA) and NCMA blocks. Shell has a 65% interest in Central Block and 100% interest in ECMA. In August 2018, we acquired ENI's interest in the NCMA block, increasing our interest from 63.2% to 80.5%. We also have interests ranging from 35% to 100% in exploration activities in blocks 5(c), 5(d), 6(d), and Atlantic Area blocks 3, 5, and 6.

Rest of South America

We have a 40% interest in a gas pipeline connecting Uruguay to Argentina.

TRADING AND SUPPLY

Through our Shell Energy organisation, we market a portion of our share of equity production of LNG and trade LNG volumes around the world through our hubs in the UK, Dubai and Singapore. Trading and Supply also markets and trades natural gas, power and carbon-emission rights mainly in North America and Europe, of which a portion includes equity volumes from our upstream operations. We also market gas in Australia and Mexico, and power in Brazil.

NEW ENERGIES

Our New Energies business explores emerging opportunities linked to the energy transition and invests in those where we believe sufficient value is available. We focus on new fuels for transport, such as advanced biofuels, hydrogen and charging for battery-electric vehicles; and power, including from low-carbon sources such as wind and solar, as well as natural gas. Alongside our work in new fuels and power, we are exploring how digital technologies can best support our activities and customers.

The New Energies portfolio is being built through organic growth and acquisitions. Most of these opportunities are in business sectors that are different from Shell's existing oil and gas businesses but have some similarities and/or adjacencies to our Downstream and gas and power trading businesses. New Energies companies are subject to the Shell Control Framework. Some are not yet in full compliance and we are working to bring them into compliance with the Shell Control Framework in a fit-for-purpose manner.

New fuels

We have a demonstration plant at the Shell Technology Centre Bangalore, India, that demonstrates a technology called IH2 that turns waste feedstock into transport fuel. The plant is in its final research and development stage, ahead of potentially scaling up for commercial production. We are also

investing in renewable natural gas (RNG) for use in natural-gas fuelled vehicles in the USA and in Europe. RNG is collected from landfill sites, food waste or manure and then processed until it is fully interchangeable with conventional natural gas.

In the USA, in August 2018, we announced plans to expand and upgrade the JC Biomethane plant in Junction City, Oregon, which we acquired in May 2018.

We are part of a joint-venture, H2 Mobility Germany to install hydrogen fuelling pumps at around 100 locations across Germany during 2019. Shell is taking part in several other initiatives to encourage the adoption of hydrogen-electric energy as a transport fuel.

Shell has also opened 26 hydrogen refuelling sites in Germany, the USA, the UK and Canada and has announced the construction of four stations in the Netherlands.

Shell offers fast charging services for electric vehicles (EV) at 26 retail sites in the Netherlands, China and the UK and is working with IONITY, a joint venture of automotive manufacturers, to offer 500 high-powered charging points across 10 European countries.

NewMotion, which we acquired at the end of 2017, operates private electric charge points in the Netherlands, Germany, France and the UK, for home and business use.

In January 2019, we acquired Greenlots, a California-based EV charging company. This acquisition marks Shell's entry into the US EV market providing EV charging solutions at scale, including vehicle charging points, smart software and grid services to commercial and residential customers.

Power

We have interests in five onshore wind power projects in the USA and in one offshore wind power project – NoordzeeWind (Shell interest 50%) in the Netherlands. In total, our share of the energy capacity from these projects is more than 400 megawatts (MW).

In June 2018, the final investment decision was taken on the Borssele III and IV offshore wind farm projects in the Netherlands (Shell interest 20%). These wind farms are designed to have a total installed capacity of 731.5 MW. In December 2018, we formed 50/50 joint ventures with EDF Renewables and EDP Renewables to build wind farms off the coast of New Jersey and Massachusetts, respectively. This marks our entry into the US offshore wind market.

In 2018, we completed the acquisition of a 43.8% interest in Silicon Ranch Corporation, a developer, owner and operator of solar energy assets in the USA. In December 2018, a solar park started at Shell Moerdijk, the Netherlands, providing power to our chemicals plants.

In January 2019, we acquired a 49% interest in Cleantech Solar, which provides solar power to commercial and industrial customers across South-East Asia and India.

In February 2018, we completed the acquisition of First Utility, a leading independent UK household energy and broadband provider. In February 2019, we acquired sonnen, a provider of smart energy storage systems and innovative energy services for households, and Limejump, a UK-based digital energy-technology company.

INTEGRATED GAS DATA TABLE

LNG liquefaction volumes				Million tonnes
	2018	2017	2016	
Australia	12.1	11.1 [A]	9.5 [A]	
Brunei	1.6	1.6	1.6	
Egypt	0.3	0.2	0.2	
Malaysia [B]	0.6	1.3	1.3	
Nigeria	5.1	5.2	4.5	
Norway	0.1	0.1	0.1	
Oman	2.4	2.0	2.0	
Peru	0.8	0.9	0.9	
Qatar	2.3	2.4	2.4	
Russia	3.1	3.1	3.0	
Trinidad and Tobago	5.8	5.3	5.4	
Total	34.3	33.2	30.9	

[A] Includes LNG liquefaction volumes related to our share in equity securities of Woodside, that were disposed of in 2017.

[B] Includes LNG liquefaction volumes related to our share in equity securities of Malaysia LNG Tigo, that were disposed of in 2018.

LNG AND GTL PLANTS AT DECEMBER 31, 2018

LNG liquefaction plants in operation				
	Asset	Location	Shell interest (%)	100% capacity (mtpa)[A]
Europe				
Norway	Gasnor	Bergen	100.0	0.3
Asia				
Brunei	Brunei LNG	Lumut	25.0	7.8
Oman	Oman LNG	Sur	30.0	7.1
	Qalhat LNG	Sur	11.0 [B]	3.7
Qatar	Qatargas 4	Ras Laffan	30.0	7.8
Russia	Sakhalin LNG	Prigorodnoye	27.5	9.6
Oceania				
Australia	Australia North West Shelf	Karratha	16.7	16.9
	Gorgon LNG T1	Barrow Island	25.0	5.2
	Gorgon LNG T2	Barrow Island	25.0	5.2
	Gorgon LNG T3	Barrow Island	25.0	5.2
	Queensland Curtis LNG T1	Curtis Island	50.0	4.3
	Queensland Curtis LNG T2	Curtis Island	97.5	4.3
Africa				
Egypt	Egyptian LNG T1	Idku	35.5	3.6
	Egyptian LNG T2	Idku	38.0	3.6
Nigeria	Nigeria LNG	Bonny	25.6	22.0
South America				
Peru	Peru LNG	Pampa Melchorita	20.0	4.5
Trinidad and Tobago	Atlantic LNG T1	Point Fortin	46.0	3.0
	Atlantic LNG T2/T3	Point Fortin	57.5	6.6
	Atlantic LNG T4	Point Fortin	51.1	5.2

[A] As reported by the operator.

[B] Interest, or part of the interest, is held via indirect shareholding.

LNG liquefaction plants under construction

	Asset	Location	Shell interest (%)	100% capacity (mtpa)
Oceania				
Australia	Prelude	Browse Basin	67.5	3.6
North America				
Canada	LNG Canada T1-2	Kitimat	40.0	14.0

GTL plants in operation

	Asset	Location	Shell interest (%)	100% capacity (b/d)
Asia				
Malaysia	Shell MDS	Bintulu	72.0	14,700
Qatar	Pearl	Ras Laffan	100.0	140,000

Upstream

Key statistics

\$ million, except where indicated

	2018	2017	2016
Segment earnings	6,798	1,551	(3,674)
Including:			
Revenue (including inter-segment sales)	47,733	40,192	32,936
Share of profit of joint ventures and associates	285	623	222
Interest and other income	600	1,188	839
Operating expenses [A]	12,157	12,656	14,501
Exploration	1,132	1,804	1,614
Depreciation, depletion and amortisation	13,006	17,303	16,779
Taxation charge/(credit)	8,791	2,409	(938)
Capital investment [A]	12,525	13,648	47,507
Divestments [A]	2,198	11,542	1,726
Oil and gas production available for sale (thousand boe/d)	2,709	2,777	2,784

[A] See "Non-GAAP measures reconciliations" on pages 263-264.

OVERVIEW

Our Upstream business explores for and extracts crude oil, natural gas and natural gas liquids. It also markets and transports oil and gas, and operates infrastructure necessary to deliver them to market. We are also involved in the extraction of bitumen from mined oil sands and its conversion into synthetic crude oil.

BUSINESS CONDITIONS

Global oil demand grew by 1.2 million barrels per day (b/d), or 1.2%, to 99.2 million b/d in 2018, according to the International Energy Agency's *Oil Market Report* published in January 2019. Brent crude oil, an international benchmark, traded between \$51 per barrel (/b) and \$86/b in 2018, ending the year at the lower price of \$51/b. It averaged \$71/b for the year, \$17/b higher than in 2017, and \$27/b higher than in 2016 when the average price was at its lowest average level since 2004.

On a yearly average basis, West Texas Intermediate crude oil traded at a \$6/b discount to Brent in 2018, compared with \$3/b in 2017. The discount widened from 2017, reflecting constrained pipeline capacity from the landlocked Cushing storage hub to the US Gulf Coast. US oil exports increased from 2017, which helped to limit further widening of the price differential.

Global gas demand is estimated to have grown by about 3.2% in 2018, which is higher than the average annual growth rate of 2.4% since the beginning of the century. A combination of weather conditions, implementation of new policies such as the partial substitution of coal by gas-fired power generation in China, and global economic growth led to an increase in demand in most regions.

In the USA, the natural gas price at the Henry Hub averaged \$3.1 per million British thermal units (MMBtu) in 2018, 3% higher than in 2017, and traded in a range of \$2.5-4.9/MMBtu. There was some downward pressure on prices due to strong supply growth, which averaged 11% higher than 2017, helped by higher oil prices and new gas pipeline capacity. However, gas prices were also supported by a range of factors, such as below-normal storage inventory levels, and demand growth due to colder than normal weather in the second half of 2018, the completion of LNG liquefaction projects, increased exports to Mexico by pipeline, and US industrial demand.

In Europe, natural gas prices were higher than in 2017. The average price at the UK National Balancing Point (NBP) was 33% higher in 2018. At the main continental gas trading hubs – in the Netherlands, Belgium and Germany – prices were also stronger, as reflected by stronger Dutch Title Transfer Facility (TTF) prices. European gas prices were supported by record prices for carbon dioxide (CO₂) allowances (EUAs) which averaged €16/tCO₂ in 2018 compared to €6/tCO₂ in 2017, resulting in higher preference for gas over coal in power generation. Gas prices were also supported by lower nuclear power output, particularly in Belgium and Spain, lower than normal temperatures early in the year, and competition from North-East Asian markets for LNG supplies for storage replenishment ahead of winter.

See "Market overview" on pages 21-23.

PRODUCTION AVAILABLE FOR SALE

In 2018, production was 989 million boe, or 2,709 thousand boe/d, compared with 1,014 million boe, or 2,777 thousand boe/d in 2017. Liquids production decreased by 2% and natural gas production decreased by 3% compared with 2017.

Decreases were mainly due to divestments (around 199 thousand boe/d) and field declines (around 66 thousand boe/d). Increases were mainly from new field start-ups and the continuing ramp-up of existing fields (around 173 thousand boe/d), in particular in the Permian Basin in the USA, Lula South in Brazil, Schiehallion, Loyal and Clair phase 2 in the UK, Kaikias and Stones in the US Gulf of Mexico, and stronger operational performance, which contributed additional volumes of around 38 thousand boe/d. Other items had a net negative impact of around 14 thousand boe/d.

EARNINGS 2018-2017

Segment earnings in 2018 were \$6,798 million, which included a net gain of \$23 million. This included a net gain of \$886 million on sale of assets, mainly related to our divestments in Iraq, Malaysia, Oman and Ireland, as well as a gain of \$149 million related to the fair value accounting of commodity derivatives. These gains were partly offset by a charge of \$561 million related to the impact of the weakening Brazilian real on a deferred tax position, a net impairment charge of \$350 million mainly related to assets in North America and deep-water rig joint ventures, and a charge of \$90 million related to the release of historic currency differences.

Segment earnings in 2017 were \$1,551 million, which included a net charge of \$1,540 million. The net charge included impairment charges of \$2,557 million, mainly related to divestments of our oil sands interests in Canada, onshore assets in Gabon and our interest in the Corrib gas project in Ireland, a charge of \$1,089 million related to US tax reform legislation, and redundancy and restructuring charges of \$163 million. These charges were partly offset by gains on divestments of \$1,463 million, mainly related to a package of assets in the UK North Sea, a credit of \$772 million mainly reflecting the release of tax liabilities, and other items with a net positive impact of \$34 million.

Excluding the net gains described above, segment earnings in 2018 were \$6,775 million, compared with \$3,091 million in 2017. Earnings benefited from higher realised oil and gas prices (around \$4,770 million) and lower well write-offs (around \$400 million). These impacts were partly offset by the impact of movements in deferred tax positions (around \$1,520 million) and lower production volumes (around \$510 million).

EARNINGS 2017-2016

Segment earnings in 2017 were \$1,551 million, which included a net charge of \$1,540 million as described above.

Segment earnings in 2016 were a loss of \$3,674 million, which included a net charge of \$970 million. The net charge included impairment charges of \$1,147 million, redundancy and restructuring charges of \$654 million; a \$235 million provision for onerous drilling rig contracts; \$198 million related to the reassessment of deferred tax positions in Malaysia; and a net charge on fair value accounting of certain commodity derivatives and gas contracts of \$145 million. These charges were partly offset by a gain of \$661 million related to the impact of a strengthening Brazilian real on a deferred tax position, divestment gains of \$645 million, and a credit of \$103 million reflecting a statutory tax rate reduction in the UK.

Excluding the net charges described above, segment earnings in 2017 were \$3,091 million compared with a loss of \$2,704 million in 2016, principally as a result of higher realised oil and gas prices, lower deferred tax positions and depreciation, partly offset by lower production volumes mainly due to divestments and higher well write-offs.

CAPITAL INVESTMENT

Capital investment in 2018 was \$12.5 billion, compared with \$13.6 billion in 2017. Capital investment in 2017 included \$1.5 billion related to the acquisition of a 50% interest in 1745844 Alberta Ltd. (formerly known as Marathon Oil Canada Corporation). The lower capital investment in 2018 reflected our continuing efforts to improve capital efficiency by pursuing lower-cost development solutions, partly offset by increased investments in exploration acreage additions and lease renewals in Nigeria.

DIVESTMENTS

Divestments in 2018 were \$2.2 billion, compared with \$11.5 billion in 2017. Divestments in 2018 were mainly the sale of our assets in Iraq (West Qurna 1 field), Ireland (Corrib gas project), Malaysia (North Sabah Enhanced Oil Recovery (EOR) PSC), Norway (Draugen and Gjøa fields), Oman (Mukhaizna oil field), the UK (Triton assets) and the USA (non-core net mineral acres in the Permian Basin).

PORTFOLIO AND BUSINESS DEVELOPMENT

We took the following key portfolio decisions during 2018:

- In Argentina, we started developing three blocks in the Vaca Muerta shales basin – Cruz de Lorena and Sierras Blancas (Shell interest 90%) and Coiron Amargo Sur Oeste (Shell interest 80%).
- In Brazil's Santos Basin, we signed 35-year PSCs for the Saturno (Shell interest 50% as operator) and Tres Marias (Shell interest 40%) deep-water exploration blocks.
- Also in Brazil, we won four deep-water blocks in the Campos and Potiguar basins; we solely secured one exploration block as operator and secured three blocks in joint-bids (Shell interest 40%).
- Additionally, in Brazil, we took the final investment decisions (FID) for the Berbigão (P68) and Atapu I (P70) floating production, storage and offloading (FPSO) vessels (Shell interest 25%, subject to unitisation), and Mero I, located in the Libra block (Shell interest 20%).
- In Egypt, we approved the FID for the development of Phase 9B of the West Delta Deep Marine (WDDM) offshore concession (Shell interest 50%).
- In Kazakhstan, we took the FID for the development of the Karachaganak Gas Debottlenecking project (Shell interest 29.3%).
- In Malaysia, we took the FID for the development of the Gorek, Larak and Bakong gas fields in Block SK408 offshore Sarawak (Shell interest 30%) and the development of the Pegaga gas field in Block SK320 offshore Sarawak (Shell interest 20%).
- In Mauritania, we signed two PSCs with the government for the exploration and potential future production of hydrocarbons in the offshore blocks C-10 and C-19 (Shell interest 90% as operator). The blocks, which have a total area of approximately 23,675 square kilometres, are located in the West African Atlantic Margin exploration basin.
- In Mexico, we won nine deep-water exploration blocks; four blocks on our own (Shell interest 100%), four with our partner Qatar Petroleum International Limited (Shell interest 60%), and one with our partner Pemex Exploración y Producción (Shell interest 50%). The total area of these nine blocks is 18,996 square kilometres. We will be the operator of all nine blocks.
- In Nigeria, we renewed a number of onshore oil mining leases in the Niger Delta for 20 years (Shell interest 30%).
- Also in Nigeria, we took the FID on Assa North, Gbaran Enwhe and Gbaran Nodal Compression projects (Shell interest 30%).
- In the UK North Sea, we announced the FID for the redevelopment of the Penguins oil and gas field (Shell interest 50%). The project will use a FPSO and is expected to have a peak production of around 45 thousand boe/d.
- Also in the UK North Sea, we announced FIDs for development of our operated oil and gas fields – Fram (Shell interest 32%), Arran (Shell interest 44.6%) and Gannet E (Shell interest 50%) along with the Gannet Export infrastructure investment in the central North Sea and the Shearwater gas infrastructure hub; and the non-operated Alligin oil field West of Shetland (Shell interest 50%).

- Additionally, in the UK, we acquired a 22.5% non-operated interest in the P1830 licence and a 30% interest in the P1028 and P1189 licences; P1189 includes the Cambo discovery north-west of Shetland, where the successful conclusion of well-testing operations on the appraisal well was confirmed.
- In the US Gulf of Mexico, we announced the FID to develop the Vito deep-water field. Vito (Shell interest 63.1%) is expected to reach an average peak production of 100 thousand boe/d.

In January 2019, we announced the FID for the Basrah Gas Company Natural Gas Liquids expansion project in Iraq that will increase the capacity to 1.4 billion scf/d (Shell interest 44%).

In February 2019, we agreed the heads of terms for the resolution of the OML 118 negotiations, including the PSC dispute with the Nigerian National Petroleum Corporation (NNPC), following which we have a clear commercial framework for a potential Bonga South West Aparo FID, and announced an invitation to tender.

We achieved the following operational milestones in 2018:

- In Brazil, we announced first production from our fourteenth FPSO (P69), in Lula Extreme South, which is expected to ramp up to full production capacity in 2019 (Shell interest 25%, pre-unitisation).
- In Nigeria, we announced a notable discovery, Epu Deep, which is a near-field gas discovery in the greater Gbaran area, onshore Niger Delta. It was discovered in the Epu Field block OML 28, located beneath the producing Epu Field in the Central Swamp area of the Niger Delta (Shell interest 30%).
- In the UK, we announced the start-up of the second phase of the Clair field, with an expected peak production of 106 thousand boe/d (Shell interest 28%).
- In the US Permian Basin, we nearly doubled our production in 2018 and matured an inventory of resources in excess of 1 billion boe that breaks even at less than \$40 per barrel.
- In the US Gulf of Mexico, we announced one of our largest exploration finds in the past decade from the Whale deep-water well (Shell interest 60%). It was discovered in the Alaminos Canyon Block 772, adjacent to the Shell-operated Silvertip field and approximately 16 kilometres from the Shell-operated Perdido platform.
- Also, in the US Gulf of Mexico, we announced a large deep-water discovery, in the Dover well (Shell interest 100%). The Dover discovery is our sixth in the Norphlet geologic play. It is located approximately 21 kilometres from the Appomattox deep-water platform.
- We also completed the construction of the Appomattox deep-water platform in the US Gulf of Mexico. We expect to start production in 2019, with an expected average peak production of approximately 175,000 thousand boe/d (Shell interest 79%).
- Additionally, in the US Gulf of Mexico, we commenced production from Coulomb phase 2 (Shell interest 100%).
- We announced the start of production of Kaikias Phase 1, a subsea development in the US Gulf of Mexico with an estimated peak production of 40 thousand boe/d (Shell interest 80%). It will produce oil and gas through a subsea tie-back to the nearby Shell-operated Ursa production hub.

In February 2019, we announced the start of production from our fifteenth FPSO (P67), in Lula North, which is expected to ramp up to full production capacity in 2019 (Shell interest 25%, pre-unitisation).

In the Netherlands, the shareholders of the Nederlandse Aardolie Maatschappij B.V. (NAM) (Shell interest 50%) and the Dutch government signed a heads of agreement (HoA) that includes measures to support the reduction of production and to ensure the financial robustness of NAM. As part of the agreement, NAM's shareholders have agreed for NAM not to declare dividends for 2018 or 2019.

We continued to divest selected assets during 2018, including:

- In Iraq, we sold our 19.6% interest in the West Qurna 1 field. We also handed over operations of the Majnoon field to the Iraqi government.
- In Ireland, we sold our 45% interest in the Corrib gas project.
- In Malaysia, we completed the sale of our 50% interest in the 2011 North Sabah EOR Production Sharing Contract.
- In Norway, we sold our entire 44.6% interest in the Draugen field and 12% interest in the Gjøa field.
- In Oman, we sold our 17% interest in the Mukhaizna oil field.
- In the UK, we sold our interest in the Triton Cluster, which comprises the central UK North Sea assets: Bittern (Shell interest 39.6%), Triton FPSO (Shell interest 26.4%), Gannet E (Shell interest 50%) and Belinda/Evelyn (Shell interest 100%).
- In the US Permian Basin, we divested approximately 10,500 non-core net mineral acres and primarily undeveloped assets.

In Denmark, we announced the sale of our 36.8% non-operating interest in our joint venture, the Danish Underground Consortium. The transaction is expected to complete in 2019, subject to partner and regulatory approvals.

BUSINESS AND PROPERTY

Our subsidiaries, joint ventures and associates are involved in all aspects of upstream activities, including matters such as land tenure, entitlement to produced hydrocarbons, production rates, royalties, pricing, environmental protection, social impact, exports, taxes and foreign exchange.

The conditions of the leases, licences and contracts under which oil and gas interests are held vary from country to country. In almost all cases outside North America, the legal agreements are generally granted by, or entered into with, a government, state-owned company, government-run oil and gas company or agency, and the exploration risk usually rests with the independent oil and gas company. In North America, these agreements may also be with private parties that own mineral rights. Of these agreements, the following are most relevant to our interests:

- Licences (or concessions), which entitle the holder to explore for hydrocarbons and exploit any commercial discoveries. Under a licence, the holder bears the risk of exploration, development and production activities, and is responsible for financing these activities. In principle, the licence holder is entitled to the totality of production less any royalties in kind. The government, state-owned company or government-run oil and gas company may sometimes enter into a joint arrangement as a participant sharing the rights and obligations of the licence but usually without sharing the exploration risk. In a few cases, the state-owned company, government-run oil and gas company or agency has an option to purchase a certain share of production.
- Lease agreements, which are typically used in North America and are usually governed by terms similar to licences. Participants may include governments or private entities, and royalties are either paid in cash or in kind.

- PSCs entered into with a government, state-owned company or government-run oil and gas company. PSCs generally oblige the independent oil and gas company, as contractor, to provide all the financing and bear the risk of exploration, development and production activities in exchange for a share of the production. Usually, this share consists of a fixed or variable part that is reserved for the recovery of the contractor's cost (cost oil). The remaining production is split with the government, state-owned company or government-run oil and gas company on a fixed or volume/revenue-dependent basis. In some cases, the government, state-owned company or government-run oil and gas company will participate in the rights and obligations of the contractor and will share in the costs of development and production. Such participation can be across the venture or on a field-by-field basis. Additionally, as the price of oil or gas increases above certain predetermined levels, the independent oil and gas company's entitlement share of production normally decreases, and vice versa. Accordingly, its interest in a project may not be the same as its entitlement.

EUROPE

Denmark

We have a non-operating interest in a producing concession in Denmark (Shell interest 36.8%). In October 2018, we announced the sale of this non-operating interest in the Danish Underground Consortium. The transaction is expected to complete in 2019, subject to partner and regulatory approvals.

Italy

We have a 39% interest in the Val d'Agri producing concession, operated by ENI.

We also have a 25% interest in the Tempa Rossa concession operated by Total. The start-up of production at the Tempa Rossa field is expected in 2019.

Netherlands

Shell and ExxonMobil are 50:50 shareholders in Nederlandse Aardolie Maatschappij B.V. (NAM). An important part of NAM's gas production comes from the onshore Groningen gas field, in which NAM holds a 60% interest. The remaining 40% interest is held by EBN, a Dutch government entity.

Production from the Groningen field induces earthquakes that cause damage to houses and other buildings and structures in the region. This has led to complaints and claims for compensation for damage from the local community. NAM is working with the Dutch government and other stakeholders to fulfil its obligations to the residents of the area, which includes compensation for damage caused by above-mentioned earthquakes.

Since 2013, the Dutch Minister of Economic Affairs and Climate (the Minister) has set an annual production level for the Groningen field taking into account all interests, including safety of the residents, security of supply in the domestic gas market as well as supply commitments in EU member states. Production in the gas year 2017-2018 (ending October 1, 2018) was capped at 21.6 billion cubic metres; actual production in this period was 20.1 billion cubic metres. In March 2018, the Minister announced a government decision to close in the Groningen field as soon as possible, with production expected to end around 2030, as a base scenario.

Apart from production reductions, over the years, a variety of other measures have been taken by NAM, the Minister and the government.

NAM funded and led an in-depth study and data acquisition programme into the earthquakes and its effects. Specific building regulations were issued and, in 2018, an independent government body was set up to handle damage claims by the local community. Starting in November 2018, the Minister has taken over from NAM the duty of care with respect to the strengthening of buildings and the Minister now decides on the scope and prioritisation thereof. NAM will pay the costs associated with these activities. See "Risk Factors" on page 17.

In June 2018, NAM's shareholders and the Dutch government signed a Heads of Agreement (HoA) to reduce production from Groningen and to ensure the financial robustness of NAM to fulfil its obligations. In the HoA, NAM's shareholders have agreed not to declare dividends for 2018 and 2019. In September 2018, detailed agreements were signed to further implement the HoA. As part of these agreements, Shell guarantees the performance by NAM of the NAM's payment obligations vis-à-vis the Dutch government in relation to earthquake-related damages and costs of strengthening, up to a maximum of 30% in the NAM, which equals Shell's indirect interest in the Groningen production system.

The Ministerial production instruction for the Groningen gas field for the gas year 2018/2019 is to produce a volume of 19.4 billion cubic meters, based on a year with an average temperature profile. This instruction and the associated amendments in the Mining Act in effect constitute for NAM a legal obligation to produce.

NAM also has a 60% interest in the Schoonebeek oil field and operates 25 other hydrocarbon production licences onshore and offshore in the North Sea.

Norway

We are a partner in 32 production licences on the Norwegian continental shelf. We are the operator in 13 of these, of which three are producing: the Gaupe field (Shell interest 60%), the Knarr field (Shell interest 45%), and the Ormen Lange gas field (Shell interest 17.8%). We have interests in the producing fields Troll, Kvitebjørn, Sindre and Valemon, where we are not the operator.

UK

We operate a significant number of our interests on the UK continental shelf under a 50:50 joint venture agreement with ExxonMobil. In addition to our oil and gas production from North Sea fields, we have various interests in the Atlantic Margin area where we are not the operator, principally in the West of Shetland area (Clair, Shell interest 28%, and Schiehallion, Shell interest approximately 45%).

In January 2018, we announced the FID for the redevelopment of the Penguins oil and gas field (Shell interest 50%) in the UK North Sea. Also, in 2018, we announced FIDs for development of our operated oil and gas fields – Fram (Shell interest 32%), Arran (Shell interest 44.6%) and Gannet E (Shell interest 50%) along with the Gannet Export infrastructure investment in the central North Sea and the Shearwater gas infrastructure hub; and a non-operated Alligin oil field West of Shetland (Shell interest 50%).

In May 2018, we acquired a 22.5% non-operated stake in the P1830 licence and a 30% stake in the P1028 and P1189 licences. P1189 includes the Cambo discovery north-west of Shetland and in August 2018 the successful conclusion

of well-testing operations on the appraisal well in the Cambo field was confirmed.

In September 2018, we sold our interest in the Triton cluster, which comprises the central UK North Sea assets: Bittern (Shell interest 39.6%), Triton FPSO (Shell interest 26.4%), Gannet E (Shell interest 50%) and Belinda/Evelyn (Shell interest 100%).

In November 2018, we announced the start-up of the second phase of the Clair field, with an expected peak production of 106 thousand boe/d (Shell interest 28%).

Rest of Europe

We also have interests in Albania, Bulgaria, Germany and Greenland.

ASIA (INCLUDING THE MIDDLE EAST AND RUSSIA)

Brunei

Shell and the Brunei government are 50:50 shareholders in Brunei Shell Petroleum Company Sendirian Berhad (BSP). BSP has long-term oil and gas concession rights onshore and offshore Brunei, and sells most of its gas production to Brunei LNG Sendirian Berhad (see "Integrated Gas" on page 31), with the remainder (12% in 2018) sold in the domestic market.

In addition to our interest in BSP, we are the operator of the Block A concession (Shell interest 53.9%), which is under exploration and development. We have a 35% non-operating interest in the Block B concession, where gas and condensate are produced from the Maharaja Lela field.

We also have non-operating interests in deep-water exploration Block CA-2 (Shell interest 12.5%) and in exploration Block N (Shell interest 50%), both under PSCs.

Iran

Shell transactions with Iran are disclosed separately. See "Section 13(r) of the US Securities Exchange Act of 1934 Disclosure" on page 262.

Iraq

We have a 44% interest in the Basrah Gas Company, which gathers, treats and processes associated gas that was previously being flared from the Rumaila, West Qurna 1 and Zubair fields. The processed gas and associated products, such as condensate and LPG, are sold to the domestic market and surplus condensate and LPG are exported. In 2018, Basrah Gas processed on average around 800 million scf/d of associated gas into dry gas, condensate and LPG.

In January 2019, we announced the FID for the Basrah Gas Company Natural Gas liquids expansion project that will increase the capacity to 1.4 billion scf/d (Shell interest 44%).

In March 2018, we sold our 19.6% interest in the West Qurna 1 field. In June 2018, we handed over operations of the Majnoon field to the Iraqi government.

Kazakhstan

We are the joint operator of the onshore Karachaganak oil and condensate field (Shell interest 29.3%), where we have a licence to the end of 2037. Karachaganak produced around 399 thousand boe/d, on a 100% basis, in 2018.

We have a 16.8% interest in the North Caspian Sea Production Sharing Agreement which includes the Kashagan field in the Kazakh sector of the Caspian Sea. The North Caspian Operating Company is the operator. This shallow-water field covers an area of approximately 3,400 square kilometres. Phase 1 development of the field is expected to lead to plateau oil production capacity of about 370 thousand b/d by 2019, on a 100% basis, with the possibility of increases with additional phases of development. Production started in 2016.

We also have an interest of 55% in the Pearls PSC in the Kazakh sector of the Caspian Sea. It includes two oil fields, Auezov and Khazar, and covers an area of around 520 square kilometres.

We also have a 7.4% interest in Caspian Pipeline Consortium, which owns and operates an oil pipeline running from the Caspian Sea to the Black Sea across parts of Kazakhstan and Russia.

In 2018, we took the FID for the development of the Karachaganak Gas Debottlenecking project (Shell interest 29.3%).

Malaysia

We explore for and produce oil and gas offshore Sabah and Sarawak under 17 PSCs, in which our interests range from 20% to 85%.

Offshore Sabah, we operate two producing oil fields (Shell interests ranging from 29% to 35%). These include the Gumusut-Kakap deep-water field (Shell interest 29%), where production is via a dedicated floating production system, and the Malikai deep-water field (Shell interest 35%). We also have a 21% interest in the Siakap North-Petai deep-water field and a 30% interest in the Kebabangan field, both operated by third parties. In March 2018, we completed the sale of our 50% interest in the 2011 North Sabah EOR PSC. Additionally, we have exploration interests in Blocks SB-J, SB-G, SB-N, SB-3G, ND-6 and ND-7 PSCs.

Offshore Sarawak, we are the operator of 10 producing gas fields (Shell interests ranging from 37.5% to 50%). The M3S field (Shell interest 70%), F23SW field (Shell interest 50%) and Serai field (Shell interest 37.5%) reached the end of life. F23SW was abandoned successfully in 2018, while the abandonment for M3S will be completed in 2019 and Serai abandonment will be completed between 2019 and 2020. Nearly all the gas produced offshore Sarawak is supplied to Malaysia LNG (we divested our remaining 15% interest in June 2018) and to our gas-to-liquids plant in Bintulu. See "Integrated Gas" on page 31.

In 2018, we took the FID for the development of Gorek, Larak and Bakong gas fields in Block SK408 offshore Sarawak (Shell interest 30%) and the development of Pegaga gas field in Block SK320 offshore Sarawak (Shell interest 20%).

We also have a 40% interest in the 2011 Baram Delta EOR PSC and a 50% interest in Block SK-307, and interests in exploration Blocks SK318, SK320, SK408 and SK319 (operational extension application submitted to the regulator).

Oman

We have a 34% interest in Petroleum Development Oman (PDO); the Omani government has a 60% interest. PDO is the operator of more than 160 oil fields, mainly located in central and southern Oman, over an area of 76,152 square kilometres. The concession expires in 2044.

In April 2018, we sold our 17% interest in the Mukhaizna oil field.

United Arab Emirates

In Abu Dhabi, we have a 15% interest in the licence of ADNOC Gas Processing, which expires in 2028. ADNOC Gas Processing exports propane, butane and heavier-liquid hydrocarbons, which it extracts from the wet gas associated with the oil produced by ADNOC Onshore.

Rest of Asia

We also have interests in Jordan, Kuwait, the Philippines and Turkey.

AFRICA

Egypt

We have a 50% interest in the Badr Petroleum Company (BAPETCO), a self-operated joint venture between Shell and the Egyptian General Petroleum Corporation (EGPC). BAPETCO onshore operations are in the Western Desert where we have an interest in nine oil and gas producing development leases, as well as four exploration concessions (North East Obaiyed, North Matruh, North East El Shawish and North Umbaraka).

We have interests in two gas-producing areas offshore the Nile Delta. We have a 40% interest in the Rashid Petroleum Company, a self-operated joint venture between Shell, EGPC and Edison, which operates the Rosetta concession (Shell interest 80%).

We also have a 25% interest in the Burullus Gas Company (Burullus), a self-operated joint venture between Shell, EGPC and PETRONAS. Burullus operates the West Delta Deep Marine concession (Shell interest 50%), which supplies gas to both the domestic market and the Egyptian LNG plant (see "Integrated Gas" on page 32).

We also have a 60% interest in the development rights over the Harmattan Deep discovery and in the Notus discovery offshore the Nile Delta.

In April 2018, we approved the FID for the development of Phase 9B of the WDDM offshore concession (Shell interest 50%).

Nigeria

Our share of production, onshore and offshore, in Nigeria was 255 thousand boe/d in 2018, compared with 266 thousand boe/d in 2017. Security issues, sabotage and crude oil theft in the Niger Delta continued to be significant challenges in 2018.

Onshore

The Shell Petroleum Development Company of Nigeria Limited (SPDC) is the operator of a joint venture (Shell interest 30%) that has 17 Niger Delta onshore oil mining leases (OML). The 20-year renewals of 16 oil mining leases (OMLs): 17, 20, 21, 22, 23, 25, 27, 28, 31, 32, 33, 35, 36, 43, 45 and 46 were achieved in December 2018. These OMLs expire in October 2038. To provide funding, alternative funding arrangements, including with commercial banks, are in place for certain key projects.

SPDC supplies gas to Nigeria LNG Ltd (see "Integrated Gas" on page 32) mainly through its Gbaran-Ubie and Soku projects.

In 2018, we took the FIDs on Assa North, Gbaran Enwhe and Gbaran Nodal Compression projects (Shell interest 30%).

Also in 2018, we announced a notable near-field exploration gas discovery in the greater Gbaran area, onshore Niger Delta. It was discovered in the Epu Field block OML 28, located beneath the producing Epu Field in the Central Swamp of the Niger Delta (Shell interest 30%).

Offshore

Our main offshore deep-water activities are carried out by Shell Nigeria Exploration and Production Company Limited (SNEPCO, Shell interest 100%), which has interests in four deep-water blocks, under PSC terms, in which production is via two FPSOs – Bonga and Erha. SNEPCO operates OMLs 118 (including the Bonga field FPSO, Shell interest 55%) and 135 (Bolia and Doro, Shell interest 55%) and has a 43.8% non-operating interest in OML 133 (including the Erha FPSO) and a 50% non-operating interest in oil prospecting licence (OPL) 245 (Zabazaba, Etan).

We have two non-producing offshore interests OPL 284 (Shell interest 45%) and OPL 286 (Shell interest 66% as operator).

Authorities in various countries are investigating our investment in Nigerian oil block OPL 245 and the 2011 settlement of litigation pertaining to that block. See Note 25 to the "Consolidated Financial Statements" on pages 211-213.

SNEPCO also has an approximate 43% interest in the Bonga South West/Aparo development via its 55% interest in OML 118. In February 2019, we agreed the heads of terms for the resolution of the OML 118 negotiations including the PSC dispute with the NNPC, following which we now have a clear commercial framework for a potential Bonga South West Aparo FID and announced an invitation to tender. A timeframe for the FID will be announced after the commercial framework is agreed.

SPDC also has three shallow-water licences (OMLs 74, 77 and 79) and a 40% interest in the non-Shell-operated Sunlink joint venture that has one shallow-water licence (OML 144); all four OMLs expire in 2034.

In our Nigerian operations, we face various risks and adverse conditions which could have a material adverse effect on our operational performance, earnings, cash flows and financial condition (see "Risk factors" on page 17). There are limitations to the extent to which we can mitigate these risks. We carry out regular portfolio assessments to remain a competitive player in Nigeria for the long term. We support the Nigerian government's efforts to improve the efficiency, functionality and domestic benefits of Nigeria's oil and gas industry, and we monitor legislative developments. We monitor the security situation and liaise with host communities, governmental and non-governmental organisations to help promote peace and safe operations. We continue to provide transparency of spills management and reporting, along with our deployment of oil-spill response capability and technology. We execute a maintenance strategy to support sustainable equipment reliability and have implemented a multi-year programme to reduce routine flaring of associated gas. See "Climate change and energy transition" on page 77.

Rest of Africa

We also have interests in Algeria, Mauritania, Namibia and Tunisia.

NORTH AMERICA

Canada

We have approximately 1,400 mineral leases in Canada, mainly in Alberta and British Columbia. We produce and market natural gas, natural gas liquids, synthetic crude oil and bitumen.

Shales

We have approximately 1,200 mineral leases with over 1.7 million net mineral acres (2017: 2.6 million revised to 2.1 million). During the year, we relinquished 0.5 million net mineral acres. Our position is primarily in the Duvernay play in Alberta and the Montney play in British Columbia. Activity includes drill-to-fill of our existing infrastructure and an investment focus on our liquid-rich shale acreage.

In 2018, we drilled 70 wells. We have interests in 937 productive wells. We operate four natural gas processing and extraction plants in Alberta and four natural gas processing plants in British Columbia.

With the announcement of the FID for LNG Canada in 2018, our Groundbirch asset is positioned as a possible feedstock to the project.

Bitumen and synthetic crude oil

Synthetic crude oil is produced by mining bitumen-saturated sands, extracting the bitumen from the sands and transporting it to a processing facility where hydrogen is added to produce a wide range of feedstocks for refineries. We have a 50% interest in 1745844 Alberta Ltd. (formerly known as Marathon Oil Canada Corporation), which holds a 20% interest in the Athabasca Oil Sands Project.

Carbon capture and storage (CCS)

We operate the Quest CCS project (Shell interest 10%), which captured and safely stored more than 1 million tonnes of carbon dioxide in 2018.

Offshore

In December 2018, the Sable Offshore Energy project (Shell interest 31.3%) stopped natural gas production off the coast of Nova Scotia, Canada. A multi-year decommissioning and restoration phase has begun. We have also relinquished all our exploration licences off the west coast of British Columbia.

USA

We have approximately 25,000 mineral leases in the USA. We produce oil and gas in deep water in the Gulf of Mexico, heavy oil in California and oil and gas from shale in Pennsylvania, Texas and Louisiana. The majority of our oil and gas production interests are acquired under leases granted by the owner of the minerals underlying the relevant acreage, including many leases for federal onshore and offshore tracts. Such leases usually run on an initial fixed term that is automatically extended by the establishment of production for as long as production continues, subject to compliance with the terms of the lease (including, in the case of federal leases, extensive regulations imposed by federal law).

Gulf of Mexico

The Gulf of Mexico is our major production area in the USA and accounts for around 54% of our oil and gas production in the country. We have an interest in approximately 264 federal offshore leases and our share of production averaged 299 thousand boe/d in 2018.

In 2018, we announced one of our largest US Gulf of Mexico exploration finds in the past decade from the Whale deep-water well (Shell interest 60%

as operator). It was discovered in the Alaminos Canyon Block 772, adjacent to our Silvertip field and approximately 16 kilometres from the Shell-operated Perdido platform.

We are the operator of seven production hubs – Mars A, Mars B, Auger, Perdido, Ursa, Enchilada/Salsa and Stones – as well as the West Delta 143 Processing Facilities (Shell interests ranging from 38% to 100%). We also have non-operating interests in Nakika (Shell interest 50%) and Caesar Tonga (Shell interest 22.5%).

In 2018, we commenced production from Coulomb phase 2 (Shell interest 100% as operator). Coulomb ties into the Nakika non-operated platform.

In April 2018, we announced the FID to develop the Vito deep-water field. Vito is expected to reach an average peak production of 100 thousand boe/d (Shell interest 63.1%).

We continued with the development of the Appomattox project, with first oil expected in 2019. In May 2018, we announced a large exploration discovery in the Norphlet geologic play from the Dover deep-water well. Dover is operated by us (100%) and is Shell's sixth discovery in the Norphlet. The discovery is located approximately 20 kilometres from the Appomattox platform.

In May 2018, production started from the Kaikias deep-water project. Kaikias (Shell interest 80%) is a subsea tie-back to the Shell-operated Ursa platform. The Kaikias estimated peak production is 40 thousand boe/d.

From November 2017 to July 2018, our production from the Gulf of Mexico was adversely impacted by the shut-in of the Enchilada/Salsa assets (ESA), with subsequent impact on Auger and its associated fields (Llano, Macaroni and Habanero) – all driven by a November 2017 ESA incident involving a third-party owned and operated gas export pipeline. Production for Auger and associated fields resumed in May 2018 and production from ESA resumed in July 2018.

After our acquisition of the Stones FPSO (Shell interest 100%) in January 2018, we shut it down for maintenance in February and resumed production in June.

Shales

We have approximately 23,000 mineral leases with nearly 1.3 million net mineral acres. Our activity is focused in the Permian Basin in West Texas and the Marcellus and Utica plays in Pennsylvania. We also have a non-Shell-operated interest in the Haynesville shale gas formation in Northern Louisiana.

In 2018, we drilled 340 wells. We have interests in more than 2,300 productive wells and operate seven central processing facilities. The USA represents 65% of our shales proved reserves and 76% of our shales liquids proved reserves. In the Permian Basin, we nearly doubled our production in 2018, ending the year with an output of around 147 thousand boe/d and have matured an inventory of resources in excess of 1 billion boe that breaks even at less than \$40 per barrel.

In April 2018, we sold approximately 10,500 non-core net mineral acres and associated assets in the Permian Basin.

California

We have a 51.8% interest in Aera Energy LLC which operates approximately 15,000 wells in the San Joaquin Valley in California, mostly producing heavy oil and associated gas.

Alaska

With the exception of two remaining positions in the long-established North Slope area, we have exited all other leases. We retain a non-operating interest of 50% in 13 federal leases, operated by ENI. An exploratory drilling operation for this joint venture was permitted by ENI and is under way. We continue to evaluate our 18 state leases at nearby Western Harrison Bay, which have geologic affinity with recent discoveries announced by other North Slope operators.

Rest of North America

We also have interests in Mexico.

SOUTH AMERICA

Argentina

Shales

We have more than 162 thousand net mineral acres (2017: 260 thousand revised to 156 thousand) in the Vaca Muerta basin, a liquids and gas-rich play located in the Neuquén Province. The operated acreage includes blocks in Cruz de Lorena and Sierras Blancas (Shell interest 90%), Coiron Amargo Sur Oeste (Shell interest 80%), and Bajada de Añelo (Shell interest 50%). We have a 45% non-Shell-operated interest in the Rincon La Ceniza and La Escalonada blocks. We have interests in 36 producing wells and drilled seven wells in 2018 in our operated acreage. We have a 90% interest in our operated Sierras Blancas/Cruz de Lorena central processing facility. In December 2018, we announced the start of the development phase of three blocks in the Vaca Muerta basin (Cruz de Lorena, Sierras Blancas and Coiron Amargo Sur Oeste).

Brazil

We operate several producing fields in the Campos Basin, offshore Brazil. They consist of the Bijupirá and Salema fields (Shell interest 80%) and the BC-10 field (Shell interest 50%). Our operated portfolio also includes the Gato do Mato field in the Santos Basin and the adjacent Sul de Gato do Mato area (Shell interest 80%), for which development options are being evaluated. Additionally, in the operated portfolio, in the Santos Basin, we have 10 offshore exploration concessions in the Barreirinhas Basin (Shell interests ranging from 50% to 100%) and a pre-salt PSC for Alto Cabo Frio Oeste (Shell interest 55% as operator).

In March 2018, during the fifteenth deep-water bid round organised by the Brazilian National Petroleum Agency (ANP), we secured two exploration blocks as operator, one in the Potiguar Basin (Shell Interest 100%) and one in the Campos Basin (Shell Interest 40%). In September 2018, we added the Saturno block in the fifth pre-salt bid round (Shell interest 50%), in the Santos Basin.

In our non-operated portfolio, in the Santos Basin, we have a 30% interest in the BM-S-9, Entorno de Sapinhoá and BM-S-9A blocks with the Sapinhoá and Lapa fields, as well as 25% interests in the BM-S-11 and BM-S-11A concessions with the Lula (including Iracema area), Berbigão, Sururu and Atapú fields, which are accumulations subject to ongoing unitisation agreements. Lula unitisation impact (Shell interest of 23%, compared to 25% applicable until the unitisation effective date) was recognised in September

2018, as negotiations are in an advanced stage, with a subsequent cash settlement related to pre-unitisation costs and production expected during 2019. The Sapinhoá unitisation (combined Shell interest unaltered at 30%, being 1.1% held through the Entorno de Sapinhoá PSC and 28.9% via the BM-S-9 concession contract) has been in effect since November 2018 and the first tranche of cash settlement occurred in December 2018. Also, in the Santos Basin, we hold a 20% non-operator interest in BM-S-50 offshore exploration block, where the Sagitário prospect was discovered. In addition, we hold a 20% non-operator interest in the Libra block, where commerciality of Mero I was declared, well tests were initiated and where exploration is ongoing. The Libra field is also subject to unitisation with adjoining areas, for which a unitisation agreement is still subject to government approval.

In March 2018, during the fifteenth deep-water bid round, we won two additional, non-operated, deep-water exploration blocks in the Potiguar Basin (Shell interest 40%) and in June 2018, we won a PSC to explore the Tres Marias block at the fourth pre-salt bid round held by the ANP (Shell interest 40%).

The activities of operated and non-operated fields are currently supported by 15 producing deep-water FPSOs, of which the fourteenth (P69) delivered first oil in October 2018 and fifteenth (P67) in February 2019. Ramp up to full production capacity is expected during 2019. Two additional FPSOs are expected to be brought online over the period 2019-2020 (Berbigão (P68) and Atapú I (P70)).

Rest of South America

We also have interests in Colombia and Uruguay.

TRADING AND SUPPLY

We market and trade crude oil from most of our Upstream operations.

Oil and gas information

Proved developed and undeveloped reserves of Shell subsidiaries and Shell share of joint ventures and associates

	Crude oil and natural gas liquids (million barrels)	Natural gas (thousand million scf)	Synthetic crude oil (million barrels)	Bitumen (million barrels)	Total (million boe) [A]
Shell subsidiaries					
Increase/(decrease) in 2018:					
Revisions and reclassifications	489	2,766	32	—	997
Improved recovery	41	7	—	—	42
Extensions and discoveries	329	836	—	—	474
Purchases and sales of minerals in place	(73)	(599)	—	—	(175)
Total before taking production into account	786	3,011	32	—	1,337
Production [B]	(600)	(3,487)	(20)	—	(1,222)
Total	186	(476)	12	—	117
At January 1, 2018	4,300	30,324	649	—	10,177
At December 31, 2018	4,486	29,847	661	—	10,294
Shell share of joint ventures and associates					
Increase/(decrease) in 2018:					
Revisions and reclassifications	(4)	(3,566)	—	—	(617)
Improved recovery	—	—	—	—	0
Extensions and discoveries	18	5	—	—	19
Purchases and sales of minerals in place	—	(37)	—	—	(6)
Total before taking production into account	16	(3,598)	—	—	(604)
Production [C]	(38)	(743)	—	—	(166)
Total	(23)	(4,341)	—	—	(771)
At January 1, 2018	313	10,108	—	—	2,056
At December 31, 2018 [D]	290	5,768	—	—	1,285
Total					
Increase/(decrease) before taking production into account	802	(587)	32	—	733
Production	(639)	(4,230)	(20)	—	(1,388)
Increase/(decrease)	163	(4,817)	12	—	(655)
At January 1, 2018	4,613	40,432	649	—	12,233
At December 31, 2018	4,776	35,615	661	—	11,578
Reserves attributable to non-controlling interest in					
Shell subsidiaries at December 31, 2018	—		331	—	331

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 standard cubic feet (scf) per barrel.

[B] Included 43 million barrels of oil equivalent (boe) consumed in operations (natural gas: 245 thousand million scf; synthetic crude oil: 1 million barrels).

[C] Included 7 million boe consumed in operations (natural gas: 41 thousand million scf).

[D] Includes 110 million boe related to our 36.8 % interest in the Danish Underground Consortium in Denmark. In October 2018, we announced the sale of this interest. The transaction is expected to be completed in 2019, subject to partner and regulatory approvals.

PROVED RESERVES

The proved oil and gas reserves of Shell subsidiaries and the Shell share of the proved oil and gas reserves of joint ventures and associates are set out in more detail in "Supplementary information – oil and gas (unaudited)" on pages 215-226.

Before taking production into account, our proved reserves increased by 733 million boe in 2018. This comprised of increases of 1,337 million boe from Shell subsidiaries and of decreases of 604 million boe from the Shell share of joint ventures and associates.

After taking production into account, our proved reserves decreased by 655 million boe in 2018 to 11,578 million boe at December 31, 2018.

SHELL SUBSIDIARIES

Before taking production into account, Shell subsidiaries' proved reserves increased by 1,337 million boe in 2018. This comprised of increases of 786 million barrels of oil and natural gas liquids, 519 million boe (3,011 thousand million scf) of natural gas and 32 million barrels of synthetic crude oil. The 1,337 million boe increase is the net effect of a net increase of 997 million boe from revisions and reclassifications, an increase of 42 million boe from improved recovery, an increase of 474 million boe from extensions and discoveries, and a net decrease of 175 million boe related to purchases and sales of minerals in place.

After taking into account production of 1,222 million boe (of which 43 million boe were consumed in operations), Shell subsidiaries' proved reserves increased by 117 million boe in 2018 to 10,294 million boe. In 2018, Shell subsidiaries' proved developed reserves (PD) decreased by 126 million boe to 8,054 million boe, and proved undeveloped reserves (PUD) increased by 242 million boe to 2,239 million boe.

SHELL SHARE OF JOINT VENTURES AND ASSOCIATES

Before taking production into account, the Shell share of joint ventures and associates' proved reserves decreased by 604 million boe in 2018. This comprised an increase of 16 million barrels of crude oil and natural gas liquids and a decrease of 620 million boe (3,598 thousand million scf) of natural gas. The 604 million boe decrease comprises a net decrease of 617 million boe from revisions and reclassifications and an increase of 19 million boe from extensions and discoveries and a net decrease of 6 million boe related to purchases and sales.

After taking into account production of 166 million boe (of which 7 million boe were consumed in operations), the Shell share of joint ventures and associates' proved reserves decreased by 771 million boe to 1,285 million boe at December 31, 2018.

In 2018, the Shell share of joint ventures and associates' PD decreased by 738 million boe to 1,138 million boe and PUD decreased by 34 million boe to 146 million boe.

PROVED UNDEVELOPED RESERVES

In 2018, Shell subsidiaries and the Shell share of joint ventures and associates' PUD increased by 208 million boe to 2,385 million boe. There were decreases of 702 million boe due to maturation to PD, mainly 218 million boe in Prelude (Australia), 86 million boe in Kolo Creek (Nigeria), and 398 million boe spread across other fields. These were offset by increases of 392 million boe due to revisions and net increases of 493 million boe due to extensions and discoveries – mainly in the Permian Basin (106 million boe), Vito (105 million boe) and Mero (85 million boe) – and decreases of 18 million boe due to sales of minerals in place and increases of 43 million boe due to improved recovery spread across other fields.

In addition to the maturation of 702 million boe from PUD to PD, 169 million boe was matured to PD from contingent resources through PUD as a result of project execution during the year.

PUD held for five years or more (PUD5+) at December 31, 2018, amounted to 272 million boe, a decrease of 280 million boe compared with the end of 2017. These PUD5+ remain undeveloped because development either

requires the installation of compression equipment and the drilling of additional wells, which will be executed when required to support existing gas delivery commitments (Russia), or will take longer than five years because of the complexity and scale of the project (Australia and the UK). The decrease in PUD5+ during 2018 was driven mainly by changes in Prelude (Australia), Kolo Creek (Nigeria), Tempa Rossa (Italy), and Kashagan (Kazakhstan).

The fields with the largest PUD5+ at December 31, 2018, were Jansz-lo and Gorgon (Australia), Lunskeye (Russia), Clair (UK) and Forcados-Yokri (Nigeria).

During 2018, we spent \$9 billion on development activities related to PUD maturation.

DELIVERY COMMITMENTS

We sell crude oil and natural gas from our producing operations under a variety of contractual obligations. Most contracts generally commit us to sell quantities based on production from specified properties, although some natural gas sales contracts specify delivery of fixed and determinable quantities, as discussed below.

In the past three years, we met our contractual delivery commitments, with the notable exceptions of Malaysia, Egypt and Trinidad and Tobago. In the period 2019-2021, we are contractually committed to deliver to third parties, joint ventures and associates a total of approximately 7,700 billion scf of natural gas from our subsidiaries, joint ventures and associates. The sales contracts contain a mixture of fixed and variable pricing formulae that are generally referenced to the prevailing market price for crude oil, natural gas or other petroleum products at the time of delivery.

In the period 2019-2021, we expect to meet our delivery commitments for almost all the areas in which they are carried, with an estimated 73% coming from PD, 5% through the delivery of gas that comes available to us from paying royalties in cash, and 22% from the development of PUD as well as other new projects and purchases.

The key exceptions are:

- Egypt (with a shortfall of 750 billion scf of natural gas), where the diversion of gas from the offshore West Delta Deep Marine fields to domestic use is expected to continue in the near future, leaving our commitment to deliver liquefied natural gas under force majeure; and
- Trinidad and Tobago, where PD for most fields fail the economic test at the yearly average price for natural gas. However, we expect to cover 85% of our delivery commitments from existing developed resource volumes, resulting in an expected true shortfall of some 95 billion scf; and
- In Malaysia, one of the third-party gas supply lines was under repair during 2018, with completion expected in the third quarter of 2019. We expect a contractual shortfall of 35 billion scf in 2019. Force majeure has been declared, and no penalties have been incurred.

Summary of proved oil and gas reserves of Shell subsidiaries and Shell share of joint ventures and associates

(at December 31, 2018)

Based on average prices for 2018

	Crude oil and natural gas liquids (million barrels)	Natural gas (thousand million scf)	Synthetic crude oil (million barrels)	Total (million boe)[A]
Proved developed				
Europe	252	3,794	—	906
Asia	1,568	14,032	—	3,988
Oceania	108	5,844	—	1,116
Africa	335	1,573	—	606
North America				
USA	629	1,706	—	923
Canada	21	721	661	807
South America	633	1,238	—	847
Total proved developed	3,546	28,908	661	9,193
Proved undeveloped				
Europe	125	969	—	292
Asia	215	1,180	—	419
Oceania	21	2,607	—	470
Africa	85	971	—	252
North America				
USA	388	441	—	464
Canada	2	268	—	48
South America	394	271	—	440
Total proved undeveloped	1,230	6,707	—	2,385
Total proved developed and undeveloped				
Europe	377	4,763	—	1,198
Asia	1,783	15,212	—	4,406
Oceania	129	8,451	—	1,586
Africa	420	2,544	—	858
North America		—		
USA	1,017	2,147	—	1,387
Canada	23	989	661	855
South America	1,027	1,509	—	1,288
Total	4,776	35,615	661	11,578
Reserves attributable to non-controlling interest in Shell subsidiaries	—	—	331	331

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

EXPLORATION

In 2018, we made notable discoveries in the US Gulf of Mexico and Nigeria. In January 2018, we announced one of our largest US Gulf of Mexico exploration finds in the past decade from the Whale deep-water well (Shell interest 60% as operator). Other notable discoveries include Epu Deep (Shell interest 30%), a near-field gas discovery in the greater Gbaran area in the Niger Delta of Nigeria, and Dover, a large discovery in the Norphlet geological play in the US Gulf of Mexico (Shell Interest 100% as operator). Discoveries are being evaluated further in order to establish the extent of commercially producible volumes.

We continue to strengthen our portfolio in Brazil, Mauritania, Mexico and the UK. In Brazil, we signed 35-year PSCs for the Saturno (Shell Interest 50% as operator) and Tres Marias (Shell Interest 40%) deep-water exploration blocks in the Santos Basin. We also won four Brazilian deep-water blocks in the Campos and Potiguar basin, we secured one exploration block on our own (Shell interest 100%), and three in joint bids (Shell interest 40%). Of the newly acquired blocks, we will operate two.

In January 2018, we won nine exploration blocks in the deep-water bid round in Mexico; four blocks on our own (Shell interest 100%), four with our partner Qatar Petroleum International Limited (Shell interest 60%), and one with our partner Pemex Exploración y Producción (Shell interest 50%). The total area of these nine blocks is 18,996 square kilometres. We will be the operator of all nine blocks.

In May 2018, in the UK, we acquired a 22.5% non-operated interest in the P1830 licence and a 30% interest in the P1028 and P1189 licences. P1189 includes the Cambo discovery north-west of Shetland and the successful conclusion of well-testing operations on the appraisal well in the Cambo field was confirmed in August 2018.

Additionally, in July 2018, we signed two PSCs with the government of Mauritania for the exploration and potential future production of hydrocarbons in the offshore blocks C-10 and C-19 (Shell Interest 90% as operator). The blocks are located in the West African Atlantic Margin exploration basin with a total area of approximately 23,675 square kilometres.

In 2018, we participated in 50 productive exploratory wells (excluding Shales) with proved reserves allocated (Shell share: 22 wells). In total, the net undeveloped acreage in our exploration portfolio decreased by around 11 million acres in 2018. The largest contributions were relinquishments and divestments in Canada, Kenya, New Zealand, Indonesia and Namibia, offset by new licence entries in Brazil, Mauritania, Mexico, and the UK.

In addition, we participated in 234 Shales productive exploratory wells with proved reserves allocated (Shell share: 118 wells).

For further information, see 'Supplementary Information – oil and gas (unaudited)' on page 235.

LOCATION OF OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
Location of oil and gas exploration and production activities [A] (at December 31, 2018)

	Exploration	Development and/or production	Shell operator[B]
Europe			
Albania	■		■
Bulgaria	■		■
Cyprus		■	
Denmark		■	
Germany	■	■	
Greenland	■		
Italy	■	■	
Netherlands	■	■	■
Norway	■	■	■
UK	■	■	■
Asia			
Brunei	■	■	■
China		■	■
India		■	■
Indonesia		■	
Jordan	■		■
Kazakhstan	■	■	
Malaysia	■	■	■
Myanmar	■		■
Oman	■	■	
Philippines	■	■	■
Qatar		■	■
Russia	■	■	
Turkey	■		■
Oceania			
Australia	■	■	■
Africa			
Algeria	■		■
Egypt	■	■	■
Gabon	■		■
Mauritania	■		■
Morocco	■		
Namibia	■		■
Nigeria	■	■	■
Tanzania	■	■	■
Tunisia		■	■
North America			
Canada	■	■	■
Mexico	■		■
USA	■	■	■
South America			
Argentina	■	■	■
Bolivia	■	■	■
Brazil	■	■	■
Colombia	■		■
Trinidad and Tobago	■	■	■
Uruguay	■		■

[A] Includes joint ventures and associates. Where a joint venture or an associate has properties outside its base country, those properties are not shown in this table.

[B] In several countries where "Shell operator" is indicated, Shell is the operator of some but not all exploration and/or production ventures.

OIL AND GAS PRODUCTION AVAILABLE FOR SALE

Crude oil and natural gas liquids [A]						Thousand barrels
	2018		2017		2016	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe						
Denmark	13,036	—	15,467	—	15,423	—
Italy	10,921	—	8,733	—	6,818	—
Norway	13,528	—	19,529	—	21,656	—
UK	31,431	—	45,020	—	41,426	—
Other [B]	795	1,417	860	1,272	877	872
Total Europe	69,711	1,417	89,609	1,272	86,200	872
Asia						
Brunei	283	18,738	1,138	15,831	952	17,402
Kazakhstan	32,432	—	29,491	—	21,330	—
Malaysia	24,650	—	26,574	—	27,241	—
Oman	76,847	—	77,687	—	80,567	—
Russia	22,003	10,403	22,049	10,899	22,134	10,966
Other [B]	28,769	7,768	30,180	7,859	49,128	7,850
Total Asia	184,984	36,909	187,119	34,589	201,352	36,218
Total Oceania [B]	8,883	—	9,098	—	8,524	1,268
Africa						
Gabon	—	—	9,750	—	12,838	—
Nigeria	53,102	—	56,337	—	62,739	—
Other [B]	8,265	—	9,003	—	9,427	—
Total Africa	61,367	—	75,090	—	85,004	—
North America						
USA	140,035	—	109,430	—	102,795	—
Canada	13,111	—	10,775	—	10,883	—
Total North America	153,146	—	120,205	—	113,678	—
South America						
Brazil	118,681	—	111,093	—	78,477	—
Other [B]	3,414	—	3,325	—	2,935	—
Total South America	122,095	—	114,418	—	81,412	—
Total	600,186	38,326	595,539	35,861	576,170	38,358

[A] Reflects 100% of production of subsidiaries except in respect of production-sharing contracts (PSCs), where the figures shown represent the entitlement of the subsidiaries concerned under those contracts.
[B] Comprises countries where 2018 production was lower than 7,300 thousand barrels or where specific disclosures are prohibited.

Synthetic crude oil						Thousand barrels
	2018		2017		2016	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
North America - Canada	19,514	—	33,183	—	53,603	—

Bitumen						Thousand barrels
	2018		2017		2016	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
North America - Canada	—	—	1,681	—	4,606	—

Natural gas [A]

Million standard cubic feet

	2018		2017		2016	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe						
Denmark	45,027	—	52,105	—	47,143	—
Germany	40,368	—	48,002	—	51,483	—
Ireland	44,833	—	52,515	—	44,660	—
Netherlands	—	271,303	—	343,126	—	402,759
Norway	239,253	—	243,352	—	242,736	—
UK	82,695	—	174,478	—	190,185	—
Other [B]	16,422	—	13,125	—	10,076	—
Total Europe	468,598	271,303	583,577	343,126	586,283	402,759
Asia						
Brunei	21,205	157,476	29,880	158,877	26,918	155,881
China	42,419	—	43,899	—	43,699	—
Kazakhstan	78,575	—	80,623	—	77,122	—
Malaysia	237,102	—	221,590	—	221,661	—
Philippines	44,017	—	42,958	—	45,070	—
Russia	4,044	136,652	4,052	137,890	4,141	133,396
Thailand	25,973	—	60,742	—	59,774	—
Other [B]	378,785	117,976	288,728	118,352	383,763	118,366
Total Asia	832,120	412,104	772,472	415,119	862,148	407,643
Oceania						
Australia	648,735	18,923	591,860	18,708	418,793	36,704
New Zealand	40,153	—	51,943	—	58,239	—
Total Oceania	688,888	18,923	643,803	18,708	477,032	36,704
Africa						
Egypt	148,721	—	122,439	—	145,198	—
Nigeria	232,899	—	236,370	—	184,188	—
Other [B]	30,669	—	36,187	—	34,901	—
Total Africa	412,289	—	394,996	—	364,287	—
North America						
USA	355,075	—	286,529	—	309,298	—
Canada	247,890	—	224,529	—	253,509	—
Total North America	602,965	—	511,058	—	562,807	—
South America						
Bolivia	55,480	—	59,673	—	67,191	—
Brazil	68,865	—	70,100	—	31,020	—
Trinidad and Tobago	104,454	—	73,000	—	78,433	—
Other [B]	8,062	—	8,370	—	7,960	—
Total South America	236,861	—	211,143	—	184,604	—
Total	3,241,721	702,330	3,117,049	776,953	3,037,161	847,106

[A] Reflects 100% of production of subsidiaries except in respect of PSCs, where the figures shown represent the entitlement of the subsidiaries concerned under those contracts.

[B] Comprises countries where 2018 production was lower than 41,795 million scf or where specific disclosures are prohibited.

AVERAGE REALISED PRICE BY GEOGRAPHICAL AREA

Crude oil and natural gas liquids

	2018		2017		2016	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe	68.23	64.24	50.52	46.88	38.62	40.75
Asia	64.06	70.66	49.08	53.44	38.11	43.95
Oceania	61.63	—	45.64	—	36.64	33.76 [A]
Africa	71.02	—	53.39	—	42.73	—
North America - USA	61.87	—	47.23	—	37.50	—
North America - Canada	43.72	—	36.00	—	25.76	—
South America	62.67	—	48.10	—	38.58	—
Total	63.96	70.43	49.00	53.23	38.60	43.58

[A] Included Shell's 14% share of Woodside Petroleum Limited (Woodside) from January 2016 to April 2016. Woodside is a publicly listed company on the Australian Securities Exchange for which we have limited access to data; accordingly, the numbers are estimated. The accounting classification of Woodside was changed from an associate to an investment in securities in April 2016.

Synthetic crude oil

	2018	2017	2016
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America - Canada	48.90	45.90	37.61

Bitumen

	2018	2017	2016
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America - Canada	—	34.46	25.74

Natural gas

	2018		2017		2016	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe	7.12	4.06	5.48	4.77	4.75	4.19
Asia	2.99	7.06	2.84	5.45	2.32	4.63
Oceania	8.95	4.15	6.21	3.11	5.31	4.33 [B]
Africa	3.02	—	2.44	—	2.33	—
North America - USA	3.12	—	3.00	—	2.21	—
North America - Canada	1.35	—	1.85	—	1.71	—
South America	3.50	—	2.93 [A]	—	1.83	—
Total	4.64	5.74	3.90 [A]	5.11	3.16	4.41

[A] As revised, following a reassessment.

[B] Included Shell's 14% share of Woodside from January 2016 to April 2016. Woodside is a publicly listed company on the Australian Securities Exchange for which we have limited access to data; accordingly, the numbers are estimated. The accounting classification of Woodside was changed from an associate to an investment in securities in April 2016.

AVERAGE PRODUCTION COST BY GEOGRAPHICAL AREA

Crude oil, natural gas liquids and natural gas [A]						\$/boe
	2018		2017		2016	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe	15.03	6.37	13.19	5.58	13.70	5.45 [B]
Asia	6.52	6.24	7.71	6.87	6.32	6.62
Oceania	8.41	32.18	9.24	28.83	8.87	16.19 [C]
Africa	8.25	—	9.53	—	9.93	—
North America - USA	12.78	—	16.11	—	21.44	—
North America - Canada	11.58	—	14.53	—	13.59	—
South America	8.60	—	8.08	—	7.64	—
Total	9.66	6.81	10.55	6.82	10.92	6.57 [B]

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

[B] As revised following a reassessment.

[C] Included Shell's 14% share of Woodside from January 2016 to April 2016. Woodside is a publicly listed company on the Australian Securities Exchange for which we have limited access to data; accordingly, the numbers are estimated. The accounting classification of Woodside was changed from an associate to an investment in securities in April 2016.

Synthetic crude oil			\$/barrel
	2018	2017	2016
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	20.15	23.77	26.14

Bitumen				\$/barrel
	2018	2017	2016	
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries	
North America – Canada	—	16.19	14.19	

Downstream

Key statistics

	\$ million, except where indicated		
	2018	2017	2016
Segment earnings [A]	7,601	8,258	6,588
Including:			
Revenue (including inter-segment sales)	340,038	268,979	203,550
Share of profit of joint ventures and associates [A]	1,785	1,956	2,244
Interest and other income	345	154	851
Operating expenses [B]	20,743	19,583	19,681
Depreciation, depletion and amortisation	4,064	3,877	3,681
Taxation charge [A]	1,515	1,783	1,008
Capital investment [B]	7,564	6,416	6,057
Divestments [B]	1,718	2,703	2,889
Refinery availability (%) [C]	91	91	90
Chemical plant availability (%) [C]	93	92	90
Refinery processing intake (thousand b/d)	2,648	2,572	2,701
Oil products sales volumes (thousand b/d)	6,783	6,599	6,483
Chemicals sales volumes (thousand tonnes)	17,644	18,239	17,292

[A] See Note 4 to the "Consolidated Financial Statements" on pages 181-184. Segment earnings are presented on a current cost of supplies basis.

[B] See "Non-GAAP measures reconciliations" on pages 263-264.

[C] The basis of calculation differs from that used for the "Refinery and chemical plant availability" measure in "Performance indicators" on page 28, which excludes downtime due to uncontrollable factors and, in 2017, excludes assets which were not part of Shell's operational performance metrics because of portfolio activity (Fredericia and former Motiva sites).

OVERVIEW

Our Downstream business is made up of a number of different Oil Products and Chemicals activities, part of an integrated value chain, that trades and refines crude oil, and other feedstocks into a range of products which are moved and marketed around the world for domestic, industrial and transport use. The products we sell include gasoline, diesel, heating oil, aviation fuel, marine fuel, biofuel, lubricants, bitumen and sulphur. In addition, we produce and sell petrochemicals for industrial use worldwide.

Our Oil Products activities comprise Refining and Trading, and Marketing, referred to as classes of business. Marketing includes Retail, Lubricants, Business to Business (B2B), Pipelines and Biofuels. Chemicals has major manufacturing plants, located close to refineries, and its own marketing network. In Trading and Supply, we trade crude oil, oil products and petrochemicals, to optimise feedstocks for Refining and Chemicals, to supply our Marketing businesses and third parties, and for our own profit.

BUSINESS CONDITIONS

Global oil demand grew by 1.2 million barrels per day (b/d), or 1.2%, to 99.2 million b/d, according to the International Energy Agency's (IEA) Oil Market Report published in January 2019 (Oil Market Report). Oil demand growth in 2018 was 0.4 million b/d lower than in 2017.

Industry gross refining margins were lower on average in 2018 than in 2017 in each of the key refining hubs of Europe, Singapore and the USA. Periods of high crude prices led to reductions in oil products demand. Refinery capacity additions, especially in the Middle East and Asia, combined with tempered demand growth have led to generally lower refinery utilisations. Refinery activity continued to be low in Latin America.

Cracker industry margins fell in all three main regions in 2018. Asian naphtha cracker margins fell sharply in the fourth quarter, amid continuing concerns

over the potential impact of US tariffs, while US ethane cracker margins came under pressure from new cracker unit start-ups. Supported by healthy European demand, European naphtha cracker margins decreased the least during 2018.

See "Market overview" on page 23.

REFINERY AND CHEMICAL PLANT AVAILABILITY

Refinery availability was 91% in 2018, unchanged from 2017.

Chemicals plant availability was 93% in 2018, compared with 92% in 2017, benefiting from lower unplanned downtime at three of our sites (Moerdijk, Pernis and Scotford).

OIL PRODUCTS AND CHEMICALS SALES

Oil products sales volumes increased by 3% in 2018 compared with 2017, reflecting higher trading volumes and, to a lesser extent, higher marketing volumes despite the sale of the Downstream Argentina business to Raízen (volumes reported at 50% Shell share).

Chemicals sales volumes decreased by 3% in 2018 compared with 2017, principally due to the divestment of assets in Japan and operational issues, including Rhine water levels affecting supply in Germany and a fire at the plant in Stanlow in the UK.

EARNINGS 2018-2017

Segment earnings in 2018 of \$7,601 million are presented on a current cost of supplies basis (see "Summary of results" on page 24). Segment earnings on a first-in, first-out basis were \$7,143 million, which were \$458 million lower than on a current cost of supplies basis (2017 first-in, first-out segment earnings were \$964 million higher). See "Non-GAAP measures reconciliations" on page 263.

Downstream Continued

Segment earnings in 2018 of \$7,601 million were 8% lower than in 2017. Earnings in 2018 included a net gain of \$34 million, compared with a net charge in 2017 of \$824 million, described at the end of this section.

Excluding the impact of these items, earnings in 2018 were \$7,567 million, compared with \$9,082 million in 2017. Refining and Trading accounted for 20% of these 2018 earnings, Marketing for 53% and Chemicals for 27%.

The decrease in Downstream earnings, excluding the net charges, of \$1,515 million (-17%) compared with 2017 was driven by higher operating costs (around \$700 million), adverse foreign exchange effects (around \$530 million), lower base Chemicals margins (around \$370 million), and lower refining margins (around \$150 million), partly offset by higher Marketing margins (around \$360 million). Other impacts were a net charge of around \$120 million. Operating costs were higher due to higher maintenance costs (Chemicals and Refining assets) and higher costs for Marketing growth opportunities. Chemicals margins were impacted by higher feedstock costs globally, higher utility costs and new cracker start-ups in the USA, and operational issues in Europe. Marketing margins benefited from favourable market conditions at the end of the year. The other net negative impacts were mainly portfolio effects.

The decrease in earnings of \$1,515 million analysed by class of business was as follows:

- Refining and Trading earnings were \$949 million lower than in 2017, principally due to higher costs (including impact of a full year of former Motiva site costs) and adverse currency rate exchange effects. Realised refining margins were lower, with weaker margins in all regions except Canada. In the USA, weaker margins were offset by improved operations, particularly at Deer Park following Hurricane Harvey in 2017. Canada saw significant margin improvement due to positive market conditions. Europe suffered a weaker margin environment although boosted by improved operations at our Pernis refinery in the Netherlands. Asia suffered a very low margin environment. Trading earnings were lower than in 2017 from losses due to weaker trading opportunities.
- Marketing earnings were \$20 million lower than in 2017. Weaker Lubricants results were due to higher costs and foreign exchange effects. Raízen earnings were lower due to lower sugar prices. Other negative impacts included the absence of one-off tax gains from 2017 and higher pension costs. Partly offsetting these impacts were improved earnings from our Retail business, benefiting from favourable market conditions at the end of the year. Results from our Retail China ventures fell due to a new tax policy.
- Chemicals earnings were \$546 million lower than in 2017. Results were impacted by higher feedstock costs in the East, higher utility costs and cracker start-ups in the USA and operational issues in Europe (mainly at Stanlow and Rheinland).

Segment earnings in 2018 included a net gain of \$34 million. A number of offsetting items included charges for impairment of \$386 million (mainly expenditure at Bukom and assets at Stanlow), and costs related to restructuring of \$109 million (a number of initiatives across Downstream) more than offset by net gains from fair value accounting of commodity derivatives of \$233 million, gains from disposal of assets \$225 million (mainly our Downstream assets in Argentina and other smaller disposals) and a gain from one-off tax items of \$118 million (mainly corporation tax rate

changes in the Netherlands and the USA). Other net charges of \$47 million included a one-off gain from the Ontario cap-and-trade scheme and onerous contracts related to Stanlow.

Segment earnings in 2017 included a net charge of \$824 million, reflecting impairment charges of \$315 million reported in depreciation (mainly expenditure at Bukom and charges in relation to the Phenol 3 unit at the Chemicals cracker at Deer Park), redundancy and restructuring charges of \$200 million, charges of \$142 million related to US tax reform legislation and a tax rate change in France and other net charges of \$231 million (mainly onerous contract provisions in Refining and Trading and a legal provision in Chemicals). Partly offsetting these impacts were divestment gains of \$39 million (including a \$546 million net charge from the Motiva transaction, mainly related to tax, which were more than offset by gains on the sale of assets in Saudi Arabia, Africa, Australia, Hong Kong and Macau) and a net gain from fair value accounting of commodity derivatives of \$25 million.

EARNINGS 2017-2016

Segment earnings were presented on a current cost of supplies basis which were \$964 million lower in 2017 than on a first-in, first-out basis (2016: \$1,085 million lower).

Segment earnings in 2017 of \$8,258 million were 25% higher than in 2016. Earnings in 2017 included a net charge of \$824 million described above. Earnings in 2016 included a net charge of \$655 million, reflecting redundancy and restructuring charges of \$523 million, impairments of \$506 million, a net charge from fair value accounting of commodity derivatives of \$373 million and other net charges of \$25 million. These were partly offset by net gains on divestments of \$772 million reported in interest and other income.

Excluding the impact of these items, earnings in 2017 were \$9,082 million, compared with \$7,243 million in 2016. Refining and Trading accounted for 27% of these 2017 earnings, Marketing for 44% and Chemicals for 29%.

The increase in Downstream earnings, excluding the net charges, of \$1,839 million (25%) compared with 2016 was driven by higher realised refining and trading margins (around \$1,230 million), improved chemical margins (around \$870 million), a lower effective tax rate (around \$380 million) and other net negative impacts (around \$640 million). Refining and trading margins were higher in part following the Motiva transaction in May 2017. Chemicals margins were higher from improved operating performance and the lower effective tax rate resulting from one-off impacts and a change in the geographical split of earnings. The other net negative impacts included higher depreciation charges and costs, following the Motiva transaction, and lower marketing margins, impacted by a shortage of feedstock from our Pearl gas-to-liquids (GTL) plant in Qatar to our Lubricants business.

CAPITAL INVESTMENT

Capital investment was \$7.6 billion in 2018, compared with \$6.4 billion in 2017. Capital investment in Refining was in line with 2017 at \$2.4 billion (including capital investment to our former Motiva assets in both years). Capital investment in Marketing increased by \$0.5 billion to \$2.0 billion (mainly attributable to growth in China, India, Indonesia, Mexico and Russia). In Chemicals, capital investment increased by \$0.7 billion to \$3.2 billion (increase mainly from investment in our new cracker facilities in Pennsylvania).

DIVESTMENTS

Divestments were \$1.7 billion in 2018, compared with \$2.7 billion in 2017. The principal divestments in 2018 were the sale of Downstream businesses in Argentina to Raízen, the sale of Chemicals assets in Japan and the sale of an interest in Shell Midstream Partners, L.P. in the USA.

PORTFOLIO AND BUSINESS DEVELOPMENTS

We continued to high-grade our portfolio in 2018, including:

- In Argentina, we completed the sale of our Downstream business to Raízen. The business acquired by Raízen will continue the relationship with Shell through various commercial agreements, including long-term brand licence agreements as well as products supply and offtake contracts.
- In the USA, Shell Midstream Partners, L.P., sold approximately 36 million common units for total gross proceeds of \$980 million.
- In Japan, we sold all our shares in Shell Chemicals Japan Limited to Uyeno; making Uyeno the branded distributor of Shell Chemicals products in Japan.
- In Pakistan we transferred 29% of our shareholding in Pakistan Refinery Limited (PKL) to Pakistan State Oil. We retain a shareholding of 4% in the Karachi Refinery.

We also continued to grow selected parts of our portfolio, including:

- In China, the China National Offshore Oil Corporation (CNOOC) and Shell Nanhai B.V. (Shell) announced the official start-up of the second ethylene cracker at their Nanhai petrochemicals complex in Huizhou, Guangdong Province. The new ethylene cracker increases ethylene capacity at the complex by around 1.2 million tonnes per year, more than doubling the capacity of the complex, and benefits from integration with adjacent CNOOC refineries. The new facility will also include a styrene monomer and propylene oxide (SMPO) plant.
- In the USA, we announced the start of production of the fourth alpha olefins unit at the Geismar chemicals manufacturing site (Shell interest 100%). Start-up operations began in December 2018.

BUSINESS AND PROPERTY REFINING AND TRADING

Refining

We have interests in 21 refineries worldwide with the capacity to process a total of 2.8 million barrels of crude oil per day (Shell share). Our refining capacity is 36% in Europe and Africa, 40% in the Americas and 24% in Asia and Oceania.

In 2018, we divested our downstream business in Argentina, including the Buenos Aires Refinery, to Raízen, which is a joint venture between Shell (50%) and Cosan (50%). We also sold about 29% of our shareholding in the Karachi Refinery in Pakistan, retaining a 4% shareholding.

Trading and Supply

Through our main trading offices in London, Houston, Singapore, Dubai and Rotterdam, we trade crude oil, natural gas, LNG, electricity, refined products, chemical feedstocks and environmental products. Trading and Supply trades in physical and financial contracts, lease storage and transportation capacities, and manages shipping and wholesale commercial fuel activities globally. This includes supplying feedstocks for our refineries and chemical plants and finished products such as gasoline, diesel and aviation fuel to our Marketing businesses and customers.

Operating in around 30 countries, with more than 140 Shell and joint venture terminals, we believe our supply and distribution infrastructure is well positioned to make deliveries around the world.

Through its Shipping and Maritime business, Trading and Supply has an interest in around 2,000 Shell-associated vessels and other floating facilities on any given day, including managing one of the world's largest fleets of LNG carriers. Shipping and Maritime enables the Shell Trading organisation to deliver safely on its contracts. This includes supplying feedstocks for our refineries and chemical plants and finished products such as gasoline, diesel and aviation fuel to our Marketing businesses and customers.

Shell Wholesale Commercial Fuels provides transport, industrial and heating fuels. Our range of products, from reliable main-grade fuels to premium products, is designed to provide tangible vehicle and business benefits.

MARKETING

Retail

There were more than 44,000 Shell-branded retail stations operating in over 75 countries at the end of 2018. We operate different models across these markets, including full ownership of retail stations through to franchise agreements. Every day, more than 30 million customers pass through these sites to buy fuel and convenience items, including beverages and snacks, and services such as car washes.

We have more than 100 years' experience in fuel development. Aided by our innovative partnership with Scuderia Ferrari, we have concentrated on developing fuels with special formulations designed to clean engines and improve performance. We sold such fuels under the Shell V-Power brand in 63 countries as at the end of 2018. In selected markets, we are increasingly offering customers lower-carbon energy solutions including biofuels, electric vehicle charging, hydrogen and various gaseous fuels like LNG.

Lubricants

Across more than 100 countries, we produce, market and sell technically advanced lubricants for passenger cars, motorcycles, trucks, coaches, and machinery used in the manufacturing, mining, power generation, agriculture and construction sectors.

We also manufacture premium lubricants from natural gas using GTL base oils produced at our Pearl GTL plant in Qatar (see "Integrated Gas" page 31).

We have a global lubricants supply chain with a network of four base oil manufacturing plants, 31 lubricant blending plants, nine grease plants and three GTL base oil storage hubs.

Through our marine activities, we primarily provide lubricants, but also fuels and related technical services, to the shipping and maritime sectors. We supply around 180 grades of lubricants and six types of fuel to vessels worldwide, ranging from large ocean-going tankers to small fishing boats.

Business to Business

Our Business-to-Business (B2B) activities encompass the sale of fuels and speciality products and services to a broad range of commercial customers.

Shell Aviation supplies fuel at about 900 airport locations and operates across 45 countries (refuelling and lubricants presence).

Shell Bitumen supplies over 1,600 customers across 36 countries and provides enough bitumen to resurface 450 kilometres of road lanes every day. It also invests in technology research and development to create innovative products.

Shell Sulphur Solutions is a business that manages the complete value chain of sulphur, from refining to marketing. The business provides sulphur for industries such as mining and textiles and also develops new products that incorporate sulphur, such as fertilisers.

Pipelines

Shell Pipeline Company LP (Shell interest 100%) owns and operates 10 tank farms across the USA. It transports more than 1.5 billion barrels of crude oil and refined products a year through about 6,000 kilometres of pipelines in the Gulf of Mexico and five US states. Our various non-Shell-operated ownership interests provide about a further 13,000 pipeline kilometres.

We carry more than 40 types of crude oil and more than 20 grades of gasoline, as well as diesel, aviation fuel, chemicals and ethylene.

Shell Midstream Partners, L.P., a midstream limited partnership, owns, operates, develops and acquires pipelines and other midstream assets in the USA. Its assets consist of interests in entities that own crude oil and refined products pipelines and terminals that serve as key infrastructure to transport onshore and offshore crude oil production to Gulf Coast and Midwest refining markets. It also delivers refined products from those markets to major demand centres. Its assets also include interests in entities that own natural gas and refinery gas pipelines that transport offshore natural gas to market hubs and deliver refinery gas from refineries and plants to chemical sites along the Gulf Coast. Shell controls the general partner.

Biofuels

Raízen, our joint venture in Brazil (Shell interest 50%), produces ethanol from sugar cane, with an annual production capacity of more than 2 billion litres; exports sugar, with an annual production of about 4.2 million tonnes; and manages a retail network. Raízen opened its first cellulosic ethanol plant at its Costa Pinto mill in Brazil in 2015, which produced almost 15.5 million litres in 2018. When fully operational, the mill is expected to produce around 40 million litres a year of advanced biofuels from sugar-cane residues.

CHEMICALS

Manufacturing

Our plants produce a range of base chemicals, including ethylene, propylene and aromatics, as well as intermediate chemicals such as styrene monomer, propylene oxide, solvents, detergent alcohols, ethylene oxide and ethylene glycol. We have the capacity to produce around 6.5 million tonnes of ethylene a year.

Marketing

Each year, we supply about 18 million tonnes of petrochemicals to around 1,000 industrial customers worldwide. Our products are used to make numerous everyday items, from clothing and cars to detergents and bicycle helmets.

DOWNSTREAM BUSINESS ACTIVITIES WITH IRAN, SUDAN AND SYRIA

IRAN

Shell transactions with Iran are disclosed separately. See "Section 13(r) of the US Securities Exchange Act of 1934 Disclosure" on page 262.

SUDAN

We ceased all operational activities in Sudan in 2008.

SYRIA

We ceased supplying polyols, via a Netherlands-based distributor, to private sector customers in Syria in 2018. Polyols are commonly used for the production of foam in mattresses and soft furnishings.

DOWNSTREAM DATA TABLES

The tables below reflect Shell subsidiaries and instances where Shell owns the crude oil or feedstocks processed by a refinery. In addition, the tables include the Buenos Aires refinery on a 50% basis following the sale to Raízen in October 2018 (100% basis up to that date). Other joint ventures and associates are only included where explicitly stated.

Oil products - cost of crude oil processed or consumed [A]		\$/barrel		
	2018	2017	2016	
Total	59.94	46.78	34.47	

[A] Includes Upstream and Integrated Gas margins on crude oil supplied by Shell subsidiaries, joint ventures and associates.

Crude distillation capacity [A]		Thousand b/calendar day [B]		
	2018	2017	2016	
Europe	970	970	973	
Asia	704	704	808	
Oceania	—	—	—	
Africa	82	82	82	
Americas	1,157	1,176	1,223	
Total	2,913	2,932	3,086	

[A] Average operating capacity for the year, excluding mothballed capacity.

[B] Calendar day capacity is the maximum sustainable capacity adjusted for normal unit downtime.

Ethylene capacity [A]		Thousand tonnes/year		
	2018	2017	2016	
Europe	1,701	1,702	1,702	
Asia	2,529	1,904	2,222	
Oceania	—	—	—	
Africa	—	—	—	
Americas	2,268	2,267	2,235	
Total	6,498	5,873	6,159	

[A] Includes the Shell share of capacity entitlement (offtake rights) of joint ventures and associates, which may be different from nominal equity interest. Nominal capacity is quoted at December 31.

Oil products - crude oil processed [A]		Thousand b/d		
	2018	2017	2016	
Europe	897	892	898	
Asia	545	528	563	
Oceania	—	—	—	
Africa	66	54	68	
Americas	1,041	997	1,088	
Total	2,549	2,471	2,617	

[A] Includes natural gas liquids, share of joint ventures and associates and processing for others.

Refinery processing intake [A]		Thousand b/d		
	2018	2017	2016	
Crude oil	2,434	2,364	2,317	
Feedstocks	214	208	384	
Total	2,648	2,572	2,701	
Europe	896	892	896	
Asia	543	539	568	
Oceania	—	—	—	
Africa	66	54	67	
Americas	1,143	1,087	1,170	
Total	2,648	2,572	2,701	

[A] Includes crude oil, natural gas liquids and feedstocks processed in crude distillation units and in secondary conversion units.

Refinery processing outturn [A]		Thousand b/d		
	2018	2017	2016	
Gasolines	966	955	1,021	
Kerosines	321	290	326	
Gas/Diesel oils	965	925	942	
Fuel oil	284	265	277	
Other	321	334	386	
Total	2,858	2,769	2,952	

[A] Excludes own use and products acquired for blending purposes.

Oil product sales volumes [A][B]		Thousand b/d		
	2018	2017	2016	
Europe				
Gasolines	323	317	309	
Kerosines	294	272	258	
Gas/Diesel oils	745	758	765	
Fuel oil	178	170	183	
Other products	314	362	287	
Total	1,854	1,879	1,802	

Asia				
Gasolines	373	399	388	
Kerosines	210	216	195	
Gas/Diesel oils	543	516	519	
Fuel oil	407	349	354	
Other products	620	536	593	
Total	2,153	2,016	2,049	
Oceania				
Gasolines	—	—	—	
Kerosines	—	23	55	
Gas/Diesel oils	—	—	—	
Fuel oil	—	—	—	
Other products	—	—	—	
Total	—	23	55	

Africa				
Gasolines	42	43	41	
Kerosines	10	13	10	
Gas/Diesel oils	74	78	66	
Fuel oil	2	2	1	
Other products	6	6	7	
Total	134	142	125	

Americas				
Gasolines	1,446	1,415	1,331	
Kerosines	236	212	205	
Gas/Diesel oils	567	545	540	
Fuel oil	117	92	69	
Other products	276	275	307	
Total	2,642	2,539	2,452	

Total product sales [C]				
Gasolines	2,184	2,174	2,069	
Kerosines	750	736	723	
Gas/Diesel oils	1,929	1,897	1,890	
Fuel oil	704	613	607	
Other products	1,216	1,179	1,194	
Total	6,783	6,599	6,483	

[A] Excludes deliveries to other companies under reciprocal sale and purchase arrangements, which are in the nature of exchanges. Sales of condensate and natural gas liquids are included.

[B] Includes the Shell share of Raizen's sales volumes.

[C] Certain contracts are held for trading purposes and reported net rather than gross. The effect in 2018 was a reduction in oil product sales of approximately 458,000 b/d (2017: 596,000 b/d; 2016: 839,000 b/d).

Downstream Continued

Chemicals sales volumes [A]		Thousand tonnes		
	2018	2017	2016	
Europe				
Base chemicals	4,069	4,059	3,670	
Intermediates and others	1,994	2,056	2,073	
Total	6,063	6,115	5,743	
Asia				
Base chemicals	2,140	2,515	2,200	
Intermediates and others	3,082	3,243	2,927	
Total	5,222	5,758	5,127	
Oceania				
Base chemicals	—	—	—	
Intermediates and others	—	—	—	
Total	—	—	—	
Africa				
Base chemicals	—	—	—	
Intermediates and others	—	—	22	
Total	—	—	22	
Americas				
Base chemicals	3,842	3,839	4,041	
Intermediates and others	2,517	2,527	2,359	
Total	6,359	6,366	6,400	
Total product sales				
Base chemicals	10,051	10,413	9,911	
Intermediates and others	7,593	7,826	7,381	
Total	17,644	18,239	17,292	

[A] Excludes feedstock trading and by-products.

MANUFACTURING PLANTS AT DECEMBER 31, 2018

Refineries in operation

Thousand barrels/calendar day, 100% capacity [B]

	Location	Asset class	Shell interest (%) [A]	Crude distillation capacity	Thermal cracking/ visbreaking/ coking	Catalytic cracking	Hydro- cracking
Europe							
Denmark	Fredericia	●	100	68	39	—	—
Germany	Miro [C]		32	287	36	87	—
	Rheinland	■●	100	325	44	—	80
	Schwedt [C]		38	214	40	54	—
Netherlands	Pernis	■●	100	404	45	48	83
Asia							
Japan	Mizue (Toa) [C]	●◆	2	64	24	38	—
	Yamaguchi [C]	◆	1	110	—	25	—
	Yokkaichi [C]	●◆	3	234	—	55	—
Pakistan	Karachi [C]		4	43	—	—	—
Philippines	Tabangao		55	96	31	—	—
Saudi Arabia	Al Jubail [C]	●◆	50	292	61	—	45
Singapore	Pulau Bukom	■●	100	463	72	34	55
Africa							
South Africa	Durban [C]	◆	36	165	23	34	—
Americas							
Argentina	Buenos Aires [C]	●◆	50	99	18	20	—
Canada							
Alberta	Scotford	◆	100	92	—	—	74
Ontario	Sarnia	◆	100	73	4	19	9
USA							
California	Martinez	●	100	144	43	65	38
Louisiana	Convent	◆	100	239	—	83	49
	Norco	■	100	229	26	108	39
Texas	Deer Park	■●	50	312	82	68	53
Washington	Puget Sound	●◆	100	137	23	52	—

[A] Shell interest is rounded to the nearest whole percentage point; Shell share of production capacity may differ.

[B] Calendar day capacity is the maximum sustainable capacity adjusted for normal unit downtime.

[C] Not operated by Shell.

- Integrated refinery and chemical complex.
- Refinery complex with cogeneration capacity.
- ◆ Refinery complex with chemical unit(s).

Major chemical plants in operation [A]

		Thousand tonnes/year, Shell share capacity [B]				
	Location	Ethylene	Styrene monomer	Ethylene glycol	Higher olefins [C]	Additional products
Europe						
Germany	Rheinland	315	—	—	—	A
Netherlands	Moerdijk	971	816	153	—	A, I
UK	Mossmorran [D]	415	—	—	—	—
	Stanlow [D] [E]	—	—	—	315	I
Asia						
China	Nanhai [D]	1,100	650	415	—	A, I, P
Singapore	Jurong Island	281	1,069	1,159	—	A, I, P, O
	Pulau Bukom	1,148	—	—	—	A, I
Americas						
Canada	Scotford	—	485	520	—	A, I
USA	Deer Park	836	—	—	—	A, I
	Geismar	—	—	400	965	I
	Norco	1,432	—	—	—	A
Total		6,498	3,020	2,647	1,280	

[A] Major chemical plants are large integrated chemical facilities, typically producing a range of chemical products from an array of feedstocks, and are a core part of our global Chemicals business.

[B] Shell share of capacity of subsidiaries, joint arrangements and associates (Shell and non-Shell-operated), excluding capacity of the Infineum additives joint ventures.

[C] Higher olefins are linear alpha and internal olefins (products range from C6-C2024).

[D] Not operated by Shell.

[E] Our Shell Higher Olefins Plant (SHOP) facilities at Stanlow suffered a fire in August 2018; rebuild was considered uneconomic and the decision was taken in December 2018 to decommission all Shell units on site.

A Aromatics, lower olefins.

I Intermediates.

P Polyethylene, polypropylene.

O Other.

Other chemical locations [A]

	Location	Products
Europe		
Germany	Karlsruhe	A
	Schwedt	A
Netherlands	Pernis	A, I, O
Americas		
Argentina	Buenos Aires	I
Canada	Sarnia	A, I
USA	Martinez	O
	Mobile	A
	Puget Sound	I

[A] Other chemical locations reflect locations with smaller chemical units, typically serving more local markets.

A Aromatics, lower olefins.

I Intermediates.

O Other.

Corporate

Earnings

	2018	2017	2016
Segment earnings	(1,479)	(2,416)	(1,751)
Comprising:			
Net interest and investment expense [A]	(2,192)	(2,413)	(1,824)
Net foreign exchange gains/(losses) [B]	(67)	(292)	3
Taxation and other [C]	780	289	70

\$ million

[A] Mainly Shell's interest expense (excluding accretion expense) and interest income, together with the Shell share of joint ventures and associates' net interest expense, and net gains on sales from Shell insurance entities' portfolio of debt securities.

[B] On Shell's financing activities, together with the Shell share of joint ventures and associates' net foreign exchange gains/(losses) on financing activities.

[C] Other earnings mainly comprise headquarters and central functions' costs not recovered from business segments, and net gains on sale of properties.

OVERVIEW

The Corporate segment covers the non-operating activities supporting Shell. It comprises Shell's holdings and treasury organisation, its self-insurance activities and its headquarters and central functions. All finance expense and income as well as related taxes are included in the Corporate segment earnings rather than in the earnings of the business segments.

The holdings and treasury organisation manages many of the Corporate entities and is the point of contact between Shell and external capital markets. It conducts a broad range of transactions - from raising debt instruments to transacting foreign exchange. Treasury centres in London and Singapore support these activities.

Headquarters and central functions provide business support in the areas of communications, finance, health, human resources, information technology, legal services, real estate and security. They also provide support for the shareholder-related activities of the Company. The central functions are supported by business service centres located around the world, which process transactions, manage data and produce statutory returns, among other services. The majority of the headquarters and central-function costs are recovered from the business segments. Those costs that are not recovered are retained in Corporate.

EARNINGS 2018-2016

Segment earnings in 2018 were a loss of \$1,479 million, compared with a loss of \$2,416 million in 2017 and a \$1,751 million loss in 2016.

Net interest and investment expense decreased by \$221 million compared with 2017. This was due to a decrease in interest expense due to more capitalised interest, coupled with higher interest income from increases to both cash levels and higher interest rates. In 2017, net interest and investment expense increased by \$589 million compared with 2016. Interest expense increased due to the inclusion of a full year of interest on debt assumed on the BG acquisition in 2016, finance leases entered into during 2017 and higher interest rates (see Note 14 to the "Consolidated Financial Statements" on page 191).

The Corporate segment includes net foreign exchange gains/(losses) from financing positions. Net foreign exchange gains/(losses) generally relate to the impact of changes in exchange rates on non-functional currency loans and cash balances in operating companies. In 2018, unfavourable exchange rate movements resulted in a net foreign exchange loss. In 2017 there were exchange rate gains, but these were more than offset by a charge of \$545 million from restructuring of funding in North America.

Taxation and other earnings increased by \$491 million in 2018, compared with 2017, due to increased tax credits from foreign exchange losses, which were partially offset by increased corporate expenses and depreciation

charges. In 2017, taxation and other earnings increased by \$219 million compared with 2016, due to lower costs incurred in connection with the BG acquisition and integration in 2017, which were partly offset by a charge in 2017 due to US tax reform legislation.

SELF-INSURANCE

We mainly rely on self-insurance for many of our risk exposures and capital is set aside to meet self-insurance obligations (see "Risk factors" on page 18). We seek to ensure that the capital held to support the self-insurance obligations is at a level at least equivalent to what would be held in the third-party insurance market. Periodically, surveys of key assets are undertaken that provide risk-engineering knowledge and best practices to Shell subsidiaries with the aim to reduce their exposure to hazard risks. Actions identified during these surveys are monitored to completion.

INFORMATION TECHNOLOGY AND CYBER SECURITY

Given our digitalisation efforts and increasing reliance on information technology (IT) systems for our operations, we continuously monitor external developments and actively share information on threats and security incidents. Shell employees and contract staff are subject to mandatory courses and regular awareness campaigns aimed at protecting us against cyber threats. We periodically test and adapt cyber-security response processes and seek to enhance our security monitoring capability.

Given our dependence on IT systems for our operations and the increasing role of digital technologies across our business, we are aware that cyber-security attacks could cause significant harm to Shell in the form of loss of productivity, loss of intellectual property, regulatory fines and/or reputational damage. As a result, we continuously measure and, where required, further improve our cyber-security capabilities to reduce the likelihood of successful cyberattacks. Our cyber-security capabilities are embedded into our IT systems and our IT landscape is protected by various detective and protective technologies. The identification and assessment capabilities are built into our support processes and adhere to industry best practices. The security of IT services, operated by external IT companies, is managed through contractual clauses and through formal supplier assurance reports.

Shell is frequently subject to cyberattacks. In 2018, none of these events led to breaches of our business-critical IT landscape and, as such, did not result in any material business impact. When significant incidents occur, they are followed up with a thorough root-cause analysis and, if needed, will result in appropriate follow-up actions.

See "Risk factors" on page 19.

Liquidity and capital resources

We manage our businesses to deliver strong cash flows to fund investment for profitable growth. Our aim is that, across the business cycle, “cash in” (including cash from operations and divestments) at least equals “cash out” (including capital expenditure, interest and dividends), while maintaining a strong balance sheet. Our priorities for applying our cash are the servicing and reduction of debt commitments, payment of dividends, followed by a balance of capital investment and share buybacks.

FINANCIAL CONDITION AND LIQUIDITY

Strong operational performance in 2018, together with improved commodity prices and proceeds from our divestment programme, supported the commencement of a share buyback programme of at least \$25 billion, by the end of 2020, subject to further progress with debt reduction and oil price conditions. \$3.9 billion of share buybacks were completed in 2018. Gearing was reduced in the year and, at December 31, 2018, was 20.3% (2017: 25.0%). Gearing is a key measure of our capital structure and is defined as net debt (total debt less cash and cash equivalents) as a percentage of total capital (net debt plus total equity). With effect from 2018, the net debt calculation includes the fair value of derivative financial instruments used to hedge foreign exchange and interest rate risks relating to debt and associated collateral balances. We believe that this amendment is useful, because it reduces the volatility of net debt caused by fluctuations in foreign exchange and interest rates and eliminates the potential impact of related collateral payments or receipts. Across the business cycle, we aim to manage gearing within a range of 0-30%. Note 14 to the “Consolidated Financial Statements” on page 191 provides information on our debt arrangements, including gearing.

We are affected by the global macroeconomic environment, as well as financial and commodity market conditions. This exposes us to treasury and trading risks, including liquidity risk, market risk (interest rate risk, foreign exchange risk and commodity price risk) and credit risk. See “Risk factors” on page 18 and Note 19 to the “Consolidated Financial Statements” on pages 202-207. The size and scope of our businesses require a robust financial control framework and effective management of our various risk exposures.

LIQUIDITY

We satisfy our funding and working capital requirements from the cash generated from our operations, the issuance of debt and divestments. In 2018, access to the international debt capital markets remained strong, with our debt principally financed from these markets through central debt programmes consisting of:

- a \$10 billion global commercial paper (CP) programme, with maturities not exceeding 270 days;
- a \$10 billion US CP programme, with maturities not exceeding 397 days;
- an unlimited Euro medium-term note (EMTN) programme (also referred to as the Multi-Currency Debt Securities Programme); and
- an unlimited US universal shelf (US shelf) registration.

All these CP, EMTN and US shelf issuances are issued by Shell International Finance B.V., the issuance company for Shell, with its debt being guaranteed by Royal Dutch Shell plc (the Company).

We also maintain a committed credit facility, which was increased in September 2018 to \$8.8 billion and which expires in 2020. It remained undrawn at December 31, 2018. This facility and internally available liquidity provide back-up coverage for our CP programmes. Other than certain borrowing by local subsidiaries, we do not have any other committed credit facilities.

Our total debt decreased by \$8.8 billion in 2018 to \$76.8 billion at December 31, 2018. The amount excluding finance leases will mature as follows: 15% in 2019; 9% in 2020; 8% in 2021; 7% in 2022; and 61% in 2023 and beyond. The portion of debt maturing in 2019 is expected to be repaid from a combination of cash balances, cash generated from operations, divestments and the issuance of new debt.

In 2018, we issued \$3 billion of bonds under our US shelf registration. Periodically, for working capital purposes, we issued CP. We believe our current working capital is sufficient for our present requirements.

While our subsidiaries are subject to restrictions, such as foreign withholding taxes on the transfer of funds in the form of cash dividends, loans or advances, such restrictions are not expected to have a material impact on our ability to meet our cash obligations.

MARKET RISK AND CREDIT RISK

In the normal course of business, financial instruments of various kinds are used for the purposes of managing exposure to commodity price, foreign exchange and interest rate movements. Our treasury and trading operations are highly centralised and seek to manage credit exposures associated with our substantial cash, commodity, foreign exchange and interest rate positions. Our portfolio of cash investments is diversified to avoid concentrating risk in any one instrument, country, or counterparty. We monitor our investments and adjust them in light of new market information. Exposure to failed financial and trading counterparties was not material in 2018. Treasury standards are applicable to all our subsidiaries, and each subsidiary is required to adopt a treasury policy consistent with these standards. Other than in exceptional cases, the use of external derivative instruments is confined to specialist trading and central treasury organisations that have appropriate skills, experience, supervision, control and reporting systems.

PENSION COMMITMENTS

We have substantial pension commitments, the funding of which is subject to capital market risks (see “Risk factors” on page 18). We address key pension risks in a number of ways. Principal among these is the Pensions Forum, chaired by the Chief Financial Officer, which oversees Shell’s input to pension strategy, policy and operation. The forum is supported by a risk committee in reviewing the results of assurance processes with respect to pension risks. In general, local trustees manage the funded defined benefit pension plans, with contributions paid based on independent actuarial valuations in accordance with local regulations. Our total employer contributions to funded and unfunded defined benefit pension plans were \$0.8 billion in 2018 and are estimated to be \$0.9 billion in 2019.

Capitalisation table

	\$ million	
	Dec 31, 2018	Dec 31, 2017
Equity attributable to Royal Dutch Shell plc shareholders	198,646	194,356
Current debt	10,134	11,795
Non-current debt	66,690	73,870
Total debt [A]	76,824	85,665
Total capitalisation	275,470	280,021

[A] Of total debt, \$62.7 billion (2017: \$70.1 billion) was unsecured and \$14.1 billion (2017: \$15.6 billion) was secured. See Note 14 to the “Consolidated Financial Statements” on pages 191-193 for further disclosure on debt.

STATEMENT OF CASH FLOWS

Cash flow from operating activities in 2018 was an inflow of \$53.1 billion, compared with \$35.7 billion in 2017, mainly due to higher earnings and a favourable working capital impact. The increase in cash flow from operating activities in 2017, compared with \$20.6 billion in 2016, was mainly due to higher earnings.

Cash flow from investing activities in 2018 was an outflow of \$13.7 billion, compared with \$8.0 billion in 2017. The increased cash outflow was mainly due to lower proceeds from the sale of assets and securities in 2018. The decreased cash outflow in 2017 compared with \$31.0 billion in 2016 was mainly due to the acquisition of BG in 2016 and higher proceeds from the sale of assets in 2017.

Cash flow from financing activities in 2018 was an outflow of \$32.5 billion, compared with outflows of \$27.1 billion in 2017 and \$0.8 billion in 2016. In 2018, this included payment of dividends to Royal Dutch Shell plc shareholders of \$15.7 billion (2017: \$10.9 billion; 2016: \$9.7 billion), net repayment of debt of \$8.3 billion (2017: \$11.8 billion net repayment of debt; 2016: \$11.1 billion net issuance of debt), repurchases of shares of \$3.9 billion and interest paid of \$3.6 billion (2017: \$3.6 billion; 2016: \$2.9 billion).

Cash and cash equivalents were \$26.7 billion at December 31, 2018 (2017: \$20.3 billion; 2016: \$19.1 billion).

CASH FLOW FROM OPERATING ACTIVITIES

The most significant factors affecting our cash flow from operating activities are earnings, which are mainly impacted by: realised prices for crude oil, natural gas and liquefied natural gas (LNG); production levels of crude oil, natural gas and LNG; refining and marketing margins; and movements in working capital.

The impact on earnings from changes in market prices depends on: the extent to which contractual arrangements are tied to market prices; the dynamics of production-sharing contracts; the existence of agreements with governments or

state-owned oil and gas companies that have limited sensitivity to crude oil and natural gas prices; tax impacts; and the extent to which changes in commodity prices flow through into operating costs. Changes in benchmark prices of crude oil and natural gas in any particular period therefore provide only a broad indicator of changes in our Integrated Gas and Upstream earnings in that period. In the longer term, replacement of proved oil and gas reserves will affect our ability to maintain or increase production levels, which in turn will affect our earnings and cash flows. Changes in any one of a range of factors derived from either within the industry or the broader economic environment can influence refining and marketing margins. The precise impact of any such changes depends on how the oil markets respond to them. The market response is affected by factors such as: whether the change affects all crude oil types or only a specific grade; regional and global crude-oil and refined-products inventories; and the collective speed of response of refiners and product marketers in adjusting their operations. As a result, margins fluctuate from region to region and from period to period.

CAPITAL INVESTMENT

The level of capital investment in 2018 and 2017 reflects our discipline, focus and capital efficiency, which have allowed us to maintain our investment levels at below the \$25-\$30 billion range. Capital investment in 2016 included \$52.9 billion relating to the acquisition of BG.

Capital investment [A]				\$ million
	2018	2017	2016	
Integrated Gas	4,460	3,827	26,214	
Upstream	12,525	13,648	47,507	
Downstream	7,564	6,416	6,057	
Corporate	230	115	99	
Total capital investment	24,779	24,006	79,877	

[A] See "Non-GAAP measures reconciliations" on page 263.

Cash flow information [A]

	2018	2017 [B]	\$ billion 2016 [B]
Cash flow from operating activities excluding working capital movements			
Integrated Gas	16.3	8.7	8.0
Upstream	21.9	16.3	9.8
Downstream	10.8	12.6	10.4
Corporate	0.7	0.3	0.9
Total	49.6	37.9	29.0
(Increase)/decrease in inventories	2.8	(2.1)	(5.7)
(Increase)/decrease in current receivables	2.0	(2.6)	(4.1)
Increase/(decrease) in current payables	(1.3)	2.4	1.4
(Increase)/decrease in working capital	3.4	(2.3)	(8.4)
Cash flow from operating activities	53.1	35.7	20.6
Cash flow from investing activities	(13.7)	(8.0)	(31.0)
Cash flow from financing activities	(32.5)	(27.1)	(0.8)
Currency translation differences relating to cash and cash equivalents	(0.4)	0.6	(1.5)
Increase/(decrease) in cash and cash equivalents	6.4	1.2	(12.7)
Cash and cash equivalents at the beginning of the year	20.3	19.1	31.8
Cash and cash equivalents at the end of the year	26.7	20.3	19.1

[A] See the "Consolidated Statement of Cash Flows" on page 171.

[B] With effect from 2018, presentation of Cash flow from operating activities has been revised. Prior period comparatives within Cash flow from operating activities have been revised to conform with current year presentation. Overall, the revisions do not have an impact on the previously published Cash flow from operating activities. See the "Consolidated Statement of Cash Flows".

DIVESTMENTS

In 2018, we continued to divest assets that fail to deliver competitive performance or no longer meet our longer-term strategic objectives, including Integrated Gas assets in Thailand, Malaysia and New Zealand, Upstream assets in Ireland, Iraq, Norway and Oman, as well as Downstream assets in Argentina. We also sold part of our interest in Shell Midstream Partners, L.P., while retaining control.

Divestments [A]	\$ million		
	2018	2017	2016
Integrated Gas	3,124	3,077	352
Upstream	2,198	11,542	1,726
Downstream	1,718	2,703	2,889
Corporate	62	18	17
Total	7,102	17,340	4,984

[A] See "Non-GAAP measures reconciliations" on page 263.

DIVIDENDS

Our policy is to grow the dollar dividend through time, in line with our view of our underlying earnings and cashflow. When setting the dividend, the Board of Directors looks at a range of factors, including the macroeconomic environment, the current balance sheet and future investment plans. We returned \$15.7 billion to our shareholders through dividends in 2018.

The fourth quarter 2018 interim dividend of \$0.47 per share will be payable to shareholders on the register at February 15, 2019. See Note 23 to the "Consolidated Financial Statements" on page 211. The Board expects that the first quarter 2019 interim dividend will be \$0.47 per share, equal to the US dollar dividend for the same quarter in 2018.

PURCHASES OF SECURITIES

At the 2018 Annual General Meeting (AGM), shareholders granted an authority, which expires at the earlier of the close of business on August 22, 2019, and the end of the 2019 AGM, for the Company to repurchase up to a maximum of 10% of its issued ordinary shares, excluding treasury shares (834 million ordinary shares). In accordance with this authority, on July 26, 2018, the Company announced the immediate start of a share buyback programme of at least \$25 billion, by the end of 2020, subject to further progress with debt reduction and oil price conditions. As at December 31, 2018, 125 million A ordinary shares with a nominal value of €8.8 million (\$10.6 million) (1.52% of the Company's total issued share capital at December 31, 2018) had been purchased and cancelled for a total cost of \$3.9 billion including expenses, at an average price of \$31.55 per share. This means that 709 million ordinary shares could still be repurchased under the current AGM authority at December 31, 2018. The purpose of the share repurchases in 2018 as well as in the period ended January 28, 2019, was to reduce the issued share capital of the Company. A new resolution will be proposed at the 2019 AGM to renew the authority for the Company to purchase its own share capital, up to specified limits, for a further year. This proposal will be described in more detail in the 2019 Notice of Annual General Meeting.

Shares are also purchased by the employee share ownership trusts and trust-like entities (see the "Directors' Report" on page 94) to meet delivery commitments under employee share plans. All share purchases are made in open-market transactions.

The table below provides information on purchases of shares in 2018, as well as in the period ended January 31, 2019, by the Company and affiliated purchasers. Purchases in euros and sterling are converted into dollars using the exchange rate on each transaction date.

Purchases of equity securities by issuer and affiliated purchasers in 2018 [A]

Purchase period	A shares			B shares		A ADSs[B]	
	Number purchased for employee share plans	Number purchased for cancellation [C]	Weighted average price (\$)[D]	Number purchased for employee share plans	Weighted average price (\$)[D]	Number purchased for employee share plans	Weighted average price (\$)[D]
January	5,098,000	—	35.49	5,159,100	36.38	2,916,028	68.18
February	2,922,672	—	35.50	1,226,154	36.55	—	—
March	—	—	—	135,255	32.20	94,706	64.78
April	283,438	—	31.70	—	—	—	—
May	4,493,320	—	34.82	1,408,045	35.97	—	—
June	—	—	—	83,800	35.99	61,195	67.33
July	187,000	1,811,707	34.33	—	—	—	—
August	—	22,124,641	32.87	—	—	—	—
September	233,910	19,118,621	32.76	99,500	33.76	63,116	66.03
October	—	17,789,837	33.41	—	—	—	—
November	—	30,058,425	30.97	—	—	—	—
December	268,252	34,343,523	29.42	111,810	28.89	603,228	56.54
Total 2018	13,486,592	125,246,754	31.89	8,223,664	36.13	3,738,273	66.16
January	—	19,086,716 [E]	29.95	—	—	1,854,168	59.21
Total 2019	—	19,086,716	29.95	—	—	1,854,168	59.21

[A] Reported as at settlement date.

[B] American Depository Shares.

[C] Under the share buyback programme.

[D] Includes stamp duty and brokers' commission.

[E] As at January 28, 2019, the end of the second tranche of the share buyback programme.

CONTRACTUAL OBLIGATIONS

The table below summarises our principal contractual obligations at December 31, 2018, by expected settlement period. The amounts presented have not been offset by any committed third-party revenue in relation to these obligations.

Contractual obligations					
	Less than 1 year	Between 1 and 3 years	Between 3 and 5 years	5 years and later	Total
Debt [A]	9.1	11.1	8.8	33.5	62.6
Finance leases [A]	2.1	3.9	3.6	13.4	22.9
Operating leases [A]	4.8	6.8	4.7	7.9	24.2
Purchase obligations [B]	27.8	22.3	14.1	50.9	115.1
Other long-term contractual liabilities [C]	—	0.7	0.2	0.9	1.8
Total	43.7	44.9	31.6	106.5	226.7

[A] See Note 14 to the "Consolidated Financial Statements" on pages 191-193. Debt contractual obligations exclude interest, which is estimated to be \$1.8 billion payable in less than one year, \$3.0 billion between one and three years, \$2.6 billion between three and five years, and \$14.4 billion in five years and later. For this purpose, we assume that interest rates with respect to variable interest rate debt remain constant at the rates in effect at December 31, 2018, and that there is no change in the aggregate principal amount of debt other than repayment at scheduled maturity as reflected in the table. Finance lease contractual obligations include interest.

[B] As revised, Purchase obligations disclosed in the above table exclude commodity purchase obligations that are not fixed or determinable and are principally intended to be resold in a short period of time through sale agreements with third parties. Examples include long-term non-cancellable LNG and natural gas purchase commitments and commitments to purchase refined products or crude oil at market prices. Inclusion of such commitments would not be meaningful in measuring liquidity and cash flow, as the cash outflows generated by these purchases will generally be offset in the same periods by cash received from the related sales transactions.

[C] Includes all obligations included in "Trade and other payables" in "Non-current liabilities" in the "Consolidated Balance Sheet" that are contractually fixed as to timing and amount. In addition to these amounts, Shell has certain obligations that are not contractually fixed as to timing and amount, including contributions to defined benefit pension plans (see Note 17 to the "Consolidated Financial Statements" on pages 197-200) and obligations associated with decommissioning and restoration (see Note 18 to the "Consolidated Financial Statements" on page 201).

At December 31, 2018, the Trust had total equity of £nil (2017: £nil; 2016: £nil), reflecting cash of £3 million (2017: £2 million; 2016: £2 million) and unclaimed dividends of £3 million (2017: £2 million; 2016: £2 million). The Trust only records a liability for an unclaimed dividend, and a corresponding amount of cash, to the extent that dividend cheque payments have not been presented within 12 months, have expired or have been returned unpresented.

GUARANTEES AND OTHER OFF-BALANCE SHEET ARRANGEMENTS

There were no off-balance sheet arrangements at December 31, 2018, or 2017, reasonably likely to have a material effect on Shell.

FINANCIAL INFORMATION RELATING TO THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST

The results of operations and financial position of the Royal Dutch Shell Dividend Access Trust (the Trust) are included in the consolidated results of operations and financial position of Shell. Certain condensed financial information in respect of the Trust is given below. See "Royal Dutch Shell Dividend Access Trust Financial Statements" on pages 251-255.

The Shell Transport and Trading Company Limited and BG Group Limited have each issued a dividend access share to Computershare Trustees (Jersey) Limited (the Trustee). For the years 2018, 2017 and 2016, the Trust recorded income before tax of £5,328 million, £4,567 million, and £3,879 million respectively. In each period, this reflected the amount of dividends received on the dividend access shares.

Environment and society

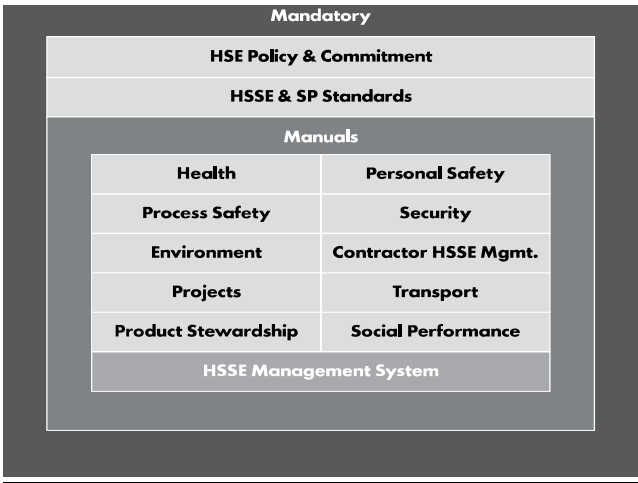
Our success in business depends on our ability to meet a range of environmental and social challenges. We must operate safely and manage the effect our activities can have on neighbouring communities and wider society. If we fail to do this, we may incur liabilities or sanctions, lose business opportunities, harm our reputation, or our licence to operate may be impacted (see “Risk factors” on page 17).

Data in this section are reported on a 100% basis in respect of activities where we are the operator. Reporting on this operational control basis differs from that applied for financial reporting purposes in the “Consolidated Financial Statements” on pages 167-214. Detailed data and information on our 2018 environmental and social performance will be published in the Shell Sustainability Report in April 2019.

CONTROL FRAMEWORK

The Shell General Business Principles set out our responsibilities to shareholders, customers, employees, business partners and society. They set the standards for the way we conduct business, with integrity and respect for people, the environment and communities. All ventures that we operate must conduct their activities in line with our business principles. We aim to minimise the environmental impact of new projects and existing operations and we engage with local communities and non-governmental organisations to understand and respond to their concerns. Shell conducts an environmental, social and health impact assessment for every major project. This helps us to understand and manage the effects our projects could have on the surrounding environment and local communities. We have standards and a clear governance structure in place to help manage potential impacts. Our standards are defined in our Health, Safety, Security, Environment and Social Performance (HSSE & SP) Control Framework (Control Framework), in line with the Shell Commitment and Policy on Health, Security, Safety, the Environment and Social Performance and the Shell Code of Conduct, and are supported by a number of guidance documents. They apply to every Shell entity, including all employees and contract staff, and to Shell-operated ventures. The Control Framework defines standards and accountabilities at each level of the organisation and sets out the procedures and processes people are required to follow. We manage HSSE & SP risks to as low as reasonably practicable, which is a business responsibility supported by the HSSE & SP function. The process safety and HSSE & SP assurance team provides assurance on the effectiveness of HSSE & SP controls to the Board.

HSSE & SP Control Framework



Our three Golden Rules require our employees and contract staff to comply with laws and regulations as well as our standards and procedures, to intervene in unsafe or non-compliant situations, and to respect our neighbours.

We expect ventures not operated by us to apply standards and principles similar to our own. We support these ventures in their implementation of our HSSE & SP Control Framework, or of a similar framework, and offer to review the effectiveness of their implementation. Even if such a review is not carried out, we periodically evaluate HSSE & SP risks faced by the ventures which we do not operate. If one of these ventures does not meet our expectations, we work to put plans in place, in agreement with our partners, to improve performance.

Shell aims to work with suppliers that behave in a safe, economically, environmentally and socially-responsible manner. Our approach to suppliers is set out in our Shell General Business Principles and Shell Supplier Principles. These principles cover expectations in areas such as business integrity, health and safety, and human rights. Working with suppliers in this way is central to maintaining a strong societal support for our operations.

SAFETY

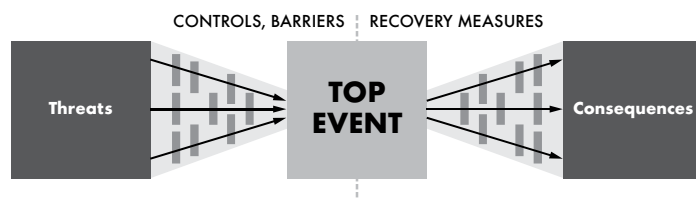
Safety is central to the responsible delivery of energy. We develop and operate our facilities with the aim of preventing any incidents that may harm our employees, contract staff or nearby communities, or cause damage to our assets or adversely impact the environment. We manage safety risks across our businesses through clear standards, controls and compliance systems, combined with a safety-focused culture. We focus on the three areas of safety with the highest risks associated with our activities: personal, process, and transport. We ensure that people responsible for tasks involving a significant safety hazard have the necessary training and skills. Safety performance is included in our annual bonus scorecard for all our employees. Also see “Directors’ Remuneration Report” on page 133.

We continue to strengthen the safety culture and leadership among our employees and contract staff, with the focus on caring for people. Our safety goal is to achieve no harm and no leaks across all our operations. We refer to this as our Goal Zero ambition.

We expect everyone working for us to intervene and stop work that may appear to be unsafe. In addition to our ongoing safety awareness programmes, we hold an annual global safety day to give employees and contract staff time to reflect on how to prevent incidents. We expect everyone working for us to comply with our 12 mandatory Life-Saving Rules. If employees break these rules, they face disciplinary action up to and including termination of employment. If contract staff break the Life-Saving Rules, they can be removed from the worksite.

Process safety management is about keeping hazardous substances inside pipes, tanks and vessels so they do not cause any harm to people or the environment. It starts at the design and construction stage of our projects and is implemented throughout the life cycle of these facilities to ensure they are operated safely, well-maintained and regularly inspected. Our global standards and operating procedures define the controls and physical barriers we require to prevent incidents. For example, our offshore wells are designed with at least two independent barriers in the direction of flow to mitigate the risk of an uncontrolled release of hydrocarbons. We regularly inspect, test and maintain these barriers to ensure they meet our standards. In the event of a loss of containment such as a spill or a leak, we employ independent recovery measures to prevent the release from becoming catastrophic. This system of barriers and recovery measures is known as a “bow-tie”, a model that visually represents a system where process safety hazards are managed through prevention and response barriers. Since 2016, we have been working on strengthening barriers that involve critical safety tasks carried out by frontline staff. We have been working on embedding a set of process safety fundamentals, which provide clear guidelines for good operating practice to prevent unplanned releases.

Risk management approach



We also routinely prepare and practise our emergency response to potential incidents such as a spill or a fire. This involves working closely with local services and regulatory agencies to jointly test our plans and procedures. These tests continually improve our readiness to respond. If an incident does occur, we have procedures in place to reduce the impact on people and the environment.

Transporting large numbers of people, products and equipment by road, rail, sea and air poses safety risks. We develop best-practice standards within Shell to find ways of reducing travel and transport safety risks, and work with specialist contractors, industry bodies, non-governmental organisations and governments.

Shell employees and contractors drove a combined distance of around 600 million kilometres on business in 2018 in more than 60 countries. We run road safety programmes, such as those that promote safe driving techniques and behaviour. We require everyone driving more than 7,500 kilometres a year on company business on public roads and those who drive in road safety high-risk countries to take a defensive driving course. Outside our operations, we also work to improve road safety in several communities and countries where we operate.

While we continually work to minimise the likelihood of incidents, some do occur. Tragically, two contractors lost their lives while working for Shell in 2018. We require all incidents to be investigated to understand the underlying causes and seek to translate these into improvements in standards or ways of working that can be applied broadly across similar facilities in Shell.

As set out in “Performance indicators” on page 28, our total recordable case frequency (injuries per million working hours) was 0.9 in 2018, compared with 0.8 in 2017, and there were 121 operational Tier 1 and 2 process safety events in 2018, compared with 166 in 2017. Detailed information on our 2018 safety performance will be published in the Shell Sustainability Report in April 2019.

Pakistan

In June 2017, a devastating roll-over incident occurred in Pakistan involving a road tanker hired by a company that was providing road transport services to Shell Pakistan Limited, following which people from a nearby village approached the incident site to collect spilled fuel. Tragically, the fuel ignited resulting in the loss of more than 200 lives and left many other people seriously injured.

Following the incident Shell Pakistan Limited provided immediate relief support, including providing food supplies for 150 affected families for nine months and medical supplies to hospitals. Shell Pakistan Limited has also contributed to long-term relief efforts for those impacted. For example, the CARE Foundation, in partnership with Shell Pakistan Limited, has ‘adopted’ two public schools within the impacted villages to improve infrastructure and education standards. Shell Pakistan Limited is also working with the National Rural Support Programme to help restore livelihoods of people in affected communities, providing vocational training and support for setting up small businesses.

We finalised our internal investigations in 2018 and we continue to implement our learnings from the incident. This includes deep reflection by the Board and Executive Committee, who have initiated several improvement programmes to be adopted throughout the Shell Group. We have developed and started the implementation of a road transport improvement project, specifically targeted at the management of fuel transport in high-risk countries. We are working with road transport companies in other locations where factors relevant to the Pakistan incident may exist and have also started sharing what we have learned with others in the fuel transport industry.

Shell Pakistan Limited continues to work with regulators, emergency services and the wider oil and gas industry in Pakistan with a view to improving safety standards. Shell Pakistan Limited has also required the road transport companies it hires to improve the safety of their transport fleets and has ongoing safety engagements with hauliers and their drivers, seeking to help them to identify and address the risks associated with driving fuel tankers. This has included emergency-response drills to build and test capability.

Road transportation remains a challenging and complex area for industry worldwide. Sadly, in October 2018, there was another roll-over incident in Pakistan involving a customer tanker, which resulted in the death of the relief driver and a spill. This incident was outside of Shell’s operational control and outside of our reporting scope. See “Directors’ Remuneration Report” on page 119.

ENVIRONMENT

We carefully consider the potential environmental impact of our activities and how local communities might be affected during the lifetime of our projects and operations. We seek to comply with environmental regulations, to continually improve our performance, and to prepare to respond to future challenges and opportunities. We use external standards and guidelines, such as those developed by the World Bank and International Finance Corporation, to inform our approach. We have global environmental standards, which we believe meet applicable regulatory requirements and often exceed them. Our standards cover our environmental performance, including managing emissions of greenhouse gases (GHG), using energy more efficiently, flaring less gas during oil production, preventing spills and leaks of hazardous materials, using less fresh water and conserving biodiversity wherever we operate.

For example, the availability of fresh water is a growing challenge in some parts of the world. A combination of increasing demand for water resources, growing stakeholder expectations and concerns, and water-related legislation may drive actions that affect our ability to secure access to fresh water and to discharge water from our operations. We manage our water use carefully, and we tailor our use of fresh water to local conditions because water constraints affect people at the local or regional level. In some cases, we use alternatives to fresh water in our operations; these include recycled water, processed sewage water and desalinated water. For example, at our gas-to-liquids plant in the Qatari desert, we clean and reuse industrial process water. This means that we reduce our use of the country's scarce natural water resources. An assessment of risks to water availability is required to be undertaken for each of our assets and projects and, in areas of water scarcity, we develop water-management action plans that identify ways to use less fresh water, recycle water and closely monitor its use.

In 2018, our intake of fresh water was 199 million cubic metres, about the same as 2017. Around 90% of our fresh water intake was used for manufacturing oil products and chemicals, with the balance mainly used for oil and gas production. Around 40% of freshwater intake was from public utilities, such as municipal water supplies.

See "Climate change and energy transition" on pages 71-78 for more information on how we manage our GHG emissions.

SPILLS

Large spills of crude oil, oil products and chemicals associated with our operations can adversely impact the environment and result in major clean-up costs as well as fines and other damages. They can also affect our licence to operate and harm our reputation. We have requirements and procedures designed to prevent spills.

Our business units are responsible for organising and executing oil-spill responses in line with Shell guidelines as well as with relevant legal and regulatory requirements. All our offshore installations have plans in place to respond to spills. These plans detail response strategies and techniques, available equipment, and trained personnel and contracts. We are able to call upon site-managed resources such as containment booms. We are also able to draw upon the contracted services of oil-spill response organisations their containment booms, collection vessels, aircraft or other equipment if required for large spills. We conduct regular exercises that seek to ensure these plans remain effective. We have further developed our capability to respond to spills to water and maintain a Global Response Support

Network comprised of trained staff to support our worldwide response capability. This is also supported by our global Oil Spill Expertise Centre, which tests local capability and maintains our capability globally to respond to a significant spill into a marine environment.

We are a founding member of the Marine Well Containment Company, a non-profit industry consortium providing a well-containment response system for the Gulf of Mexico. In addition, we are a founding member of the Subsea Well Response Project, an industry cooperative effort to enhance global well-containment capabilities, which has transitioned to Oil Spill Response Limited, an industry consortium.

We also maintain site-specific emergency-response plans in the event of an onshore spill. Like the offshore response plans, these are designed to meet Shell guidelines as well as relevant legal and regulatory requirements. They also provide for the initial assessment of incidents and the mobilisation of resources needed to manage them.

In 2018, the number of operational spills of more than 100 kilograms decreased to 92 from 104 in 2017 (see "Performance indicators" on page 28). At the time of publication of this Report, there was one spill under investigation in Nigeria that may result in adjustments.

Spills in Nigeria

Most oil spills in the Niger Delta region of Nigeria continue to be caused by crude oil theft or sabotage of oil and gas production facilities, as well as illegal oil refining, including the distribution of illegally refined products. In 2018, close to 90% of the number of oil spills of more than 100 kilograms from The Shell Petroleum Development Company of Nigeria Limited (SPDC) joint venture facilities was due to illegal activities by third parties. However, there are instances where spills occur due to operational reasons. Irrespective of the cause, SPDC cleans up and remediates areas impacted by spills originating from its facilities. In the case of operational spills, SPDC also pays compensation to people and communities impacted by the spills. Once clean-up and remediation work are completed, the work is inspected and, if satisfactory, approved and certified by Nigerian regulators.

To reduce the number of operational spills, SPDC is focused on implementing its ongoing work programme to appraise, maintain and replace key sections of pipelines and flow lines. Over the last seven years, approximately 1,300 kilometres of pipelines and flow lines have been replaced. This is managed through a pipeline and flow line integrity management system that proactively manages pipeline integrity, puts barriers in place where necessary, and recommends when and where pipeline sections should be replaced to prevent failures. In 2018, this integrity management system was enhanced to manage integrity threats arising from frequent pipeline sabotage or vandalism.

SPDC continues to undertake initiatives to prevent and minimise spills caused by theft and sabotage of its facilities in the Niger Delta. In 2018, SPDC continued on-ground surveillance efforts on the SPDC joint venture's areas of operation, including its pipeline network, to mitigate incidences of third-party interference and ensure that spills are detected and responded to as quickly as possible. There are also daily overflights of the pipeline network to identify any new spill incidents or illegal activities. SPDC has also implemented anti-theft protection mechanisms on key infrastructure, such as wellheads and manifolds.

Since 2012, SPDC has worked with the International Union for Conservation of Nature to enhance remediation techniques and to protect biodiversity at sites affected by oil spills in SPDC's areas of operation in the Niger Delta. Based on this partnership, SPDC has launched further improvement initiatives to help strengthen its remediation and restoration efforts.

SPDC also works with a range of stakeholders in the Niger Delta to build greater trust in spill response and clean-up processes. Local communities take part in the remediation work for operational spills. In certain instances, some non-governmental organisations have also participated in joint investigation visits along with government regulators, SPDC and impacted communities, to establish the cause and volume of oil spilled.

In addition, SPDC has implemented several initiatives and partnerships to raise awareness on the negative impact of crude oil theft and illegal oil refining. Examples include community-based pipeline surveillance and the promotion of alternative livelihoods through Shell's flagship youth entrepreneurship programme, Shell LiveWIRE.

In 2015, SPDC, on behalf of the SPDC joint venture and the Bodo community, signed a memorandum of understanding (MOU) granting access to SPDC to begin the clean-up of areas affected by two operational spills in 2008. The MOU also provided for the selection of two international contractors to conduct the clean-up and to be overseen by an independent project director. The clean-up project suffered a delay in 2016 and most of 2017 due to access challenges from the community. After engagement with the Bodo community and other stakeholders over two years, beginning in September 2015, and managed by the Bodo Mediation Initiative, the first phase of clean-up and remediation activities started in September 2017. The clean-up consists of three phases: 1) removal of free-phase surface oil, 2) remediation of soil, 3) planting of mangroves and monitoring. The first phase was completed in August 2018 and the contract procurement process for phase two is expected to be finalised in 2019. Should activities continue uninterrupted, phase two (soil remediation) is expected to take approximately two years to complete. However, for it to be successful, there must be no re-contamination of cleaned-up sites from illegal third-party activities, such as crude oil theft and illegal refining.

SPDC remains committed to the implementation of the 2011 United Nations Environmental Programme (UNEP) Report on Ogoniland. Over the last seven years, SPDC has taken action on all the UNEP recommendations addressed to it as operator of the joint venture and has already addressed the majority of these recommendations. Throughout 2018, SPDC representatives continued to actively support the clean-up process within the governance framework established in August 2016 by the Nigerian government to oversee the process. The UNEP report recommended the creation of an Ogoni Trust Fund (OTF) with an initial capital of \$1 billion, to be co-funded by the Nigerian government, the SPDC joint venture and other operators in the area. The SPDC joint venture remains fully committed to contributing its share of \$900 million over five years to the OTF and made available \$10 million in early 2017 to help set up the Hydrocarbon Pollution and Remediation Project (HYPREP), a government-led body to clean up the contaminated sites in Ogoniland and other Niger Delta areas. In July 2018, the SPDC joint venture deposited an additional \$170 million into an escrow account to fund HYPREP's activities, which completes its first-year contribution of \$180 million. HYPREP has issued contract award letters

for phased remediation activities and is aiming for contractors to be in place in early 2019.

HYDRAULIC FRACTURING

Shale oil and gas continue to play an important role in meeting global energy demand. Over the last decade, we have expanded our onshore oil and gas portfolio using advances in technology to access previously uneconomic tight-oil and tight-gas resources, including those locked in shale formations.

One of the key technologies applied in tight-oil and tight-gas fields is known as hydraulic fracturing, a technique used since the 1950s. It involves pumping fluids that are typically around 99.5% water and sand and around 0.5% chemical additives into tight sand or shale rock at high pressure. This creates thread-like fissures, through which oil and gas can flow.

Shell has developed and publicly shared a set of five global operating principles that govern the onshore shale oil and gas activities where it operates and where hydraulic fracturing is used. The principles cover safety, air quality, water protection and usage, land use and engagement with local communities. We review our Onshore Operating Principles annually and update them as new technologies, challenges and regulatory requirements emerge. We believe we can safely and responsibly explore, develop and produce shale oil and gas using hydraulic fracturing technology. We also support appropriate and fit-for-purpose regulations.

Shell strives to minimise the use of water in its shale operations. Depending on local conditions, we typically use a combination of fresh water, non-potable groundwater, produced water and waste water. We work to reduce and ideally eliminate our freshwater intake. We deploy responsible withdrawal practices when using fresh water. Shell disposes of water safely and in compliance with applicable laws. Flowback water is typically transferred to a disposal facility. Meanwhile, we take produced water to a treatment plant for processing and then reuse it, as much as possible, for additional wells. When recycling is not reasonably practicable, or volumes exceed our operational needs, we may store and treat produced water, share it with other producers, or dispose of it in an environmentally responsible way.

Potable groundwater aquifers are typically isolated from the hydrocarbon-producing shale formations by several thousand feet of impermeable rock. However, we often need to drill through potable groundwater aquifers to reach shale formations. Hence, we design our drilling, hydraulic fracturing and production activities in a way that maintains isolation from potable groundwater aquifers. Before we drill a well, we conduct a hazard assessment to analyse risks to groundwater aquifers, then design and implement control measures. We employ at least two physical barriers, consisting of steel casing and cement, between the wellbore and potable groundwater aquifers. We monitor wellbore integrity before, during and after hydraulic fracturing and during production. Moreover, we routinely test groundwater in our assets.

Since 2015, we have worked to reduce the number of chemical additives in the composition of hydraulic fracturing fluids used in our shale operations. We support full disclosure of the chemical additives used in hydraulic-fracturing fluids for Shell-operated wells, as well as regulations that require suppliers to release information on chemical additives. We have stringent procedures for handling hydraulic-fracturing chemicals.

SEISMICITY

As oil and gas fields mature, seismic activity may increase in certain circumstances based on the unique geology of individual fields. For example, in recent years, public concern about gas production in Groningen province in the Netherlands has grown as a result of an increase in the number of, and energy released by, induced earthquakes in the area (see "Upstream" on page 39). The Groningen field is operated by Nederlandse Aardolie Maatschappij B.V. (NAM, Shell interest 50%) and is one of the largest onshore gas fields in Europe. A range of actions have been taken to improve safety, liveability and economic prospects in the region. NAM is working together with all relevant parties to fulfil commitments to the residents of the area and reinstate governance by the appropriate authorities.

Overall, the likelihood of induced seismicity due to hydraulic fracturing or produced water disposal well operations being felt on the surface is relatively low. However, Shell takes concerns around induced seismicity seriously and proactively manages the risk in accordance with, and sometimes beyond, regulatory requirements. We have added induced seismicity to our Onshore Operating Principles and developed internal guidelines that are applied to our shale assets. The guidelines outline a risk assessment process and provide a framework for risk management. Subsurface and surface conditions vary from basin to basin, which means that management practices need to reflect the risk profile of each basin and provide customised responses to the risks. We are supportive of state and provincial regulations that are fit-for-purpose and science-based.

ENVIRONMENTAL COSTS

We are subject to a variety of environmental laws, regulations and reporting requirements in the countries where we operate. Infringing any of these laws, regulations and requirements could result in significant costs, including clean-up costs, fines, sanctions and third-party claims, as well as harm our reputation and our ability to do business.

Our ongoing operating expenses include the costs of avoiding unauthorised discharges into the air and water, and the safe disposal and handling of waste.

We place a premium on developing effective technologies that are also safe for the environment. However, when operating at the forefront of technology, there is always the possibility that a new technology brings with it environmental impacts that have not been assessed, foreseen or determined to be harmful when originally implemented. While we believe we take all reasonable precautions to limit these risks, we are subject to additional remedial environmental and litigation costs as a result of our operations' unknown and unforeseen impacts on the environment. Although these costs have so far not been material to us, no assurance can be given that this will always be the case.

SECURITY

Our operations expose us to civil unrest, criminality, terrorism, piracy, acts of war, cyber disruption and risks of pandemic diseases that could have a material adverse effect on our business (see "Risk factors" on page 16). We seek to obtain the best possible information to enable us to assess threats and risks. We conduct detailed assessments for all sites and activities, and implement appropriate risk-mitigation measures to detect, deter and respond to security threats. This includes building strong and open relationships with government security agencies, the physical hardening of

sites, journey management, and information risk management. We conduct training and awareness campaigns, including travel advice and medical assistance before travel. The identities of our employees and contract staff and their access to our sites and activities, both physical and logistical, are consistently verified and controlled. We manage and exercise crisis response and management plans.

NEIGHBOURING COMMUNITIES

Earning the trust of local communities is essential to the success of our projects and operations. Our global requirements for social performance aim to ensure that we operate in a responsible way, by avoiding or minimising the negative social impacts of our operations. They also help us maximise the benefits of our activities, such as employment and contractual opportunities that can support local economies.

Specifically, these requirements set clear rules and expectations for how we engage with and respect communities that may be impacted by our operations. We require Shell-operated major projects and facilities to have a social performance plan that defines actions for managing potential negative and positive impacts on the communities where they operate. Integral to these plans is the identification of the social environment, the stakeholders who may be vulnerable to the operations, and an appropriate community feedback mechanism for listening and responding to queries, or resolving complaints, in a timely manner. We have specific requirements in place to avoid, minimise or mitigate potential impacts on indigenous peoples' traditional lifestyles, cultural heritage or involuntary resettlement. More information can be found at <https://www.shell.com/sustainability/communities/working-with-communities.html>.

HUMAN RIGHTS

Respect for human rights is embedded in our Business Principles and in our Code of Conduct. Our approach is informed by the Universal Declaration of Human Rights, the core conventions of the International Labour Organization and the United Nations' Guiding Principles on Business and Human Rights.

We work closely with other companies and non-governmental organisations to continuously improve the way we apply these principles. Our focus is on four key areas where respect for human rights is critical to the way we operate: communities, security, labour rights, and supply chain. We have systems and processes in place for contracting and procurement, recruitment and employment, security and social performance. We require all our companies and our contractors to respect the human rights of our workforce and our neighbouring communities. More information about our approach to human rights can be found at <https://www.shell.com/sustainability/transparency/human-rights.html>.

Climate change and energy transition

Shell has long recognised that greenhouse gas (GHG) emissions from the use of fossil fuels are contributing to the warming of the climate system. In December 2015, 195 nations adopted the Paris Agreement. We welcomed the efforts made by governments to reach this global climate agreement, which entered into force in November 2016. We fully support the Paris Agreement's goal to keep the rise in global average temperature this century to well below two degrees Celsius (2°C) above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5°C. In pursuit of this goal, we also support the vision of a transition towards a net-zero emissions energy system. Shell agrees with the Intergovernmental Panel on Climate Change (IPCC) 1.5°C special report, which states that in order to limit warming to 1.5°C above pre-industrial levels, the world economy would need to transform in a number of complex and connected ways. Meeting this challenge would require an even more rapid escalation in the scale and pace of change in the coming decades than was foreseen in the Paris Agreement.

Society faces a dual challenge: how to transition to a low-carbon energy future to manage the risks of climate change, while also extending the economic and social benefits of energy to everyone on the planet. This is an ambition that requires changes in the way energy is produced, used and made accessible to more people while drastically cutting emissions.

We believe that the need to reduce GHG emissions, which are largely caused by burning fossil fuels, will transform the energy system in this century. This transformation will generate both challenges and opportunities for our existing and future portfolio.

We welcome and support efforts, such as those led by the Task Force on Climate-related Financial Disclosures (TCFD), to increase transparency and to promote investors' understanding of companies' strategies to respond to the risks and opportunities presented by climate change. We believe that companies should be clear about how they plan to be resilient in the energy transition. In 2017, we joined the Oil and Gas Preparer Forum, initiated by the TCFD and convened by the World Business Council for Sustainable Development. The forum's objectives are to review the current state of climate-related financial disclosures, to identify examples of effective disclosure practices and make proposals on how disclosures may evolve over time. The Shell Energy Transition Report published in April 2018 (2018 SET report) described the energy transition and considered Shell's resilience against future scenarios. The 2018 SET report followed our discussions with the TCFD about increasing transparency to help investors understand climate-related risks and opportunities. Our approach to the energy transition as described in the 2018 SET report, in combination with the Shell Sustainability Report (April 2019) aims to complement this Report in responding to TCFD recommendations, including discussing the energy transition and Shell's portfolio resilience.

OUR GOVERNANCE AND MANAGEMENT OF CLIMATE CHANGE RISKS AND OPPORTUNITIES

Climate change and risks resulting from GHG emissions have been identified as a significant risk factor for Shell and are managed in accordance with other significant risks through the Board and Executive Committee. See "Corporate governance" on pages 103-104.

Shell has a climate change risk management structure in place which is supported by standards, policies and controls.

This includes the work of the Board, which discussed a number of regular agenda items, among them reporting on environmental topics. Throughout 2018, the Board discussed the businesses' Net Carbon Footprint ambition. In addition, some of the Non-executive Directors received dedicated updates from management and external experts on New Energies, the various business models, advantages and disadvantages of having positions along the power value chain, and the opportunities for Shell in the New Energies area. During the annual dedicated strategy meeting, the Board debated the longer-term challenges of the future of mobility and the changing mobility landscape in the context of climate change and energy transition.

The Board committees (see "Corporate governance" on page 100) play an important role in assisting the Board with regard to governance and management of climate change risks and opportunities.

The role of the Corporate and Social Responsibility Committee (CSRC) is to review and advise the Board on Shell's strategy, policies and performance in the areas of safety, environment, ethics and reputation. It regularly discusses the Company's approach to combatting climate change. In 2018, this included the energy transition, GHG emission targets (including advice to the Remuneration Committee), policy on methane, Shell's Net Carbon Footprint and nature-based solutions.

The Remuneration Committee (REMCO) is responsible for determining the Directors' Remuneration Policy in alignment with our business strategy. In 2018, activities for REMCO included setting annual bonus performance measures and targets, for example, by continuing to include GHG intensity metrics in the scorecard following recommendations by the CSRC embedding the energy transition into the Chief Executive Officer (CEO) and Chief Financial Officer's (CFO) personal performance goals, and discussing the incorporation of energy transition measures into long-term incentives. In 2018, Shell took a major step forward in delivering our strategy by announcing plans to link short-term targets to reduce the Net Carbon Footprint of energy products we sell to executive remuneration. In 2019, REMCO decided to include an energy transition condition into the 2019 Long-Term Incentive Plan (LTIP) based on recommendations from CSRC. This condition will include our first three-year target towards achieving our Net Carbon Footprint ambition along with other measures that will help us to achieve our strategic ambitions in the long term, related to growth of Shell's power business, commercialising opportunities in advanced biofuel technology and the development of sinks to capture and store carbon. See "Directors' Remuneration Report" on pages 119-147. The Shell employee scorecard structure for determining employees' annual bonus in 2018 was consistent with the Executive Directors' scorecard. The energy transition condition in the 2019 LTIP will apply to all Senior Executives as well as the Executive Directors.

The Audit Committee has key responsibilities in assisting the Board in fulfilling its oversight responsibilities in relation to areas such as the effectiveness of the system of risk management and internal control. Any concerns regarding improvement needed are promptly reported to the Board.

The CEO is the most senior individual with accountability for climate change risk. We have set up several dedicated climate change and GHG-related forums at different levels of the organisation where climate change issues are addressed, monitored and reviewed, and each Shell subsidiary has

operational responsibility for implementing climate change policies and strategies.

A senior manager – the Executive Vice President for Safety and Environment – reporting directly to the Projects & Technology Director is accountable, among other things, for oversight of GHG issues. This manager’s department includes the dedicated Group Carbon team, which is accountable for monitoring and examining the strategic implications of climate change for Shell and the impact of developments in governmental policy and regulation. The Group Carbon team is responsible for preparing proposed policy positions based on analysis within Shell and external input. The team also provides advice to Shell companies to ensure consistency in application of our core principles and policy tasks in interactions with policymakers. Reporting to the same manager is the HSSE & SP Assurance and Reporting team, which is accountable for the delivery of Shell’s non-financial reporting and for auditing the businesses’ performance against our HSSE & SP Control Framework requirements, including climate change risk management. See “Environment and society” on page 66.

Group Carbon also has oversight of Shell’s GHG management programme and supports the different lines of business in embedding GHG management strategies. The team includes GHG project managers to advise the largest projects in managing GHG-related topics, from both a risk and an opportunity standpoint. Risk management at an asset or project level is a structured process of identifying and assessing risks, planning and implementing responses, monitoring, improving and closing out action items that have an impact on projects and assets’ objectives and performance. Shell policy requires these large projects to obtain formal sign-off on abatement plans and targets.

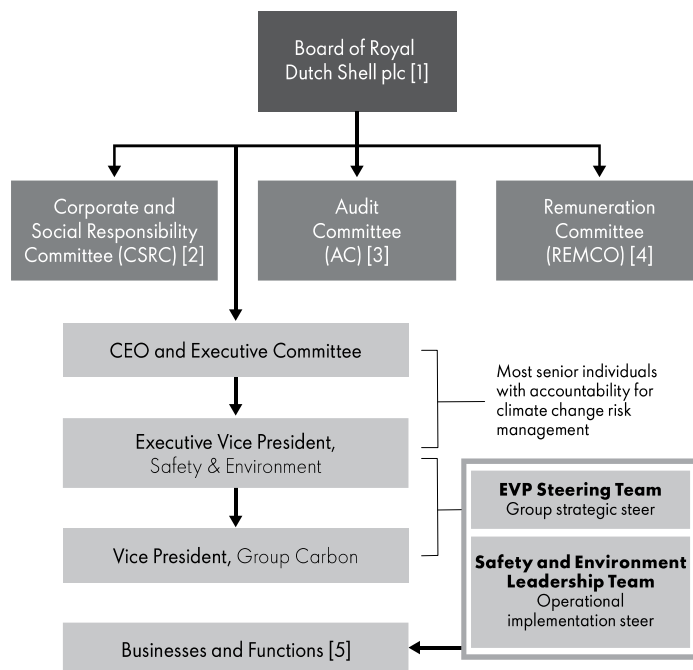
Further support for embedding GHG management is provided by a global risk support team for GHG and energy management. This team is a network of subject-matter experts in GHG topics that works globally and across our lines of business. Team members are experts in their relevant disciplines, defining improvement areas globally and capturing and sharing best practices.

The above-mentioned teams and experts have provided their input to shape a set of mandatory manuals and complementary guidance documents which are ultimately based on our HSSE & SP Control Framework. These documents provide guidance on how to monitor, communicate and report changes in the risk environment, and how to review the effectiveness of actions taken to manage the identified risks, including ways to:

- ensure consistent assessment of climate risk across Shell;
- clarify expectations for risk management and reporting, including roles and responsibilities;
- strengthen decision-making through better visibility and understanding of the climate risk by line of business; and
- enable integration of Shell’s reporting.

For more detail on our definition of risk categories and their relationship to different time horizons, see page 75.

Climate change management organogram



- [1] Oversight of climate change risk management.
- [2] Non-executive Directors appointed by the Board to review and advise on sustainability policies and practices including climate change.
- [3] Non-executive Directors appointed by the Board to oversee the effectiveness of the system of risk management and internal control.
- [4] Non-executive Directors appointed by the Board to set the remuneration policy in alignment with strategy.
- [5] Responsible for implementing Shell’s GHG strategy. They are represented in the Safety and Environment Leadership Team.

This structured approach supports the prioritisation of risks and opportunities. We actively monitor the GHG footprint of all our assets, as well as our products, to quantify future regulatory costs related to GHG or other climate-related policies. This allows us to effectively prioritise areas of greater concern and assess mitigation options and the most viable responses. Climate-related risks are analysed in context of other identified material risks. See “Risk factors” on pages 15-20.

Our portfolio exposure is reviewed annually against changing GHG regulatory regimes and physical conditions to identify emerging risks. We test the resilience of our portfolio against externally published future pathways, including a low emissions pathway. In 2017, Shell announced a long-term ambition to reduce the Net Carbon Footprint of its energy products. This was followed by an announcement, in December 2018, of our intention to set short-term targets in line with that ambition.

Meeting the Net Carbon Footprint ambition requires evolving our portfolio over the medium to longer term, to reduce the carbon intensity of the products that we sell. We plan for this by developing future aspired portfolio shapes that would meet our ambition and use these to guide investment decisions. Within the selected portfolio shapes, individual projects are developed to be as resilient to the future scenarios as possible.

To assess the resilience of new projects, we consider the potential costs associated with operational GHG emissions. Consistent with our desire to stay in step with society's progress toward the goals of the Paris Agreement, in 2018, we moved away from using a flat project screening value (PSV) of \$40/tonne of GHG emissions, to country-specific estimates of future carbon costs. These estimates were developed using the current Nationally Determined Contributions (NDCs) submitted by countries as part of the Paris Agreement. Accordingly, we believe they more accurately reflect society's current implementation of the Paris Agreement rather than a flat \$40/tonne PSV. By 2050, our estimates for some countries increase to \$85/tonne of GHG emissions.

These are the first NDCs to implement the Paris Agreement and they are scheduled to be revised at regular intervals. Therefore, as countries update their NDCs, we expect to update our estimates as well. The United Nations believes the current NDCs are consistent with limiting the average global temperature rise to around three degrees Celsius above pre-industrial levels. In coming decades, we expect countries to tighten these NDCs in order to meet the goal of the Paris Agreement.

Also, we apply additional sensitivity tests for our high-emitting projects by using long-term carbon cost estimates consistent with limiting the average global temperature rise to well below two degrees Celsius.

In addition, projects in the most GHG-exposed asset classes are benchmarked against GHG intensity targets that reflect standards sufficient to allow them to compete and prosper in a more GHG-constrained future. These processes can lead to projects being stopped, designs being changed, and potential GHG mitigation investments being identified, in preparation for when regulation would make these investments commercially compelling. Our approach continues to evolve and become more sophisticated to reflect our increasing understanding of the shifting policy landscape and the differing pace of energy transitions underway in different regions.

While monitoring emerging climate change plans, we consider the robustness of our activities against a range of scenarios, as referenced in the 2018 SET report. We believe our business strategy is resilient to the envisaged implementation of the Paris Agreement, which is now progressing through countries' development of individual plans in their NDCs. The emissions of energy consumers from their use of Shell energy products are for a large part covered by these NDCs. The Paris Agreement acknowledges that emissions will continue and even grow in some parts of the world. It does not stipulate that emissions must fall in all sectors or countries simultaneously, or that all actors within the system will reduce their emissions at the same time or to the same degree. What is important is that overall emissions fall.

OUR PORTFOLIO AND CLIMATE CHANGE

We are seeking cost-effective ways to manage GHG emissions and see potential business opportunities in developing such solutions. We seek to contribute to reducing global GHG emissions in a number of ways:

- supplying more natural gas to replace coal for power generation;
- progressing carbon capture and storage (CCS);
- implementing energy-efficiency measures in our operations where reasonably practicable;
- developing new fuels for transport such as advanced biofuels and hydrogen;

- participating throughout the power value chain with a focus on natural gas and renewable electricity; and
- working with nature-based solutions.

To support this, we continue to advocate the introduction of effective government-led carbon pricing mechanisms.

While we are committed to reducing our GHG intensity, as energy demand increases and easily accessible oil and gas resources decline, we may develop resources that require more energy and advanced technologies to produce. If our production becomes more energy intensive, this could result in an associated increase in direct GHG emissions from our upstream facilities.

Some governments have introduced carbon pricing mechanisms, which we believe can be an effective measure to reduce GHG emissions across the economy at lowest overall cost to society, and we expect more governments to follow. However, we believe measures taken by governments to control national energy transitions may also have unintended consequences when prohibition of one technology may support other substitute technologies that could result in an increase in overall GHG emissions.

See "Risk factors" on page 16.

NATURAL GAS

According to the IEA, more than 40% of global CO₂ emissions in 2015 came from electricity and heat generation. For many countries, using more gas in power generation instead of coal can make a large contribution, at lower cost, in meeting their GHG emission reduction objectives. We expect that, in combination with renewables and the use of CCS, natural gas will be essential for significantly lowering GHG emissions. Natural gas made up more than half of Shell's proved reserves at the end of 2018. As one of the leaders in liquefied natural gas (LNG), together with our portfolio of conventional gas assets and our technologies for recovering gas from tight-rock formations, we can supply natural gas to replace coal for power generation. Natural gas can also act as a partner for intermittent renewable energy, such as solar and wind, to maintain a steady supply of electricity, because gas-fired plants can start and stop relatively quickly.

Methane is a greenhouse gas. When released into the atmosphere, it has a much higher global warming impact than CO₂. Natural gas consists mainly of methane. Efforts to address climate change therefore require the industry to reduce both deliberate and unintended methane emissions from the gas value chain, from production to the final consumer.

The IEA estimates that natural gas operations have an average methane leakage rate of 1.7%. At this rate, natural gas emits between 45% and 55% less GHG emissions than coal when burnt at a power plant, but higher levels of methane emissions would reduce this benefit. We recognise the importance of reducing methane emissions. Methane from the flaring and venting of gas (including equipment venting) in our upstream oil and gas operations was the largest contributor to our reported methane emissions in 2018. We are working to reduce methane emissions from these sources by reducing the overall level of flaring and venting. In addition, we continue to implement leak detection and repair programmes across our sites to identify unintended losses and high-emission equipment, such as high-bleed pneumatic devices, so they can be replaced or repaired. We continue to work on confirming that we have identified all potential methane sources and that we have reported our

emissions from these sources in line with regulations and industry standards. In 2017, we joined the Climate and Clean Air Coalition Oil & Gas Methane Partnership. It brings together industry, governments and non-governmental organisations to improve quantification of methane emissions globally and work towards reducing them. In November 2017, Shell – along with seven other energy companies – signed guiding principles for reducing methane emissions across the natural gas value chain. The principles focus on: continually reducing methane emissions; advancing strong performance across gas value chains; improving accuracy of methane emissions data; advocating sound policies and regulations on methane emissions; and increasing transparency. In 2018, we succeeded in encouraging a further 10 companies to sign up to them.

In September 2018, Shell announced a target to maintain Shell's methane emissions intensity below 0.20% by 2025. This target covers all Upstream and Integrated Gas oil and gas assets for which Shell is the operator. The intensity baseline and target are presented as percentage figures, which represent the estimated amount of methane emissions for Shell's operated gas and oil assets as a percentage of the amount of the total gas marketed or, for those assets that have no marketed gas, the amount of marketed oil and condensate (e.g. assets that re-inject produced gas). Methane emissions include those from unintentional leaks, venting and incomplete combustion, for example in flares and turbines. In 2018, our overall methane intensity was 0.08% for assets with marketed gas and 0.01% for assets without marketed gas. Asset level intensities ranged from below 0.01% to 0.9%. Our methane emissions are calculated using the best methods currently available: a combination of industry standard emission factors (established emissions rates per throughput or per piece of equipment), engineering calculations and some actual measurements. There are uncertainties associated with methane emissions quantification. To reduce these uncertainties, our Upstream and Integrated Gas businesses are rolling out methane improvement programmes that focus on further improving data quality and reporting, and on continued implementation of leak detection and repair programmes and methane abatement opportunities. By 2025, all Shell-operated assets are expected to have implemented more robust quantification methodologies. Externally, we continue to work on new technologies and improved quantification methods through partnerships and several other initiatives.

Shell is also a member of the Oil and Gas Climate Initiative (OGCI), a CEO-led initiative to lead the industry's response to climate change. One of OGCI's focus areas is methane management. In September 2018, OGCI announced a target to reduce the collective average methane intensity of its members' aggregated upstream gas and oil operations by one fifth to below 0.25% by 2025, with an ambition to achieve 0.20%, corresponding to a reduction of one third.

Detailed information on our approach to managing methane emissions and performance will be published in the Shell Sustainability Report in April 2019.

CARBON CAPTURE AND STORAGE

CCS is a technology used for capturing CO₂ before it is emitted into the atmosphere, then transporting it by pipelines or ships and injecting it into a deep geological formation for permanent storage. In the IPCC Global Warming of 1.5°C special report, the middle-of-the-road scenario (P3) shows cumulative abatement provided by CCS of 687 billion tonnes of CO₂ by 2100, compared with 230 million tonnes of man-made CO₂ that has been injected to date, according to the Global CCS Institute (*Global Status of CCS 2018* report). In November 2015, we launched our Quest CCS project in Canada (Shell interest 10%), which has captured and safely stored more than 3 million tonnes of CO₂ since it began operating. We are involved in a

CO₂ capture test centre in Mongstad, Norway, the Northern Lights CCS project for capturing and storing industrial CO₂, also in Norway, and the development of the Gorgon CO₂ injection project in Australia, which is due to start up in 2019. We also have technology that can remove both CO₂ and sulphur dioxide from industrial flue gases. It is being used at Boundary Dam, a third-party coal-fired power plant in Canada.

ENERGY EFFICIENCY

We continue to work on improving energy efficiency at our oil and gas production facilities, refineries and chemical plants. Measures include our GHG and energy management programme that focuses on the efficient operation of existing equipment. This means, for example, using monitoring systems which give us real-time information that we can use to make energy-saving changes and identify opportunities for energy-saving investments in the medium term. Shell's scorecard incorporates GHG metrics that help create additional incentives for all our employees to reduce GHG emissions in our portfolio. Also see "Directors' Remuneration Report" on page 133.

NEW ENERGIES

Our New Energies business explores emerging opportunities linked to the energy transition and invests in those where we believe sufficient value is available. New Energies is an emerging opportunity, in which we plan to invest on average \$1-2 billion a year until 2020 as we look for commercial investments that build on our strengths in new and fast-growing segments of the energy industry. We focus on new fuels for transport, such as advanced biofuels, hydrogen and charging for battery-electric vehicles; and power, including from low-carbon sources such as wind and solar as well as natural gas. Alongside our work in new fuels and power, we are exploring how digital technologies can best support our activities and customers. See "Integrated Gas" on page 33.

New fuels

We invest in a range of low-carbon technologies and fuels, including hydrogen and battery-electric vehicle charging. We believe that hydrogen has the potential to be an important low-carbon transport fuel. We are involved in several initiatives to encourage the adoption of hydrogen-electric energy. See "Integrated Gas" on page 33.

Biofuels

We believe that low-carbon biofuels will continue to play a valuable part in reducing CO₂ emissions in the transport sector in the coming decades. The international market for biofuels has grown over the past decade, driven largely by the introduction of new energy policies in Europe and the USA that call for more renewable, lower-carbon fuels for transport. They represent approximately 4% of global transport fuels today.

In 2018, we used around 9.5 billion litres of biofuel in our gasoline and diesel blends worldwide to comply with applicable mandates and targets in the markets where we operate. Through our own long-established sustainability clauses in supply contracts, we request that the biofuels we buy are produced in a way that is environmentally and socially responsible across the life cycle of the production chain.

From cultivation to use, some biofuels emit significantly less CO₂ compared with conventional gasoline. But this depends on several factors, such as how the feedstock is cultivated and the way biofuels are produced. Other challenges include concerns over land competing with food crops, labour rights, and the water used in the production process.

Where possible, we source biofuels that have been certified against internationally recognised sustainability standards. Shell supports the adoption of international sustainability standards, including the Round Table on Responsible Soy, the Roundtable for Sustainable Palm Oil, and Bonsucro, a non-profit organisation for sugar cane. We also support the Roundtable for Sustainable Biomaterials and the International Sustainability and Carbon Certification scheme, both of which can be used for any feedstocks. We also continue to work with industry, governments and voluntary organisations towards the development and adoption of internationally recognised sustainability standards for biofuels.

Our Raízen joint venture (Shell interest 50%) in Brazil has produced low-carbon biofuel from sugar cane since 2011. Through our Raízen joint venture, we produce one of the lowest CO₂ biofuels available today. Raízen produces approximately 2 billion litres of ethanol from sugar cane annually. Brazilian sugar-cane ethanol can reduce CO₂ emissions by around 70% when compared with conventional gasoline, from cultivation of the sugar cane to using the ethanol as fuel.

In 2015, Raízen opened its first advanced biofuels plant at the Costa Pinto mill in Brazil. The technology was first developed from our funding of the Iogen Energy venture, which was subsequently transferred to Raízen. In 2018, the plant produced 15.5 million litres of cellulosic ethanol from sugar-cane residues. It is expected to produce 40 million litres a year once fully operational.

Outside Brazil, we continue to invest in new ways of producing biofuels from sustainable feedstocks, such as biofuels made from waste products or cellulosic biomass. In 2017, we completed construction of a demonstration plant at the Shell Technology Centre Bangalore, India. The plant demonstrates a technology called IH2® that turns waste feedstock into transport fuel. The plant can process around five tonnes per day of feedstock, such as agricultural waste, and aims to demonstrate the technology for possible scaling up and commercialisation.

We continue to look for opportunities to invest in third-party technologies and to collaborate in scaling these up for commercialisation. In 2018, we announced our support, together with British Airways, for a project led by Velocys to install a waste-to-renewable jet fuel plant in the UK. If installed, a plant would use post-recycled waste, destined for landfill or incineration, and convert it into cleaner-burning, sustainable fuels.

In line with our strategy of developing more sustainable feedstocks for transport, we are also investing in renewable natural gas (RNG) for use in natural-gas fuelled vehicles, in the USA and in Europe. RNG is collected from landfill sites, food waste or manure and then processed until it is fully interchangeable with conventional natural gas. The use of RNG in natural-gas vehicles, either in the form of compressed natural gas (CNG) or LNG, offers customers already using these vehicles an attractive alternative for lowering their CO₂ footprint.

In the USA, in August 2018, we announced plans to expand and upgrade the JC Biomethane plant in Junction City, Oregon, which we acquired in May 2018. This will increase the facility's capacity to produce RNG from agricultural waste, through a process called anaerobic digestion.

Power

Power is the fastest-growing segment of the energy system. We expect that people and companies around the world will use more electricity to power

transport and industry, instead of coal and oil, as part of the drive to lower carbon emissions. To help meet this demand, Shell aims to become an integrated power player and grow, over time, a material new business. We are working to deliver more electricity generated by renewable energy, from developing wind and solar projects to selling electricity generated by renewable sources. See "Integrated Gas" on page 33.

NATURE-BASED SOLUTIONS

We believe that nature will play an important role in the transition to a lower-carbon world. Using nature to capture carbon from the atmosphere presents an immediate opportunity. It can help to bridge the gap until other low-carbon solutions are deployed at scale, or to compensate for emissions which cannot be avoided. Nature-based solutions are expected to be one of Shell's tools to reduce the Net Carbon Footprint of our energy products by around half by the middle of the century. Nature-based projects typically involve the protection or redevelopment of natural ecosystems such as forests and wetlands, allowing those ecosystems to capture and store more carbon on our behalf. These projects, which also support local communities and conserve biodiversity, generate carbon-emission rights that then can be bought by energy consumers around the world.

OUR STRATEGY ON CLIMATE CHANGE

Our strategy to assess and manage risks and opportunities resulting from climate change includes consideration of different time horizons and specific risks:

- societal risk: the potential for a deteriorating relationship with the public, other companies, and governments in countries where Shell operates;
- commercial risk: the potential for structural shifts in demand profiles for industry products;
- regulatory risk: the potential for strengthening of existing and introduction of new regulations; and
- physical risk: the potential impact on our facilities and the communities in which we operate due to changing physical conditions.

This is how we describe the different time horizons and the relevance for the identification of risks and business planning:

- Short term (up to three years): detailed financial projections are developed and used to manage performance and expectations on a three-year cycle. This three-year plan is shared with the Board;
- Medium term (three years up to around 10 years): the majority of production and earnings expected to be generated in this period come from our existing assets; and
- Long term (beyond around 10 years): for this period, the current Shell portfolio is not representative of our future performance or the potential risks. Decision making and risk identification on the thematic structure of the future portfolio are guided by associated emerging questions.

Shell has a rigorous approach to understanding, managing and mitigating climate risks to its facilities. Shell also requires each business and function to monitor, communicate and report changes in the risk environment and the effectiveness of actions taken to manage identified risks on an ongoing basis. This is outlined in a toolkit for risk management including our Risk Management Manual and complementary guidance documents that cover specific aspects such as climate risk.

Each Shell business unit needs to consider the acceptability of climate-related risks in their portfolios. To ensure that informed judgements are made, businesses' senior managers present their current assessments of the

Climate change and energy transition Continued

likelihood of the climate-related risks discussed above materialising and their potential impact, along with summaries of current mitigation efforts under way within their business unit. Each risk is then categorised as either acceptable or as needing improvement.

We aim to reduce the GHG intensity of our portfolio and we continue to work on improving the energy efficiency of our existing operations. In addition, and as a better way to inform and drive our investment choices and adapt our business over time, in November 2017 we announced our ambition to reduce the Net Carbon Footprint of our energy products in step with society's drive to reduce GHG emissions. We aim to reduce the Net Carbon Footprint of the energy products we sell – expressed in grams of CO₂ equivalent per megajoule consumed – by around half by 2050. As an interim step, by 2035, and predicated on societal progress, we aim for a reduction of around 20% compared with our 2016 level. Our approach to calculating the Net Carbon Footprint covers emissions directly from Shell operations (including from the extraction, transportation and processing of raw materials, and transportation of products), those generated by third parties who supply energy to us for production, and our customers' emissions from their use of our energy products. Also included are emissions

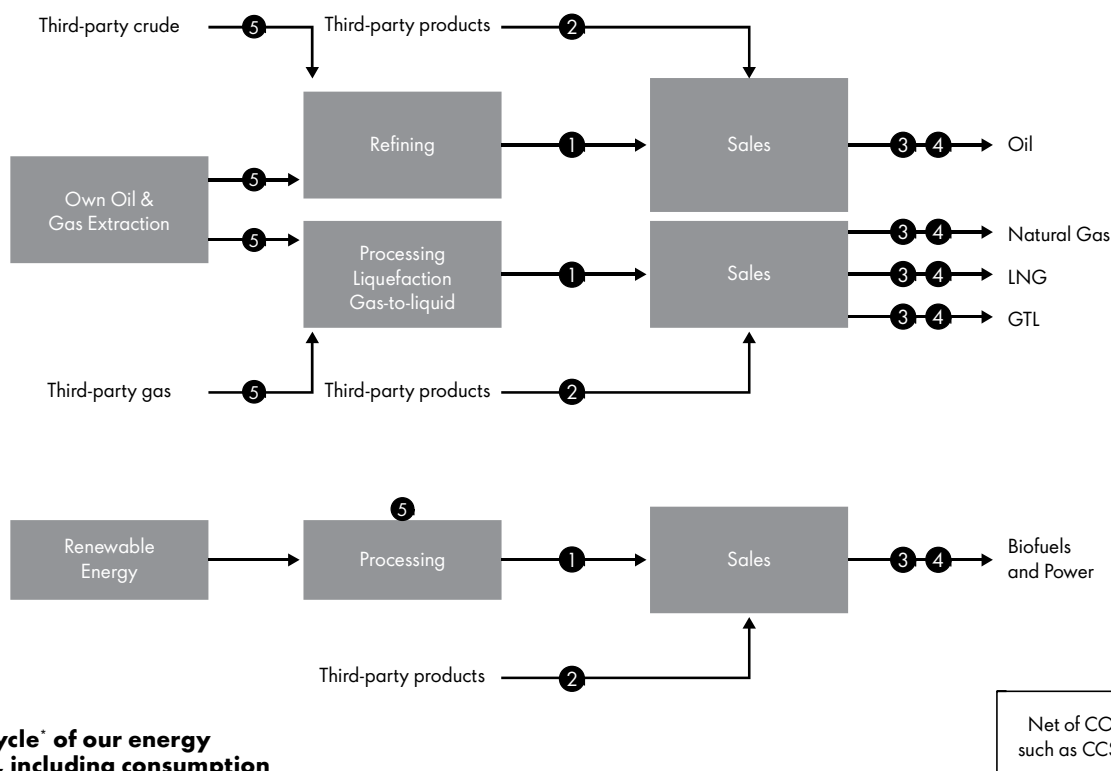
from elements of this life cycle not owned by Shell, such as oil and gas processed by Shell but not produced by Shell, or from oil products and electricity marketed by Shell that have not been processed or generated at a Shell facility. The calculation also includes biofuels, as well as emissions that we offset by using CCS or natural carbon sinks, such as forests and wetlands. Chemicals and lubricants products, which are not used to produce energy, are excluded from the scope of this ambition.

When selecting our Net Carbon Footprint ambition, we have purposefully chosen a wide and meaningful frame against which to manage our performance. The calculation of the Net Carbon Footprint includes not only emissions from our own operations and those from third parties in parts of our supply chains that produce and bring energy to the market but also emissions of our customers from the use of the energy products we sell to them. The emissions from our operations are important but those of our customers from their use of the energy products are much larger in proportion.

The diagram below illustrates the scope of the Net Carbon Footprint calculation:

Scope of our Net Carbon Footprint

Emissions from energy products included within the Net Carbon Footprint framework.



Full life cycle* of our energy products, including consumption

- 1 Emissions from bringing own products to market
- 2 Emissions from bringing third-party products to market
- 3 Emissions from use of own products
- 4 Emissions from use of third-party products
- 5 Emissions from use of own products

¹ The 'life cycle' calculation tracks the energy molecules end-to-end but does not include emissions associated with construction or decommissioning of facilities.
² Nature Based Solutions.

To meet the decarbonisation goals of the Paris Agreement, society needs an increasing supply of energy products that produce lower or zero GHG emissions over their full life cycle, to use those products more efficiently and to store emissions that cannot be avoided in sinks. Within this framework, our strategy is to keep increasing the share of such low-carbon energy products in our portfolio, while also developing carbon sinks. By broadening our focus to the full life-cycle emissions from the energy products that we sell to our customers, instead of solely on our operational emissions, we believe we will be better aligned with societal need and growing customer demand for more energy with lower life-cycle GHG emissions. Therefore, our strategy is to reduce our Net Carbon Footprint, mainly by increasing the proportion of lower-carbon products such as natural gas, biofuels, electricity and hydrogen in the mix of products we sell to our customers.

We will publish annual updates on our progress towards lowering the Net Carbon Footprint of our energy products. See the Shell Sustainability Report to be published in April 2019 for more information.

Our long-term ambition is to reduce the Net Carbon Footprint of our energy products to be in line with that of society as a whole by 2050, a stretching aspiration that aims to ensure that Shell continues to develop a resilient and relevant portfolio over the coming decades. While this is a long-term aspiration that will need periodic recalibration in line with the pace of change in broader society and the wider energy system, it is intended to help ensure that we remain relevant and are competitively positioned in the energy transition. This means supplying energy products and services that our customers need, now and in the future, and developing a resilient portfolio in line with our purpose of providing more and cleaner energy to society.

In the period to 2035, we believe that all forms of GHG reduction measures must be accelerated and increased in scale by society. Major improvements in energy efficiency and new sources of energy, such as renewables, combined with the use of cleaner fossil fuels, such as replacing coal with natural gas, are needed to meet the growing global population's energy needs while reducing GHG emissions. In addition, the world will need significant growth in CCS and sustained reductions in demand. Massive reforestation is also needed to limit temperature rises to 1.5°C. The management of GHG emissions is increasingly important to our shareholders as concerns over climate change lead to tighter environmental regulations. Policies and regulations designed to limit the increase in global temperatures to well below 2°C could have a material adverse effect on Shell – through higher operating costs and reduced demand for some of our products. We actively monitor and assess these potential developments and are best able to manage them when local policies provide a stable and predictable regulatory foundation for our future investments. At this stage, industry is still facing significant uncertainty about how local regulatory policies and consumer behaviour will shape the evolution of the energy system and which technologies and business models will thrive.

In December 2018, we announced our intention to set short-term Net Carbon Footprint targets. Early 2019, it was decided to set a Net Carbon Footprint target for 2021 of 2-3% lower than our 2016 Net Carbon Footprint of 79 grams of CO₂ equivalent per megajoule. While we have received third-party limited assurance on our 2016 Net Carbon Footprint, we are currently re-evaluating our assurance processes to ensure that we will be able to obtain third-party assurance in parallel with the projected timing of our future Net Carbon Footprint disclosures.

OUR PERFORMANCE

Data in this section are reported on a 100% basis in respect of activities where we are the operator. Reporting on this operational control basis differs from that applied for financial reporting purposes in the "Consolidated Financial Statements" on pages 167-214. Detailed data and information on our 2018 environmental and social performance will be published in the Shell Sustainability Report in April 2019.

Our direct GHG emissions decreased from 73 million tonnes of CO₂ equivalent in 2017 to 71 million tonnes of CO₂ equivalent in 2018. The main contributors to this decrease were divestments (for example in Argentina, Canada, Gabon, Iraq, Malaysia and the UK). The level of flaring in our Upstream and Integrated Gas businesses combined decreased by more than 35%, compared to 2017, primarily as a result of the Majnoon divestment in Iraq. These decreases were partly offset by inclusion of the assets previously operated by the Motiva Enterprises LLC joint venture in our data for the full year in 2018, increased production at our Pearl gas-to-liquids (GTL) plant in Qatar and the start-up of our Prelude floating liquefied natural gas asset in Australia.

In 2015, we signed up to the World Bank's "Zero Routine Flaring by 2030" initiative. This is an important initiative to ensure that all stakeholders, including governments and companies, work together to address routine flaring. Flaring, or burning off, of gas in our Upstream and Integrated Gas businesses contributed around 7% of our overall direct GHG emissions in 2018. More than 40% of this flaring took place at facilities where there was no infrastructure to capture the gas produced with oil, known as associated gas.

Our involvement in Basrah Gas Company (BGC), a non-Shell-operated joint venture between Shell, South Gas Company and Mitsubishi Corporation in the south of Iraq, continues to reduce flaring in the country. It is the largest gas company in Iraq's history and the world's largest flaring reduction project. BGC captures associated gas that would otherwise be flared from three non-Shell-operated oil fields in southern Iraq (Rumaila, West Qurna 1 and Zubair). The gathered gas is processed into dry gas, liquefied petroleum gas (LPG) and condensate. Dry gas is supplied to the gas network in southern Iraq and then used to generate electricity. LPG and condensate are delivered to South Gas Company for distribution in the domestic market and excess production is exported. In 2018, BGC processed an average of 800 million standard cubic feet of gas per day.

Around 35% of flaring in our Upstream and Integrated Gas facilities in 2018 took place in assets operated by The Shell Petroleum Development Company of Nigeria Limited (SPDC). Flaring from SPDC-operated facilities fell by more than 50% between 2014 and 2018. Flaring intensity levels in SPDC decreased in 2018 compared with 2017, partly due to improved compressor availability and facility outages in the Western Delta. SPDC continues to make progress in close collaboration with its joint venture partners and the Federal Government of Nigeria towards the objective of ending the continuous flaring of associated gas. Two new gas-gathering projects (Adibawa and Otumara) came on stream at the end of 2017 and two more (the Forcados Yokri Integrated Project and Southern Swamp Associated Gas Gathering Solutions) are expected to be completed in 2019.

GHG emissions data are provided below in accordance with UK regulations. GHG emissions comprise CO₂, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulphur hexafluoride and nitrogen trifluoride. The data are calculated using locally regulated methods where they exist. Where there is no locally regulated method, the data are calculated using the 2009 API Compendium, which is the recognised industry standard under the GHG Protocol Corporate Accounting and Reporting Standard. There are inherent limitations to the accuracy of such data. Oil and gas industry guidelines (IPIECA/API/IOGP) indicate that a number of sources of uncertainty can contribute to the overall uncertainty of a corporate emissions inventory.

Greenhouse gas emissions

	2018	2017
Emissions (million tonnes of CO ₂ equivalent)		
Direct [A]	71	73
Energy indirect [B]	11	12
Intensity ratio (tonne/tonne)		
All facilities [C]	0.24	0.25

[A] Emissions from the combustion of fuel and the operation of facilities, calculated using global warming potentials from the IPCC's *Fourth Assessment Report*.

[B] Emissions from the purchase of electricity, heat, steam and cooling for our own use, calculated using a market-based method as defined by the GHG Protocol Corporate Accounting and Reporting Standard.

[C] In tonnes of total direct and energy indirect GHG emissions per tonne of crude oil and feedstocks processed and petrochemicals produced in Downstream manufacturing, oil and gas available for sale, LNG and GTL production in Integrated Gas and Upstream. Additional information by segment will be published on www.shell.com/ghg.

Detailed information on our 2018 GHG emissions will be published in the Shell Sustainability Report in April 2019 and on www.shell.com/ghg.

The statements in this "Climate change and energy transition" section, including those related to Net Carbon Footprint, are forward-looking statements based on management's current expectations and certain material assumptions and, accordingly, involve risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied herein. See "About this Report" on pages 05-06 and "Risk factors" on page 15-20.

Our people

Performing competitively in the evolving energy landscape requires competent and empowered people working safely together across Shell. We recruit, train and recompense people according to a strategy that aims to organise our businesses effectively. We accelerate development of our people; grow and strengthen our leadership capabilities; and enhance employee performance through strong engagement. Our people are essential to the successful delivery of the Shell strategy and to sustaining business performance over the long term.

EMPLOYEE OVERVIEW

The employee numbers presented here are the full-time equivalent number of people employed by Shell on a full- or part-time basis, working in Shell subsidiaries, Shell-operated joint operations, non-Shell-operated joint operations, or seconded to joint ventures and associates.

At December 31, 2018, there were 81,000 Shell employees, compared with 83,000 at December 31, 2017, and 91,000 at December 31, 2016. The reduction in 2018 was driven by portfolio activities and our continued effort to improve operational efficiency and to reduce costs. These changes were partly offset by the insourcing of specific skill sets into the organisation (predominantly in IT) and other external recruitment to build our talent pipeline. We continue to leverage and expand capabilities to ensure a sustainable talent pool.

During 2018, we employed an average of 82,000 people, shown by geographical area in the table below and by business segment in Note 26 to the “Consolidated Financial Statements” on page 213.

Average number of employees by geographical area

	2018	2017 [A]	2016 [A]
	Thousand		
Europe	24	25	26
Asia	28	28	28
Oceania	2	2	2
Africa	4	5	6
North America	21	24	29
South America	2	2	4
Total	82	86	95

[A] As revised, to align with the current year definition.

EMPLOYEE COMMUNICATION AND INVOLVEMENT

We strive to maintain a healthy employee and industrial relations environment in which dialogue between management and our employees – both directly and, where appropriate, through employee representative bodies – is embedded in our work practices. On a regular basis, management engages with our employees through a range of formal and informal channels, including emails from the Chief Executive Officer, webcasts, townhalls, team meetings, face-to-face gatherings, breakfast briefings, interviews, helplines and online publications via our intranet. For further information on stakeholder engagement, see the Corporate governance section on pages 98-99.

Strong employee engagement is especially important in maintaining strong business delivery in times of change. The annual Shell People Survey is one of the principal tools used to measure employee engagement, motivation, affiliation and commitment to Shell. It provides insights into employees’

views and has had a consistently high response rate. In 2018, the response rate was 82%, which was an increase of 2% compared with 2017, and the average employee engagement score was 77 points out of 100, which was an increase of one point compared with 2017.

We promote safe reporting of views about our processes and practices. In addition to local channels, the Shell Global Helpline enables our people and third parties to report potential breaches of the Shell General Business Principles and Shell Code of Conduct, confidentially and anonymously, in a variety of languages. Shell Internal Audit (SIA) is the custodian of the Shell Global Helpline process in Shell, which is managed by an independent third party. SIA is accountable for ensuring that the Shell Global Helpline functions as intended and that all allegations of Code of Conduct breaches (including bribery and corruption) are investigated and followed up on as appropriate. The Board has formally delegated the responsibility for reviewing the functioning of the Shell Global Helpline, and the reports arising from its operation, to the Audit Committee. The Audit Committee is also authorised to ensure that arrangements are in place for the proportionate and independent investigation of reported matters and for follow-up action.

DIVERSITY AND INCLUSION

Our intention is to sustain a diverse workforce and an inclusive environment that respects and shows care for all our people and helps improve our business performance. Our diversity and inclusion (D&I) approach focuses on talent acquisition, progression, retention, leadership visibility, and on inclusive culture. Our leaders aim to be role models for D&I and assume accountability for continuous progress. We believe that diverse teams led by inclusive leaders are more engaged, and therefore deliver better safety and business performance. By embedding D&I into our operations, we have a better understanding of the needs of our people as well as the needs of our varied customers, partners and stakeholders throughout the world. It also allows us to benefit from a wider external talent pool for recruitment purposes.

We provide equal opportunity in recruitment, career development, promotion, training and rewards for all our people, including those with disabilities. In 2018, we introduced our workplace accessibility service, which currently serves 62 locations globally. This service ensures that all employees have access to reasonable adjustments so that they can work effectively and productively. In addition, we implemented a global minimum standard for maternity leave of 16 weeks.

Our focus on workplace inclusion also continues in other areas. For example, in 2018, we were recognised as one of the top three organisations in the Workplace Pride global lesbian, gay, bisexual, transgender and intersexed (LGBTI) inclusive workplace benchmark and earned a 100% score in the Human Rights Campaign Foundation’s Corporate Equality Index. In addition, the 2018 Hampton Alexander Review ranked Shell first out of the Financial Times Stock Exchange (FTSE) 350 Oil & Gas Industry index companies and seventh out of the FTSE 100 Top 10 Best Performers. We actively monitor representation of women and local nationals in senior leadership positions and have talent-development processes to support us in mitigating any biases and delivering a more diverse representation.

Our people Continued

In 2018, 46% of our graduate recruits were female. At the end of 2018, the proportion of women in senior leadership positions was 24% compared with 22% at the end of 2017. "Senior leadership positions" is a Shell measure based on senior salary group levels and is distinct from the term "senior manager" in the statutory disclosures set out below.

Gender diversity data (at December 31, 2018)				Number
	Men		Women	
Directors of the Company	6	55%	5	45%
Senior managers [A]	701	73%	264	27%
Employees (thousand)	56	69%	25	31%

[A] Senior manager is defined in section 414C(9) of the Companies Act 2006 and, accordingly, the number disclosed comprises the Executive Committee members who were not Directors of the Company, as well as other directors of Shell subsidiaries.

The local national coverage is the number of senior local nationals (both those working in their respective base country and those expatriated) as a percentage of the number of senior leadership positions in their base country.

Local national coverage (at December 31)			
	Number of selected key business countries		
	2018	2017	2016
Greater than 80%	10	10	10
Less than 80%	10	10	10
Total	20	20	20

CODE OF CONDUCT

In line with the UN Global Compact Principle 10 (Businesses should work against corruption in all its forms, including extortion and bribery), we maintain a global anti-bribery and corruption/anti-money laundering (ABC/AML) programme designed to prevent or detect, and remediate and learn from, potential violations. The programme is underpinned by our commitment to prohibit bribery, money laundering and tax evasion, and to our Shell General Business Principles and Code of Conduct.

We do not tolerate the direct or indirect offer, payment, solicitation or acceptance of bribes in any form. Facilitation payments are also bribes and are prohibited. The Shell Code of Conduct includes specific guidance for Shell staff (which comprises employees and contract staff) on requirements to avoid or declare actual, potential or perceived conflicts of interest, and on offering or accepting gifts and hospitality.

Communications from leaders emphasise both the importance of these commitments and compliance with requirements. These are reinforced with both global and targeted communications to ensure that Shell staff are frequently reminded of their obligations. Supporting the Code of Conduct, we have mandatory risk-based procedures and controls that address a range of compliance risks and ensure we focus resources, reporting and attention appropriately. By making a commitment to our core values – honesty, integrity and respect – and following the Code of Conduct, we protect Shell's reputation.

In 2018, we introduced mandatory ethical leadership workshops for senior executives across our global operations, to reinforce and explore the level of commitment to ethics and compliance expected of leaders at this level.

The workshops focus on values, behaviours, business pressures and leadership practices. The workshops are part of our wider work to cultivate a strong corporate culture where impeccable ethics are a matter of personal pride for every employee, rather than only a compliance issue.

As part of our commitment to ethics and compliance, we ensure that our policies, standards and procedures are communicated to Shell employees and contract staff and, where necessary and appropriate, to agents and business partners. Particular areas of focus with third parties include our due diligence procedures, and clearly articulated requirements (for example, through the use of standard contract clauses). In addition, we publish our Ethics and Compliance Manual on shell.com to demonstrate our commitment in this area.

The Shell Ethics and Compliance Office assists the businesses and functions with the ABC/AML and other programme implementation, and monitors and reports on progress. Legal counsel provides legal advice globally and supports the programme's implementation. The Shell Ethics and Compliance Office regularly reviews and revises the ABC/AML and other programmes to ensure they remain up to date with applicable laws, regulations and best practices. This includes incorporating results from relevant internal audits, reviews and investigations.

We have a duty to investigate all good faith allegations of breaches of the Code of Conduct, however they are raised. We are committed to ensuring all such incidents are investigated by specialists in accordance with our Investigation Principles. Violation of the Code of Conduct or its policies can result in disciplinary action, up to and including contract termination or dismissal. In some cases, we may report a violation to the relevant authorities, which could lead to legal action, fines or imprisonment.

Internal investigations confirmed 370 substantiated breaches of the Code of Conduct in 2018. As a result, we dismissed or terminated the contracts of a total of 92 employees and contract staff.

EMPLOYEE SHARE PLANS

We have a number of share plans designed to align employees' interests with our performance through share ownership. For information on the share-based compensation plans for Executive Directors, see the "Directors' Remuneration Report" on pages 119-147.

PERFORMANCE SHARE PLAN, LONG-TERM INCENTIVE PLAN AND EXCHANGED AWARDS UNDER THE BG LONG-TERM INCENTIVE PLAN

Conditional awards of the Company's shares are made under the terms of the Performance Share Plan (PSP) to around 16,000 employees each year. Senior executives receive conditional awards of the Company's shares under the terms of the Long-term Incentive Plan (LTIP) rather than under the terms of the PSP. The extent to which the awards vest under both plans is determined over a three-year performance period, but the performance conditions applicable to each plan are different. Under the PSP, 50% of the award is linked to certain of the indicators described in "Performance indicators" on pages 27-28, averaged over the period. From 2017 onwards, 12.5% of the award is linked to free cash flow (FCF) and the remaining 37.5% is linked to a comparative performance condition which involves a comparison with four of our main competitors over the period, based on three measures. Under the LTIP, from 2017, 25% of the award is linked to the FCF measure and the remaining 75% is linked to the

comparative performance condition mentioned above. Prior to 2017, 50% of the PSP award and all of the LTIP award were linked to a comparative performance condition based on four measures.

Separately, following the BG acquisition, certain employee share awards made in 2015 under BG's Long-Term Incentive Plan were automatically exchanged for equivalent awards over shares in the Company. These awards either do not have performance conditions or have the same performance conditions applied as the Company's LTIP. Awards take the form of either conditional awards or nil cost options.

Under all plans, all shares that vest are increased by an amount equal to the notional dividends accrued on those shares during the period from the award date to the vesting date. In certain circumstances, awards may be adjusted before delivery or reclaimed after delivery. None of the awards results in beneficial ownership until the shares vest.

See Note 21 to the "Consolidated Financial Statements" on page 208.

RESTRICTED SHARE PLAN

Under the Restricted Share Plan, awards are made on a highly selective basis to senior staff. Shares are awarded subject to a three-year retention period. All shares that vest are increased by an amount equal to the notional dividends accrued on those shares during the period from the award date to the vesting date. In certain circumstances, awards may be adjusted before delivery or reclaimed after delivery.

GLOBAL EMPLOYEE SHARE PURCHASE PLAN

Eligible employees in participating countries may participate in the Global Employee Share Purchase Plan. This plan enables them to make contributions from net pay towards the purchase of the Company's shares at a 15% discount to the market price, either at the start or at the end of an annual cycle, whichever date offers the lower market price.

UK SHELL ALL EMPLOYEE SHARE OWNERSHIP PLAN

Eligible employees of participating Shell companies in the UK may participate in the Shell All Employee Share Ownership Plan, under which monthly contributions from gross pay are made towards the purchase of the Company's shares. For every six shares purchased by the employee, an additional free matching share is provided.

UK SHARESAVE SCHEME

Eligible employees of participating Shell companies in the UK have been able to participate in the UK Sharesave Scheme. Options have been granted over the Company's shares at market value on the invitation date. These options are normally exercisable after completion of a three-year or five-year contractual savings period. No further grants will be made under this plan.

Separately, following the acquisition of BG, certain participants in the BG Sharesave Scheme chose to roll over their outstanding BG share options into options over the Company's shares. The BG option price (at a discount of 20% to market value) was converted into an equivalent Company option price at a ratio agreed with Her Majesty's Revenue and Customs. These options are normally exercisable after completion of a three-year contractual savings period.

Strategic Report signed on behalf of the Board

/s/ Linda M. Szymanski

Linda M. Szymanski

Company Secretary
March 13, 2019

Governance

The Board of Royal Dutch Shell plc

CHARLES O. HOLLIDAY

Chair

Tenure

Chair – Four years (appointed Chair May 19, 2015)
On Board – 8.5 years (appointed September 1, 2010)
(see page 98 for further information)

Board Committee membership

Chair of the Nomination and Succession Committee

Outside interests/commitments

Presiding Director of HCA Holdings, Inc. Director of Deere & Company.
Member of the Critical Resource's Senior Advisory Panel. Member of the Royal Academy of Engineering.

Age 71

Nationality US citizen

Career

Charles (Chad) Holliday was appointed Chair of the Board of Royal Dutch Shell plc with effect from May 19, 2015.

He was Chief Executive Officer of DuPont from 1998 to 2009, and Chairman from 1999 to 2009. He joined DuPont in 1970 after receiving a B.S. in industrial engineering from the University of Tennessee and held various manufacturing and business assignments, including a six-year Tokyo-based posting as President of DuPont Asia/Pacific.

He has previously served as Chairman of the Bank of America Corporation, The Business Council, Catalyst, the National Academy of Engineering, the Society of Chemical Industry – American Section and the World Business Council for Sustainable Development. He is a founding member of the International Business Council.

Relevant skills and experience

Chad has a distinguished track record as an international businessman. He was originally appointed to the Board as a Non-executive Director in September 2010 and, prior to his May 2015 appointment as Chair of the Board, served as Chair of the Corporate and Social Responsibility Committee and Member of the Remuneration Committee.

He has a deep understanding of international strategic, commercial and environmental issues, and gained extensive experience in the areas of safety and risk management during his time with DuPont. During his time as Chair, he has been committed to developing and maintaining a strong dialogue with investors and other key stakeholders and has ensured that their views are considered during Board discussions and decision-making. He has also demonstrated a strong commitment to ensuring that the highest standards of corporate governance, safety, ethics and compliance are maintained. Chad is a particularly avid advocate of greater diversity, which is reflected in the Board's current diversity mix and increased diversity goals across the Shell Group.

Chad's performance has been evaluated by the other Directors, led by Gerard Kleisterlee, Deputy Chair and Senior Independent Director.

GERARD KLEISTERLEE

Deputy Chair and Senior Independent Director

Tenure

8.5 years (appointed November 1, 2010)

Board Committee membership

Chair of the Remuneration Committee and member of the Nomination and Succession Committee

Outside interests/commitments

Chairman of Vodafone Group plc, Chairman of the Supervisory Board of ASML Holding N.V.

Age 72

Nationality Dutch

Career

Gerard was President/Chief Executive Officer and Chairman of the Board of Management of Koninklijke Philips N.V. from 2001 to 2011. Having joined Philips in 1974, he held several positions before being appointed as Chief Executive Officer of Philips' Components division in 1999 and Executive Vice-President of Philips in 2000.

He was a member of the board of Directors of Dell Inc. from 2010 to 2013 and, a member of the Supervisory Board of Daimler AG from 2009 to 2014. From 2014 to 2016, he was a Non-executive Director of IBEX Global Solutions plc.

Relevant skills and experience

Gerard is a Dutch businessman with a distinguished career with one of the largest electronics companies in the world. Through a variety of senior roles, he was responsible for operations in places such as Europe, Taiwan, China and Hong Kong. Gerard is also currently Chair of Vodafone, one of the UK's largest global companies, which provides services to more than 500 million customers.

Gerard's business experience provides him with a broad and deep understanding of the geopolitical, strategic and commercial challenges an evolving business faces. His experience – gained at Philips, Dell and Vodafone, businesses that have seen significant changes in technology and consumer behaviour – is a great asset to the Board as Shell transitions to a lower-carbon energy system.

Gerard is a seasoned leader, making him ideally suited to his position as our Senior Independent Director, Deputy Chair and Chair of our Remuneration Committee. He raises the bar on the level of Board debate, with his insightful, concise and direct questions.

BEN VAN BEURDEN

Chief Executive Officer

Tenure

Five years (appointed January 1, 2014)

Board Committee membership

N/A

Outside interests/commitments

No external appointments

Age

60

Nationality

Dutch

Career

Ben was Downstream Director from January to September 2013. Before that, he was Executive Vice President Chemicals from 2006 to 2012. In this period, he also served on the boards of a number of leading industry associations, including the International Council of Chemicals Associations and the European Chemical Industry Council. Prior to this, he held a number of operational and commercial roles in both Upstream and Downstream, including Vice President Manufacturing Excellence. He joined Shell in 1983, after graduating with a Master's Degree in Chemical Engineering from Delft University of Technology, the Netherlands.

Relevant skills and experience

Ben has over 35 years of Shell experience and has built a deep industry understanding and proven management experience across the technical and commercial roles which he has undertaken over his career.

Since 2016, Ben has led Shell to deliver strong financial results, total shareholder returns and earnings per share. Ben has also led Shell through ending the scrip dividend and the start of a \$25 billion share buyback programme. Under his leadership Shell New Energies has been established and Shell has announced industry-leading initiatives in response to the global challenge of the energy transition to a lower-carbon future, including the introduction of Shell's Net Carbon Footprint ambition. Shell is now at the forefront of a cross-industry push to reduce the greenhouse gas impact of natural gas with the Methane Guiding Principles.

Ben has led the Company to complete the acquisition of BG Group and fully integrate it into our operations, executed an impressive reshaping of our portfolio and completed a divestment programme of \$30 billion of non-core assets, making the Shell Group simpler.

JESSICA UHL

Chief Financial Officer

Tenure

Two years (appointed March 9, 2017)

Board Committee membership

N/A

Outside interests/commitments

No external appointments

Age

51

Nationality

US citizen

Career

Jessica was Executive Vice President Finance for the Integrated Gas business from January 2016 to March 2017. Previously, she was Executive Vice President Finance for Upstream Americas from 2014 to 2015, Vice President Finance for Upstream Americas Unconventionals from 2013 to 2014, Vice President Controller for Upstream and Projects & Technology from 2010 to 2012, Vice President Finance for the global Lubricants business from 2009 to 2010, and Head of External Reporting from 2007 to 2009. She joined Shell in 2004 in finance and business development, supporting the Renewables business.

Prior to joining Shell, Jessica worked for Enron in the USA and Panama from 1997 to 2003 and for Citibank in San Francisco, USA from 1990 to 1996. She obtained an MBA at INSEAD in 1997.

Relevant skills and experience

Jessica is a highly regarded executive with a track record of delivering key business objectives, from cost leadership in complex operations to M&A delivery. Jessica's extensive experience combines an external perspective with 15 years of Shell experience: she has held finance leadership roles in Europe and the USA, in Shell's Upstream, Integrated Gas and Downstream businesses, as well as in Projects & Technology.

Jessica's tenure as CFO has also been impressive. She was appointed not long after the BG acquisition, when Shell's debt, gearing and development costs were high and when the oil price was still recovering from the lower levels in 2016. In these challenging conditions, but with great enthusiasm, clarity and discipline, Jessica has been a leading force in delivering on the financial promises Shell had made to its shareholders, and with great success. In 2018 Shell delivered \$39 billion in free cash flow (\$28 billion in 2017). This made it possible for Shell to decrease its net debt and gearing and increase shareholder distributions, following the removal of the scrip dividend, and the start of the share buyback programme.

The Board of Royal Dutch Shell plc Continued

ANN GODBEHERE

Non-executive Director

Tenure

10 months (appointed May 23, 2018)

Board Committee membership

Member of the Audit Committee

Outside interests/commitments

Non-executive Director of UBS AG and UBS Group AG since 2009 and 2014[A], respectively, and Rio Tinto plc and Rio Tinto Limited since 2010[B]. Senior Independent Director of Rio Tinto plc, Fellow of the Institute of Chartered Professional Accountants and a Fellow of the Certified General Accountants Association of Canada.

[A] On February 25, 2019, UBS AG and UBS Group AG announced that Ann would not seek re-election at their Annual General Meeting on May 2, 2019, after serving 10 years on the Board.

[B] On February 27, 2019, Rio Tinto plc and Rio Tinto Limited announced that Ann would not seek re-election at their Annual General Meeting on April 10, 2019, after serving 9 years on the Board.

Age

63

Nationality

Canadian and British

Career

Ann started her career with Sun Life of Canada in 1976 in Montreal, Canada and joined M&G Group in 1981 where she served as Senior Vice President and Controller for both life and health and property and casualty businesses throughout North America. She joined Swiss Re in 1996 and served as Chief Financial Officer from 2003 to 2007. From 2008 to 2009, she was interim Chief Financial Officer and an Executive Director of Northern Rock bank in the initial period following its nationalisation.

She served as a Non-executive Director of Prudential plc from 2007 to 2017 and British American Tobacco plc from 2011 to 2018.

Relevant skills and experience

Ann is a former CFO, a Fellow at the Institute of Chartered Accountants, and has more than 25 years of experience in the financial services sector. She has worked her entire career in international business and has lived in or served on boards in nine countries. Although still in her first year with Shell, she has been adding exceptional value by bringing both her experience and new perspective to the Board.

Ann's highly relevant skills, particularly in investment appraisal and financial risk management, are a welcome addition to our Board and Audit Committee. Her long international business career brings with it an invaluable global perspective and understanding, which is reflected in the insights and constructive challenges she brings to the boardroom.

As part of her induction, Ann visited our Middle East and US Upstream operations. These visits, combined with Ann's unquenchable thirst for knowledge, greatly increased her understanding of Shell's businesses, further strengthening the valuable contributions she had already been making to the Board. More information on these visits can be found under Induction and Training within this Report.

EULEEN GOH

Non-executive Director

Tenure

4.5 years (appointed September 1, 2014)

Board Committee membership

Chair of the Audit Committee

Outside interests/commitments

Chairman of SATS Limited. Non-executive Director of Capitaland Limited, DBS Bank Limited, DBS Group Holdings Limited and Temasek Trustees Pte Limited [A]. Trustee of the Singapore Institute of International Affairs Endowment Fund. Chairman of the Governing Council of the Singapore Institute of Management and Non-executive Director of Singapore Health Services Pte Limited, both of which are not-for-profit organisations.

[A] On April 1, 2019, Euleen is retiring from the Board of Temasek Trustees Pte Ltd.

Age

63

Nationality

Singaporean

Career

Euleen is an Associate of the Institute of Chartered Accountants in England and Wales, a Fellow of the Singapore Institute of Chartered Accountants and has professional qualifications in banking and taxation. She held various senior management positions within Standard Chartered Bank and was Chief Executive Officer of Standard Chartered Bank, Singapore, from 2001 until 2006.

She has also held non-executive appointments on various boards including Aviva plc, MediaCorp Pte Limited, Singapore Airlines Limited, Singapore Exchange Limited, Standard Chartered Bank Malaysia Berhad and Standard Chartered Bank Thai plc. She was previously Non-executive Chairman of the Singapore International Foundation and Chairman of International Enterprise Singapore and the Accounting Standards Council, Singapore.

Relevant skills and experience

Euleen's current roles as Chair or Board Director of various international companies provide significant experience in the area of strategy development and international businesses. She is a champion of diversity and constructively challenges the Board and management to constantly raise the bar in this area.

Being based in Singapore and as Chair of the Risk Committee of the largest bank in South East Asia, Euleen is close to key emerging/growth markets for our business. Euleen's risk management expertise has elevated the Board's deep deliberations around risk governance. Her extensive travel around the world, through her various executive and non-executive roles, has equipped her with broad geopolitical insight and significant knowledge of operating in the Asian region.

Euleen leverages her great approachability and financial acumen to pose probing and insightful questions, both in and beyond the boardroom. This provides a strong foundation for her role as Chair of our Audit Committee and contributes to well-rounded and incisive Board discussions.

CATHERINE J. HUGHES**Non-executive Director****Tenure**

1.5 years (appointed June 1, 2017)

Board Committee membership

Member of the Corporate and Social Responsibility Committee and member of the Remuneration Committee

Outside interests/commitments

Non-executive Director of SNC-Lavalin Group Inc.

Age

56

Nationality

Canadian and French

Career

Catherine was Executive Vice President International at Nexen Inc., from January 2012 until her retirement in April 2013, where she was responsible for all oil and gas activities including exploration, production, development and project activities outside Canada. She joined Nexen in 2009 as Vice President Operational Services, Technology and Human Resources.

Prior to joining Nexen Inc., she was Vice President Oil Sands at Husky Oil from 2007 to 2009 and Vice President Exploration & Production Services, from 2005 to 2007. She started her career with Schlumberger in 1986 and held key positions in various countries, including Italy, Nigeria, the UK, the USA and France, and was President of Schlumberger Canada Limited for five years. She was a Non-executive Director of Statoil from 2013 to 2015.

Relevant skills and experience

Catherine contributes her industry knowledge and ease of engagement with other Directors and managers in the boardroom. With her 30 years of oil and gas sector experience, she brings a geopolitical outlook and deep understanding of the industry. An engineer by training, she has also spent a significant part of her career working in senior human resources roles. The Board highly regards her perspectives on our industry and our most important asset, our people.

Catherine has a strong track record of executing operational discipline with a focus on performance metrics and a continual drive for excellence. Her knowledge of the technology underpinning oil and gas operations, logistics, procurement and supply chains benefits the Board greatly as it considers various projects and investment or divestment proposals.

She also leverages her industry knowledge – combined with her commitment to the highest standards of corporate governance and safety, ethics and compliance – in her membership of our Corporate and Social Responsibility Committee, while leveraging her human resources experience in her membership on the Remuneration Committee.

ROBERTO SETUBAL**Non-executive Director****Tenure**

1.5 years (appointed October 1, 2017)

Board Committee membership

Member of the Audit Committee

Outside interests/commitments

Member of the board of International Monetary Conference (IMC), the Economic and Social Development Council of the Presidency of Brazil, and the International Business Council of the World Economic Forum. He is also President of the Fundação Itaú Social and a Member of the Executive Committee of the Instituto Itaú Cultural.

Age

64

Nationality

Brazilian

Career

Roberto was Chief Executive Officer and Vice Chairman of the Board of Directors of Itaú Unibanco Holding S.A. in Sao Paulo, Brazil, until April 2017. At that time, he retired as Chief Executive Officer and currently serves as Co-Chairman of the Board of Directors. Following a brief period with Citibank in New York, he joined Banco Itaú in 1984 where he held a variety of senior roles in investment banking, consumer credit operations and retail banking before being appointed Chief Executive Officer in 1994. Following the merger of Banco Itaú and Unibanco, he was appointed to the position of President and Chief Executive Officer of Itaú Unibanco Holding S.A. Previously, he was a Non-executive Director of Petrobras S.A., President of the IMC and Vice-Chairman of the IIF.

Relevant skills and experience

Roberto brings significant experience in capital markets and financial services to the Board and has a deep understanding of international strategic management, commercial operations and risk management. He was instrumental in designing and then executing a strategy that led to Itaú becoming the largest bank in Brazil.

His deep financial knowledge enables him to make robust, demanding and constructive challenges to our investment considerations and helps to ensure that projects are aligned with our strategic intent.

Despite spending most of his life in Brazil, Roberto has a strong understanding of global business. Naturally, he also brings an invaluable perspective and insight into operating in his native country, a key growth market for Shell. His contributions also demonstrate his strong advocacy for the highest standards of corporate governance, ethics and compliance. This, combined with his experience of operating in challenging markets, helps to deepen the Board's analyses of difficult matters with multi-faceted risks.

SIR NIGEL SHEINWALD GCMG

Non-executive Director

Tenure

6.5 years (appointed July 1, 2012)

Board Committee membership

Chair of the Corporate and Social Responsibility Committee and member of the Remuneration Committee

Outside interests/commitments

Non-executive Director of Invesco Limited and Raytheon UK. Senior Adviser to Taniun Inc. and to the Universal Music Group. Visiting Professor and Council Member of King's College, London.

Age

65

Nationality

British

Career

Sir Nigel was a senior British diplomat who served as British Ambassador to the USA from 2007 to 2012, before retiring from the Diplomatic Service. Prior to this, he served as Foreign Policy and Defence Adviser to the Prime Minister and as British Ambassador and Permanent Representative to the European Union in Brussels. He joined the Diplomatic Service in 1976 and served in Brussels, Washington, Moscow and in a wide range of policy roles in London. Since 2012, he has taken on a number of international business roles, and supported organisations involved in higher education and international affairs.

Relevant skills and experience

Sir Nigel's distinguished track record including three of the most senior international roles in British public service has given him broad geopolitical and public policy experience, as well as knowledge of regulatory issues, communications and stakeholder management. He has a global and strategic outlook which enables him to identify emerging issues that could present geopolitical or reputational challenges.

Sir Nigel brings a unique government policy perspective to our strategic discussions particularly on topics such as the energy transition, which are strongly influenced by the views of governments and a complex range of interested parties. His many contributions to the Board on this and other strategic and operational topics often reflect the interconnections between geopolitics, business and external stakeholder engagement.

He is used to operating in challenging environments and is committed to active external engagement. This, and his understanding of public policy and regulatory issues through his career in government service and membership of think tank and university boards, makes him well suited to the role of Chair of our Corporate and Social Responsibility Committee.

LINDA G. STUNTZ

Non-executive Director

Tenure

7.5 years (appointed June 1, 2011)

Board Committee membership

Member of the Corporate and Social Responsibility Committee and member of the Nomination and Succession Committee

Outside interests/commitments

Director of Edison International

Age

64

Nationality

US citizen

Career

Linda is a founding partner of the law firm of Stuntz, Davis & Staffier, P.C., which is based in Washington, DC[A]. Her law practice included energy and environmental regulation, as well as matters relating to government support of technology development and transfer. She was a member of the US Secretary of Energy Advisory Board from 2015 to 2017, she chaired the Electricity Advisory Council of the US Department of Energy from 2008 to 2009 and was a member of the board of Directors of Schlumberger Limited from 1993 to 2010 and Raytheon Company from 2004 to 2015.

From 1989 to 1993, she held senior policy positions at the US Department of Energy, including Deputy Secretary.

[A] Linda retired from Stuntz, Davis & Staffier, P.C in January 2019.

Relevant skills and experience

Linda's Harvard legal training and deep practical legal experience bring unique and valuable expertise in energy-industry and environmental law, as well as extensive public policy experience, to our Board. This is conveyed through her in-depth knowledge of the gas and power industries and her work on issues related to climate change and energy-related measures to minimise greenhouse gas emissions.

As a board director of publicly traded companies for more than 25 years, Linda has provided strategic and legal advice to many energy companies and has substantial experience in overseeing and working with businesses with operations around the world. She has a broad understanding of technology and its development/commercialisation within our industry, from her work with the US government and on the Schlumberger board. She has significant knowledge and understanding of cyber risks as a result of her Raytheon and Edison International board service.

Linda's unique background, coupled with her exceptional ability to frame clear questions that tackle the key points of complex issues, helps deepen the Board's constructive challenges and considerations of critical industry-related matters, particularly those related to the energy transition.

GERRIT ZALM**Non-executive Director****Tenure**

Six years (appointed January 1, 2013)

Board Committee membership

Member of the Audit Committee and member of the Remuneration Committee

Outside interests/commitments

Director of Moody's Corporation in April 2018

Age

66

Nationality

Dutch

Career

Gerrit was an adviser to PricewaterhouseCoopers during 2007, Chairman of the trustees of the International Accounting Standards Board from 2007 to 2010, and an adviser to Permira from 2007 to 2008. He was Chief Economist of DSB Bank from July 2007 to January 2008, Chief Financial Officer from January 2008 to December 2008, and Chairman of the Managing Board of ABN AMRO Bank N.V. from 2010 to 2016. He was Minister of Finance of the Netherlands, twice, from 1994 to 2002 and from 2003 to 2007. In between, he was Chairman of the parliamentary party of the VVD.

Prior to 1994, he was head of the Netherlands Bureau for Economic Policy Analysis, a professor at Vrije Universiteit Amsterdam and held various positions at the Ministry of Finance and the Ministry of Economic Affairs. He studied General Economics at Vrije Universiteit Amsterdam and received an Honorary Doctorate in Economics from that university.

Relevant skills and experience

An economist by background, Gerrit's distinguished twelve-year service as the Minister of Finance to the Netherlands, coupled with his experience gained from his time with ABN AMRO Bank, brings deep and valuable understanding of Dutch politics and financial markets to the Board. His international financial management expertise and strategic development experience also benefits the Audit Committee.

A highly regarded and seasoned leader in both the public and private spheres, his significant experience in analysing financial commitments from both a wider public stakeholder and global business standpoint serves the Board well, particularly when considering investment proposals. Gerrit consistently and concisely articulates the logic and reasoning behind his views, benefitting both the Board and management. His questions often trigger other analytical questions from fellow Directors, which serves to deepen and widen Board discussions.

LINDA M. SZYMANSKI**Company Secretary****Tenure**

Two years (appointed January 1, 2017)

Age

51

Nationality

US citizen

Career

Linda was General Counsel of the Upstream Americas business and Head of Legal US, based in the USA, from 2014 to 2016. Previously, she was Group Chief Ethics & Compliance Officer based in the Netherlands from 2011 to 2014. Since joining Shell in 1995, she has also held a variety of legal positions in the Shell Oil Company in the USA, including Chemicals Legal Managing Counsel and other senior roles in employment, litigation, and commercial practice.

Relevant skills and experience

Linda is our Corporate Secretary and also plays an important role as Shell's General Counsel Corporate, overseeing corporate legal teams in the Netherlands, UK, Switzerland, the USA and Canada.

The various legal roles Linda has undertaken at our headquarters, and in supporting both the Upstream and Downstream businesses, have provided her with a strong understanding of our global operations and people. Her experience of engaging with the Board in previous roles, coupled with her broad understanding and engagement across Shell's businesses and functions, helps to ensure that the right matters come to the Board at the right time.

BOARD DIVERSITY

Non-executive Director tenure



0 to 3 years
4 to 6 years
7 to 9 years

Director nationality



British 9%
Dutch 27%
American 27%
Canadian 18%
Brazilian 9%
Singaporean 9%

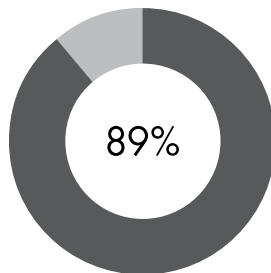
Gender diversity



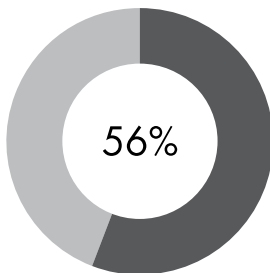
Female
Male

Non-executive Director sector experience

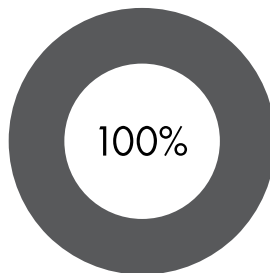
Regulatory/Government affairs/Public policy



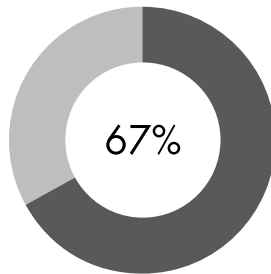
Oil & gas/Extractives/Energy



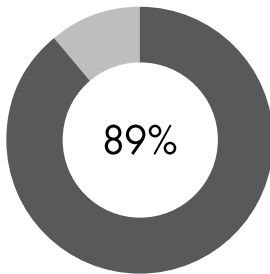
Strategy development



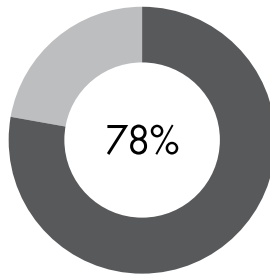
Engineering/Industrial



Consumer/Marketing



Accounting and Finance



Senior Management

The Senior Management of the Company comprises the Executive Directors and those listed below. All are members of the Executive Committee (see "Corporate governance" on page 101).

JOHN ABBOTT Downstream Director

Tenure
Five years (appointed October 2013)

Age
58

Nationality
British

Career
John was previously Executive Vice President Manufacturing, responsible for oil refineries and petrochemicals plants worldwide. He joined Shell in 1981, and has held various management positions in refining, chemicals and upstream heavy oil, working in Canada, the Netherlands, Singapore, Thailand, the UK and the USA.

On April 13, 2018, John was elected as a Non-executive Director of Fiat Chrysler Automobiles N.V.

HARRY BREKELMANS Projects & Technology Director

Tenure
Four years (appointed October 2014)

Age
53

Nationality
Dutch

Career
Harry was previously Executive Vice President for Upstream International Operated based in the Netherlands. He joined Shell in 1990 and has held various management positions in Exploration and Production, Internal Audit, and Group Strategy and Planning. From 2011 to 2013, he was Country Chair – Russia and Executive Vice President for Russia and the Caspian region.

ANDREW BROWN [A] Upstream Director

Tenure
Six years (appointed January 2016 (Upstream International Director from 2012 to 2016))

Age
57

Nationality
British

Career
Andrew was previously Executive Vice President for Shell's activities in Qatar and a member of the Upstream International Leadership Team. He was awarded the Order of the British Empire in 2012 for his services to British-Qatari business relations.

[A] On January 17, 2019, the Company announced that Andrew Brown will step down from the role of Upstream director on June 30, 2019 and will be replaced with Wael Sawan. Andy will remain available to Wael and the Executive Committee to assist with transition until September 30, 2019, and will then leave the company after 35 years' distinguished service.

RONAN CASSIDY Chief Human Resources & Corporate Officer

Tenure
Three years (appointed January 2016)

Age
52

Nationality
British

Career
Ronan was previously Executive Vice President Human Resources, Upstream International. He joined Shell in 1988 and has held various human resources positions in Upstream and Downstream.

DONNY CHING

Legal Director

Tenure

Five years (appointed February 2014)

Age

54

Nationality

Malaysian

Career

Donny was previously General Counsel for Projects & Technology based in the Netherlands. He joined Shell in 1988 based in Australia and then moved to Hong Kong and later to London. In 2008, he was appointed Head of Legal at Shell Singapore, having served as Associate General Counsel for Gas & Power in Asia-Pacific.

WAEI SAWAN

Upstream Director

Tenure

Appointed with effect from July 2019

Age

44

Nationality

Canadian

Career

Wael is currently Executive Vice President Deep water and a member of the Upstream leadership team. He joined Shell in 1997 and has worked in Retail and various commercial and New Business Development projects. Wael has worked in Europe, Africa, Asia and the Americas.

MAARTEN WETSELAAR

Integrated Gas and New Energies Director

Tenure

Three years (appointed January 2016)

Age

50

Nationality

Dutch

Career

Maarten was previously Executive Vice President of Integrated Gas based in Singapore. He joined Shell in 1995 and has held various financial, commercial and general management roles in Downstream, Trading and Upstream.

Directors' Report

MANAGEMENT REPORT

This Directors' Report, together with the "Strategic Report" on pages 07-81, serves as the Management Report for the purpose of Disclosure Guidance and Transparency Rule 4.1.8R.

FINANCIAL STATEMENTS AND DIVIDENDS

The "Consolidated Statement of Income" and "Consolidated Balance Sheet" can be found on pages 168-169 respectively.

The table below sets out the dividends on each class of share and each class of American Depositary Share (ADS [A]). The Company announces its dividends in dollars and, at a later date, announces the euro and sterling equivalent amounts using a market exchange rate. Dividends on Royal Dutch Shell plc A shares (A shares) are paid by default in euros, although holders may elect to receive dividends in sterling. Dividends on Royal Dutch Shell plc B shares (B shares) are paid by default in sterling, although holders may elect to receive dividends in euros. Dividends on ADSs are paid in dollars.

[A] ADSs are listed on the New York Stock Exchange under the symbols RDSA and RDSB. Each ADS represents two shares – two A shares in the case of RDSA or two B shares in the case of RDSB.

The Directors have announced a fourth-quarter interim dividend as set out in the table below, payable on March 25, 2019, to shareholders on the Register of Members at close of business on February 15, 2019. The closing date for dividend currency elections was March 1, 2019 [A] and the euro and sterling equivalents announcement date was March 11, 2019.

[A] A different dividend currency election date may apply to shareholders holding shares in a securities account with a bank or financial institution ultimately through Euroclear Nederland. This may also apply to other shareholders who do not hold their shares either directly on the Register of Members or in the corporate sponsored nominee arrangement. Such shareholders can contact their broker, financial intermediary, bank or financial institution for the election deadline that applies.

DIRECTORS' RESPONSIBILITIES IN RESPECT OF THE PREPARATION OF THE ANNUAL REPORT AND ACCOUNTS

The Directors are responsible for preparing the Annual Report, including the financial statements, in accordance with applicable laws and regulations. These require the Directors to prepare financial statements for each financial year. As such, the Directors have prepared the Consolidated and Parent Company Financial Statements in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU). In preparing these financial statements, the Directors have also elected to comply

with IFRS as issued by the International Accounting Standards Board (IASB). The Directors must not approve the financial statements unless they are satisfied that they give a true and fair view of the state of affairs of Shell and the Company and of the profit or loss of Shell and the Company for that period. In preparing these financial statements, the Directors are required to:

- adopt the going concern basis unless it is inappropriate to do so;
- select suitable accounting policies and then apply them consistently;
- make judgements and accounting estimates that are reasonable and prudent; and
- state whether IFRS as adopted by the EU and IFRS as issued by the IASB have been followed.

The Directors are responsible for keeping adequate accounting records that are sufficient to show and explain the transactions of Shell and the Company and disclose with reasonable accuracy, at any time, the financial position of Shell and the Company and to enable them to ensure that the financial statements comply with the Companies Act 2006 (the Act) and, as regards the Consolidated Financial Statements, with Article 4 of the IAS Regulation and therefore are in accordance with IFRS as adopted by the EU. The Directors are also responsible for safeguarding the assets of Shell and the Company and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

Each of the Directors, whose names and functions can be found on pages 82-87, confirms that, to the best of their knowledge:

- the financial statements, which have been prepared in accordance with IFRS as adopted by the EU and with IFRS as issued by the IASB give a true and fair view of the assets, liabilities, financial position and profit of Shell and the Company; and
- the Management Report includes a fair review of the development and performance of the business and the position of Shell, together with a description of the principal risks and uncertainties that it faces.

Furthermore, so far as each of the Directors is aware, there is no relevant audit information of which the auditors are unaware, and each of the Directors has taken all the steps that ought to have been taken in order to become aware of any relevant audit information and to establish that the auditors are aware of that information.

Dividends

	2018							
	A shares			B shares[A]			A ADSs	B ADSs
	\$	€	pence	\$	pence	€	\$	\$
Q1	0.47	0.4011	35.18	0.47	35.18	0.4011	0.94	0.94
Q2	0.47	0.4048	36.50	0.47	36.50	0.4048	0.94	0.94
Q3	0.47	0.4124	36.77	0.47	36.77	0.4124	0.94	0.94
Q4	0.47	0.4181	35.94	0.47	35.94	0.4181	0.94	0.94
Total announced in respect of the year	1.88	1.6364	144.39	1.88	144.39	1.6364	3.76	3.76
Amount paid during the year		1.6001	142.36		142.36	1.6001	3.76	3.76

[A] It is expected that holders of B shares will receive dividends through the dividend access mechanism applicable to such shares. The dividend access mechanism is described more fully on pages 243-245.

The Directors consider that the Annual Report, including the financial statements, taken as a whole, is fair, balanced and understandable and provides the information necessary for shareholders to assess Shell's position and performance, business model and strategy.

The Directors consider it appropriate to continue to adopt the going concern basis of accounting in preparing the financial statements.

The Directors are responsible for the maintenance and integrity of the Shell website (www.shell.com). Legislation in the UK governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

VIABILITY STATEMENT

The "Strategic Report" includes information about Shell's strategy, financial condition, cash flows and liquidity, as well as the factors, including the principal risks, likely to affect Shell's future development. "Business overview" on page 12 describes Shell's business model, including competitive advantages and key strengths. The Directors assess Shell's prospects both at an operating and strategic level, each involving different time horizons. To this end, the Directors assess Shell's portfolio and strategy against a wide range of outlooks, including assessing the potential impacts of various possible energy transition pathways and scenarios for changes in societal expectations in relation to climate change. Shell recognises in its strategy that the world is transitioning to a lower-carbon energy system (see "Climate change and energy transition" on pages 71-78). The Risk Factors section on pages 15-20 provides an overview of the principal risks Shell is exposed to in its operations.

On an annual basis, the Directors approve a detailed three-year operating plan, which forecasts Shell's cash flows and ability to service financing requirements, pay dividends and fund investing activities during the period. Shell's three-year operating plan includes assumptions in relation to internal and external parameters. Some of the key assumptions include the impact of commodity prices, exchange rates and schedules of growth programmes. Considering the degree of change possible in these parameters, Shell has deemed a three-year period of assessment appropriate for the longer-term viability statement.

In making the viability assessment, Shell has also considered the financial impact of each of the following severe but possible scenarios that could threaten Shell's viability. In reviewing these stress tests, the Directors have considered possible mitigation steps and have made certain assumptions regarding the availability of future funding options, including the ability to raise future financing in line with the operating plan window.

Scenario	Link to principal risks
A significant HSSE event	[A]
A low oil and gas price environment with \$40/b Brent (2018 real terms)	[B]
A significant HSSE event in a low oil and gas price environment	[A] and [B]
Sustained impact from politically adverse developments, lower growth in developing countries, as well as lower growth in Europe	[B] and [C]
Unplanned shut down of a major cashgenerating asset for a year	[A]

[A] The nature of our operations exposes us, and the communities in which we work, to a wide range of health, safety, security and environment risks.

[B] We are exposed to fluctuating prices of crude oil, natural gas, oil products and chemicals.

[C] We are exposed to treasury and trading risks, including liquidity risk, interest rate risk, foreign exchange risk, commodity price risk and credit risk. We are affected by the global macroeconomic environment as well as financial and commodity market conditions.

Taking account of Shell's position and principal risks at December 31, 2018, the Directors have a reasonable expectation that Shell will be able to continue in operation and meet its liabilities as they fall due over its three-year operating plan period.

NON-FINANCIAL INFORMATION STATEMENT

The Non-Financial Information Statement below forms part of the Strategic Report on pages 07-81.

Non-Financial Information Statement

REPORTING REQUIREMENT	WHERE TO READ MORE IN THIS REPORT	PAGE
Business model	Business overview	12-14
Non-financial KPIs	Performance indicators	28
Environmental matters	Environment and society, Climate change and energy transition	66-78
Employees	Our people	79-81
Social matters	Environment and society	70
Respect for human rights	Environment and society	70
Anti-corruption and anti-bribery matters	Our people	80

REPURCHASES OF SHARES

At the 2018 Annual General Meeting (AGM), shareholders granted an authority, which expires on the earlier of the close of business on August 22, 2019, and the end of the 2019 AGM, for the Company to repurchase up to a maximum of 834 million of its shares (excluding purchases for employee share plans). In accordance with this authority, on July 26, 2018, we announced the immediate start of a share buyback programme of at least \$25 billion by the end of 2020 subject to further progress with debt reduction and oil price conditions.

During 2018, 125 million A ordinary shares with a nominal value of €8.8 million (\$10.6 million) (1.52% of the Company's total issued share capital at December 31, 2018) were purchased and cancelled for a total cost of \$3.9 billion including expenses, at an average price of \$31.55 per share.

The purpose of the shares repurchased in 2018 under the share buyback programme is to reduce the issued share capital of the Company. This is in order to offset the number of shares issued under the Scrip Dividend Programme and to significantly reduce the equity issued in connection with the Company's combination with BG Group. The Scrip Dividend Programme was cancelled with effect from the fourth quarter 2017 interim dividend. More information can be found at www.shell.com/scrip. From January 1, 2019, to January 28, 2019, the end of the second tranche of the share buyback programme, a further 19.1 million A shares (0.23% of the Company's total issued share capital at December 31, 2018) were purchased for cancellation for a total cost of \$572 million including expenses, at an average price of \$29.95 per share. This means that 690 million ordinary shares could still be repurchased under the current AGM authority.

The Board continues to regard the ability to repurchase issued shares in suitable circumstances as an important part of Shell's financial management. A resolution will be proposed at the 2019 AGM to renew the authority for the Company to purchase its own share capital, up to specified limits, for a further year. This proposal will be described in more detail in the Notice of Annual General Meeting.

BOARD OF DIRECTORS

The Directors during the year were Ben van Beurden, Ann Godbehere (appointed with effect from May 23, 2018), Eileen Goh, Charles O. Holliday, Catherine J. Hughes, Gerard Kleisterlee, Roberto Setubal, Sir Nigel Sheinwald, Linda G. Stuntz, Jessica Uhl, Hans Wijers (who stood down on May 22, 2018), and Gerrit Zalm.

RETIREMENT, REAPPOINTMENT AND APPOINTMENT OF DIRECTORS

In line with the UK Corporate Governance Code (Code), all Directors will retire at the 2019 AGM and seek reappointment by shareholders. Shareholders will also be asked to vote on the appointment of Neil Carson with effect from June 1, 2019.

The biographies of all current Directors are given on pages 82-87 and biographies for those seeking appointment or reappointment will also be included in the Notice of Annual General Meeting. Details of the Executive Directors' contracts can be found on pages 145-146 and copies are available for inspection from the Company Secretary. Furthermore, a copy of the form of these contracts has been filed with the US Securities and Exchange Commission and incorporated by reference as an exhibit to this Report.

The terms and conditions of appointment of Non-executive Directors are set out in their letters of appointment with the Company which, in accordance with the Code, are available for inspection from the Company Secretary. A copy of the form of these letters of appointment has also been filed with the US Securities and Exchange Commission and incorporated by reference as an exhibit to this Report.

No Director is, or was, materially interested in any contract subsisting during or at the end of the year that was significant in relation to the Company's business. See also "Related party transactions" below.

DIRECTORS' INTERESTS

The interests (in shares of the Company or calculated equivalents) of the Directors in office at the end of the year, including any interests of a "connected person" [A], can be found in the "Directors' Remuneration Report" on pages 135-136.

[A] "Connected person" has the meaning given to "person closely associated" within the Market Abuse Regulation.

Changes in Directors' share interests during the period from December 31, 2018, to March 13, 2019, can be found in the "Directors' Remuneration Report" on pages 135-136.

QUALIFYING THIRD-PARTY INDEMNITIES

The Company has entered into a deed of indemnity with each Director who served during the year under identical terms. The deeds indemnify the Directors to the widest extent permitted by the applicable laws of England against all liability incurred as a Director or employee of the Company or of certain other entities.

RELATED PARTY TRANSACTIONS

Other than disclosures given in Notes 09 and 27 to the "Consolidated Financial Statements" on pages 188-189 and 214 respectively, there were no transactions or proposed transactions that were material to either the Company or any related party. Nor were there any transactions with any related party that were unusual in their nature or conditions.

POLITICAL CONTRIBUTIONS

No donations were made by the Company or any of its subsidiaries to political parties or organisations during the year. Shell Oil Company administers the non-partisan Shell Oil Company Employees' Political Awareness Committee (SEPAC), a political action committee registered with the US Federal Election Commission. Eligible employees may make voluntary personal contributions to the SEPAC.

RECENT DEVELOPMENTS AND POST-BALANCE SHEET EVENTS

There are no material recent developments or post-balance sheet events to report.

LIKELY FUTURE DEVELOPMENTS

Information relating to likely future developments can be found in the "Strategic Report" on pages 07-81.

RESEARCH AND DEVELOPMENT

Information relating to Shell's research and development, including expenditure, can be found in "Business overview" on page 12.

DIVERSITY AND INCLUSION

Information concerning diversity and inclusion can be found in "Our people" on pages 79-80.

EMPLOYEE COMMUNICATION AND INVOLVEMENT

Information concerning employee communication and involvement can be found in "Our people" on page 79.

CORPORATE SOCIAL RESPONSIBILITY

A summary of Shell's approach to corporate social responsibility can be found in "Environment and society" on pages 66-70 and "Our people" on pages 79-81. Further details will be available in the Shell Sustainability Report 2018.

GREENHOUSE GAS EMISSIONS

Information relating to greenhouse gas emissions can be found in "Climate change and energy transition" on pages 71-78.

FINANCIAL RISK MANAGEMENT, OBJECTIVES AND POLICIES

Descriptions of the use of financial instruments and Shell's financial risk management objectives and policies, and exposure to market risk (including price risk), credit risk and liquidity risk can be found in Note 19 to the "Consolidated Financial Statements" on pages 202-207.

SHARE CAPITAL

The Company's issued share capital on December 31, 2018, is set out in Note 8 to the "Parent Company Financial Statements" on pages 243-245. The percentage of the total issued share capital represented by each class of share is given below.

Share capital percentage

Share class	%
A ordinary	54.42
B ordinary	45.58
Sterling deferred	de minimis

TRANSFER OF SECURITIES

There are no significant restrictions on the transfer of securities.

SHARE OWNERSHIP TRUSTS AND TRUST-LIKE ENTITIES

Shell has three primary employee share ownership trusts and trust-like entities: a Dutch foundation (stichting) and two US Rabbi Trusts. The shares held by the Dutch foundation are voted by its Board and the shares in the US Rabbi Trusts are voted by the Voting Trustee, Newport Trust Company. Both the Board of the Dutch foundation and the Voting Trustee are independent of Shell.

The UK Shell All Employee Share Ownership Plan has a separate related share ownership trust. Shares held by the trust are voted by its trustee, Computershare Trustees Limited, as directed by the participants.

SIGNIFICANT SHAREHOLDINGS

Information concerning significant shareholdings can be found on page 257.

ARTICLES OF ASSOCIATION

Information concerning the Articles of Association can be found on pages 104-112.

LISTING RULE INFORMATION [A]

Information concerning the amount of interest capitalised by Shell can be found in Note 6 to the "Consolidated Financial Statements" on page 184.

[A] This information is given in accordance with Listing Rule 9.8.4R.

AUDITOR

A resolution relating to the appointment of Ernst & Young LLP as auditor for the financial year 2019 will be proposed at the 2019 AGM.

CORPORATE GOVERNANCE

The Company's statement on corporate governance is included in the "Corporate governance" report on pages 95-112 and is incorporated in this Directors' Report by way of reference.

ANNUAL GENERAL MEETING

The AGM will be held on May 21, 2019, at the Circustheater, Circusstraat 4, 2586 CW, The Hague, The Netherlands. The Notice of Annual General Meeting will include details of the business to be put to shareholders at the AGM.

Signed on behalf of the Board

/s/ Linda M. Szymanski

Linda M. Szymanski

Company Secretary
March 13, 2019

Corporate governance

Dear Shareholders,

First, I would like to take you back to my opening statement at the beginning of this Report. There, I highlighted the importance of public trust, and the pages which followed provided more information on how we strive to achieve this trust. We operate in more than 70 countries, each with their own culture and expectations. We believe that operating in line with our core principles of honesty, integrity and respect for people and adhering to the Shell General Business Principles, Code of Conduct and Code of Ethics, helps everyone across Shell to do what is right and to comply with the relevant laws and regulations where they work. This will help us achieve the trust we strive for.

At the beginning of this Report, I also highlighted the importance of transparency, especially when working to earn trust. In the Governance section of this report, which starts on page 82, we provide not just the assurances legislation and regulation require from us, but we also try to provide a deeper understanding of the composition of our Board through new disclosure of the attributes each Director brings to our business. Further, we have enhanced our reporting of the diversity of skills and experience represented in the boardroom and how the Board was evaluated in 2018. In addition, we have included a new section on stakeholder engagement, an area of reporting that we plan to build on in the coming years, information on our Board activities during the year, the activities of our Committees and a detailed overview of our control framework.

We provide information on our governance arrangements and how we have applied the main principles and complied with the relevant provisions set out in the 2016 UK Corporate Governance Code (the Code) issued by the Financial Reporting Council (FRC). As I referenced in last year's report, the Code was under review by the FRC in 2017/18, and in July 2018 the outcome of this review was published in the form of the 2018 UK Corporate Governance Code (the New Code). The New Code applies to company reporting periods commencing on or after January 1, 2019, and we will report in accordance with this New Code next year. The New Code reiterates the importance of the "comply or explain" approach of its application and recognises that an alternative to complying with a provision may be justified in particular circumstances based on a range of factors, including the size, complexity and history of a company. One of the provisions of the New Code brings a new recommended nine-year limit to the tenure of the Board Chair. As this is a provision that directly relates to me, our Senior Independent Director, Gerard Kleisterlee provides a clear explanation of how the Board proposes to address this on page 98.

Building public trust this year also involved strengthening our public commitment to the Paris Agreement on climate change. In our joint statement with institutional investors on behalf of Climate Action 100+, we have committed to operationalise our ambition of around 50% Net Carbon Footprint reduction by 2050, through the setting of short-term targets which will be linked to executive remuneration. Further, as part of our transparency efforts within remuneration, we have published our CEO Pay Ratio, in line with new legislation. Although this is not required until 2020, we were keen to publish this information early. For full details, please see our Directors' Remuneration Report on page 138.

During the year, the Board spent time on a number of key matters related to transitioning to a lower-carbon energy system, such as our Sky scenario report and the Shell Energy Transition report. In addition, the Board discussed Shell's Net Carbon Footprint ambition and some of our Non-executive Directors

received dedicated updates from management and external experts on New Energies, the various business models, advantages and disadvantages of having positions in various value chains and the opportunities for Shell in this area. Furthermore, the Board held its annual two-day, strategy-focused meeting in Italy. External developments – including the energy transition – and their potentially uncertain impact set the background for this meeting, and for the critical but exciting decisions Shell will take as we navigate our course. The decisions this Board will take will be essential in shaping a resilient future for Shell. Given that and the importance of robust relationships in the boardroom as we consider and deliberate these matters, we invested time to strengthen the relationships both among Directors, particularly given new joiners over the last year, and between the Board and the Executive Committee. In addition, given the developments in our strategy over the last few years, this meeting provided an opportunity to take stock of the strategy and to reflect on and deepen the understanding of that strategy. More information on this can be found on page 98.

Succession is another key topic that remains a Board priority, and 2018 brought several changes to the composition of the Board. At the AGM, shareholders were asked to vote on the appointment of Ann Godbehere as a Non-executive Director with effect from May 23, 2018. The appointment was overwhelmingly endorsed by shareholders, and we are delighted with the valuable contributions she has already made. Hans Wijers stood down from his role as Non-executive Director at the 2018 AGM, after nine years on the Board, resulting in changes to our Senior Independent Director, Chair of the Remuneration Committee and Chair of the Corporate and Social Responsibility Committee.

In January 2019, we announced the intention to propose to this year's AGM that Neil Carson be appointed a Non-executive Director of the Company with effect from June 1, 2019. Neil has a wealth of expertise and brings a proven track record of utilizing his strong operational exposure, familiarity with capital-intensive business and a first-class international perspective on driving value in complex environments. We hope that you support his election. As with all our appointments, we believe that diversity is a critical factor for success, but we also recognise it is a continuous journey. Diversity is a key aspect within our succession planning, and we consistently stress test the talent pipeline from a diversity perspective. As I reference above, we have enhanced our reporting on the diversity of skills and experience represented in the boardroom this year, and this can be found on pages 82-88.

The Board completed its annual performance evaluation in December 2018. The process was internally facilitated, and we again used the support of an external consultant to assist with the administration of the process. We built on last year's evaluation by conducting the review in three stages, covering our two-day strategy-focused meeting; a skills and experience evaluation, which has input into the additional disclosure within our Board diversity overview; and our Board and Committees. The process again proved to be a valuable exercise generating reflective discussions and planned actions. You can read more about the process on pages 100-101.

In addition to leading the process for the Board changes noted above, the Nomination and Succession Committee also continued its focus on ongoing succession planning, monitored and reviewed corporate governance developments and made related recommendations to the Board. There were numerous corporate governance developments throughout the year, including the publication of the New Code, which will make 2019 yet another busy year for our Committees. The Board plans to propose modifications to the Company's Articles of Association (the Articles) at the 2019 AGM.

The Articles were last updated and approved by shareholders in 2010. The modifications will primarily reflect developments in best practice and provide additional clarification and flexibility. The modifications to be proposed have been reviewed by the Nomination and Succession Committee. Details of the modifications will be included in the 2019 Notice of Annual General Meeting.

Finally, we hope this report demonstrates a fair and balanced view of our governance processes. I would also like to thank my fellow Directors, my colleagues and our workforce around the world for their considerable efforts.

Chad Holliday

Chair

March 13, 2019

STATEMENT OF COMPLIANCE

The Board confirms that, throughout the year, the Company has applied the main principles and complied with the relevant provisions set out in the Code issued by the Financial Reporting Council (FRC) (the Code) in April 2016 [A][B]. In addition to complying with applicable corporate governance requirements in the UK, the Company must follow the rules of Euronext Amsterdam as well as Dutch securities laws because of its listing on that exchange. The Company must likewise follow US securities laws and the New York Stock Exchange (NYSE) rules and regulations because its securities are registered in the USA and listed on the NYSE.

[A] A copy of the Code can be found on the FRC's website (frc.org.uk).

[B] In July 2018, the FRC issued an updated version of the Code which applies to accounting periods beginning on or after January 1, 2019.

NYSE GOVERNANCE STANDARDS

In accordance with the NYSE rules for foreign private issuers, the Company follows home-country practice in relation to corporate governance.

However, foreign private issuers are required to have an audit committee that satisfies the requirements of the US Exchange Act Rule 10A-3. The Company's Audit Committee satisfies such requirements. The NYSE also requires a foreign private issuer to provide certain written affirmations and notices to the NYSE, as well as a summary of the significant ways in which its corporate governance practices differ from those followed by domestic US companies under NYSE listing standards (see Section 303A.11 of the NYSE Listed Company Manual). The Company's summary of its corporate governance differences is given below and can be found at www.shell.com/investor.

NON-EXECUTIVE DIRECTOR INDEPENDENCE

The Board follows the provisions of the Code in determining Non-executive Director independence, which states that at least half of the Board, excluding the Chair, should comprise Non-executive Directors determined by the Board to be independent. In the case of the Company, the Board has determined that all the Non-executive Directors at the end of 2018 are independent.

NOMINATING/CORPORATE GOVERNANCE COMMITTEE AND COMPENSATION COMMITTEE

The NYSE listing standards require that a listed company maintain a nominating/corporate governance committee and a compensation committee, both composed entirely of independent directors and with certain specific responsibilities. The Company's Nomination and Succession Committee and Remuneration Committee both comply with these requirements, except that the terms of reference of the Nomination and Succession Committee require only a majority of the committee members to be independent.

AUDIT COMMITTEE

As required by NYSE listing standards, the Company maintains an Audit Committee for the purpose of assisting the Board's oversight of its financial statements, its internal audit function and its independent auditors. The Company's Audit Committee is in full compliance with US Exchange Act Rule 10A-3 and Sections 303A.06 and 303.07 of the NYSE Listed Company Manual.

The Company's Audit Committee is not directly responsible for the appointment of independent auditors. However, the Company's Audit Committee makes recommendations to the Board for it to put to shareholders for approval in Annual General Meetings. UK legislation provides that it is for shareholders to agree the appointment, reappointment and removal of the Company's independent auditors.

SHAREHOLDER APPROVAL OF SHARE-BASED COMPENSATION PLANS

The Company complies with the Listing Rules published by the Financial Conduct Authority (FCA), which require shareholder approval for the adoption of share-based compensation plans which are either long-term incentive plans in which one or more Directors can participate or plans which involve or may involve the issue of new shares or the transfer of treasury shares. Under the FCA rules, such plans cannot be changed to the advantage of participants without shareholder approval, except for certain minor amendments, for example to benefit the administration of the plan or to take account of tax benefits. The rules on the requirements to seek shareholder approval for share-based compensation plans, including those in respect of material revisions to such plans, may deviate from the NYSE listing standards.

CODE OF BUSINESS CONDUCT AND ETHICS

The NYSE listing standards require that listed companies adopt a code of business conduct and ethics for all directors, officers and employees and promptly disclose any waivers of the code for directors or executive officers. The Company has adopted the Shell General Business Principles (see below), which satisfy the NYSE requirements. The Company also has internal procedures in place by which any employee can raise in confidence accounting, internal accounting controls and auditing concerns. Additionally, any employee can report concerns to management by telephone or over the internet without jeopardising their position (see below).

SHELL GENERAL BUSINESS PRINCIPLES

The Shell General Business Principles define how Shell subsidiaries are expected to conduct their affairs and are underpinned by the Shell core values of honesty, integrity and respect for people. These principles include, among other things, Shell's commitment to support fundamental human rights in line with the legitimate role of business and to contribute to sustainable development. They are designed to mitigate the risk of damage to our business reputation and to prevent violations of local and international legislation. They can be found at www.shell.com/sgbp. See "Risk factors" on page 19.

SHELL CODE OF CONDUCT

Directors, officers, employees and contract staff are required to comply with the Shell Code of Conduct, which instructs them on how to behave in line with the Shell General Business Principles. This code clarifies the basic rules and standards they are expected to follow and the behaviour expected of them. These individuals must also complete mandatory Code of Conduct training.

Designated individuals are required to complete additional mandatory training on antitrust and competition laws, anti-bribery, anti-corruption and anti-money laundering laws, data protection laws and trade compliance requirements (see "Risk factors" on page 19). The Shell Code of Conduct can be found at www.shell.com/codeofconduct.

CODE OF ETHICS

Executive Directors and Senior Financial Officers of Shell must also comply with a Code of Ethics. This code is specifically intended to meet the requirements of Section 406 of the Sarbanes-Oxley Act and the listing requirements of the NYSE (see above). It can be found at www.shell.com/codeofethics.

SHELL GLOBAL HELPLINE

Employees, contract staff, third parties with whom Shell has a business relationship (such as customers, suppliers and agents), and any member of the public (including shareholders) may raise ethics and compliance concerns (anonymously if preferred) through the Shell Global Helpline. This is a worldwide confidential reporting mechanism, operated by an independent external third party, and is available 24 hours a day, seven days a week by telephone and at www.shell.com or <https://shell.alertline.eu>. Concerns are assessed and managed by a specialist investigations team under a mandate from the Audit Committee.

BOARD STRUCTURE AND COMPOSITION

During 2018, the Board comprised the Chair; two Executive Directors, namely the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO); and eight Non-executive Directors, including the Deputy Chair and Senior Independent Director.

A list of current Directors, including their biographies, can be found on pages 82-87. The Board recognises its collective responsibility for the long-term success of the Company. Generally, it meets eight times a year [A] and has a formal schedule of matters reserved to it. This includes: overall strategy and management; corporate structure and capital structure; financial reporting and control, including approval of the Annual Report and Form 20-F, and interim dividends; oversight and review of risk management and internal control; significant contracts; and succession planning and new Board appointments. The full list of matters reserved to the Board for decision can be found at www.shell.com/investor.

[A] See page 100 for the number of meetings held in 2018.

ROLE OF DIRECTORS

The roles of the Chair, a non-executive role, and the CEO are separate, and the Board has agreed their respective responsibilities.

The Chair is responsible for the leadership and management of the Board and for ensuring that the Board and its committees function effectively. One way in which this is achieved is by ensuring Directors receive accurate, timely and clear information. He is also responsible for agreeing and regularly reviewing the training and development needs of each Director (see "Induction and training" below) which he does with the assistance of the Company Secretary. The Company Secretary also advises the Board on all governance matters.

The CEO bears overall responsibility for the implementation of the strategy agreed by the Board, the operational management of the Company and

the business enterprises connected with it. He is supported in this by the Executive Committee which he chairs (see page 101).

NON-EXECUTIVE DIRECTORS

Non-executive Directors are appointed by the Board or by shareholders at general meetings and, in accordance with the Code, must seek re-election by shareholders on an annual basis. Their letter of appointment refers to a specific term of office, such term being subject to the provisions of the Code and the Company's Articles of Association (the Articles). Upon appointment, Non-executive Directors confirm they are able to allocate sufficient time to meet the expectations of the role. Appointments are subject to a minimum of three months' notice of termination, and there is no compensation provision for early termination.

The Non-executive Directors bring a wide range and balance of skills and international business experience to Shell. Through their contribution to Board meetings and to Board committee meetings, they are expected to challenge and help develop proposals on strategy and bring independent judgement on issues of performance and risk. Generally, prior to each meeting of the Board, the Chair and the Non-executive Directors meet without the Executive Directors to discuss, among other things, the performance of individual Executive Directors. A number of Non-executive Directors also meet major shareholders periodically.

The role of the Senior Independent Director is to provide a sounding board for the Chair and to serve as an intermediary for the other Directors when necessary. The Senior Independent Director is available to shareholders if they have concerns which contact through the normal channels of Chair, CEO or CFO has failed to resolve or for which such contact is inappropriate.

All of the Non-executive Directors are considered by the Board to be independent.

CONFLICTS OF INTEREST

Certain statutory duties with respect to directors' conflicts of interest are in force under the Companies Act 2006 (the Act). In accordance with the Act and the Articles, the Board may authorise any matter that otherwise may involve any of the Directors breaching their duty to avoid conflicts of interest. The Board has adopted a procedure to address these requirements. It includes the Directors completing detailed conflict of interest questionnaires. The matters disclosed in the questionnaires are reviewed by the Board and, if considered appropriate, authorised in accordance with the Act and the Articles. Conflicts of interest as well as any gifts and hospitality received by and provided by Directors are kept under review by the Board. Further information relating to conflicts of interest can be found on pages 106-107.

SIGNIFICANT COMMITMENTS OF THE CHAIR

The Chair's other significant commitments are given in his biography on page 82.

INDEPENDENT PROFESSIONAL ADVICE

All Directors may seek independent professional advice in connection with their role as a Director. All Directors have access to the advice and services of the Company Secretary. The Company has provided both indemnities and directors' and officers' insurance to the Directors in connection with the performance of their responsibilities. Copies of these indemnities and the

directors' and officers' insurance policies are open to inspection. A copy of the form of these indemnities has been previously filed with the SEC and is incorporated by reference as an exhibit to this Report.

BOARD ACTIVITIES DURING THE YEAR

The Board generally meets eight times a year. However, in 2018, there were 10 meetings, nine of which were held in The Hague, the Netherlands and one in Florence, Italy.

The agenda for each meeting included a number of regular items, including reports from the CEO, the CFO and other members of the Executive Committee, from each of the Board committees and from the various functions, including finance (which includes investor relations), health and security, human resources, and legal (which includes the Company Secretary). The Board also considered and approved the quarterly, half-year and full-year financial results and dividend announcements and, at most meetings, considered a number of investment, divestment and financing proposals.

During the year, the Board received reports and presentations on certain Shell activities (including those in Brazil, Canada, the Netherlands, Nigeria, Oman, Pakistan and Russia), the New Energies business, digital strategy and the Shell brand. The Board also spent considerable time discussing ethics and compliance, including how to continue to build a strong corporate culture. In addition, it received reports on ethics and compliance, litigation, risk management and internal control, safety and environmental performance, senior management succession and corporate governance developments. The Board continued to receive updates, from a committee set up in 2017, on matters related to investigations and litigation against the Company regarding OPL 245, a deep-water block in Nigeria.

Progress against our strategy is closely monitored by the Executive Committee and discussed at each Board meeting. In addition, each year the Board holds a strategy-focused meeting, generally over two days, to discuss and deepen understanding of the individual and holistic elements of the overall Shell strategy. The meeting is held away from the office to encourage more relaxed and free-flowing discussions. This also helps to strengthen the relationship between the Board and Executive Committee. In 2018, the meeting was held in Italy, which enabled the Board to engage with senior management from Ferrari, which has been a Shell innovation partner for more than 50 years.

At its strategy meeting, progress was reviewed against our short-term plans and our vision for the future. The Board debated the business priorities and longer-term challenges of the evolving mobility landscape. The Non-executive Directors shared their expertise and provided independent oversight to the discussion.

As it has in previous years, certain Board Committees and Non-executive Directors conducted site visits of various Shell operations and overseas offices (see "Induction and training" below). These visits were designed to provide Directors with first-hand insights into some key portfolio positions. Directors also held various workforce engagements in these locations, as well as external stakeholder engagements.

CHAIR TENURE

Charles O. Holliday (Chad) was appointed as Chair in 2015 after 4.5 years on the Board as a Non-executive Director. He will reach a tenure of nine years in September 2019.

In January 2019, the New Code came into force and with it came a new recommended tenure of the chair. The New Code advises that the chair should not remain in post beyond nine years from the date of first appointment to the board. However, the New Code pragmatically acknowledges the situation in which we find ourselves, with a Chair approaching nine years, and if a clear explanation is provided, the New Code permits a limited time extension where this would support a Company's succession plan and diversity policy, particularly in those cases where the chair was an existing Non-executive Director on appointment.

The Nomination and Succession Committee, and the Board, have discussed this New Code requirement at length. In addition, the Company Secretary engaged with proxy advisory firms and some of our largest investors on the matter. Furthermore, Gerard Kleisterlee, our Senior Independent Director, engaged with investors on this topic at our governance event in December 2018 and communicated our preference for Chad Holliday to remain as Chair until our 2021 AGM.

The Board believes that retaining Chad until then would facilitate more effective phasing of his succession. An earlier departure would be disruptive and could leave a significant deficiency in Shell Board experience by 2020, when the current Senior Independent Director (Gerard Kleisterlee) and longest-serving Director (Linda G. Stuntz) will also have reached a nine-year tenure.

The Board believes that Chad continues to be a very effective Chair. Although the Board will continue to assess his objectivity, the Board is confident that he continues to exercise objective judgment, despite his tenure approaching nine years. In fact, the Board finds the continuity of his corporate knowledge and experience essential to complement and support the new skills and experience of its Director appointments of the last two years, as well as those that we will need to make in the next two years.

Further, the Board finds that his deep understanding and knowledge of the Shell Group, coupled with the strong Shell relationships he has established, enable him to effectively challenge management as well as coach other Non-executive Directors on the intricacies and nuances of the business, thereby better equipping them to likewise effectively challenge management and enhance overall governance. The Board has also achieved near gender parity and increased diversity under Chad's leadership as Chair.

He is well placed to lead the Board through the next two years, which are critical to succession planning, and to continue the strengthening of diversity among the Board and Senior Management.

Note: The text relating to Chair tenure is provided by Gerard Kleisterlee, Senior Independent Director.

STAKEHOLDER ENGAGEMENT

Shell recognises the important role it has to play in society and is deeply committed to public collaboration and stakeholder engagement. This commitment is at the heart of one of Shell's three strategic ambitions: to

sustain a strong societal licence to operate and contribute to society through our activities.

Shell places a high value on collaboration and has a long track record of working in partnerships with others, be it with investors, industry and trade groups, universities, governments or NGOs. We believe that our work with organisations around the world gives us greater insight into our business, and that sharing knowledge and experience with others contributes to developing better policies and practices.

Collaboration is particularly critical where society, including businesses, governments and consumers, faces issues as complex and challenging as climate change. Shell recognises that it has an important role to play in collaboration with its stakeholders.

In particular, Shell appreciates the long-term relationship it has with institutional investors and acknowledges the positive role that can be played by ongoing engagement and dialogue. In December 2018, Shell released a joint statement with a leadership group of institutional investors on behalf of the global investor initiative, Climate Action 100+. The announcement sets out key steps that Shell has decided to take to demonstrate alignment with the goals of the Paris Agreement on climate change: Shell announced that it will operationalise its Net Carbon Footprint (NCF) ambition by setting NCF-specific short-term targets, and that it will incorporate a link between the energy transition and the long-term remuneration of executives.

Shell further built on its Net Carbon Footprint ambition, taking a significant leadership position within the oil and gas sector with strong support from stakeholders. The statement is the result of long-term, ongoing engagement that has helped to inform and refine our strategy. What is clear from the joint statement is that there is strong support for this level of engagement with stakeholders and for our commitments as announced in the statement.

Shell also recognises the importance of its other stakeholders, including employees, customers and suppliers. For many years, the Board has recognised the importance of engaging with all our stakeholders, the need to understand and consider their views, and take account of these when making decisions.

This manifests itself through regular employee engagement in relation to all aspects of our work, community consultations for projects with potential social impacts, and Shell's strong focus on health and safety and environmental issues. In light of the New Code, the Board will be taking more concrete actions to assure the views of our stakeholders are considered in Board discussions and decision-making, as highlighted at the end of the Board evaluation section.

Shell also works closely with commercial third parties to deliver its strategic ambitions in mutually beneficial ways. For example, Shell created the Contractor Safety Leadership initiative to encourage Shell companies and their contractors to collaborate more effectively to improve safety and standardise procedures, yielding positive results. Shell is also present on the Steering Committee of the Permian Road Safety Coalition, an innovative collaboration of cross-industry efforts to improve road safety. These are just

a few examples of the ways in which Shell can leverage its position and share its experience to make a positive contribution to society.

Further insight on our engagement with stakeholders can be found within our Sustainability Report and our report on payments to governments, scheduled for publication in April 2019.

INDUCTION AND TRAINING

Following appointment to the Board, Directors receive a comprehensive induction tailored to their individual needs. This includes site visits and meetings with senior management to enable them to build up a detailed understanding of Shell's business and strategy, and the key risks and issues which they face. For Ann Godbehere, who was appointed to the Board with effect from May 23, 2018, Director-specific briefing materials were provided and induction sessions were held with various businesses and functions. She also participated in separate site visits: she visited our operations in Qatar, where she met with the Minister of Energy and Industry and connected with Qatar Shell senior female employees and the senior leadership team. While in Qatar, Ann also visited Pearl GTL, the world's largest gas-to-liquids plant, and the Qatargas 4 gas liquefaction plant.

Throughout the year, regular updates on developments in legal matters, governance and accounting are provided to all Directors. The Board regards site visits as an integral part of ongoing Director training. During the year, Catherine Hughes visited the Shell Scotford Complex in Canada, which consists of a bitumen upgrader, oil refinery, chemicals plant and a carbon capture and storage (CCS) facility. She also visited Kitimat, the site of our project involving the planned construction of a new greenfield gas liquefaction plant. Our Audit Committee visited our Trading and Supply operations at our London offices and our Corporate Social Responsibility Committee (CSRC) visited the Moerdijk chemical complex and our operations in Nigeria. More information on these visits can be found on pages 101-102 for the CSRC and pages 113-114 for the Audit Committee. Additional training is available so that Directors can update their skills and knowledge as appropriate.

ATTENDANCE AT BOARD AND BOARD COMMITTEE MEETINGS

Attendance during 2018 for all Board and Board committee meetings is given in the table below.

Attendance at Board and Board committee meetings [A]

	Board	Audit Committee	Corporate and Social Responsibility Committee	Nomination and Succession Committee	Remuneration Committee
Ben van Beurden	10/10				
Ann Godbehere	7/7	3/3			
Euleen Goh [B]	9/10	6/6			
Charles O. Holliday	10/10			7/7	
Catherine J. Hughes	10/10		6/6		5/5
Gerard Kleisterlee	10/10			5/5	5/5
Roberto Setubal	10/10	6/6			
Sir Nigel Sheinwald	10/10		6/6		5/5
Linda G. Stuntz	10/10	3/3	4/4	7/7	
Jessica Uhl	10/10				
Hans Wijers [C]	3/3		1/2	1/2	
Gerrit Zalm [D]	9/10	6/6			5/5

[A] The first figure represents attendance and the second figure the possible number of meetings. For example, [10/10] signifies attendance at [ten] out of [ten] possible meetings. Where a Director stood down from the Board or a Board committee during the year, or was appointed during the year, only meetings before standing down or after the date of appointment are shown.

[B] During 2018, an unscheduled Board meeting was held at short notice. Euleen Goh was unable to attend this meeting due to a clash with scheduled travel arrangements.

[C] Hans Wijers was unable to attend one Nomination Committee meeting held during the year due to a clash with a pre-agreed business commitment.

[D] Gerrit Zalm was asked not to attend an ad-hoc teleconference held in 2018 as the subject of the call was a matter where Gerrit Zalm was subject to certain conditions designed to avoid any actual or perceived conflicts of interest.

BOARD EVALUATION

The 2018 Board evaluation was facilitated internally, led by the Nomination and Succession Committee and managed by the Company Secretary. The review was undertaken in three stages:

Board Evaluation



At each stage members of the Board completed surveys online using the Lintstock Review Service platform. Lintstock are a London-based corporate advisory firm with no other connection with the Company. Separately, and to obtain additional executive perspectives, the Executive Committee also completed surveys in Phases One and Three.

Phase One – Strategy day review

Phase One focused on the effectiveness of the Board's annual two-day, strategy-focused meeting, including the agenda and time management at the event, the quality of materials distributed in advance, and the role of the Board in determining the strategic plan and overseeing implementation. The review placed particular focus on the Board's understanding of the views and requirements of various stakeholder groups, in the context of Shell's strategic plan.

Phase Two – Skills and experience

Following feedback from investors seeking greater understanding of the skills and experience represented on the Board, the Board decided to enhance reporting in this area.

To support this enhanced disclosure, the Board undertook a refreshed Board skills and experience review, where their skills and experience, obtained outside of Shell over the duration of each Director's career, were updated and ranked against a list of criteria.

The outcome of this review is reflected in the biographical narratives on pages 82-87, and the enhanced diversity disclosure and skill-set reporting on page 88.

Phase Three – Board and Committees

Undertaken in November/December and ahead of the final Board meeting of 2018, the scope of Phase Three was broader, with greater focus on the effectiveness of the Board, the Chair and each of the Board committees. Surveys were built around the output of the previous year's review, and took into account the trends and themes that emerged from the Strategy Day Review conducted earlier in the year. The exercise also involved a review of the induction and ongoing training opportunities available to the Directors, as well as the individual contribution of each Director.

From the completed surveys, a report was prepared with concise narrative and supporting graphical data, including a series of key recommendations and one-page executive summary. The anonymity of all respondents was ensured throughout the process.

At its meeting in December, the performance of the Board as a whole and of the Board committees was discussed by the Nomination and Succession Committee and subsequently by the full Board. Observations by Executive Committee members on Board performance, which had been provided in a separate report, were also discussed. The discussions were led by the Chair and focussed on matters such as:

- Board composition, dynamics, expertise and support;
- the Board's understanding of the views and requirements of investors, employees, governments, customers and communities;
- the management and focus of meetings; and
- the capacity of the organisation to deliver Shell's strategy.

The top priorities for the Board over the coming year were discussed and it was agreed that they included:

- Board composition, Board and senior management succession;
- the Board's understanding of the views of all our stakeholders and, more explicitly, ensuring these are considered as relevant in the Board's discussions and decision-making; and
- strengthening the appropriate balance of the Board's focus on the energy transition and New Energies business, as well as current operational matters.

After the Chair recused himself from the meeting, the Deputy Chair discussed the evaluation report on the Chair's performance. He summarised the strength of the positive ratings on such items as the Chair's communication and relationship with the CEO and other Directors, dealing with specific Director-related matters, availability outside of Board meetings, management of Board meetings, and his relationship with major shareholders and other stakeholders. The CEO and CFO confirmed the positive feedback received from wider Shell staff on the Chair's engagement style as well as his clear respect for the boundary between executive and non-executive responsibilities. Upon re-joining the meeting, the Deputy Chair provided a summary of the overview to the Chair.

The 2019 Board evaluation will be externally facilitated.

EXECUTIVE COMMITTEE

The Executive Committee operates under the direction of the CEO in support of his responsibility for the overall management of Shell's business. The CEO has final authority in all matters of management that are not within the duties and authorities of the Board or of the shareholders' general meeting. The current composition of the Executive Committee is as follows:

Executive Committee

Ben van Beurden	CEO [A][B]
Jessica Uhl	CFO [A][B]
John Abbott	Downstream Director [B]
Harry Brekelmans	Projects & Technology Director [B]
Andrew Brown	Upstream Director [B][C]
Ronan Cassidy	Chief Human Resources & Corporate Officer [B]
Donny Ching	Legal Director [B]
Maarten Wetselaar	Integrated Gas and New Energies Director [B]

[A] Director of the Company.

[B] Designated an Executive Officer pursuant to US Exchange Act Rule 3b-7. Beneficially owns less than 1% of outstanding classes of securities.

[C] Wael Sawon will take up the role of Upstream Director and become a member of the Executive Committee from July 1, 2019, taking over from Andrew Brown. Andrew will remain available to Wael and the Executive Committee to assist with the transition until September 30, 2019. Note [B] above will apply to Wael from July 1, 2019.

BOARD COMMITTEES

There are four standing Board committees made up of Non-executive Directors. These are the:

- Audit Committee;
- Corporate and Social Responsibility Committee;
- Nomination and Succession Committee; and
- Remuneration Committee.

Each of these Board committees has produced a report which has been approved by the relevant chair. A copy of each Committee's terms of reference is available from the Company Secretary and can be found at www.shell.com/investor.

AUDIT COMMITTEE

The Audit Committee Report, which sets out the composition and work of the Audit Committee during 2018, is on pages 113-118.

CORPORATE AND SOCIAL RESPONSIBILITY COMMITTEE

The members of the Corporate and Social Responsibility Committee are Sir Nigel Sheinwald (Chair of the Committee with effect from May 23, 2018), Catherine J. Hughes and Linda Stuntz (appointed with effect from May 23, 2018). Hans Wijers stood down as Chair of the Committee on May 22, 2018. The Committee met six times during the year; the Committee members' attendances are shown on page 100.

The role of the CSRC is to review and advise the Board on Shell's strategy, policies and performance in the areas of safety, environment, ethics and reputation against the Shell General Business Principles, the Shell Code of Conduct, and the HSSE & SP Control Framework. Conclusions and recommendations made by the Committee are reported directly to the Executive Committee and Board.

The Committee fulfils its responsibilities by reviewing a wide range of areas, including the management of health, safety, security, environmental and social impacts of projects and operations. The Committee reviews detailed reports, papers and internal audits covering these areas, visits Shell operations around the world, and meets a wide range of staff and stakeholders. In addition, it provides input into the Shell Sustainability Report and reviews a draft of the report before publication, with the next Sustainability Report to be published in April 2019.

In 2018, the CSRC balanced its time between safety, environment, and ethics, all underpinned by a strong focus on corporate culture and conduct. The topics discussed in depth included personal and process safety, road safety, the energy transition and climate change, Shell's Net Carbon Footprint ambition, the Company's environmental and societal licence to operate, and its ethics programme. The CSRC also discussed Shell's operations and the challenges faced in Pakistan, Nigeria and the Netherlands. In 2018, the Committee held five meetings in person and one meeting by conference call.

The CSRC conducted two major site visits in 2018. In February, the Committee visited Nigeria, where over three days they met with Shell staff, government officials, and representatives from local non-governmental organisations to gain a deeper understanding of operations in the Niger Delta.

In December, the Committee spent a day visiting our Moerdijk facility in the Netherlands, where they discussed process safety performance and local site challenges, including our relationship with the local community.

In 2019, the Committee's focus will include:

- safety, including process safety and road transport;
- the environment, including Shell's role in light of the Paris Agreement on climate change, providing advice to the Remuneration Committee on energy transition-related metrics, plastics, and operational environmental matters;
- ethics and compliance, including conduct and culture; and
- country focus, including Nigeria, Brazil, Canada (LNG Canada) and the Netherlands (Groningen). The Committee will visit Singapore in 2019.

NOMINATION AND SUCCESSION COMMITTEE

The members of the Nomination and Succession Committee are Charles O. Holliday (Chair of the Committee), Linda G. Stuntz and Gerard Kleisterlee (appointed with effect from May 23, 2018). Hans Wijers stood down as a member of the Committee on May 22, 2018. The Committee met seven times during the year; the Committee members' attendances are shown on page 100.

The Committee continually reviews the leadership needs of the Company, based on the skills, experience, diversity and length of tenure on the Board as a whole, and identifies and nominates suitable candidates for the Board's approval to fill vacancies when they arise. In addition, it makes recommendations on who should be appointed Chair of the Audit Committee, the Corporate and Social Responsibility Committee and the Remuneration Committee and, in consultation with the relevant chair, recommends who should sit on each of the Board committees. It also makes recommendations on corporate governance guidelines, monitors compliance with corporate governance requirements and makes recommendations on disclosures connected with corporate governance of its appointment processes.

During 2018, the Committee dealt with the appointment of a new Non-executive Director, Ann Godbehere. As with all appointments to the Board, the appointment process involved the Committee agreeing on a candidate profile and, following an interview and benchmarking process, making a recommendation to the Board. The Board then sought shareholder approval for the appointment at the 2018 AGM held in May, proposing that the appointment be effective from May 23, 2018. The appointment was overwhelmingly endorsed by shareholders.

In addition to continuing its ongoing programme of succession planning for the Non-executive Directors and in particular for the Deputy Chair and Senior Independent Director, the Committee also considered the senior management talent pipeline and scheduled a series of meetings with prospective candidates with potential future senior leadership appointments in mind. It also considered any potential conflicts of interest and the independence of the Non-executive Directors and led the Board evaluation process.

In accordance with its terms of reference, the Committee monitored and reviewed corporate governance developments throughout the year. Such developments were numerous and included UK government proposals related to matters such as executive pay and the role of employees and other stakeholders, and a wide-ranging reform of the Code by the FRC. As referenced by the Chair, the New Code was published by the FRC in 2018, and the Committee continues to work with the Board to address the new requirements. The Committee continues to monitor and review these and other corporate governance developments, as well as considering whether and how current Company governance matters should be strengthened, and this is likely to keep the Committee engaged for the remainder of 2019 and beyond.

The Board continues to take the issue of boardroom diversity seriously and believes maintaining an appropriate level of diversity is key to its effective performance. Accordingly, the Committee's focus on diversity has resulted in strengthening the Board's composition by gender, nationality, skill set and industry experience over recent years. Reporting has been enhanced in this area, on pages 82-88. The New Code requires us to build on this work by overseeing the development of a diverse pipeline for succession more broadly. While the Committee continuously strives to improve diversity, as evidenced on the Board, we recognise that we have more work to do within senior management [A]. At the end of 2018, 12.5% of our Executive Committee, about 24% of our senior leadership staff and around half of Shell's graduate recruits are female. Additionally, in Shell's key countries more than 50% of leaders are local nationals. While we are proud of these achievements, we will continue to strive for more. How we oversee diversity, particularly with respect to succession pipelines, will be a focus for the Committee in the year ahead.

[A] More information on gender diversity is given in "Our people" on pages 79-80.

The Committee was assisted during the year by Russell Reynolds, external global search firms whose main role was to propose suitable candidates. Russell Reynolds do not have any connection with the Company other than that of search consultants.

REMUNERATION COMMITTEE

The Directors' Remuneration Report, which sets out the composition and work of the Remuneration Committee, the Directors' remuneration for 2018 and the Directors' Remuneration Policy which was approved by shareholders at the 2017 AGM, is on pages 119-147.

SHAREHOLDER COMMUNICATIONS

The Board recognises the importance of two-way communication with the Company's shareholders. The Chair, the Deputy Chair and Senior Independent Director, the CEO, the CFO and the Executive Vice President Investor Relations each meet regularly with major shareholders and report the views of such shareholders to the Board. As well as the Company giving a balanced report of results and progress at each AGM, all shareholders have an opportunity to ask questions in person. Shareholders are also free to contact the Company directly at any time of the year via dedicated shareholder email addresses or via dedicated shareholder telephone numbers as given on the inside back cover of this Report. Shell's website at www.shell.com/investor contains information for institutional and retail shareholders alike.

The Company's Registrar, Equiniti, operates an internet access facility for registered shareholders, providing details of their shareholdings at www.shareview.co.uk. Facilities are also provided for shareholders to lodge proxy appointments electronically. The Company's Corporate Nominee service, facilitated by Equiniti, provides a facility for investors to hold their shares in the Company in paperless form.

RESULTS PRESENTATIONS AND ANALYSTS' MEETINGS

The planned dates of the quarterly, half-yearly and annual results presentations, as well as all major analysts' meetings, are announced in advance on the Shell website and through a regulatory release. Generally, presentations are broadcast live via webcast and teleconference. Other meetings with analysts or investors are not normally announced in advance, nor can they be followed remotely by webcast or any other means. Procedures are in place to ensure that discussions in such meetings are always limited to non-material information or information already in the public domain.

Results and meeting presentations can be found at www.shell.com/investor. This is in line with the requirement to ensure that all shareholders and other parties in the financial market have equal and simultaneous access to information that may influence the price of the Company's securities.

NOTIFICATION OF MAJOR SHAREHOLDINGS

Information concerning notifications of major shareholdings can be found on page 257.

RESPONSIBILITY FOR PREPARING THE ANNUAL REPORT AND ACCOUNTS

Information concerning the responsibility for preparing the Annual Report and Accounts can be found on page 91.

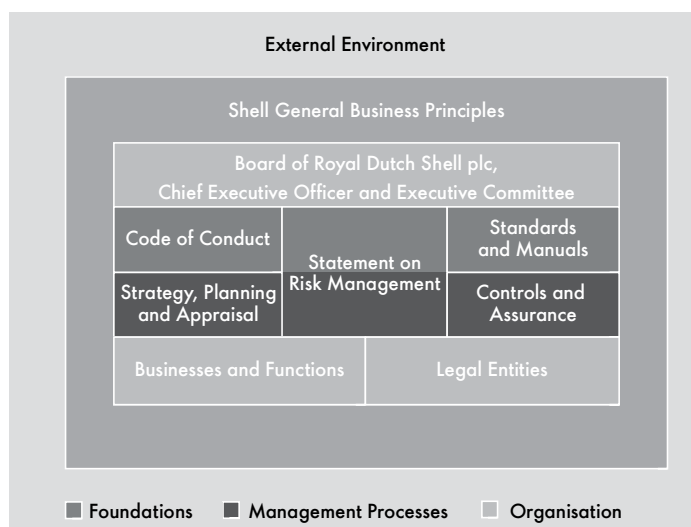
CONTROLS AND PROCEDURES

The Board is responsible for maintaining a sound system of risk management and internal control, and for regularly reviewing its effectiveness. It has delegated authority to the Audit Committee to assist it in fulfilling its responsibilities in relation to internal control and financial reporting (see "Audit Committee Report" on pages 113-118).

A single overall control framework is in place for the Company and its subsidiaries that is designed to manage rather than eliminate the risk of failure to achieve business objectives. It therefore only provides a reasonable and not an absolute assurance against material misstatement or loss.

The diagram below illustrates the control framework's key components: "Foundations", "Management Processes" and "Organisation". "Foundations" comprises the objectives, principles and rules that underpin and establish boundaries for Shell's activities. "Management Processes" refers to the more significant management processes, including how strategy, planning and appraisal are used to improve performance and how risks are to be managed through effective controls and assurance. "Organisation" sets out how the various legal entities relate to each other and how their business activities are organised and managed, and how authority is delegated.

Control framework



The system of risk management and internal control over financial reporting is an integral part of the control framework. Regular reviews are performed to identify the significant risks to financial reporting and the key controls designed to address them. These controls are documented, responsibility is assigned, and they are monitored for design and operating effectiveness. Controls found not to be effective are remediated. The principal risks faced by Shell are set out in "Risk factors" on pages 15-20.

The Board has conducted its annual review of the effectiveness of Shell's system of risk management and internal control, including financial, operational and compliance controls.

Shell has a variety of processes for obtaining assurance on the adequacy of risk management and internal control and implements a broad array of measures to manage its various risks which are set out in the relevant sections of this Report. There are also risks that Shell accepts or does not seek to fully mitigate. The Executive Committee and the Board regularly consider group-level risks and associated control mechanisms.

The Company has developed a risk appetite framework that reflects three distinct lenses: Strategic Risk Appetite, Operational Risk Appetite and Conduct Risk Appetite. These three lenses aim to capture the range and variety of risks that the Company will be exposed to, with specific risk appetite parameters identified and monitored for each lens.

The Strategic Risk Appetite lens is focused on current and future portfolio considerations, taking into account parameters such as country concentration or exposure to higher-risk countries. It also considers "long range" developments to monitor key assumptions or beliefs in relation to energy markets. The Operational Risk Appetite lens is focused on more material operational exposures and promotes both a more granular assessment of key risks that the organisation faces and the purposeful assessment of risk appetite. The Conduct Risk Appetite lens brings together a number of leading and lagging risk indicators, which help to provide a more holistic view of the culture of the organisation.

The financial framework sets certain boundary conditions in the consideration of risk appetite, as the financial resilience of the Company should logically inform the aggregate level of risk appetite that could be sustained.

Shell has a climate change risk management structure in place which is supported by standards, policies and controls (see “Risk factors” on page 16 and “Climate change and energy transition” on pages 71-78). Climate change and risks resulting from greenhouse gas emissions have been identified as significant risk factors for Shell and are managed in accordance with other significant risks through the Board and Executive Committee.

Many of our major projects and operations are conducted in joint arrangements or associates, which may reduce the degree of control and ability to identify and manage risks (see “Risk factors” on page 19). In each case, Shell appoints a representative to manage its interests who seeks to ensure that such projects operate under equivalent standards to Shell.

We operate in more than 70 countries that have differing degrees of political, legal and fiscal stability. This exposes us to a wide range of political developments that could result in changes to contractual terms, laws and regulations. In addition, we and our joint arrangements and associates face the risk of litigation and disputes worldwide (see “Risk factors” on page 17). We continuously monitor geopolitical developments and societal issues relevant to our interests. Employees who engage with government officials are subject to specific training programmes, procedures and regular communications, in addition to Shell General Business Principles and Shell Code of Conduct compliance. We are prepared to exit a country if we believe we can no longer operate in that country in accordance with our standards and applicable law, and we have done so in the past.

The Board confirms that there is a robust process for identifying, evaluating and managing the principal risks. Further, the Board carries out a robust assessment of the Company’s emerging risks, the procedures in place to identify the emerging risks, and how the risks are being managed or mitigated to the achievement of Shell’s objectives. This has been in place throughout 2018 and up to the date of this Report and is regularly reviewed by the Board and accords with the FRC Guidance on Risk Management, Internal Control and Related Financial and Business Reporting.

MANAGEMENT’S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES OF SHELL

As indicated in the certifications in Exhibits 12.1 and 12.2 of this Report, Shell’s CEO and CFO have evaluated the effectiveness of Shell’s disclosure controls and procedures at December 31, 2018. Based on that evaluation, they concluded that Shell’s disclosure controls and procedures are effective.

MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING OF SHELL

Management, including the CEO and CFO, is responsible for establishing and maintaining adequate internal control over Shell’s financial reporting and the preparation of the “Consolidated Financial Statements”. It conducted an evaluation of the effectiveness of Shell’s internal control over financial reporting and the preparation of the “Consolidated Financial Statements” based on the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the

Treadway Commission (COSO). On the basis of this evaluation, management concluded that, at December 31, 2018, the Company’s internal control over financial reporting and the preparation of the “Consolidated Financial Statements” was effective.

Ernst & Young LLP, the independent registered public accounting firm that audited the “Consolidated Financial Statements”, has issued an attestation report on the Company’s internal control over financial reporting, as stated in its report on page 166.

THE TRUSTEE’S AND MANAGEMENT’S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES FOR THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST

The Trustee of the Royal Dutch Shell Dividend Access Trust (the Trustee) and Shell’s CEO and CFO have evaluated the effectiveness of the disclosure controls and procedures in respect of the Dividend Access Trust (the Trust) at December 31, 2018. On the basis of this evaluation, these officers have concluded that the disclosure controls and procedures of the Trust are effective.

THE TRUSTEE’S AND MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING OF THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST

The Trustee and the Company’s management are responsible for establishing and maintaining adequate internal control over the Trust’s financial reporting. The Trustee and the Company’s management conducted an evaluation of the effectiveness of internal control over financial reporting based on the Internal Control – Integrated Framework (2013) issued by COSO. On the basis of this evaluation, the Trustee and management concluded that, at December 31, 2018, the Trust’s internal control over financial reporting was effective.

Ernst & Young LLP, the independent registered public accounting firm that audited the Trust’s financial statements, has issued an attestation report on the Trustee’s and management’s internal control over financial reporting, as stated in its report on page 249.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There has not been any change in the internal control over financial reporting of Shell or the Trust that occurred during the period covered by this Report that has materially affected, or is reasonably likely to materially affect, the internal control over financial reporting of Shell or the Trust. Material financial information of the Trust is included in the “Consolidated Financial Statements” and is therefore subject to the same disclosure controls and procedures as Shell. See the “Royal Dutch Shell Dividend Access Trust Financial Statements” on pages 251-255 for additional information.

ARTICLES OF ASSOCIATION

The following summarises certain provisions of the Articles [A] and of the applicable corporate legislation, including the Act (the legislation). This summary is qualified in its entirety by reference to the Articles and the Act. The information provided under this section is applicable to the Articles, which were in effect during the 2018 financial year to which this Report relates. At the 2019 AGM, shareholders will be asked to consider, and if in agreement, approve the new Articles. An overview of the proposed changes will be published in the 2019 Notice of AGM.

A full comparison document highlighting all proposed modifications to the Articles will be made available at www.shell.com/investor and within the Annual General Meeting area.

[A] A copy of the Articles has been previously filed with the SEC and is incorporated by reference as an exhibit to this Report. It can be found at www.shell.com.

MANAGEMENT AND DIRECTORS

The Company has a single-tier Board of Directors headed by a Chair, with management led by a CEO. See “Board structure and composition” on page 97.

Number of Directors

The Articles provide that the Company must have a minimum of three and can have a maximum of 20 Directors (disregarding alternate directors), but these restrictions can be changed by the Board.

Directors’ shareholding qualification

The Directors are not required to hold any shares in the Company [A].

[A] While the Articles do not require Directors to hold shares in the Company, the Remuneration Committee believes that Executive Directors should align their interests with those of shareholders by holding shares in the Company. The CEO is expected to build up a shareholding of seven times his base salary over five years from appointment and other Executive Directors are expected to build up a shareholding of four times their base salary over the same period. Non-executive Directors are encouraged to hold shares with a value equivalent to 100% of their fixed annual fee and maintain that holding during their tenure. All Directors hold shares and such interests can be found in the “Directors’ Remuneration Report” on pages 135-136.

Appointment of Directors

The Company can, by passing an ordinary resolution, appoint any willing person to be a Director.

The Board can appoint any willing person to be a Director. Any Director appointed in this way must retire from office at the first AGM after his appointment. A Director who retires in this way is then eligible for reappointment.

At the general meeting at which a Director retires, shareholders can pass an ordinary resolution to reappoint the Director or to appoint some other eligible person in their place.

The only people who can be appointed as Directors at a general meeting are the following: (i) Directors retiring at the meeting; (ii) anyone recommended by a resolution of the Board; and (iii) anyone nominated by a shareholder (not being a person to be nominated), where the shareholder is entitled to vote at the meeting and delivers to the Company’s registered office, not less than six but not more than 21 days before the day of the meeting, a letter stating that he intends to nominate another person for appointment as a Director and written confirmation from that person that he is willing to be appointed.

Retirement of Directors

Under the Articles, at every AGM, the following Directors must retire from office: (i) any Director who has been appointed by the Board since the last AGM; (ii) any Director who held office at the time of the two preceding AGMs and who did not retire at either of them; and (iii) any Director who has been in office, other than as a Director holding an executive position, for a continuous period of nine years or more at the date of the meeting.

Notwithstanding the Articles, the Company complies with the Code which contains, among other matters, provisions regarding the composition of the

Board and re-election of the Directors. As a result, the Company’s current policy is that Directors are subject to annual re-election by shareholders.

Any Director who retires at an AGM may offer themselves for reappointment by the shareholders.

Removal of Directors

In addition to any power to remove Directors conferred by the legislation, the Company can pass a special resolution to remove a Director from office, even though his time in office has not ended, and can appoint a person to replace a Director who has been removed in this way by passing an ordinary resolution.

Vacation of office by Directors

Any Director automatically stops being a Director if: (i) he gives the Company a written notice of resignation; (ii) he gives the Company a written notice in which he offers to resign and the Board decides to accept this offer; (iii) all of the other Directors (who must comprise at least three people) pass a resolution or sign a written notice requiring the Director to resign; (iv) he is or has been suffering from mental or physical ill-health and the Board passes a resolution removing the Director from office; (v) he has missed Directors’ meetings (whether or not an alternate director appointed by him attends those meetings) for a continuous period of six months without permission from the Board and the Board passes a resolution removing the Director from office; (vi) a bankruptcy order is made against him or he makes any arrangement or composition with his creditors generally; (vii) he is prohibited from being a Director under the legislation; or (viii) he ceases to be a Director under the legislation or he is removed from office under the Articles. If a Director stops being a Director for any reason, he will also automatically cease to be a member of any committee or sub-committee of the Board.

Alternate directors

Any Director can appoint any person (including another Director) to act in his place as an alternate director. That appointment requires the approval of the Board, unless previously approved by the Board or unless the appointee is another Director.

Proceedings of the Board

Meetings of the Board will usually be held in the Netherlands but the Board may decide in each case when and where to have meetings and how they will be conducted. The Board can also adjourn its meetings. If no other quorum is fixed by the Board, two Directors are a quorum. A Directors’ meeting at which a quorum is present can exercise all the powers and discretions of the Board.

All or any of the Directors can take part in a meeting of the Directors by way of a conference telephone or any communication equipment which allows everybody to take part in the meeting by being able to hear each of the other people at the meeting and by being able to speak to all of them at the same time. A person taking part in this way will be treated as being present at the meeting and will be entitled to vote and be counted in the quorum. Any such meeting will be deemed to take place where the largest group of Directors participating is assembled or, if there is no such group, where the Chair of the meeting then is located.

The Board can appoint any Director as Chair or as deputy Chair and can remove him from that office at any time. Matters to be decided at a

Directors' meeting will be decided by a majority vote. If votes are equal, the Chair of the meeting has a second, casting vote.

The Board will manage the Company's business. It can use all the Company's powers, except where the Articles or the legislation say that powers can only be used by shareholders voting to do so at a general meeting. The Board is, however, subject to the provisions of the legislation, the requirements of the Articles and any regulations laid down by the shareholders by passing a special resolution at a general meeting.

The Board can exercise the Company's powers: (i) to borrow money; (ii) to guarantee; (iii) to indemnify; (iv) to mortgage or charge all or any of the Company's undertaking, property and assets (present and future) and uncalled capital; (v) to issue debentures and other securities; and (vi) to give security, either outright or as collateral security, for any debt, liability or obligation of the Company or of any third party. The Board must limit the borrowings of the Company and exercise all voting and other rights or powers of control exercisable by the Company in relation to its subsidiary undertakings so as to ensure that no money is borrowed if the total amount of the group's borrowings (as defined in the Articles) then exceeds, or would as a result of such borrowing exceed, two times the Company's adjusted capital and reserves (as defined in the Articles). Shareholders may pass an ordinary resolution allowing borrowings to exceed such limit.

The Board can delegate any of its powers or discretions to committees of one or more persons. Any committee must comply with any regulations laid down by the Board. These regulations can require or allow people who are not Directors to be members of the committee, and can give voting rights to such people but there must be more Directors on a committee than persons who are not Directors and a resolution of the committee is only effective if a majority of the members of the committee present at the time of the resolution were Directors.

Fees

The total fees paid to all of the Directors (excluding any payments made under any other provision of the Articles) must not exceed €4,000,000 a year or any higher sum decided on by an ordinary resolution at a general meeting. It is for the Board to decide how much to pay each Director by way of fees.

The Board, or any committee authorised by the Board, can award extra fees to any Director who, in its view, performs any special or extra services for the Company. The extra fees can take the form of salary, commission, profit-sharing or other benefits (and can be paid partly in one way and partly in another).

The Company can pay the reasonable travel, hotel and incidental expenses of each Director incurred in attending and returning from general meetings, meetings of the Board or committees of the Board or any other meetings which, as a Director, he is entitled to attend. The Company will pay all other expenses properly and reasonably incurred by each Director in connection with the Company's business or in the performance of his duties as a Director. The Company can also fund a Director's or former Director's expenditure and that of a Director or former Director of any holding company of the Company for the purposes permitted by the legislation and can do anything to enable a Director or former Director of the Company or any holding company of the Company to avoid incurring such expenditure all as provided in the legislation.

Pensions and gratuities

The Board or any committee authorised by the Board can decide whether to provide pensions, annual payments or other benefits to any Director or former Director, or any relation or dependant of, or person connected to, such a person. The Board can also decide to contribute to a scheme or fund or to pay premiums to a third party for these purposes. The Company can only provide pensions and other benefits to people who are or were Directors but who have not been employed by or held an office or executive position in the Company or any of its subsidiary undertakings or former subsidiary undertakings or any predecessor in business of the Company or any such other company or to relations or dependants of, or persons connected to, these Directors or former Directors if the shareholders approve this by passing an ordinary resolution.

Directors' interests

Conflicts of interest requiring authorisation by Directors

The Board may, subject to the relevant quorum and voting requirements, authorise any matter which would otherwise involve a Director breaching his duty under the legislation to avoid conflicts of interest. A Director seeking authorisation in respect of such a conflict of interest must tell the Board the nature and extent of his interest in the conflict of interest as soon as possible. The Director must give the Board sufficient details of the relevant matter to enable it to decide how to address the conflict of interest, together with any additional information which it may request.

Any Director (including the relevant Director) may propose that the relevant Director be authorised in relation to any matter which is the subject of such a conflict of interest. Such proposal and any authority given by the Board shall be effected in the same way as any other matter may be proposed to and resolved upon by the Board except that: (i) the relevant Director and any other Director with a similar interest will not count in the quorum and will not vote on a resolution giving such authority; and (ii) the conflicted Director and any other Director with a similar interest may, if the other members of the Board so decide, be excluded from any meeting of the Board while the conflict of interest is under consideration.

Where the Board gives authority in relation to a conflict of interest or where any of the situations described in (i) to (v) of "Other conflicts of interest" below applies in relation to a Director: (i) the Board may (whether at the relevant time or subsequently) (a) require that the relevant Director is excluded from the receipt of information, the participation in discussion and/or the making of decisions related to the conflict or the situation and (b) impose upon the relevant Director such other terms for the purpose of dealing with the conflict or situation as they think fit; (ii) the relevant Director will be obliged to conduct himself in accordance with any terms imposed by the Board in relation to the conflict or situation; (iii) the Board may also provide that, where the relevant Director obtains (other than through his position as a Director of the Company) information that is confidential to a third party, the Director will not be obliged to disclose that information to the Company, or to use or apply the information in relation to the Company's affairs, where to do so would amount to a breach of that confidence; (iv) the terms of the authority shall be recorded in writing (but the authority shall be effective whether or not the terms are so recorded); and (v) the Board may revoke or vary such authority at any time but this will not affect anything done by the relevant Director prior to such revocation in accordance with the terms of such authority.

Other conflicts of interest

If a Director knows that he is in any way directly or indirectly interested in a proposed contract with the Company or a contract that has been entered into by the Company, he must tell the other Directors of the nature and extent of that interest in accordance with the legislation. If he has so disclosed the nature and extent of his interest, a Director can do one or more of the following: (i) have any kind of interest in a contract with or involving the Company or another company in which the Company has an interest; (ii) hold any other office or place of profit with the Company (except that of auditor) in conjunction with his office of Director for such period and upon such terms, including as to remuneration, as the Board may decide; (iii) alone, or through a firm with which he is associated, do paid professional work for the Company or another company in which the Company has an interest (other than as auditor); (iv) be or become a Director or other officer of, or employed by or otherwise be interested in, any holding company or subsidiary company of the Company or any other company in which the Company has an interest; and (v) be or become a Director of any other company in which the Company does not have an interest and which cannot reasonably be regarded as giving rise to a conflict of interest at the time of his appointment as a Director of that other company.

Benefits

A Director does not have to hand over to the Company or its shareholders any benefit he receives or profit that he makes as a result of any matter which would otherwise involve a direct breach of his duty under the legislation to avoid conflicts of interest but which has been authorised or anything allowed under (i) to (v) of "Other conflicts of interest" above, nor is any type of contract so authorised or so allowed liable to be avoided.

Quorum and voting requirements

Subject to certain exceptions, a Director cannot vote or be counted in the quorum on a resolution of the Board relating to appointing that Director to a position with the Company or a company in which the Company has an interest or the terms or the termination of the appointment and a Director cannot vote or be counted in the quorum on a resolution of the Board about a contract in which he has an interest and, if he does vote, his vote will not be counted.

The Company can, by ordinary resolution, suspend or relax the provisions of the relevant article in the Articles to any extent or ratify any contract which has not been properly authorised in accordance with that relevant article.

Directors' indemnities

As far as the legislation allows this, the Company can indemnify any Director or former Director of the Company, of any associated company or of any affiliate against any liability and can purchase and maintain insurance against any liability for any Director or former Director of the Company, of any associated company or of any affiliate. A Director or former Director of the Company, of any associated company or of any affiliate will not be accountable to the Company or the shareholders for any benefit so provided. Anyone receiving such a benefit will not be disqualified from being or becoming a Director of the Company.

RIGHTS ATTACHING TO SHARES

The Company can issue shares with any rights or restrictions attached to them as long as this is not restricted by any rights attached to existing

shares. These rights or restrictions can be decided either by an ordinary resolution passed by the shareholders or by the Board as long as there is no conflict with any resolution passed by the shareholders.

Dividends

Currently, only A shares and B shares are entitled to a dividend.

Under the legislation, dividends are payable only out of profits available for distribution, as determined in accordance with the Act and under IFRS.

Subject to the Act, if the Directors consider that the Company's financial position justifies the payment of a dividend, the Company can pay a fixed or other dividend on any class of shares on the dates prescribed for the payments of those dividends and pay interim dividends on shares of any class of any amounts and on any dates and for any periods which it decides. Shareholders can declare dividends in accordance with the rights of shareholders by passing an ordinary resolution, although such dividends cannot exceed the amount recommended by the Board.

Dividends are payable to persons registered as the holder(s) of shares, or to anyone entitled in any other way, at a particular time on a particular day selected by the Board. All dividends will be declared and paid in proportions based on the amounts paid up on the relevant shares during any period for which that dividend is paid.

Any dividend or other money payable in cash relating to a share can be paid by sending a cheque, warrant or similar financial instrument payable to the shareholder entitled to the dividend by post to the shareholder's registered address. Alternatively, it can be made payable to someone else named in a written instruction from the shareholder (or all joint shareholders) and sent by post to the address specified in that instruction. A dividend can also be paid by inter-bank transfer or by other electronic means (including payment through CREST) directly to an account with a bank or other financial institution (or another organisation operating deposit accounts if allowed by the Company) named in a written instruction from the person entitled to receive the payment under the Articles. Such an account must be held at an institution based in the UK, unless the share on which the payment is to be made is held by Euroclear Nederland and is subject to the Dutch Securities Giro Act ("Wet giraal effectenverkeer"). Alternatively, a dividend can be paid in some other way if requested in writing by a shareholder (or all joint shareholders) and agreed with the Company. The Company will not be responsible for a payment which is lost or delayed. Unless the rights attached to any shares, the terms of any shares or the Articles say otherwise, a dividend or any other money payable in respect of a share can be declared and paid in whatever currency or currencies the Board decides using an exchange rate or exchange rates selected by the Board for any currency conversions required. The Board can also decide how any costs relating to the choice of currency will be met. The Board can offer shareholders the choice to receive dividends and other money payable in respect of their shares in alternative currencies on such terms and conditions as the Board may prescribe from time to time. Where any dividends or other amounts payable on a share have not been claimed, the Board can invest them or use them in any other way for the Company's benefit until they are claimed. The Company will not be a trustee of the money and will not be liable to pay interest on it. If a dividend or other money has not been claimed for 12 years after being declared or becoming due for payment, it will be forfeited and go back to the Company, unless the Board decides otherwise.

The Company expects that dividends in respect of B shares will be paid under the dividend access mechanism described below. Currently, the Articles provide that if any amount paid by way of dividend by a subsidiary of the Company is received by the dividend access trustee on behalf of any holder of B shares and paid by the dividend access trustee to such holder, the entitlement of such holder of B shares to be paid any dividend declared pursuant to the Articles will be reduced by the corresponding amount that has been paid by the dividend access trustee to such holder. If a dividend is declared pursuant to the Articles and the entitlement of any holder of B shares to be paid his pro rata share of such dividend is not fully extinguished on the relevant payment date by virtue of a payment made by the dividend access trustee, the Company has a full and unconditional obligation to make payment in respect of the outstanding part of such dividend entitlement immediately. Where amounts are paid by the dividend access trustee in one currency and a dividend is declared by the Company in another currency, the amounts so paid by the dividend access trustee will, for the purposes of the comparison required by the two immediately preceding sentences, be converted into the currency in which the Company has declared the dividend at such rate as the Board shall consider appropriate. For the purposes of the provisions referred to in this paragraph, the amount that the dividend access trustee has paid to any holder of B shares in respect of any particular dividend paid by a subsidiary of the Company (a "specified dividend") will be deemed to include: (i) any amount that the dividend access trustee may be compelled by law to withhold; (ii) a pro rata share of any tax that the subsidiary paying the specified dividend is obliged to withhold or to deduct from the same; and (iii) a pro rata share of any tax that is payable by the dividend access trustee in respect of the specified dividend.

The Board can offer shareholders of ordinary shares (excluding any shareholder holding shares as treasury shares) the right to choose to receive extra ordinary shares, which are credited as fully paid up, instead of some or all of their cash dividend. Before the Board can do this, shareholders must have passed an ordinary resolution authorising the Board to make this offer.

Dividend access mechanism for B shares

General

A and B shares are identical, except for the dividend access mechanism, which will only apply to B shares. Dividends paid on A shares have a Dutch source for tax purposes and are subject to Dutch withholding tax.

It is the expectation and the intention, although there can be no certainty, that holders of B shares will receive dividends through the dividend access mechanism. Any dividends paid on the dividend access shares will have a UK source for UK and Dutch tax purposes. There will be no Dutch withholding tax on such dividends. For further details regarding the tax treatment of dividends paid on the A and B shares and American Depositary Shares (ADSs), refer to "Shareholder information" on pages 260-261.

Description of dividend access mechanism

The "Shell" Transport and Trading Company, p.l.c., now The Shell Transport and Trading Company Limited (Shell Transport), and BG Group plc, now BG Group Limited (BG), have each issued a dividend access share to Computershare Trustees (Jersey) Limited as Trustee. Pursuant to a declaration of trust, the Trustee will hold any dividends paid in respect of the dividend access shares on trust for the holders of B shares and will arrange for prompt disbursement of such dividends to holders of B shares. Interest and other

income earned on unclaimed dividends will be for the account of Shell Transport and BG and any dividends which are unclaimed after 12 years will revert to Shell Transport and BG, as appropriate. Holders of B shares will not have any interest in either dividend access share and will not have any rights against Shell Transport and BG as issuers of the dividend access shares. The only assets held on trust for the benefit of the holders of B shares will be dividends paid to the Trustee in respect of the dividend access shares.

The declaration and payment of dividends on the dividend access shares will require board action by Shell Transport and BG (as applicable) and will be subject to any applicable limitations in law or in the Shell Transport or BG (as appropriate) articles of association in effect. In no event will the aggregate amount of the dividend paid by Shell Transport and BG under the dividend access mechanism for a particular period exceed the aggregate of the dividend announced by the Board of the Company on B shares in respect of the same period (after giving effect to currency conversions).

In particular, under their respective articles of association, Shell Transport and BG are each only able to pay a dividend on their respective dividend access share which represents a proportional amount of the aggregate of any dividend announced by the Company on the B shares in respect of the relevant period, where such proportions are calculated by reference to, in the case of Shell Transport, the number of B shares in existence prior to completion of the Company's acquisition of BG (the Acquisition) and, in the case of BG, the number of B shares issued as part of the Acquisition, in each case as against the total number of B shares in issue immediately following completion of the Acquisition.

Operation of the dividend access mechanism

If, in connection with the announcement of a dividend by the Company on B shares, the Board of Shell Transport and/or the Board of BG elects to declare and pay a dividend on their respective dividend access shares to the Trustee, the holders of B shares will be beneficially entitled to receive their share of those dividends pursuant to the declaration of trust (and arrangements will be made to ensure that the dividend is paid in the same currency in which they would have received a dividend from the Company).

If any amount is paid by Shell Transport or BG by way of a dividend on the dividend access shares and paid by the Trustee to any holder of B shares, the dividend which the Company would otherwise pay on B shares will be reduced by an amount equal to the amount paid to such holders of B shares by the Trustee.

The Company will have a full and unconditional obligation, in the event that the Trustee does not pay an amount to holders of B shares on a cash dividend payment date (even if that amount has been paid to the Trustee), to pay immediately the dividend announced on B shares. The right of holders of B shares to receive distributions from the Trustee will be reduced by an amount equal to the amount of any payment actually made by the Company on account of any dividend on B shares.

If for any reason no dividend is paid on the dividend access shares, holders of B shares will only receive dividends from the Company directly. Any payment by the Company will be subject to Dutch withholding tax (unless an exemption is obtained under Dutch law or under the provisions of an applicable tax treaty).

The Dutch tax treatment of dividends paid under the dividend access mechanism has been confirmed by the Dutch Revenue Service in an agreement ("vaststellingsovereenkomst") with the Company and N.V. Koninklijke Nederlandsche Petroleum Maatschappij (Royal Dutch Petroleum Company) dated October 26, 2004, as supplemented and amended by an agreement between the same parties dated April 25, 2005, and a final settlement agreement in connection with the Acquisition dated November 9, 2015. The agreements state, among other things, that dividend distributions on the dividend access shares by Shell Transport and/or BG will not be subject to Dutch withholding tax provided that the dividend access mechanism is structured and operated substantially as set out above.

The Company may not extend the dividend access mechanism to any future issuances of B shares without prior consultation with the Dutch Revenue Service.

Accordingly, the Company would not expect to issue additional B shares unless confirmation from the Dutch Revenue Service was obtained or the Company were to determine that the continued operation of the dividend access mechanism was unnecessary. Any further issue of B shares is subject to advance consultation with the Dutch Revenue Service.

The dividend access mechanism may be suspended or terminated at any time by the Company's Directors or the Directors of Shell Transport or BG, for any reason and without financial recompense. This might, for instance, occur in response to changes in relevant tax legislation.

The daily operations of the Trust are administered on behalf of the Company by the Trustee. Material financial information of the Trust is included in the "Consolidated Financial Statements" and is therefore subject to the same disclosure controls and procedures as Shell.

Pre-emption rights

Subject to the Act and the Listing Rules published by the UK's Financial Conduct Authority (FCA), any equity securities allotted by the Company for cash must first be offered to shareholders in proportion to their holdings. The Act and the Listing Rules allow for the disapplication of pre-emption rights which may be waived by a special resolution of the shareholders, either generally or specifically.

Voting

Currently, only the A and B shares have voting rights.

Changing the rights attached to the shares

The Act provides that the Articles can be amended by a special resolution.

The Articles provide that, if the legislation allows this, the rights attached to any class of shares can be changed if this is approved either in writing by shareholders holding at least three-quarters of the issued shares of that class by amount (excluding any shares of that class held as treasury shares) or by a special resolution passed at a separate meeting of the relevant shareholders. At each such separate meeting, all of the provisions of the Articles relating to proceedings at a general meeting apply, except that: (i) a quorum will be present if at least one shareholder who is entitled to vote is present in person or by proxy who owns at least one-third in amount of the issued shares of the relevant class; (ii) any shareholder who is present in person or by proxy and entitled to vote can demand a poll; and (iii) at an

adjourned meeting, one person entitled to vote and who holds shares of the class, or his proxy, will be a quorum. These provisions are not more restrictive than required by law in England.

If new shares are created or issued which rank equally with any other existing shares, the rights of the existing shares will not be regarded as changed or abrogated unless the terms of the existing shares expressly say otherwise.

Redemption provisions

The Company's shares are not subject to any redemption provisions.

Rights attaching to the sterling deferred shares

The sterling deferred shares are (unlike the A and B shares) not ordinary shares and, therefore, they have different rights and restrictions.

The sterling deferred shares have the following rights and restrictions: (i) on a distribution of assets of the Company among its shareholders on a winding-up, the holders of the sterling deferred shares will be entitled (such entitlement ranking in priority to the rights of holders of ordinary shares) to receive an amount equal to the aggregate of the capital paid up or credited as paid up on each sterling deferred share; (ii) save as provided in (i), the holders of the sterling deferred shares will not be entitled to any participation in the profits or assets of the Company; (iii) the holders of sterling deferred shares will not be entitled to receive notice of or to attend and/or speak or vote (whether on a show of hands or on a poll) at general meetings of the Company; (iv) the written consent of the holders of three-quarters in nominal value of the issued sterling deferred shares or the sanction of a special resolution passed at a separate general meeting of the holders of the sterling deferred shares is required if the special rights and privileges attaching to the sterling deferred shares are to be abrogated, or adversely varied or otherwise directly adversely affected in any way (the creation, allotment or issue of shares or securities which rank in priority to or equally with the sterling deferred shares, or of any right to call for the allotment or issue of such shares or securities, is for these purposes deemed not to be an abrogation or variation or to have an effect on the rights and privileges attaching to sterling deferred shares); (v) all provisions of the Articles relating to general meetings of the Company will apply, with necessary modifications, to every general meeting of the holders of the sterling deferred shares; (vi) subject to the legislation, the Company will have the right at any time to redeem any such sterling deferred shares (provided that it is credited as fully paid) at a price not exceeding £1 for all the sterling deferred shares redeemed at any one time (to be paid on such date as the Board shall select as the date of redemption to such one of the holders, if more than one, as may be selected by lot) without the requirement to give notice to the holder(s) of the sterling deferred shares; (vii) if any holder of a sterling deferred share to be redeemed fails or refuses to surrender the share certificate(s) or indemnity for such sterling deferred share or if the holder selected by lot to receive the redemption monies fails or refuses to accept the redemption monies payable in respect of it, such sterling deferred share will, notwithstanding the foregoing, be redeemed and cancelled by the Company and, in the event of a failure or refusal to accept the redemption monies, the Company will retain such money and hold it on trust for the selected holder without interest, and, in each case, the Company will have no further obligation whatsoever to the holder of such sterling deferred share; and (viii) no sterling deferred share will be redeemed otherwise than out of distributable profits or the proceeds of

a fresh issue of shares made for the purposes of the redemption or out of capital to the extent permitted by the legislation.

Calls on shares

The Board can call on shareholders to pay any money which has not yet been paid to the Company for their shares. This includes the nominal value of the shares and any premium which may be payable on those shares. The Board can also make calls on people who are entitled to shares by law.

Winding-up of the Company

If the Company is voluntarily wound up, the liquidator can distribute to shareholders any assets remaining after the liquidator's fees and expenses have been paid and all sums due to prior-ranking creditors (as defined under the laws of England) have been paid.

Sinking fund provisions

The shares are not subject to any sinking fund provision under the Articles or as a matter of the laws of England.

Discriminating provisions

There are no provisions in the Articles discriminating against a shareholder because of his ownership of a particular number of shares.

Limitations on rights to own shares

There are no limitations imposed by the Articles or the legislation on the rights to own shares, including the right of non-residents or foreign persons to hold or vote shares, other than limitations that would generally apply to all shareholders.

Transfer of shares

There are no significant restrictions on the transfer of shares.

Except as set out below, any shareholder can transfer some or all of his certificated shares to another person. A transfer of certificated shares must be made in writing and either in the usual standard form or in any other form approved by the Board.

Except as set out below, any shareholder can transfer some or all of his CREST shares to another person. A transfer of CREST shares must be made through CREST and must comply with the uncertificated securities rules.

The Board can refuse to register the transfer of any shares which are not fully paid. Further rights to decline registration are as follows:

Certificated shares

A share transfer form cannot be used to transfer more than one class of share. Each class needs a separate form. Transfers cannot be in favour of more than four joint holders. The share transfer form must be properly stamped to show payment of any applicable stamp duty or certified or otherwise shown to the satisfaction of the Board to be exempt from stamp duty and must be delivered to the Company's registered office, or any other place decided on by the Board. The transfer form must be accompanied by the share certificate relating to the share being transferred, unless the transfer is being made by a person to whom the Company was not required to, and did not send, a certificate. The Board can also ask (acting reasonably) for any other evidence to show that the person wishing to transfer the share is entitled to do so and, if the share transfer form is signed

by another person on behalf of the person making the transfer, evidence of the authority of that person to do so.

CREST shares

Registration of a transfer of CREST shares can be refused in the circumstances set out in the uncertificated securities rules. Transfers cannot be in favour of more than four joint holders.

Where a share has not yet been entered on the register, the Board can recognise a renunciation by that person of his right to the share in favour of some other person. Such renunciation will be treated as a transfer and the Board has the same powers of refusing to give effect to such a renunciation as if it were a transfer.

Partly paid shares

The Articles provide that, if a shareholder fails to pay the Company any amount due on his partly paid shares, the Board can enforce the Company's lien by selling all or any of the partly paid shares in any way they decide (subject to certain conditions).

Change of control

There are no provisions in the Articles that would delay, defer or prevent a change of control.

Capital changes

The conditions imposed by the Articles for changes in capital are not more stringent than those required by the applicable laws of England.

Disputes between a shareholder or ADS holder and Royal Dutch Shell plc, any subsidiary, Director or professional service provider

The Articles generally require that, except as noted below, all disputes: (i) between a shareholder in such capacity and the Company and/or its Directors, arising out of or in connection with the Articles or otherwise; (ii) so far as permitted by law, between the Company and any of its Directors in their capacities as such or as the Company's employees, including all claims made by the Company or on behalf of the Company against any or all of its Directors; (iii) between a shareholder in such capacity and the Company's professional service providers (which could include the Company's auditors, legal counsel, bankers and ADS depositories); and/or (iv) between the Company and its professional service providers arising in connection with any claim within the scope of (iii) above, shall be exclusively and finally resolved by arbitration under the Rules of Arbitration of the International Chamber of Commerce (ICC), as amended from time to time. This would include all disputes arising under UK, Dutch or US law (including securities laws), or under any other law, between parties covered by the arbitration provision. Accordingly, the ability of shareholders to obtain monetary or other relief, including in respect of securities law claims, may be determined in accordance with these provisions, and the ability of shareholders to obtain monetary or other relief may therefore be limited and their cost of seeking and obtaining recoveries in a dispute may be higher than otherwise would be the case.

The tribunal shall consist of three arbitrators to be appointed in accordance with the ICC rules. The chairman of the tribunal must have at least 20 years' experience as a lawyer qualified to practise in a common-law jurisdiction which is within the Commonwealth (as constituted on May 12, 2005) and each other arbitrator must have at least 20 years' experience as a qualified

lawyer. The place of arbitration must be The Hague, the Netherlands; and the language of the arbitration must be English.

Pursuant to the exclusive jurisdiction provision in the Articles, if a court or other competent authority in any jurisdiction determines that the arbitration requirement described above is invalid or unenforceable in relation to any particular dispute in that jurisdiction, then that dispute may only be brought in the courts of England and Wales, as is the case with any derivative claim brought under the Act. The governing law of the Articles is the substantive law of England.

Disputes relating to the Company's failure or alleged failure to pay all or part of a dividend which has been announced and which has fallen due for payment will not be subject to the arbitration and exclusive jurisdiction provisions of the Articles. Any derivative claim brought under the Act will not be subject to the arbitration provisions of the Articles.

Pursuant to the relevant depositary agreement, each holder of ADSs is bound by the arbitration and exclusive jurisdiction provisions of the Articles as described in this section as if that holder were a shareholder.

GENERAL MEETINGS

Under the applicable laws of England, the Company is required in each year to hold an AGM of shareholders in addition to any other meeting of shareholders that may be held. Each AGM must be held in the period six months from the date following the Company's accounting reference date. Additionally, shareholders may submit resolutions in accordance with Section 338 of the Act.

Directors have the power to convene a general meeting of shareholders at any time. In addition, Directors are required to call a general meeting once requests to do so have been received by the Company from shareholders representing at least 5% of such paid-up capital of the Company as carries voting rights at general meetings of the Company (excluding any paid-up capital held as treasury shares) pursuant to Section 303 of the Act. A request for a general meeting must state the general nature of the business to be dealt with at the meeting and must be authenticated by the requesting shareholders. If Directors fail to call such a meeting within 21 days from receipt of such requests, and on a date not more than 28 days after the date of the notice convening the meeting, the shareholders that requested the general meeting, or any of them representing more than half of the total voting rights of all shareholders that requested the meeting, may themselves convene a general meeting which must be called for a date not more than three months after the date upon which the Directors became subject to the requirement to call a general meeting. Any such meeting must be convened in the same manner, as nearly as possible, as that in which meetings are required to be convened by the Directors of the Company.

Under the Act, the Company is required to give at least 21 clear days' notice of any AGM or, except where the conditions in Section 307A of the Act apply, any other general meeting of the Company. In addition, the Company complies with the Code which currently states that notices of AGMs should be sent to shareholders at least 20 working days before the meeting.

The Articles require that, in addition to any requirements under the legislation, the notice for any general meeting must state where the meeting is to be held (the principal meeting place) and the location of any satellite meeting place,

which shall be identified as such in the notice as well as details of any arrangements made for those persons not entitled to attend a general meeting to be able to view and hear the proceedings (making it clear that participation in those arrangements will not amount to attendance at the meeting to which the notice relates). At the same time that notice is given for any general meeting, an announcement of the date, time and place of that meeting will, if practical, be published in a national newspaper in the Netherlands.

A shareholder is entitled to appoint a proxy (who is not required to be another shareholder) to represent and vote on behalf of the shareholder at any general meeting of shareholders, including the AGM, if a duly completed form of proxy has been received by the Company within the relevant deadlines (in general, where a poll is not demanded, 48 hours (or such shorter time as the Board decides) before the meeting).

Before a general meeting starts to do business, there must be a quorum present. Save as in relation to adjourned meetings, a quorum for all purposes is two people who are entitled to vote. They can be shareholders who are personally present, proxies for shareholders, or a combination of both. If a quorum is not present, a chairman of the meeting can still be chosen and this will not be treated as part of the business of the meeting.

If a quorum is not present within five minutes of the time fixed for a general meeting to start or within any longer period not exceeding one hour which the chairman of the meeting can decide, or if a quorum ceases to be present during a general meeting: (i) if the meeting was called by shareholders, it will be cancelled; (ii) any other meeting will be adjourned to a day (being not less than 10 days later, excluding the day on which it is adjourned and the day for which it is reconvened) with the time and place decided upon by the chairman of the meeting; and (iii) one shareholder present in person or by proxy and entitled to vote will constitute a quorum at any such adjourned general meeting and any notice of such an adjourned meeting will say this.

Notice of cancellation of a proxy's right to vote must be received at the Company's registered office (or other place specified by the Company for receipt) not later than the last time at which a proxy form should have been received to be valid for use at the meeting or on the holding of the poll at which the vote was given or the poll taken.

DEEMED DELIVERY OF DOCUMENTS

Under the Articles, if any notice, document or other information is given, sent or supplied by the Company by inland post, it is treated as being received the day after it was posted if first class post (or a service similar to first class post) was used, or 72 hours after it was posted if first class post (or a service similar to first class post) was not used. If a notice or document is sent by the Company by airmail, it is treated as being received 72 hours after it was posted. Any notice, document or other information left at a shareholder's registered address or a postal address notified to the Company in accordance with the Articles by a shareholder or a person entitled to a share by law is treated as being received on the day on which it was left.

THRESHOLD FOR DISCLOSURE OF SHARE OWNERSHIP

The Disclosure Guidance and Transparency Rules of the FCA impose an obligation on persons [A] to notify the Company of the percentage of voting rights held as a shareholder, or through the direct or indirect holding of financial

instruments, if the percentage of voting rights held in the Company reaches, exceeds or falls below 3% or any 1% threshold above 3%.

[A] For this purpose “persons” includes companies, natural persons, legal persons and partnerships.

As noted in the Articles, Section 793 of the Act governs the Company’s right to investigate who has an interest in its shares. Under that section, a public company may give notice to any person it knows or has reasonable cause to believe is, or was at any time in the preceding three years, interested in its shares in order to obtain certain information about that interest.

The Articles provide that, when a person receives a statutory notice, he has 14 days to comply with it. If he does not do so or if he makes a statement in response to the notice which is false or inadequate in some important way, the Company can decide to restrict the rights relating to the identified shares and send out a further notice to the shareholder, known as a restriction notice, which will take effect when delivered. The restriction notice will state that the identified shares no longer give the shareholder any right to attend or vote either personally or by proxy at a shareholders’ meeting or to exercise any right in relation to shareholders’ meetings. Where the identified shares make up 0.25% or more (in amount or in number) of the existing shares of a class at the date of delivery of the restriction notice, the restriction notice can also contain the following further restrictions: (i) the Board can withhold any dividend or part of a dividend (including scrip dividend) or other money which would otherwise be payable in respect of the identified shares without any liability to pay interest when such money is finally paid to the shareholder; and (ii) the Board can refuse to register a transfer of any of the identified shares which are certificated shares unless the Board is satisfied that they have been sold outright to an independent third party (as specified in the Articles). Once a restriction notice has been given, the Board is free to cancel it or exclude any shares from it at any time the Board thinks fit. In addition, the Board must cancel the restriction notice within seven days of being satisfied that all of the information requested in the statutory notice has been given. Also, where any of the identified shares are sold and the Board is satisfied that they were sold outright to an independent third party, it must cancel the restriction notice within seven days of receipt of notification of the sale. The Articles do not restrict in any way the provision of the legislation which applies to failures to comply with notices under the legislation.

The UK City Code on Takeovers and Mergers (the Takeover Code) imposes disclosure obligations on parties subject to the Takeover Code’s disclosure regime. The Takeover Code requires that an opening position disclosure be made by: (i) an offeror company after the announcement that first identifies it as an offeror and after the announcement that first identifies a competing securities exchange offeror; and (ii) an offeree company after the commencement of an offer period and, if later, after the announcement that first identifies any securities exchange offeror. An opening position disclosure must be made by any person that is interested in 1% or more of any class of relevant securities of the offeree company or any securities exchange offeror. The Takeover Code also requires any person who is, or becomes, interested in 1% or more of any class of relevant securities of an offeree company or any securities exchange offeror to make a dealing disclosure if the person deals in any relevant securities of the offeree company or any securities exchange offeror during an offer period. Where two or more persons act together pursuant to an agreement or understanding, whether formal or informal, to acquire or control an interest in relevant securities, they will normally be

deemed to be a single person for the purpose of the relevant provisions of the Takeover Code.

Rule 13d-1 of the US Securities Exchange Act of 1934 requires that a person or group that acquires beneficial ownership of more than 5% of equity securities registered under the US Securities Exchange Act, and that is not eligible to file a short-form report, disclose such information to the SEC within 10 days after the acquisition.

FURTHER INFORMATION

The following information can be found at www.shell.com/investor:

- the terms of reference of the Audit Committee, Corporate and Social Responsibility Committee, Nomination and Succession Committee and Remuneration Committee (these documents explain the Committees’ roles and the authority the Board delegates to them);
- the full list of matters reserved to the Board for decision;
- Shell General Business Principles;
- Shell Code of Conduct;
- Code of Ethics for Executive Directors and Senior Financial Officers; and
- Articles of Association.

Signed on behalf of the Board

/s/ Linda M. Szymanski

Linda M. Szymanski

Company Secretary

March 13, 2019

Audit Committee Report

Dear Shareholders,

I am pleased to present our annual Audit Committee Report 2018. I trust that this report will provide you with an insight into our work, the matters handled and the focus of the Audit Committee's (AC) deliberations during 2018. The AC assists the Board in fulfilling its oversight responsibilities in areas such as the integrity of financial reporting, the effectiveness of the risk management and internal control system and related governance and compliance matters. We are also responsible for making a recommendation to the Board on the appointment or reappointment of the external auditor.

In 2018, we discussed a variety of standing matters and areas of special focus including: plans to implement the new accounting standard IFRS 16 *Leases*; the impact of the European Union General Data Protection Regulation (EU GDPR); Shell's insurance arrangements; and information risk management. The AC visited the trading and supply office in London, which was a valuable interactive opportunity enabling us to enhance our understanding of this area through an open and constructive dialogue with management in charge of the different functional responsibilities. We received briefings from the Chief Internal Auditor on the effectiveness of Shell's risk management and internal control system and on outcomes of significant audits and notable control weaknesses, including potential improvements and mitigating actions agreed with management. Specific attention was given to topics that we considered particularly significant, including issues and judgements relating to Shell's 2018 Consolidated Financial Statements, as discussed in more detail later in this report together with how we addressed them. The independence of the external auditor was monitored in line with Shell's independence policy regarding the provision of services by the external auditor.

Ann Godbehere and I were pleased to represent the AC at the Board Day held in December 2018, where we engaged with some of our major shareholders to discuss the responsibilities of the AC, its areas of focus in 2018 and 2019 and the coverage provided by internal and external audit.

We considered the appropriateness of the viability statement and supported the development of Shell's statement in line with best practice guidance issued by the UK Financial Reporting Council (FRC). The AC also noted and considered external commentaries suggesting that viability statements should be extended beyond a period of three years. We concluded that the three-year period selected by the Board for the review of Shell's prospects, in line with the operating plan, remained suitable. The factors which we further considered in support of the viability statement are discussed later in this report.

In May 2018, Linda Stuntz stood down from the AC. I thank Linda for her service to the AC and for the invaluable input and perspective she provided as a member. Also in May, we were delighted to welcome Ann Godbehere to the Board and to the AC.

Euleen Goh

Chair of the Audit Committee
March 13, 2019

COMPOSITION OF THE AUDIT COMMITTEE

During 2018, the members of the AC were Euleen Goh (Chair of the AC), Roberto Setubal, Linda G. Stuntz (who stood down as a member on May 22, 2018), Gerrit Zalm and Ann Godbehere (appointed as a member with effect from May 23, 2018), all of whom are financially literate, independent Non-executive Directors. In respect of the year ended December 31, 2018, for the purposes of the UK Corporate Governance Code, Euleen Goh and Ann Godbehere each qualify as: a person with "recent and relevant financial experience" and competence in accounting; and, for the purposes of US securities laws, each is an "audit committee financial expert". The AC had six meetings during the year; the AC members' attendances are shown on page 100. The experience of the AC members outlined on pages 82-87 demonstrates that the AC as a whole has competence relevant to the sector in which Shell operates, as well as the necessary commercial, regulatory, financial and audit expertise required to fulfil its responsibilities. The AC members have gained further knowledge and experience of the sector as a result of their Board membership and through various site visits since their respective appointments.

RESPONSIBILITIES

The key responsibilities of the AC are to assist the Board in fulfilling its oversight responsibilities in relation to: financial reporting; the effectiveness of the system of risk management and internal control; compliance with applicable legal and regulatory requirements; monitoring the qualifications, expertise, resources and independence of both the internal and external auditors; and assessing the internal and external auditors' performance and effectiveness each year. The AC keeps the Board informed of its activities and recommendations. Where the AC is not satisfied with, or if it considers that action or improvement is required concerning any aspect of financial reporting, risk management and internal control, compliance or audit-related activities, it promptly reports these concerns to the Board.

ACTIVITIES

The AC covers a variety of topics in its meetings. These include both standing items that the AC considers as a matter of course, typically in relation to the quarterly unaudited financial statements, control issues, accounting policies and judgements and reporting matters, and a range of topics relevant to Shell's control framework. The AC invites the Chief Executive Officer, the Chief Financial Officer, the Legal Director, the Chief Internal Auditor, the Executive Vice President Controller, the Vice President Accounting and Reporting and the external auditor to attend each meeting. The Chair of the Board also regularly attends the meetings as an observer. Other members of management attend when requested. The AC regularly holds private sessions separately with the external auditor and the Chief Internal Auditor without members of management, except for the Legal Director, being present.

During 2018, the AC received comprehensive reports from management and the internal and external auditors on various topics. In particular, it discussed with the Chief Financial Officer, the Executive Vice President Controller, the Vice President Accounting and Reporting, the Chief Internal Auditor and the external auditor matters that arose on accounting policies, practices and reporting, and reviewed aggregated whistle-blowing reports, internal audit reports and analyses of financial reporting matters. The AC has access to these parties and any members of Shell's management, as necessary, to provide in-depth analysis on specific topics or on more detailed technical matters that may arise.

In view of the rapidly changing business landscape, the regulatory environment and the introduction of new technologies and digital opportunities, the AC continued to focus on the robustness of Shell's information risk management, including considering: changes made to further strengthen access management controls during 2018, security improvement initiatives, Shell's cyber monitoring and defence capabilities, and information security generally. To inform its assessment, the AC and the Chief Information Officer reviewed the status of information risk management and determined that the levels of control, activities undertaken in 2018 and further focus areas are appropriate. The AC also reviewed assurances for: proved oil and gas reserves; Brent crude oil and Henry Hub long-term natural gas price assumptions; discount rates used for financial reporting, particularly with respect to impairment testing (see below in this report and Note 2 to the "Consolidated Financial Statements" on pages 172-181 for further information); and the effectiveness of financial controls. The AC discussed future tax-related risks for Shell with the Executive Vice President Taxation, particularly in relation to the external environment, for example, implementation of base erosion and profit-shifting measures, dividend withholding tax in the Netherlands and US tax reform. The AC discussed with the Chief Ethics and Compliance Officer her annual report on compliance matters, including regulatory developments and compliance risks. Following the coming into effect of the EU GDPR in May 2018, which required Shell companies to update systems, processes, notices and ensure its contracts contain the appropriate clauses to actively demonstrate compliance, the Chief Privacy Officer provided the AC with an update on EU GDPR implementation, compliance monitoring and assurance.

In addition to the items discussed under significant issues on pages 115-116, the AC also dedicated time to other matters that it deemed relevant and appropriate, for example: the impact of changes connected with the adoption of IFRS 9 (*Financial Instruments*) and IFRS 15 (*Revenue from Contracts with Customers*); the impact of the new lease accounting standard (IFRS 16); and Shell's insurance arrangements. The AC also discussed investigations of cases involving ethics and compliance concerns. The AC discussed management's findings in such cases to satisfy itself that a rigorous process had been followed, and, where appropriate, learnings embedded by management into the systems and controls of the organisation.

The AC was briefed on litigation matters (see "Corporate governance" on page 98 and Note 25 to the "Consolidated Financial Statements" on pages 211-213); impending regulatory requirements (such as the publication of the FRC's 2018 UK Corporate Governance Code and other corporate governance reporting requirements); and market studies into external audit (namely the UK Competition and Markets Authority's market study to consider whether the market for the provision of statutory audits is working as well as it should and the UK Business, Energy and Industrial Strategy Committee inquiry on the future of audit).

In May 2018, the AC spent a day at the trading and supply office in London to deepen its understanding of the challenges faced and opportunities created by the trading and supply function. The AC was provided with information on the external environment and the relevant regulations within which the function operates. The AC engaged with members of the trading and supply function in in-depth discussions on a variety of topics including market risk, credit risk, assurance and supervision and Brexit planning.

There was no contact during the year with the FRC Corporate Reporting Review team. Following the Company's responses to matters raised by the review team in 2017, as a result of the FRC's thematic review of companies' disclosures of significant accounting judgements and sources of estimation uncertainty, the Company made the following changes in the 2017 and 2018 Consolidated Financial Statements: disclosed Shell's Brent crude oil and Henry Hub long-term natural gas price assumptions; and made a distinction between key accounting judgements and estimates and other more generic judgements and estimates applicable to Shell. The AC discussed with management the Company's responses to matters raised by the US Securities and Exchange Commission staff in relation to clarifying aspects of the Proved Undeveloped reserves disclosure in the 2018 Annual Report and Form 20-F.

The AC discussed the Company's 2018 Annual Report and Form 20-F, half-year report and quarterly unaudited financial statements with management and the external auditor. As requested by the Board, the AC advised the Board of its view that the 2018 Annual Report and Form 20-F including the financial statements for the year ended December 31, 2018, taken as a whole, is fair, balanced and understandable and provides the information necessary for shareholders to assess Shell's position and performance, business model and strategy (see the "Directors' Report" on pages 91-92). To arrive at this conclusion, the AC critically assessed drafts of the 2018 Annual Report and Form 20-F including the financial statements and discussed with management the process undertaken to ensure that these requirements were met. This process included: verifying that the contents of the 2018 Annual Report and Form 20-F are consistent with the information shared with the Board and management during the year to support their assessment of Shell's position and performance; ensuring that consistent materiality thresholds are applied for favourable and unfavourable items; considering comments from the external auditor; and receiving assurance from the Executive Committee (EC). The AC further reviewed and considered the Directors' half-year and full-year statements with respect to the going concern basis of accounting. As noted in the viability statement, the Board also reviews the strategic plan which takes account of longer-term forecasts and a wide range of outlooks. Factors considered included: the impact of commodity prices; exchange rates; schedules of growth programmes; the financial framework; Shell's business portfolio developments; the project funnel to support future growth; and running models of the financial impact of certain of Shell's principal risks materialising using severe but possible scenarios. The AC analysed the mitigating measures and sensitivities management had applied to the modelling of such scenarios when considering the viability statement and supported its inclusion in the "Directors' Report" on page 92.

The AC considered and approved the internal audit function's annual audit plan. It also reviewed Deloitte LLP's independent external quality assessment of the effectiveness of the internal audit function. The AC assessed the performance of the internal audit function as effective. The AC also considered the annual external audit plan (including assessing whether the planned materiality levels and proposed resources to execute the audit plan were consistent with the audit scope) and approved related remuneration to ensure that the level of fees would allow an effective and high-quality audit to be conducted by the external auditor.

AC EVALUATION

The AC undertakes an annual evaluation of its performance and effectiveness. As with the Board's annual performance evaluation for 2018, the AC's performance evaluation was facilitated by Lintstock Limited, a London-based corporate advisory firm. Each AC member responded to a confidential questionnaire related to the AC's performance covering questions relating to: the management of the AC in areas such as the annual cycle of work, agenda for meetings, and time and input in meetings; rating the quality of the information provided to the AC; the effectiveness of the AC's oversight in areas such as the work of internal and external audit, the Group's financial reporting, the system of internal controls and the risk management policies and practices; rating the AC's performance in reviewing and assessing significant accounting and reporting issues; and generally how to improve the AC's performance. The AC's discussion of the outcomes was assisted by a performance evaluation report produced by Lintstock, which included comparison of 2018 responses against the responses submitted by AC members in 2017.

The AC concluded that its performance in 2018 had been effective and that it fulfilled its role in accordance with its terms of reference, which can be found at www.shell.com/investor. As part of the evaluation, the AC discussed the priorities, in addition to the standing items, for its 2019 agenda, including a visit to the finance operations centre in Chennai and further discussions on IFRS 16 implementation, regulatory developments, information risk management and new business models and ventures. When assessing progress against 2017, the AC concluded that 2018 priorities identified in the 2017 evaluation (including a visit to the trading and supply office in London and further discussions on Shell's insurance arrangements, IFRS 16 implementation, regulatory developments and information risk management) had all been undertaken by the AC in 2018.

SYSTEM OF RISK MANAGEMENT AND INTERNAL CONTROL

The AC reviewed the regular reports on risks, controls and assurance, including the annual assessment of the system of risk management and internal control, in order to monitor the effectiveness of the procedures for internal control over financial reporting, compliance and operational matters. This included the Company's evaluation of the internal control over financial reporting as required under Section 404 of the Sarbanes-Oxley Act.

SIGNIFICANT ISSUES

The AC assessed the following significant issues, including those related to Shell's 2018 Consolidated Financial Statements. The AC was satisfied with how each of the issues below was addressed. As part of this assessment, the AC received reports, requested and received clarification from management, and sought assurance and received input from the internal and external auditors.

Significant issues

Subject	Issue	How the AC addressed the issue
DISPOSALS See Notes 5 and 8 to the "Consolidated Financial Statements" on pages 184 and 186-188.	<p>Shell has concluded its 2016-2018 divestment programme, as part of which several significant disposals were completed in 2018. Prior to disposal, judgement is required in determining whether a sale is highly probable. If it is, the asset should be classified as held for sale, which is a trigger for impairment testing.</p> <p>Judgement may also be required when accounting for the disposal, for example in estimating the amount of any liabilities retained by Shell.</p>	<p>The AC scrutinised the application of the held for sale classification, as well as the accounting for any ensuing disposals, including the divestment of Integrated Gas assets in India and Oman, as well as Upstream assets in Iraq, Malaysia, Norway, Oman and the UK. Particular attention was given to the accounting for any retained obligations, the assumptions used in determining any resulting charges and the tax treatment.</p>
IMPAIRMENTS See Notes 2 and 8 to the "Consolidated Financial Statements" on pages 172-181 and 186-188.	<p>The carrying amount of an asset should be tested for impairment when there is a change in circumstances such as a reduction in performance, other than short term, or being classified as held for sale.</p> <p>Despite oil prices that were higher, on average, in 2018 than in 2017, management decided not to change Shell's long-term price forecasts.</p>	<p>The oil and gas price outlook was reviewed against market developments and benchmarks, and the potential impact of certain price sensitivities were considered. The relevant discount rates utilised were also reviewed.</p> <p>The AC satisfied itself with the impairment testing performed and the impairment charges or reversals recognised in relation to certain Integrated Gas and Upstream assets. These charges or reversals were mainly triggered by market changes, asset performance and project delays.</p>
TAXATION See Notes 2 and 16 to the "Consolidated Financial Statements" on pages 172-181 and 194-197.	<p>The determination of tax assets and liabilities requires the application of judgement as to the ultimate outcome, which can change over time depending on facts and circumstances. In particular, the recognition of deferred tax assets requires management to make assumptions regarding future profitability and is therefore inherently uncertain.</p>	<p>The AC conducted an in-depth review of management's assessments on certain tax matters. The AC considered tax exposures, including the recoverability of deferred tax assets, particularly those associated with 2018 disposals, and accepted the resulting assessments of the deferred tax positions.</p>
IMPLEMENTATION OF IFRS 16 See Note 3 to the "Consolidated Financial Statements" on page 181.	<p>With effect from January 1, 2019, IFRS 16 <i>Leases</i> will replace IAS 17 <i>Leases</i>. Under the new standard, all lease contracts, with limited exceptions, are recognised in the financial statements by way of right-of-use assets and corresponding lease liabilities. Shell will apply the modified retrospective transition approach without restating comparative information.</p> <p>The amount of operating lease commitments that will be recognised on the balance sheet at the date of application depends on many factors, including the outstanding lease contracts at that date, the remaining lease term and the discount rate applied upon transition.</p>	<p>The AC appraised and approved accounting policy changes resulting from the implementation of IFRS 16. The AC reviewed management's analysis of the adoption implications for Shell, including key judgements, and concurred with their recommendations.</p>
CHANGES TO PRESENTATION OF CONSOLIDATED STATEMENT OF CASH FLOWS	<p>Shell prepares its "Consolidated Statement of Cash Flows" using the "indirect method", whereby in determining cash flow from operating activities (CFFO), income for the period is adjusted for the effects of non-cash transactions. The presentation of these non-cash transactions is not prescribed by IFRS, necessitating professional judgement.</p> <p>With effect from January 1, 2018, the reconciliation from income for the period to CFFO has been revised to provide better insights. The transparency of the CFFO excluding working capital measure has been improved and the working capital measure better correlates with the balance sheet.</p>	<p>The AC analysed the improvement initiative proposed by management and accepted that the implementation would deliver greater transparency for all users of Shell's "Consolidated Statement of Cash Flows".</p>
CYBER-SECURITY	<p>Information on the increasing importance of cyber-security and Shell's management of the associated risks was presented to the AC.</p>	<p>The AC discussed the measures in place to mitigate against these risks with the Chief Information Officer.</p>

INTERNAL AUDITOR

The internal audit function is an independent and objective assurance function which aims to improve Shell's overall control framework. The internal audit function assists in the maintenance of a systematic and disciplined approach to evaluate and improve the design and effectiveness of Shell's risk management, control and governance processes. The primary role of the internal audit function, through its assurance and investigation activities, is to safeguard value by protecting Shell's assets, reputation and sustainability in relation to the organisation's defined goals and objectives.

The AC defines the responsibility and scope of the internal audit function and approves its annual plan. The Chief Internal Auditor reports functionally to the Chair of the AC and administratively to the Chief Financial Officer. The Chair of the AC approves, in consultation with the Chief Financial Officer, all decisions regarding the performance evaluation, appointment or removal of the Chief Internal Auditor. A new Chief Internal Auditor was appointed with effect from September 2018.

The Chief Internal Auditor periodically assesses whether the purpose, authority, and responsibility of the internal audit function continue to enable it to accomplish its objectives. The result of this periodic assessment is communicated to the EC and AC. The Chief Internal Auditor maintains an internal quality assurance and improvement programme, covering all aspects of the internal audit activities, to evaluate the conformance of these activities with the Chartered Institute of Internal Auditors Standards (CIIA Standards). The programme also assesses the efficiency and effectiveness of the internal audit activities and identifies opportunities for improvement. The result of this annual assessment is communicated to the EC and AC and includes a reconfirmation to the AC of the continued validity of the charter of the internal audit function, or it proposes an update.

At least every five years, the effectiveness and quality of the internal audit function is assessed externally and the report shared with the AC. In 2018, Deloitte LLP carried out such an independent external assessment, the conclusions of which were discussed with the AC and enabled the AC to satisfy itself that the quality, experience and expertise of the function continue to be appropriate for the business. The CIIA's standard quality assessment rating scale has three levels: "generally conforms", "partially conforms", and "does not conform". Based on its assessment, Deloitte reported to the AC that the Shell internal audit function "generally conforms", which means that Deloitte appraised the function to be operating and performing in accordance with the CIIA Standards and commented on a number of leading practices including its established data analytics capability and the depth of business knowledge and expertise in the internal audit function. The overall assessment shows an improvement compared to the last independent external quality assessment in 2013.

Further, the AC reviewed and assessed management's response to significant findings by the internal audit function, including the implementation of agreed actions, and concluded that management's response properly supported the effective working of the internal audit function.

EXTERNAL AUDITOR

The AC is responsible for considering whether, in order to ensure continuing auditor independence, there should be a rotation of the independent registered public accounting firm, including consideration of the advisability and potential impact of selecting a different independent public accounting

firm. The Company's current external auditor, Ernst & Young LLP (EY), was first appointed at the Annual General Meeting (AGM) in May 2016 following the conclusion of a competitive tender process. The Company has complied with The Statutory Audit Services for Large Companies Market Investigation (Mandatory Use of Competitive Tender Processes and Audit Committee Responsibilities) Order 2014 for the 2018 financial year.

At the AGM in May 2018, a resolution to reappoint EY as external auditor until the conclusion of the next AGM was approved by shareholders. There are no current plans to retender the appointment. The current external audit partner is Allister Wilson, who has held this position since EY's initial appointment as external auditor in 2016.

During 2018, there was no review of any of EY's audits of Shell's Consolidated Financial Statements by the Audit Quality Review (AQR) team of the FRC. The AC evaluated the effectiveness of EY and the external audit process in its third year as auditor, taking into account the results of Shell management's internal survey relating to EY's performance over the financial year 2018 as well as views and recommendations from management and the Chief Internal Auditor and its own experiences with the external auditor. Key criteria of the evaluation included: professionalism in areas including competence, integrity and objectivity; efficiency, covering aspects such as service level, cost efficiency and innovation in the audit process; thought leadership and value added; and compliance with relevant legislative, regulatory and professional requirements. The AC concluded that EY had performed effectively.

Following due consideration, the AC will recommend to the Board to propose to the 2019 AGM that EY be reappointed as the external auditor of the Company for the year ending December 31, 2019. There are no contractual obligations that restrict the AC's ability to make such a recommendation.

As required under UK and US auditing standards, the AC received a letter from EY confirming its independence.

EY presented its views on the 2018 Annual Report and Form 20-F, including the financial statements and internal control over financial reporting for the year ended December 31, 2018, to the AC and to the Board.

NON-AUDIT SERVICES

The AC updated its independence policy in respect of the provision of services by the external auditor with effect from January 1, 2017, to accommodate changes in related standard and regulatory requirements. This policy, designed to safeguard auditor objectivity and independence, includes rules relating to the provision of audit services, audit-related services and other non-audit services, and stipulates which services require specific prior approval by the AC.

The policy also defines prohibited services that are not to be provided by the auditor as these represent a risk to external auditor independence. Prohibited services are any that relate to management decision taking or any other service that would compromise auditor independence or the perception thereof. These prohibited services include all services listed as prohibited in the UK and US auditor independence rules.

For certain services that are not prohibited, because of the knowledge and experience of the external auditor and/or for reasons of confidentiality, it can be more efficient or prudent to engage the external auditor rather than another party. This is particularly the case in relation to audit-related assurance services that are closely connected to the audit function where the external auditor has the benefit of knowledge gained from work already performed as part of the audit.

Under the policy, the AC will only approve services to be carried out by the external auditor or its affiliates where such services do not present a conflict of interest risk in fact or in appearance. The AC reviews quarterly reports from management on the audit and non-audit services reported in accordance with the policy or for which specific prior approval from the AC is being sought. To the extent that the fee value of an additional audit service contract does not individually exceed \$500,000, then no prior approval of the AC is required. All non-audit services where the fee for each individual contract exceeds \$50,000, including audit-related services, require individual prior approval by the AC. In each case where the audit or non-audit service contract does not exceed the relevant threshold, the matter is subsequently reported at the next quarterly AC meeting.

For UK reporting purposes, the scope of the non-audit services contracted with the external auditor in 2018 consisted mainly of interim reviews and other audit-related assurance services. The associated compensation for these audit-related services and other non-audit services amounted to 9% and 2%, respectively, of the external auditor's audit and audit-related remuneration.

FEES

Note 28 to the "Consolidated Financial Statements" on page 214 provides a specification of the auditor's remuneration.

Directors' Remuneration Report

The Directors' Remuneration Report for the year ended December 31, 2018 sets out the work of the Remuneration Committee (REMCO) in 2018 and how the policy that was approved by shareholders at the 2017 Annual General Meeting (AGM) has been implemented. The principles that underpinned REMCO's approach are set out on page 125.

STATEMENT BY THE CHAIR OF THE REMUNERATION COMMITTEE

Dear Shareholders,

INTRODUCTION

The year for REMCO started with a disappointing vote on the remuneration report for 2017, in spite of extensive and constructive engagement with a large number of our institutional investors. We have since spent considerable time with shareholders to understand this and learn how to change our approach for the future.

With respect to company performance we enjoyed a good year, rounding off a successful post BG acquisition period and delivering on our commitments. This is reflected in a high vesting percentage for our Long Term Incentive Plan (LTIP).

We also made good progress through our continued engagement with shareholders regarding the implementation of a measure for energy transition progress as part of our LTIP. Given the broad support for our direction of travel we have decided not to wait for the mandatory policy review of next year, but rather to start immediately by incorporating an energy transition metric into the 2019 LTIP. This is a first for our industry, and the design was strongly influenced by collaboration with some of our major shareholders.

In the sections below, I will cover the following:

Firstly, looking back at 2018 and its outcomes:

- 2018 Annual General Meeting – An overview of the voting outcome and the key learning from our subsequent shareholder engagements.
- Reflections on 2018 Performance – An overview of performance on key components of the 2018 annual bonus scorecard, in particular regarding safety, cash flow and operations. Insight into the Executive Directors' individual performance elements taken into account by REMCO and the resulting annual bonus award.
- Long-Term Incentive Plan – A reflection of REMCO's deliberations when determining the vesting of the 2016 LTIP award.
- CEO Remuneration – A summary of the factors considered by REMCO in its reflection on the 2018 Single Figure and an indication of several bonus structure changes that we have brought forward to implement in 2019, in advance of the 2020 policy vote.

Then looking forward at pay in the wider context and our remuneration approach in 2019 and beyond:

- Pay in the Wider Context – In the interests of transparency, we are publishing the CEO pay ratio in accordance with the new methodology a year earlier than required and this is summarised in this section together with information on how all our employees share in our success and our drive to be internally proportionate while externally competitive.
- Remuneration Policy – an update on our progress on the policy review in advance of the 2020 policy vote and details on the policy changes we have brought forward for early implementation.

2018 ANNUAL GENERAL MEETING

REMCO was disappointed with the level of the support (74.78%) received in favour of the Annual Report on Remuneration for the year ended December 31, 2017. Our engagements with shareholders and proxy voting agencies in 2018 helped us understand the voting outcome.

One of the most important points to emerge from these discussions was that we should have been clearer about why the tragic June 2017 incident in Pakistan involving a sub-contractor road tanker did not lead to a reduced bonus outcome. Based on advice from the Corporate and Social Responsibility Committee (CSRC), REMCO ensures that safety performance is appropriately considered in remuneration. We consider the wider safety performance of Shell, as well as the safety measures in the bonus scorecard. This assessment includes a consideration of what is within Shell's operational control. Although devastating, ultimately this tragedy was outside Shell's operational control. The Board discussed the Pakistan incident at length and with so much focus on the incident in our internal discussions, we did not realise that our decision regarding remuneration needed further clarification in order to be understood by our shareholders. Our extensive internal investigations are now complete and, while a Pakistani police investigation is ongoing, we do not have any new information that would change our remuneration decisions. Further information on our learnings from this road tanker incident can be found in the Safety section on page 67.

2018 PERFORMANCE

I would now like to turn to 2018 performance and, in particular, reflect on the metrics within the annual bonus scorecard.

Firstly, in respect of safety, we set a particularly challenging personal safety target for 2018. This is evidenced in the outcome, measured by Total Recordable Case Frequency (TRCF), of zero on the annual bonus scorecard. It is worth noting that had the target remained unchanged from 2017, our 2018 outcome would have been on target. Despite the TRCF score of zero, 2018 had the second lowest TRCF on record, after Shell's record low in 2017, and REMCO noted that the number of cases has halved since 2008. The tragic deaths of two contractors in Shell-operated ventures was included in the TRCF outcome. In reflecting on these deaths when determining the 2018 bonus outcome, REMCO decided that because personal safety was already at zero against a stretching target no further adjustment to the scorecard outcome was required.

Road transportation remains a challenging and complex area for our industry worldwide. We were deeply disappointed that, following the June 2017 incident, in October 2018, there was another roll-over incident in Pakistan involving a customer tanker, which resulted in the death of the relief driver and a spill. However, as this further incident was also outside the scope of Shell's operational control, REMCO has concluded that it will not be reflected in 2018 pay outcomes.

There was notable improvement in 2018 in operational process safety with a reduction in the number of Tier 1 and Tier 2 events by 27% compared to the prior year. It was also encouraging to see good delivery on the greenhouse gas (GHG) intensity measures with these all at, or better than target, with a notable reduction in flaring.

Directors' Remuneration Report Continued

Although the macroeconomic environment remained uncertain in 2018, Shell produced very strong financial results, with cash flow from operations (CFFO) of \$53 billion. Our strong financial performance allowed Shell to service and reduce debt, cover the dividend, make capital investments and execute share buybacks. Our performance relative to our competitors (BP, Chevron, ExxonMobil and Total) has also been strong, for example, Shell has regularly outperformed competitors on CFFO since early-2017. Indeed, 2018 saw significant volatility in oil and gas prices, during which time the underlying competitiveness of Shell was a key strength. Finally, while that price volatility also impacts cash flow, it is worth reiterating that REMCO has long had a policy of not adjusting remuneration measures to take into account changes in oil and gas prices and currency fluctuations. In our engagements with our largest shareholders, many have appreciated the transparency this brings.

Shell's strong financial performance was supported by the operational performance of Shell's businesses. LNG liquefaction volumes were well above target, due to better reliability and better feedstock availability.

Project delivery was also strong with delivery ahead of planned budget, with significant life-cycle cost reductions, particularly driven by the Appomattox deep-water oil and gas project in the USA where costs were more than \$1 billion below budget, partially offset by delays in schedule of more than two months on nine out of the 36 projects we track. Refinery and chemical plant availability was near target. Production was below target, affected by new field delays as well as operational challenges including Enchilda/Salsa assets and Auger and its associated fields.

ANNUAL BONUS

Taking into account the 2018 performance context, REMCO approved the annual bonus scorecard outcome of 1.31 and no discretion was applied. This brings our ten-year average scorecard outcome to 1.24. The detailed bonus scorecard breakdown is on page 133.

REMCO also approved an individual performance multiplier of 1.0 for both the CEO and CFO based on the following factors:

Pay for performance

The following table summarises performance against the individual objectives for the CEO and CFO

KEY GOALS	BEN VAN BEURDEN	JESSICA UHL
Deliver a world-class investment case	<p>Performance multiplier = 1.0</p> <p>Under the CEO's leadership, Shell continues to transform, with a clear purpose and well-defined strategic intents that balance societal progress with performance, to deliver higher returns. A strong financial performance was delivered: CFFO was \$53 billion, FCF was \$39 billion, an all-cash dividend was paid, gearing was reduced to 20.3%, and the share buyback programme was started. The \$30 billion divestment programme was also completed and investments have been made in a disciplined manner.</p> <p>In terms of broader company performance, REMCO recognised the strategic clarity the CEO has provided around the purpose and direction of Shell. The CEO set out Shell's 2020 ambition following the BG acquisition, and the 2018 numbers across all strategic themes show that the strategy is delivering. Shell delivered on commitments to shareholders and is on track to achieve its 2020 targets.</p>	<p>Performance multiplier = 1.0</p> <p>The CFO demonstrated strong cost and capital discipline leadership. This was enabled by a consistent focus on the strategic management of Shell's Financial Framework during the year, which has been a key contribution to the health and success of Shell in 2018. Key milestones included: reduced gearing, the cancellation of the scrip dividend and start of the share buyback programme, sustained investment discipline, reduced costs and a strengthened balance sheet with AA equivalent credit metrics.</p> <p>In terms of broader company performance, REMCO recognised the strategic insight the CFO has provided in terms of effective capital allocation, portfolio and investment decisions that further Shell's world-class investment case.</p>
Thrive in the energy transition	<p>The CEO led the operationalisation of Shell's NCF ambition through driving internal plans and targets, integrating business and world-class investment decisions with thriving in the energy transition, and by preparing the organisation for changing investor and customer preferences as the transition unfolds.</p> <p>The CEO continues to lead the way in the energy transition debate externally, for example, through the first joint statement with institutional shareholders, encouraging other companies to adopt the NCF methodology, and shaping the debate on energy transition with recognised scenario outlooks (Sky).</p>	<p>The CFO further matured the internal management systems relating to carbon dioxide (CO₂) in portfolio, planning and resource allocation decisions.</p> <p>The CFO led the publication of the Shell Energy Transition Report, which is aligned with the Task Force on Climate-related Financial Disclosures (TCFD) recommendations and sets out how Shell plans to be resilient to expected changes in the energy system and how its strategy helps it to thrive as the world transitions to lower-carbon energy.</p>
Strengthen licence to operate	<p>In terms of HSSE leadership, performance was mixed, which shows further improvement is required. The 2018 personal injury rate slightly worsened, following the lowest ever injury rate on record in 2017, however the long-term trend still shows improvement with an injury rate reduction of some 50% compared to 2008. There was notable improvement in 2018 in operational process safety with a reduction in the number of both Tier 1 and Tier 2 events.</p> <p>The CEO has also shown leadership and transparency in terms of Shell as a responsible company with a role to play in society.</p>	<p>The CFO maintained a strong financial disclosure, reporting and control framework.</p> <p>In terms of tax transparency, the CFO played a key role in Shell's endorsement of the responsible tax principles set out by the non-profit organisation, The B Team.</p>

The annual bonus award for the CEO was 131% of the target and 79% of the maximum opportunity. For the CFO, it was 130% of target and 65% of the maximum opportunity. REMCO sets the awards based on target and, as such, considered that the annual bonus outcomes were appropriate for 2018. Further commentary on this for the CEO is provided below in the section on Remuneration Policy.

The annual bonus for the Executive Directors is paid 50% in cash and 50% in shares subject to a three-year holding period, which applies beyond an Executive Director's tenure.

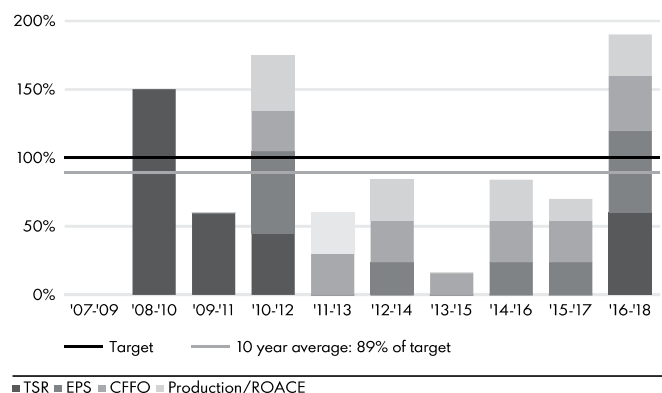
LONG-TERM INCENTIVE PLAN

The outcome of the 2016 LTIP over the performance period (financial years 2016 to 2018) was 190%. In this section I would like to set out some context on our policy, the historical vesting position for the plan and also comment specifically on performance for the period and the resulting vesting outcome for the Executive Directors.

One of the features of our pay model is the high proportion of variable pay, which makes up around 80% of the CEO's target remuneration package and around 72% for the CFO. Accordingly, we expect that pay outcomes will fluctuate based on the performance of the Company over time. Prior to latest vesting, our 10-year average vesting level was 75%, notably below the target level of 100% and maximum level of 200%.

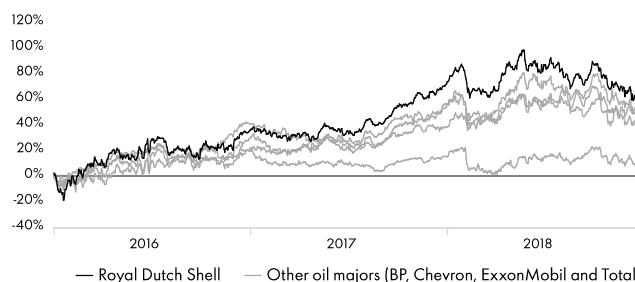
As you will see from the following chart, vesting during the last ten years has ranged from 0% to 175% and we saw a number of recent years of low LTIP vesting outcomes as Shell went through a transformation following the acquisition of BG, including the sale of non-core assets. As the benefits of this transformation start to be realised, we see strong competitive performance of Shell over the past three years relative to our competitors (BP, Chevron, ExxonMobil and Total). This will be only the third time since 2009 that the LTIP vesting has been above target (or higher than 50% of the maximum) and the 10-year average vesting outcome of the LTIP shifts to 89% of target (44.5% of maximum).

LTIP vesting



For the 2016 LTIP, Shell's total shareholder return (TSR), earnings per share (EPS) and cashflow from operations (CFFO) were highest among our competitors, while return on average capital employed (ROACE) ranked second highest. The chart below illustrates this strong relative performance in terms of TSR:

Total shareholder return 2016-2018



These outcomes reflect the success of Shell's strategy since 2016 and the progress made in building a world-class investment case. Over the 2016-2018 performance period, Shell has delivered on commitments to strengthen the financial framework; cancelling the Scrip Dividend Programme and starting the \$25 billion share buyback programme (\$4.5 billion completed as at January 28, 2019). As well as reshaping the portfolio with the \$30 billion divestment programme completed, \$10 billion of CFFO from new projects realised in 2018 while reducing underlying operating expenses (\$39 billion in 2018). Our operating expenses are lower than Shell's standalone costs in 2015, meaning we have fully absorbed the operating costs of BG and delivered even more cost savings, which demonstrates the success of the combination. The divestment programme was designed to high-grade and reshape our portfolio and strengthen our financial framework. When it started in 2016, the oil price was below \$40 a barrel and market conditions for executing a programme of this scale were challenging.

This performance is reflected in the LTIP performance measures, with CFFO measured on a rolling four-quarter basis the highest in absolute terms among our competitors from the third quarter of 2017. Shell's EPS (measured on a diluted current cost of supplies basis) has grown from \$0.60 per share in 2015 to \$2.85 in 2018. ROACE has improved as Shell has divested non-core assets and focused on capital discipline.

After considering the underlying performance of Shell relative to our competitors over the performance period, REMCO decided it was appropriate that the 2016 LTIP award vested in accordance with the set vesting schedule without adjustment.

The table below illustrates the total LTIP vesting that follows this strong performance of Shell over the past three years relative to our competitors, strong share price appreciation and the dividend yield.

In 2016, there was some fluctuation in the share price during the period that REMCO made its remuneration decisions. REMCO paid careful attention to the share price and determined it was appropriate to grant the 2016 LTIP award based on a three-month average share price, rather than a share price at the date of award, in order to moderate this volatility. This reduced the number of shares awarded.

This vesting takes the CEO's shareholding to more than 11 times base salary. The CEO's vested awards are subject to a two-year holding period, which he has voluntarily agreed to extend to three years. It is worth noting that while the CFO received a 2016 LTIP award, she was not an Executive Director at the time and therefore received a significantly smaller award.

2016 LTIP vesting outcome

BEN VAN BEURDEN

Vesting outcome: [A]

236,302 x 190% =
448,974 RDS A Shares
(€9,033,353)



Increase in

share price: [B]
448,974 x €7.215
(€3,239,346)



Accrued dividends: [C]

107,432 A Shares
(€2,936,659)



Total LTIP Vesting: [C][D]

556,406 RDS A Shares
(€15,209,358)

JESSICA UHL

Vesting outcome: [A]

13,800 x 190% =
26,220 RDS.A ADS
(\$1,190,388)



Increase in

share price: [B]
26,220 x \$16.92
(\$443,642)



Accrued dividends: [C]

6,281 RDS.A ADS
(\$391,432)



Total LTIP Vesting: [C]

32,501 RDS.A ADS
(\$2,025,462)

[A] Based on the share price at grant of €20.12 for Ben van Beurden and \$45.40 for Jessica Uhl.

[B] Calculated as the share price at vesting date minus the share price at the date of grant for Ben van Beurden €27.335 - €20.12 = €7.215 and for Jessica Uhl: \$62.32 - \$45.40 = \$16.92.

[C] Based on the share price at vesting date of €27.335 for Ben van Beurden and \$62.32 for Jessica Uhl.

[D] Vested shares are subject to a two year holding period.

CEO REMUNERATION

REMCO has acted carefully in managing pay over the course of Ben van Beurden's service as CEO. With respect to base salary, REMCO has reduced the starting base salary for the new CEO relative to his predecessor twice successively in recent history and adapted this annually in line with base salary movement of the wider Shell workforce, as indicated in the table on page 137. The variable pay opportunity has remained broadly unchanged for more than 10 years.

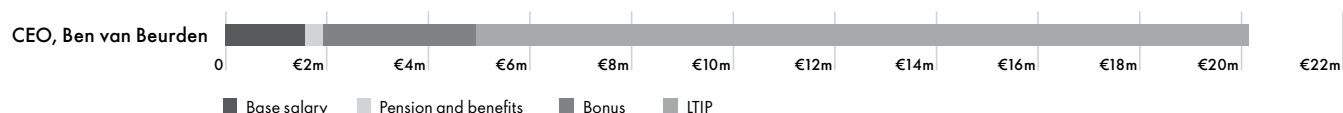
As a consequence of the LTIP vesting in particular, the single figure of remuneration for the CEO is significantly higher this year than in previous years. REMCO is sensitive to the wider societal discussions regarding the level of executive pay and spent a significant amount of time discussing the high single figure for the CEO in 2018. I want to share with you our reasons for supporting this outcome

The strength of Shell's financial performance in the performance period and in accordance with the measures under the LTIP is set out above.

In its broader deliberation on the single figure, REMCO also reflected on Shell's other achievements in the last three years and the personal leadership that Ben van Beurden has provided in this period namely:

- Completed the acquisition and integration of BG.
- Delivered a \$30 billion divestment programme, reshaping the portfolio.
- Overseen several major project investment decisions such as in the deep-water Gulf of Mexico and LNG Canada at very capital-efficient unit development costs.
- Created a New Energies business, taking Shell further into offshore wind projects (now also in the USA as well as Europe), electric vehicle charging, and domestic electricity and gas supply.
- Led the sector in framing a methodology for aligning with the Paris Agreement, including two industry firsts of a) incorporating our customers' emissions associated with the energy products we sell and b) linking nearer-term targets to remuneration.

CEO 2018 single figure of remuneration



See single total figure of remuneration on page 131.

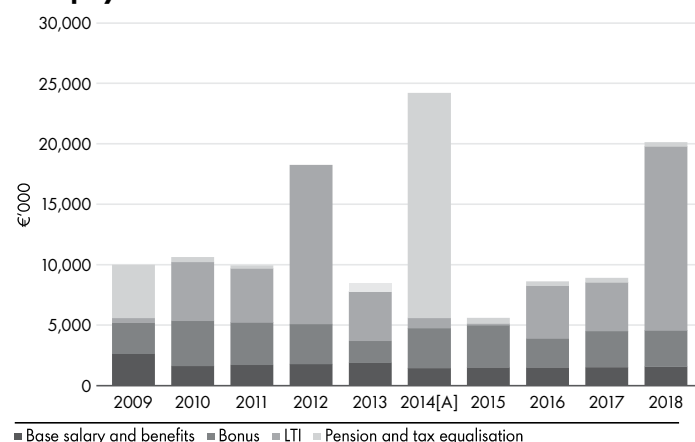
The CEO's leadership has been critical in building and delivering on a strategy that is enabling Shell to make such progress in becoming a world-class investment case.

In light of the above considerations, REMCO determined that not only was the vesting of the 2016 LTIP award appropriate on the basis of Shell's relative performance, but that this was underpinned by the broader performance of Shell and of the CEO in particular.

REMCO also considered the 2018 annual bonus outcome for the CEO and noted that while the bonus award of €3,000,000 is 131% of target, it is also 79% of the maximum opportunity. This is a result of the maximum being less than two times target. Further information on why this arose is set out in the section below on Remuneration Policy. REMCO sets the award based on target and, as such, REMCO determined that the annual bonus outcome was appropriate for 2018. Going forward, however, REMCO has decided to remove the asymmetry for the CEO by reducing the target bonus from 150% of salary to 125% of salary.

Overall, REMCO considered that taking into account the historical context and the volatility in the LTIP vesting, that the overall maximum pay opportunity for the CEO remains appropriate.

CEO pay outcomes



[A] Impacted by the increase in pension accrual (€10.7m) calculated under the UK reporting regulations and tax equalisation (€7.9m) as a result of his promotion and prior assignment to the UK.

PAY IN THE WIDER SHELL CONTEXT

Being able to share in the success of Shell is important across the workforce. The Executive Directors, Executive Committee and most Shell employees have the same annual bonus scorecard. That helps drive a shared culture and alignment with Shell's purpose, strategy and values and allows employees to share in the same success as the most senior employees in Shell. In addition, around 20% of our employees are granted performance share awards on similar terms to the conditions that also apply to the Executive Directors through the LTIP. This means that many of our employees will have a significant variable pay outcome this year.

CEO pay ratio and internal proportionality

We have sought to be transparent about our Executive Directors' pay and the wider context. In our 2017 Directors' Remuneration Report, we published an illustration of the CEO pay ratio calculated against our global workforce relative to pay ratios in FTSE 30 companies. We are building on that this year by voluntarily disclosing a pay ratio calculated in accordance with requirements introduced by the UK Companies (Miscellaneous Reporting) Regulations.

Using this new methodology, the UK CEO pay ratio when compared against the median employee is 143 (full details can be found on page 138). This is comparable to our global workforce ratio of 149. This global ratio has increased compared to the 2017 global ratio, largely because of the vesting level of the 2016 LTIP.

REMCO believes in reward packages that are externally competitive and internally proportionate, meaning the CEO is the employee with the highest proportion of variable pay as he has the highest level of responsibility. Accordingly, in years when that variable pay is high, such as 2018, the ratio will be high. In years when the variable pay is low, the ratio will follow.

We reviewed Shell's CEO pay ratio externally against the ratios that we see in other FTSE 30 companies, which we calculated based on their disclosed employee numbers and employee costs. We believe our ratio is consistent with those seen in other FTSE 30 companies, although it is challenging to draw a meaningful comparison given the different markets and industries in which they operate. REMCO looks forward to seeing how this disclosure develops as the new UK reporting requirements take hold.

CEO: Pay ratio

2018 CEO single total figure against actual average global employee costs



- ◆ Shell minimum pay ratio [A]
- ◆ Shell 2017 CEO global pay ratio [B]
- ◆ Shell 2018 CEO global pay ratio [C]
- ◆ Shell maximum pay ratio [D]

[A] Based on CEO 'minimum' pay scenario as disclosed on page 143 compared to the average global employee cost in 2018.

[B] Based on the 2017 CEO single total figure compared to the average global employee cost in 2017.

[C] Based on the 2018 CEO single total figure compared to the average global employee cost in 2018.

[D] Based on CEO 'maximum' pay scenario as disclosed on page 143 compared to the average global employee cost in 2018. The 2018 single figure ratio exceeds this theoretical maximum as the theoretical maximum excludes share price appreciation and dividends.

Gender Pay

Shell is committed to offering highly competitive reward packages and fair, non-discriminatory pay practices in every market where we employ people. We see diversity and inclusion as central to the ongoing success of the Company and are pleased to see a reduction in the mean gender pay gap for Shell companies in the UK in 2018, falling from 22.2% in the 2017 report to 18.6% in the 2018 report, published in accordance with the reporting required under the UK Equality Act 2010 (Gender Pay Gap Information) Regulations Act 2017.

This improvement reflects the work Shell is doing to encourage greater diversity. In the last 10 years, the proportion of women occupying senior leadership roles in the UK has increased from 17.7% in 2008 to 28.1% in 2018. Globally, women hold many senior positions including the role of CFO, and of Country Chair in the UK, USA and the Netherlands.

You will note, that the CFO's total remuneration for 2018 is significantly lower than the CEO's. This is principally because the LTIP grants that are now vesting were made in 2016, prior to her appointment as CFO and were accordingly lower in accordance with our principle of internally proportionate pay that increases with seniority.

As a company, we have more work to do. The pay gap will be influenced by changes to our business in the UK, as well as to our policies, so we do not expect progress to be linear. However, Shell aims to play a leading role in closing the gender gap in engineering and technology through the increased representation of women at all levels in our industry. REMCO has confidence in the policies Shell is putting in place to achieve that.

REMUNERATION POLICY

REMCO believes that the Company's strategy should be determined first, and then a remuneration policy should be set that helps deliver that strategy. Shell has three strategic ambitions that position it well for the future: to be a world-class investment case while thriving in the energy transition and maintaining a strong societal licence to operate. These are inextricably connected. However, we know that our long-term success depends on our ability to anticipate and meet future energy needs as the world works to reduce carbon emissions. REMCO has therefore been working to strengthen our remuneration arrangements to support this longer-term outlook.

Energy Transition

To date, our Remuneration Policy has reflected Shell's ambition to thrive through the transition to lower-carbon energy in the following ways:

- The inclusion of GHG intensity measures in the bonus scorecard to measure performance on the direct and indirect emissions produced by our operations. These measures already cover around 90% of Shell's operated portfolio emissions and the scorecard applies to around 55,000 employees;
- The CEO's and CFO's personal performance goals based on successfully thriving in the transition to lower-carbon energy have been considered when determining the individual performance factor for their annual bonuses;
- A strong alignment to shareholder interests with a high shareholding requirement level of 700% for the CEO. In addition, 50% of annual bonus is delivered in shares to be held for three years, and the LTIP has a three-year vesting period followed by a three-year holding period.

In 2017, Shell was the first international oil and gas company to set the ambition to reduce the NCF of the energy products it sells (a carbon intensity measure that takes into account their full life-cycle emissions including customers' emissions associated with using them) in the period to 2050. We will do that in step with society's drive to meet the goals of the Paris Agreement on climate change.

In 2018, Shell took a major step forward in delivering our strategy by announcing plans to link nearer-term targets to reduce the NCF of the energy products we sell to executive remuneration. We made this announcement in a joint statement with institutional investors on behalf of Climate Action 100+, an initiative led by institutional shareholders.

The current shareholder approved Remuneration Policy provides REMCO with the ability to set performance conditions for LTIP awards. We have

been encouraged by the strong support we have received from shareholders and have accelerated our plans, on this and some other policy matters, by including an energy transition condition in the performance conditions for the 2019 LTIP grant. This condition will initially have a 10% weighting and our intention is to increase this over time.

We discussed our approach with our major shareholders and they have helped shape our decisions, including whether it should be incorporated to the LTIP or part of a separate plan. We decided to use the existing LTIP plan to ensure integrated thinking with our world-class investment case conditions and to avoid the complexity of multiple pay structures.

The energy transition condition will apply to the Executive Directors, Executive Committee members and around 150 of Shell's senior executives in 2019. From 2020, subject to any required staff consultation, we intend to incorporate the energy transition condition into the performance share awards made to around 16,000 employees globally.

The energy transition condition will include our first three-year target towards achieving our ambition to reduce the NCF of the energy products we sell. This target is set as a range aligned to the NCF reduction trajectory that we published in 2017. This approach will cover the total emissions associated with the consumption of the energy products Shell sells, across their full life cycle, extending the focus well beyond the GHG intensity measure included in the annual bonus scorecard. The energy transition condition will also include other measures that will help us achieve our strategic ambitions in the long term, related to the growth of Shell's power business, commercialising opportunities in advanced biofuel technology and the development of systems to capture and absorb carbon. The measures were chosen in conjunction with the CSRC and are intended to focus on those elements that will make the most impact in achieving our ambition. As ever, Shell will exercise prudence and any investment decisions will have stringent value creation requirements, as does any other investment. Further information is provided on page 129.

We expect that we will have much to learn about the transition to lower-carbon energy, as it evolves. There is no right or perfect answer, but it is important that we start this journey and we will learn more as we proceed. Accordingly, REMCO expects that the energy transition performance condition will evolve over time, and that we will use the measures and target as guidance, rather than applying a formulaic vesting outcome, when making our decisions.

Other Policy Matters

As well as the work on the energy transition, REMCO has continued the remainder of its work on the new policy to be put to shareholder vote at the 2020 AGM. I want to update you on some of the areas we have discussed and decisions we have made.

We have heard concerns from some shareholders about the asymmetric annual bonus structure for the CEO, whereby more than half the maximum bonus (250% of base) can be earned for on-target performance (150% of base). This is a result of asymmetry in the bonus structure whereby the maximum award is less than two times the target award. This asymmetry was created in 2008, when REMCO increased the target to align to market pay but did not increase the maximum opportunity, given its desire to exercise restraint on the overall pay opportunity. Notwithstanding the reasons noted above why this asymmetry arose, REMCO has determined, having discussed the issue with shareholders, that the target bonus for the CEO will be reduced from 150% to 125% for the

2019 performance year onwards to reinstate symmetry in the bonus structure. REMCO considers that the total remuneration opportunity for the CEO remains competitive. As REMCO believes this is the appropriate decision, and this change can be made within the existing approved policy, REMCO decided not to wait until the next policy vote, but to accelerate implementation in the same way that it has for the energy transition condition in the LTIP.

Similarly, REMCO heard shareholder feedback that our annual bonus structure was too complex. Again, with effect from the 2019 performance year, REMCO has removed the individual performance multiplier currently used to reflect the CEO and CFO's individual performance, thus making Shell and Executive Director performance inextricably connected. This was discussed with major shareholders in my November investor roadshow.

In addition to introducing an energy transition performance condition, REMCO also reviewed the remainder of the performance measures under the LTIP. As a result of the new condition, the weighting of our other LTIP measures have been rebalanced. REMCO determined that it would retain the same vesting structure for the TSR, ROACE growth and CFFO growth measures in 2019. REMCO noted some shareholder concerns regarding the level of vesting for threshold performance. We believe that consistently beating two of the world's best companies, on a range of key financial metrics is a good outcome. Our LTIP is designed to be challenging, as evidenced by the 10-year historic vesting level noted above. We believe the view that the concept of threshold being a "minimum acceptable level" stems from plan designs with much wider comparator groups and often with single focus measures. Further details on Shell's LTIP can be found at pages 134 and 142-143.

REMCO considered whether the current approach to FCF in the LTIP, where we measure performance on an absolute basis, remained the correct measure. This measure was introduced in response to Shell's specific priorities to restructure its enlarged portfolio, complete \$30 billion of divestments and reduce debt following the BG deal. When REMCO introduced a FCF measure into the LTIP in 2017, shareholders advised this be measured on an absolute basis, in line with the realisation of the divestment programme to reduce gearing following the BG acquisition. As this is now complete, REMCO engaged shareholders about whether and how to retain the FCF measure. A number of shareholders agreed that absolute FCF is a key measure of the use of capital to drive shareholder value, and a good balance to relative CFFO, which captures operational outperformance. We therefore retained absolute FCF as a performance condition in the 2019 LTIP and will continue to review LTIP measures further for the 2020 policy.

REMCO has further work to do in preparing for the new policy to be put to shareholder vote at the 2020 AGM and this will continue during 2019. However, in implementing a set of key decisions in 2019, a year earlier than planned, REMCO is confident Executive Director pay is well-positioned to the market and well aligned with shareholder interests.

LOOKING AHEAD

The year ahead promises to be a busy one, as we look to ensure that we take into account all the evolving UK corporate governance requirements and finalise our proposals for the 2020 policy review to be put to shareholders at the 2020 AGM. I look forward to an ongoing dialogue with our shareholders and will use our engagement sessions as an opportunity to gather your valuable feedback.

THIS REPORT

This Directors' Remuneration Report for 2018 has been prepared in accordance with relevant UK corporate governance and legal requirements, in particular Schedule 8 of The Large and Medium-sized Companies and Groups (Accounts and Reports) Regulations 2008 (as amended). The Board has approved this report.

This report consists of two further sections:

- the Annual Report on Remuneration (describing 2018 remuneration as well as the planned implementation of the Directors' Remuneration Policy in 2019) which will be subject to an advisory vote at the 2019 AGM; and
- the Directors' Remuneration Policy which was approved by shareholders at the 2017 AGM and is included for reference.

Gerard Kleisterlee

Chair of REMCO
March 13, 2019

Annual Report on Remuneration

The Annual Report on Remuneration sets out:

- REMCO and its responsibilities and activities;
- an illustration of Shell's strategy and link to remuneration and a summary of remuneration policy implementation in 2018 and 2019;
- the statement of the planned implementation of policy in 2019; and
- Directors' remuneration for 2018.

The base currency in this Annual Report on Remuneration is the euro, as this is the currency of the base salary of the Executive Directors. Where amounts are shown in other currencies, an average exchange rate for the relevant year is used, unless a specific date is stated, in which case the average exchange rate for the specific date is used.

REMUNERATION COMMITTEE

The following Directors were members of REMCO during 2018:

- Gerard Kleisterlee (Chair of REMCO);
- Catherine J. Hughes;
- Sir Nigel Sheinwald; and
- Gerrit Zalm.

Biographies of the current members are given on pages 82-87; REMCO meeting attendance is given on page 100.

REMCO's key responsibilities in respect of Executive Directors include:

- setting the remuneration policy;
- agreeing performance frameworks, setting targets and reviewing performance;
- determining actual remuneration and benefits; and
- determining contractual terms.

In addition, REMCO has the responsibility for determining the Chair of the Board's remuneration and for recommending and monitoring the level and structure of remuneration for Senior Management.

REMCO operates within its terms of reference, which are regularly reviewed. They were last updated on March 13, 2019 and are available at www.shell.com.

Advice from within Shell on various subjects, including the Executive Directors' annual bonus scorecard architecture and the remuneration of Senior Management, was provided by:

- Ben van Beurden, CEO;
- Ronan Cassidy, Chief Human Resources & Corporate Officer and Secretary to REMCO; and
- Stephanie Boyde, Executive Vice President Remuneration & HR Operations.

The Chair of the Board and the CEO were consulted on remuneration proposals affecting the CEO and the CFO, respectively.

Following a competitive tender process for a shortlist of advisors approved by REMCO, PwC was selected by management to provide external advice regarding developments in remuneration market practice and Shell's remuneration structures. This selection was on the basis of credentials for assessing the risk profile of policies and their knowledge of investors' expectations and international market practice in the oil industry and other long-term businesses. PwC is a member of the Remuneration Consultants Group and operates under the group's Code of Conduct when providing

consulting advice to clients. REMCO is satisfied that the advice provided was objective and independent. The total fees paid to PwC in relation to the advice were £60,965 (excluding value-added tax). PwC provided other consultancy and accountancy services to Shell during the year. However, REMCO is satisfied that this does not compromise the independence of the advice provided to REMCO on executive remuneration matters.

REMCO also met with Andrew Ninian from the Investment Association in July, for a discussion regarding shareholder views on executive director remuneration practices and developments. No fee was paid for this meeting.

During 2018, REMCO met five times and its activities included:

- setting annual bonus performance measures and targets;
- deciding on base salaries for the CEO and the CFO;
- determining the 2017 annual bonus outcomes;
- determining vesting of the 2015 LTIP award for the CEO and the CFO;
- approving the 2017 Directors' Remuneration Report;
- discussing outcome of 2018 AGM voting on remuneration and consulting with major shareholders;
- tracking external developments and assessing their impact on Shell's Remuneration Policy;
- considering the energy transition in the context of long-term remuneration; and
- reviewing and considering the Directors' Remuneration Policy in preparation for the 2020 AGM vote.

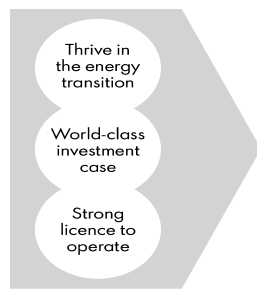
PRINCIPLES

The principles underpinning the Remuneration Committee's approach to executive remuneration serve as the foundation for everything we do and are listed below.

- Alignment with Shell's strategy: the Executive Directors' compensation package should be strongly linked to the achievement of stretching targets that are seen as indicators of the execution of Shell's strategy.
- Pay for performance: the majority of the Executive Directors' compensation (excluding benefits and pensions) should be linked directly to Shell's performance through variable pay instruments.
- Competitiveness: remuneration levels should be determined by reference internally against Shell's Senior Management and externally against companies of comparable size, complexity and global scope.
- Long-term creation of shareholder value: Executive Directors should align their interests with those of shareholders by holding shares in Royal Dutch Shell plc (the Company).
- Consistency: the remuneration structure for Executive Directors should generally be consistent with the remuneration structure for Shell's Senior Management. This consistency builds a culture of alignment with Shell's purpose and a common approach to sharing in Shell's success.
- Compliance: decisions should be made in the context of the Shell General Business Principles and Code of Conduct. Additionally, REMCO should ensure compliance with applicable laws and corporate governance requirements when designing and implementing policies and plans.
- Risk assessment: the remuneration structures and rewards should meet risk-assessment tests to ensure that shareholder interests are safeguarded and that inappropriate actions are avoided.

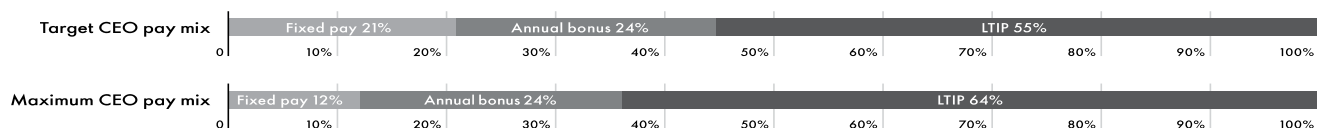
Strategy and link to 2018 remuneration

Strategy



How the strategy links to the CEO's variable pay

CEO INDIVIDUAL PERFORMANCE	The vision for thriving in the energy transition is led by the CEO and embedded in his individual performance targets.
LONG-TERM INCENTIVE PLAN	World-class investment metrics such as cash generation and capital discipline, as well as value created for shareholders, are included in the LTIP.
ANNUAL BONUS	Licence to operate measures such as operational excellence and sustainable development are included in the scorecard. These measures are key building blocks to being a world-class investment and support our journey to thrive in the energy transition.



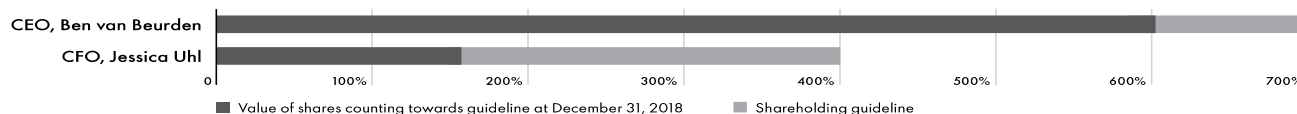
See "CEO pay scenarios" on page 143.

Remuneration at a glance

	2018	2019	2020	2021	2022	2023
FIXED PAY	Base salary: CEO: €1,527,000 CFO: €995,000 Benefits: Typically include: car allowance, transport between home and office, and medical insurance. Pension: Retirement benefits maintained in base country pension arrangements.	Base pay: CEO: €1,557,000 (+2.0%) CFO: €1,015,000 (+2.0%) Benefits: No change Pension: No change				
ANNUAL BONUS	Bonus opportunity as a percentage of salary: Target: CEO: 150% CFO: 120% Maximum: CEO: 250% CFO: 240% Award: CEO: 196% CFO: 156% Performance measures: CFFO - 30% Operational excellence - 50% Sustainable development - 20% Subject to malus and clawback	Target: CEO: 125% (reduced) CFO: 120% Maximum: CEO: 250% CFO: 240% Performance measures: No change				
LONG-TERM INCENTIVE PLAN	LTIP award as a percentage of salary: Target: CEO: 340% CFO: 270% Maximum: CEO: 680% CFO: 540% Performance measures: Absolute FCF: 25% Relative TSR: 25% Relative ROACE growth: 25% Relative CFFO growth: 25% Subject to malus and clawback	LTIP award as a percentage of salary: No change Performance measures: Absolute FCF: 22.5% Relative TSR: 22.5% Relative ROACE growth: 22.5% Relative CFFO growth: 22.5% Absolute Energy transition: 10%				
		Shares subject to three-year holding period which applies beyond an Executive Director's tenure				
		Three-year performance period			Vested shares subject to three-year holding period which applies beyond an Executive Director's tenure	

Executive Directors' shareholding

% of base salary



2016 LTIP vesting

	2016	2017	2018	2019	2020	2021
Performance measures (all relative): TSR: 30% EPS growth: 30% CFFO growth: 20% ROACE growth: 20% Subject to malus and clawback		Award: Ben van Beurden: 236,302 RDS A shares		1 March 2019 Vesting 190% TSR: 1 st EPS growth: 1 st CFFO growth: 1 st ROACE growth: 2 nd		
		Three-year performance period followed by two-year holding period (voluntarily extended to three years)				

STATEMENT OF 2019 PLANNED IMPLEMENTATION OF POLICY

The Directors' Remuneration Policy on pages 139-147 took effect from May 23, 2017 and will be effective until the 2020 AGM. This section describes elements that apply for 2019, some of which have changed compared with 2018 within the boundaries of the policy.

COMPARATOR GROUP

The 2019 benchmarking comparator group is unchanged from 2018 and consists of the other oil majors (BP, Chevron, ExxonMobil, and Total) as well as a selection of major Europe-based companies.

The comparator companies are reviewed by REMCO as part of the Remuneration Policy review every three years. The other oil majors are included in the comparator group as these represent our closest direct competitors operating in similar market conditions. The Europe-based companies are selected based on their size, complexity and global reach. REMCO uses benchmark data from these companies only as a guide to the competitiveness of the remuneration packages. We do not seek to position our remuneration at any defined point against the benchmarked positions.

2019 European comparator group

Allianz	Daimler	Rio Tinto
AstraZeneca	Diageo	Roche
BAT	GlaxoSmithKline	Siemens
Bayer	Nestle	Unilever
BHP Billiton	Novartis	Vodafone

EXECUTIVE DIRECTORS

Salaries

Effective from January 1, 2019, the base salaries were set at €1,557,000 (+2.0%) for Ben van Beurden, CEO and at €1,015,000 (+2.0%) for Jessica Uhl, CFO.

When determining base salaries, REMCO mainly considered: the external market positioning of the Executive Directors' compensation packages; Senior Management salaries; the planned average increases for 2019 for other employees across three major countries (the Netherlands, the UK and the USA); the impact of the increase on other elements of the package; the current economic conditions; and Shell's own performance.

Annual bonus

There are no changes to the scorecard measures and weightings for 2019. The measures remain aligned with a number of our performance indicators set out on pages 27-28, and are comprised of cash flow from operating activities, operational excellence and sustainable development measures.

Annual bonus scorecard targets are not disclosed prospectively because to do so in a meaningful manner would require the disclosure of commercially sensitive information. As in previous years, scorecard targets will be disclosed in the subsequent Directors' Remuneration Report when they are no longer deemed to be commercially sensitive.

For the 2019 performance year, REMCO has removed the personal performance element of the annual bonus award for the Executive Directors.

This change was discussed with shareholders during 2018 and is intended to simplify the bonus award structure in response to shareholder feedback.

In addition, the target annual bonus for the CEO has been reduced from 150% to 125% of base salary. The maximum opportunity remains unchanged and is therefore now mathematically twice the target. This change is intended to eliminate the asymmetry that existing in the bonus award structure for the CEO and is discussed in the REMCO Chair's Statement on pages 124-125.

As in the prior year, 50% of the annual bonus awarded for the 2019 performance year will be delivered in cash and 50% will be delivered in shares subject to a three-year holding period which remains in force beyond an Executive Director's tenure.

Long-term Incentive Plan

On February 1, 2019, a conditional award of performance shares under the LTIP was made to the Executive Directors resulting in 194,625 Royal Dutch Shell plc A shares (A shares) being conditionally awarded to Ben van Beurden and 49,927 Royal Dutch Shell plc A American Depositary Shares (A ADSs) to Jessica Uhl. The award had a face value of 340% (maximum vesting outcome 680%) of the base salary for the CEO and 270% (maximum vesting outcome 540%) of the base salary for the CFO, excluding potential share price appreciation and dividends. In making these awards, REMCO considered the Company's share price and determined that there was no significant share price volatility that would require an adjustment to the size of the awards.

For LTIP awards made in 2019, performance will be assessed over a three-year period based on four financial measures and a new energy transition condition. They are also subject to a TSR underpin such that if the TSR ranking is fourth or fifth, the level of the 2019 award that can vest on the basis of the other measures will be capped at 50% of the maximum.

Further information on the rationale for the new performance condition is set out in the REMCO Chair's statement on page 124 and the remaining financial measures were rebalanced accordingly. Vested LTIP shares are subject to a three-year holding period which remains in force beyond an Executive Director's tenure.

Relative performance measures:

- TSR, calculated in dollars using a 90-day averaging period around the start and end of the performance period (22.5%);
- ROACE growth (22.5%). For this purpose, in order to facilitate the comparison, the calculation of ROACE differs from that described in "Performance indicators" on page 27 as there is no adjustment for after-tax interest expense; and
- Cash flow from operating activities growth (22.5%).

The vesting schedule for the relative measures is unchanged from 2018.

Absolute performance measures:

- FCF (22.5%);
- Energy Transition (10%)

FCF

The target for FCF, along with the ranges for threshold and outstanding performance, will be set by reference to Shell's annual operating plans, being the aggregate of our plan FCF targets over the three-year performance period. Given FCF is heavily influenced by the volatility of oil prices, the annual operating plans are updated each year to set an annual target to reflect a changing oil price premise. As a result, FCF targets are set annually for each annual operating plan and will only be disclosed in aggregate retrospectively after the three-year period. While consideration has been given to setting a three-year target at the outset, REMCO has determined that such an approach would result in adjustments for oil price premise and other matters at the end of the period, given the unpredictability and volatility in oil prices. REMCO has a long-standing 'no adjustments' policy and therefore believes a more appropriate target-setting approach is to set the target based on the aggregation of the annual operating plans.

20% of the maximum available under this measure will be payable for threshold performance, rising to full vesting of that measure for outstanding performance. A straight-line vesting schedule will apply for performance between threshold and outstanding.

Energy transition

This is a new condition introduced for the 2019 award within the boundaries of the approved policy. The energy transition condition is focussed on Shell's strategic ambition to thrive in the energy transition and supports delivery of Shell's NCF ambition. The condition will consist of a mix of measures that set the foundations to contribute to Shell's strategic ambitions in the longer term:

- **Net Carbon Footprint:** a target for reducing the NCF of the energy products Shell sells (a carbon intensity measure that takes into account their full life-cycle emissions, including customers' emissions associated with using them). For the 2019 award, the target is a 2-3% reduction in NCF from the 2016 baseline NCF, which is disclosed in the 2018 Climate change section on page 77. This target is aligned with the trajectory of our NCF ambition set out in November 2017;
- **The growth of our power business:** Growth in the use of electricity and continuing decarbonisation of electricity by shifting to renewables and gas-fired power generation is recognised as a key lever in all decarbonisation scenarios. Our ambition to grow the power business is based on selective investments in generation, as well as in business models based on reselling power generated by others;
- **Advanced biofuels technology:** Biofuels are expected to play a valuable role in the changing energy mix and are likely to be the key decarbonisation levers for sectors that need to continue to use liquid fuels in the foreseeable future, such as some segments of transport and industry. For society and for Shell, commercialisation of advanced biofuel technology is one of the most important steps in energy transition;
- **The development of systems to capture and absorb carbon:** Carbon capture and storage (CCS) and carbon sinks, such as nature-based solutions are required as part of the global response to climate change.

Energy transition targets, with the exception of the NCF target, are considered to be commercially sensitive and will therefore be disclosed retrospectively. Annual updates on our progress in relation to the measures will be provided.

The vesting outcome for the part of the award weighted to the energy transition condition will range from 0% to 200% and will be determined by REMCO in its

sole discretion, after taking advice from the CSRC. In doing so, REMCO will take into account, in relation to each element, progress over the Performance Period relative to nearer-term aims in pursuit of the long-term ambition announced by Shell to reduce the NCF of energy products sold by around half by 2050, and by around 20% by 2035, in step with society's drive to meet the goals of the Paris Agreement. However, it is important to note that performance against these elements will serve simply as a starting point for REMCO who will also take into account any other considerations they deem appropriate, including (without limitation) the relative importance of these elements in meeting the long-term ambition announced by Shell. For example, REMCO may decide to allocate a greater emphasis to overall performance in relation to the NCF than the other three elements.

Adjustment (malus) and recovery (clawback)

Variable pay elements are subject to adjustment (malus) and recovery (clawback) provisions, which may apply in case of direct responsibility or supervisory accountability.

REMCO may adjust an award, for example by lapsing part or all of it, reducing the number of shares which would otherwise vest, by imposing additional conditions on it, or imposing a new holding period. Award adjustments may be made as a result of: Shell restating the relevant year(s) financial statements due to material non-compliance with any financial reporting requirement; an individual's misconduct or misconduct through the individual's direction or non-direction, which influenced the measures and outcomes used in determining the individual's annual bonus or LTIP outcome; any material breach of health and safety or environment regulations; serious reputational damage to Shell; material failure of risk management; and other exceptional events at the discretion of REMCO.

Adjustment may also apply after employment ends if the individual: (a) breaches any provision of his/her employment contract which applies after cessation of employment or any provision of an agreement entered into on termination of employment; (b) is found to have committed fraud or dishonesty with respect to Shell; (c) wilfully damaged the assets of or engaged in misconduct which, in any material respect, is or was injurious to Shell; (d) wrongfully disclosed or used any proprietary or confidential information which is related to the business, properties or affairs of Shell and the release of which is detrimental, in any material respect, to the competitive position or goodwill of Shell; (e) engaged in any activity which, in any material respect, reasonably constituted a conflict with the interests of Shell; or (f) breached any business principle or a term of any code of conduct applicable to employees or former employees of Shell.

Clawback applies in case of restatement of financial statements due to material non-compliance with any financial reporting requirement or as a result of the individual's misconduct or misconduct through the individual's direction or non-direction, which influenced the measures and outcomes used in determining his/her annual bonus or LTIP outcome.

Pension

Ben van Beurden's pension arrangements comprise a defined benefit plan for which the maximum pensionable salary has increased to €96,729 and a net pay defined contribution pension plan with an employer contribution of 27% of salary in excess of €96,729. This is the standard contribution percentage applicable to all of the Company's participating Netherlands employees in Ben van Beurden's age bracket. There are no changes to the pension plans in which Jessica Uhl participates.

NON-EXECUTIVE DIRECTORS' FEES

Non-executive Directors' fees 2018

	€	Other fees
Chair of the Board	850,000	Non-executive
Non-executive Director	135,000	Directors
Senior Independent Director	55,000	receive an
Audit Committee		additional fee
Chair [A]	60,000	of €5,000 for
Member	25,000	any Board
Corporate and Social Responsibility Committee		meeting involving
Chair [A]	35,000	intercontinental
Member	17,250	travel – except
Nomination and Succession Committee		for one
Chair [A]	25,000	meeting
Member	12,000	a year held in a
Remuneration Committee		location other
Chair [A]	40,000	than The
Member	17,250	Hague.

[A] The chair of a committee does not receive an additional fee for membership of that committee

The Chair's fee is determined by REMCO and the annual fee for Charles O. Holliday was set at €850,000 upon appointment in 2015 and will remain unchanged for 2019. The Chair of the Board does not receive any additional fee for chairing the Nomination and Succession Committee or attending any other Board committee meeting.

The other Non-executive Directors receive a basic fee. There are additional fees for the Senior Independent Director, a Board committee chair or a Board committee membership for each committee. Non-executive Directors receive an additional fee of €5,000 for any Board meeting involving intercontinental travel, except for one meeting a year held in a location other than The Hague. Business expenses (including transport between home and office and occasional business-required spouse travel) and associated tax are paid or reimbursed by the Company. The Chair has use of Company-provided accommodation in The Hague.

The Board reviews Non-executive Directors' fees periodically to ensure that they are aligned with those of other major listed companies using the FTSE 30 and the Europe Comparator group as the primary points of reference. The last review was carried out in 2018 and fees will remain unchanged for 2019.

DIRECTORS' REMUNERATION FOR 2018

NON-EXECUTIVE DIRECTORS' REMUNERATION FOR 2018

Single total figure of remuneration for Non-executive Directors (audited)						€ thousand
	Fees		Taxable benefits[A]		Total	
	2018	2017	2018	2017	2018	2017
Ann Godbehere [B]	97	N/A	—	N/A	97	N/A
Euleen Goh	220	225	—	—	220	225
Charles O. Holliday	850	850	75[C]	83	925	933
Catherine J. Hughes [D]	199	99	7	—	206	99
Gerard Kleisterlee	216	196	7	—	223	196
Roberto Setubal [E]	190	50	—	3	190	53
Sir Nigel Sheinwald	180	163	6	6	186	169
Linda G. Stuntz	197	202	13	—	210	202
Hans Wijers	93	237	1	7	94	244
Gerrit Zalm [F]	177	117	—	—	177	117

[A] UK regulations require the inclusion of benefits where these would be taxable in the UK, on the assumption that Directors are tax residents in the UK. On this premise, the taxable benefits include the cost of Non-executive Director's occasional business-required spouse travel. The Company also pays for travel between home and the head office in The Hague, where Board and committee meetings are typically held, as well as related hotel and subsistence costs. For consistency, these business expenses are not reported as taxable benefits as for most Non-executive Directors this is international travel and hence would not be taxable in the UK.

[B] Appointed as a Director with effect from May 23, 2018.

[C] Including the use of an apartment (2018: €70,015; 2017: €68,612).

[D] Appointed as a Director with effect from June 1, 2017.

[E] Appointed as a Director with effect from October 1, 2017.

[F] As a result of arrangements related to Gerrit Zalm's attendance at Board and committee meetings detailed in "Corporate governance" on page 79 of the 2017 Annual Report, his fees for 2017 have been pro-rated and exclude the period July 1, 2017 to October 24, 2017.

EXECUTIVE DIRECTORS' REMUNERATION FOR 2018

Single total figure of remuneration for Executive Directors (audited)					€ thousand
	Ben van Beurden		Jessica Uhl		
	2018	2017	2018	2017	
Salaries	1,527	1,490	995	796	
Taxable benefits	32	30	49	44	
Total fixed remuneration	1,559	1,520	1,044	840	
Annual bonus [A]	3,000	3,000	1,550	1,050	
LTIP [B]	15,209	4,021	1,783	623	
Total variable remuneration	18,209	7,021	3,333	1,673	
Total direct remuneration	19,768	8,541	4,376	2,513	
Pension [C]	369	368	196	287	
Tax equalisation [D]	—	—	289	194	
Total remuneration including pension and tax equalisation	20,138	8,909	4,862	2,994	
in dollars	23,790	10,067	5,744	3,383	
in sterling	17,817	7,811	4,302	2,625	

[A] The full value of the bonus, comprising both the 50% delivered in cash and 50% bonus delivered in shares. For 2018, the market price of A shares on February 21, 2019 (€27.745), was used to determine the number of shares delivered, resulting in 28,045 A shares for Ben van Beurden and 14,490 A shares for Jessica Uhl. For 2017, 50% of the bonus was delivered in shares and the market price of A shares on February 22, 2018 (€25.75), was used to determine the number of shares delivered, resulting in 30,102 A shares for Ben van Beurden and 10,536 A shares for Jessica Uhl.

[B] Remuneration for performance periods of more than one year, comprising the value of released LTIP awards. The amounts reported for 2018 relate to the 2016 LTIP award, which vested on March 1, 2019, at the market price of €27.335 and \$62.32 for A shares and A ADSs respectively. The value in respect of the LTIP is calculated as the product of: the number of shares of the original award multiplied by the vesting percentage; plus accrued dividend shares; and the market price of A shares or A ADSs at the vesting date. The market price of A ADSs is converted into euros using the exchange rate on the respective date. Ben van Beurden also received a release of 107,791 RDS A shares under the 2016 Deferred Bonus Plan (DBP) on March 1, 2019. The original deferred bonus share awards, which are those represented by the deferred bonus and dividend shares accrued on these shares are not considered as long-term remuneration as they relate to the 2015 short-term annual bonus value.

[C] For Ben van Beurden, the amount reported for pension consists of a net pay defined contribution amount of €369,400. The amount to be reported for his defined benefit pension accrual is zero, calculated in accordance with UK reporting requirements. For Jessica Uhl, the amount reported for pension consists of a defined contribution amount of €94,050 and a defined benefit pension accrual of €102,436.

[D] Includes tax equalisation of pension contributions to foreign pension plan(s), when they are taxable above a certain pensionable salary threshold or once a double tax treaty exemption ceases, under Dutch law. Tax equalisation is applied for the loss of pension relief for members of a foreign pension plan(s) in their host country.

NOTES TO THE SINGLE TOTAL FIGURE OF REMUNERATION FOR EXECUTIVE DIRECTORS TABLE (AUDITED)

Salaries

As disclosed in the 2017 Directors' Remuneration Report, REMCO set Ben van Beurden's base salary for 2018 at €1,527,000 (+2.5% compared with 2017) effective from January 1, 2018, and Jessica Uhl's base salary at €995,000 (+1.5% compared with 2017) effective from January 1, 2018.

Taxable benefits

Executive Directors received car allowances or lease cars, transport between home and office, occasional business-required spouse travel, as well as employer contributions to life and medical insurance plans.

Annual bonus

The scorecard measures are grouped into three sections: financial, operational excellence and sustainable development. At the beginning of the year, REMCO sets a target range and weighting for each measure. The actual outcome for each measure results in a score of between zero and two, with a score of one representing "on target". These scores are multiplied by the respective weighting of each measure and aggregated, resulting in a mathematical scorecard outcome of between zero and two. REMCO may then make an adjustment to the overall scorecard outcome in view of the wider business performance for the year.

For 2018, the Executive Director's individual performance was also considered in determining their annual bonus through the application of a multiplier between zero and 1.2.

50% of the annual bonus is delivered in shares subject to a three-year holding period which extends beyond the Executive Directors tenure.

Determination of the 2018 annual bonus

The mathematical scorecard outcome for 2018 was 1.31 and REMCO approved this outcome without exercising discretion. REMCO's considerations in determining this outcome are outlined in the REMCO Chair's statement on page 120.

REMCO determined an individual performance factor of 1.0 for the CEO and a final bonus outcome of €3,000,000 which is 131% of target and 79% of maximum. REMCO considered that it was comfortable with the outcome for 2018 in the context of business performance and noted that the higher percentage of maximum relative to the percentage of target is a consequence of having capped the maximum bonus opportunity at less than 50% of the target award. This asymmetry between target and maximum was created in 2008, when REMCO increased the target to align to market pay but did not increase the maximum opportunity given its exercise of restraint on the overall pay opportunity. For 2019, the target has been reduced to eliminate this asymmetry. Further commentary is provided in the REMCO Chair's statement on pages 124-125.

REMCO determined an individual performance factor of 1.0 for the CFO and determined a final bonus outcome of €1,550,000 which is 130% of target and 65% of maximum.

The table below summarises the 2018 annual bonus scorecard measures including their weightings, targets and outcomes. Charts illustrating the calculation of the final 2018 bonus payable to the CEO and CFO are also provided.

2018 annual bonus outcome (audited)

Measures	Weight (% of scorecard)	Threshold	Target set	Outstanding	Result achieved	Score (0-2)
Cash flow from operating activities (\$ billion)	30%	36	42	48	53	2.00
Operational excellence	50%					1.04
Production (kboe/d)	12.5%	3,638	3,750	3,863	3,666	0.25
LNG liquefaction volumes (mtpa)	12.5%	32.5	33.5	34.5	34.3	1.82
Refinery and chemical plant availability (%)	12.5%	90.1	92.1	94.1	91.9	0.90
Project delivery on schedule (%)	6.25%	60	80	100	75	0.75
Project delivery on budget (%)	6.25%	105	100	95	97	1.65
Sustainable development	20%					0.95
Total recordable case frequency (injuries/million hours)	5%	0.9	0.7	0.5	0.9	0.00
Operational Tier 1 and 2 process safety events (number)	5%	155	125	95	121	1.13
Upstream and Integrated Gas GHG intensity (tonnes of CO ₂ equivalent/tonne of hydrocarbon production available for sale)	4%	0.172	0.164	0.156	0.158	1.75
Refining GHG intensity (tonnes CO ₂ equivalent per Solomon's Utilized Equivalent Distillation Capacity (UEDC™))	4%	1.10	1.05	1.00	1.05	1.00
Chemicals GHG intensity (tonnes CO ₂ equivalent/tonne of petrochemicals production)	2%	1.02	0.97	0.92	0.96	1.20
	100%					

Mathematical scorecard outcome

1.31

2018 bonus outcome calculation

BEN VAN BEURDEN

Target bonus: €1,527,000 (base salary) x 150% = €2,290,500	×	2018 scorecard result = 1.31	×	Individual performance factor = 1.0	=	€3,000,000 [A] (196% of base salary)
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JESSICA UHL

Target bonus: €995,000 (base salary) x 120% = €1,194,000	×	2018 scorecard result = 1.31	×	Individual performance factor = 1.0	=	€1,550,000 [A] (156% of base salary)
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[A] Rounded downwards to the nearest €50,000, and half was delivered in shares subject to a three-year holding period which extends beyond the Executive Director's tenure.

LTIP vesting

In 2016, Ben van Beurden and Jessica Uhl were each granted a conditional award of performance shares under the LTIP, with a maximum vesting of two times the original award, excluding share price appreciation and dividends.

For Ben van Beurden, this award was based on 340% of his base salary, giving a maximum vesting of 680%, excluding share price appreciation and dividends. Given volatility in the share price in the decision-making period leading up to the 2016 award, REMCO decided that the share price used to determine the number of shares awarded should be based on a three-month average rather than its usual practice of the share price at the date of award. Ultimately by the time of award, the volatility had diminished with the difference between the three-month average used and the spot rate being less than 4%.

Jessica Uhl was granted an award of 13,800 A ADSs prior to her appointment as an Executive Director.

The LTIP vesting outcome at the end of the performance period (January 1, 2016, to December 31, 2018) is illustrated in the following LTIP vesting outcome table. REMCO also considered the underlying performance of Shell and decided to vest 190% of shares under the LTIP, using no discretion, resulting in 556,406 A shares for Ben van Beurden and 32,501 A ADSs for Jessica Uhl. At vesting, these shares (including accrued dividend shares) had a value of €15,209,358 and \$2,025,462 respectively. In making their decision, REMCO noted the high value of the vesting, including share price appreciation and determined that the vesting was warranted as it reflected Shell's outstanding performance in the period. It also considered the impact of share buybacks in 2018 on the vesting outcome of EPS measure. REMCO noted that the share buybacks had no impact on the rank order of Shell against the comparator group (BP, Chevron, ExxonMobil and Total) and determined that it was appropriate for the EPS measure to vest without adjustment. Further information on REMCO's considerations is provided in the REMCO Chair's statement on pages 121-122.

The CEO's vested awards are subject to a further two-year holding period. However, he has voluntarily agreed to hold these shares for three years in accordance with the holding policy introduced with the 2017 remuneration policy.

LTIP vesting outcome

Measures	Weighting	Rank versus peers	Vesting
TSR	30%	1 2 3 4 5	60%
EPS growth [A]	30%	1 2 3 4 5	60%
ROACE growth	20%	1 2 3 4 5	30%
Cash flow from operating activities growth	20%	1 2 3 4 5	40%
Total			190%

[A] Diluted EPS growth on a current cost of supplies basis.

Pension

Ben van Beurden's pension arrangements comprise a defined benefit plan with a maximum pensionable salary of €94,446, and a net pay defined contribution pension plan with a 2018 employer contribution of 24% of salary in excess of €94,446 up to April 30, 2018 and 27% from May 1, 2018, when he entered the next age bracket for contribution levels, with the option to take cash as an alternative to pension contributions (in either case subject to income tax). The CEO has elected to take his benefit in the form of contributions throughout 2018. The employer contribution levels are in line with those applicable to other Netherlands-based employees.

Jessica Uhl is a member of the Shell US retirement benefit arrangements, which include the Shell Pension Plan, a defined benefit plan, and a defined contribution plan with an employer contribution of 10% of salary. As for all other pre-2013 members of the Shell Pension Plan, she has an annual choice of two accrual formulas with different forms of benefits, one in the form of a lifetime annuity and the other allows for a lump-sum payment. She elected to accrue benefits for 2018 under the latter. She also has a deferred Dutch defined benefit pension plan, as a result of a prior Shell assignment on local Dutch terms and conditions. The employer contribution levels are lower than those applicable to other US employees and Jessica Uhl's bonus is not pensionable as an Executive Director.

See further details on pension arrangements on pages 137-138.

Scheme interests awarded to Executive Directors in 2018 (audited)

Scheme interest type	Type of interest awarded	End of performance period	Target award[A]	Potential amount vesting	
				Minimum performance (% of shares awarded)[B]	Maximum performance (% of shares of the target award[A])[C]
LTIP	Performance shares	December 31, 2020	Ben van Beurden: 190,001 A shares, equivalent to 3.4 x base salary or €5,191,800. Jessica Uhl: 49,857 A ADS shares, equivalent to 2.7 x base salary or €2,686,500.	0%	Maximum number of shares vesting is 200% of the shares awarded, before dividends, equivalent to €10,383,600 for Ben van Beurden and €5,373,000 for Jessica Uhl.

[A] The award for Ben van Beurden was based on the closing market price on February 2, 2018, for A shares of €27.325. The award for Jessica Uhl was based on the closing market price on February 2, 2018, for A ADSs of \$67.300.

[B] Minimum performance relates to the lowest level of achievement, for which no reward is given.

[C] The equivalent values exclude share price movements and accrued dividend shares.

The measures and weightings applying to LTIP awards made in 2018 were: FCF (25%); TSR (25%); ROACE growth (25%) and cash flow from operating activities growth (25%).

The LTIP will vest on the basis of the absolute performance of FCF and the ranking of the three relative performance measures, as indicated in the table below.

2018 LTIP measures and vesting schedule

PERFORMANCE MEASURE AND WEIGHTING	LINK TO STRATEGY	VESTING SCHEDULE (% OF INITIAL LTIP AWARD)
Free cash flow (25%)	Recognition of the importance of generating cash after net capital expenditure to service and reduce debt, pay dividends, buy back shares and make future capital investments.	Maximum – 200% Target – 100% Threshold – 40% Below threshold – 0%
TSR (25%)	Assessment of actual wealth created for shareholders.	1st – 200% 2nd – 150% 3rd – 80% 4th or 5th – nil
ROACE growth (25%)	Indicator of capital discipline.	
Cash flow from operating activities growth (25%)	Source of capital expenditure commitments which support sustainable growth based on portfolio and cost management.	

If the TSR ranking is fourth or fifth, the level of the award that can vest on the basis of the three other measures will be capped at 50% of the maximum.

FCF progress

As the FCF target is set based on the cumulative total of the FCF targets for the operating plans of the relevant performance periods these targets are not disclosed at award. Disclosure of the target and progress towards it will be made public at the end of each year in the performance period.

FCF progress to date on outstanding 2017 LTIP award

At December 31, 2018, FCF performance is above target, at more than \$27 billion for 2017 (target \$21 billion) and \$39 billion for 2018 (target \$29 billion). As one year of FCF performance remains, and 75% of the award is subject to relative performance conditions, this does not reflect the potential vesting of the award.

FCF progress to date on outstanding 2018 LTIP award

At December 31, 2018, FCF performance, at more than \$39 billion for 2018, is above target (\$29 billion). As two years of FCF performance remain, and 75% of the award is subject to relative performance conditions, this does not reflect the potential vesting of the award.

To deliver the shares under the LTIP, market-purchased shares are used rather than the issuing of new shares. This approach does not have a dilutive impact on shareholders.

STATEMENT OF DIRECTORS' SHAREHOLDING AND SHARE INTERESTS (AUDITED)

SHAREHOLDING GUIDELINES

REMCO believes that Executive Directors should align their interests with those of shareholders by holding shares in the Company. The CEO is expected to build a shareholding with a value of 700% of base salary, and other Executive Directors 400% of base salary. Only unfettered shares count. Unvested shares held under DBP and any shares delivered but subject to holding requirements, also count towards the guidelines. As at March 4, 2019, Ben van Beurden held shares worth 1,177% of his base salary. At March 4, 2019, Jessica Uhl held 311% of her base salary and has until March 2022 to meet her shareholding target. Non-executive Directors are encouraged to hold shares with a value equivalent to 100% of their fixed annual fee and maintain that holding during their tenure.

Executive Directors' shareholding (audited)

	Shareholding guideline (% of base salary)	Value of shares counting towards guideline (% of base salary at December 31, 2018)[A]
Ben van Beurden	700%	602%
Jessica Uhl	400%	157%

[A] Representing the value of share interests and the estimated after-tax value of DBP shares (not subject to performance conditions).

DIRECTORS' SHARE INTERESTS

The interests (in shares of the Company or calculated equivalents) of the Directors in office during 2018, including any interests of their connected persons, are set out in the table below.

Directors' share interests [A] (audited)

	January 1, 2018		December 31, 2018	
	A shares	B shares	A shares	B shares
Ben van Beurden	132,979	–	281,524	–
Ann Godbehere	–	4,700[B]	–	4,700[B]
Euleen Goh	–	12,895	–	12,895
Charles O. Holliday	–	50,000[C]	–	50,000[C]
Catherine J. Hughes	4,080	46,904	4,080	46,904
Gerard Kleisterlee	5,254	–	5,254	–
Roberto Setubal	15,400[D]	–	15,400[D]	–
Sir Nigel Sheinwald	–	1,124	–	1,124
Linda G. Stuntz	–	12,400[E]	–	12,400[E]
Jessica Uhl	35,460[F]	–	61,097[G]	–
Hans Wijers	5,251	–	5,251	–
Gerrit Zalm	2,026	–	2,026	–

[A] Includes vested LTIP awards subject to holding conditions. Excludes unvested interests in shares awarded under the LTIP and DBP.

[B] Interests at May 23, 2018, when she was appointed as a Director. Held as 2,350 ADSs (RDS.B ADS). Each RDS.B represents two B shares.

[C] Held as 25,000 ADSs (RDS.B ADS). Each RDS.B ADS represents two B shares.

[D] Held as 7,700 ADSs (RDS.A ADS). Each RDS.A represents two A shares.

[E] Held as 6,200 ADSs (RDS.B ADS). Each RDS.B represents two B shares.

[F] Held as 17,730 ADS (RDS.A ADS). Each RDS.A represents two A shares.

[G] Held as 10,941 RDS A shares and 25,078 ADS (RDS.A ADS). Each RDS.A represents two A shares.

The changes in Directors' share interests during the period from December 31, 2018, to March 13, 2019, were that Ben van Beurden's interests increased by 363,171 A shares, as 50% of his 2018 annual bonus was delivered in shares on February 22, 2019, and the 2016 LTIP and DBP

awards vested on March 1, 2019. Jessica Uhl's interests increased by 14,490 A shares, as 50% of her 2018 annual bonus was delivered in shares on February 22, 2019, and by 19,711 A ADSs as the 2016 LTIP award vested on March 1, 2019. The value of shares counting towards the shareholding guideline (as a % of base salary) for the CEO and CFO, were 1,177% and 311%, respectively, at March 4, 2019.

At March 13, 2019, the Directors and Senior Management (pages 82-90) of the Company beneficially owned, individually and in aggregate (including shares under option), less than 1% of the total shares of each class of the Company shares outstanding.

Directors' scheme interests (audited)

	LTIP/PSP subject to performance conditions[B]		DBP not subject to performance conditions[C]		Share plan interests[A]	
					Total	
	2018	2017	2018	2017	2018	2017
Ben van Beurden	715,591	707,727	159,617	226,196	875,208	933,923
Jessica Uhl	130,180	89,901	—	—	130,180	89,901

[A] Includes unvested long-term incentive awards and notional dividend shares accrued at December 31. Interests are shown on the basis of the original awards. The shares subject to performance conditions can vest at between 0% and 200%. Dividend shares accumulate each year on an assumed notional LTIP/DBP award. Such dividend shares are disclosed and recorded on the basis of the number of shares conditionally awarded but, when an award vests, dividend shares will be awarded only in relation to vested shares as if the vested shares were held from the award date. Shares released during the year are included in the "Directors' share interests" table.

[B] Total number of unvested LTIP shares at December 31, including dividend shares accrued on the original LTIP award.

[C] The number of shares deferred from the bonus (original DBP award) and the dividend shares accrued on these at December 31. Delivery of the original DBP award and the related accrued dividend shares is not subject to performance conditions.

DILUTION

In any 10-year period, no more than 5% of the issued ordinary share capital of the Company may be issued or issuable under executive (discretionary) share plans adopted by the Company, or 10% when aggregated with awards under any other employee share plan operated by the Company. To date, no shareholder dilution has resulted from these plans, although it is permitted under the rules of the plans subject to these limits.

PAYMENTS TO PAST DIRECTORS (AUDITED)

Simon Henry left the Company on June 30, 2017. On March 1, 2019, Simon Henry's 2016 LTIP award vested at 190%. The award vested on a pro-rata basis for the period of employment during the performance period. The value at vesting of the LTIP shares was £3,920,034.

In addition, on March 1, 2019, Simon Henry's 2016 DBP award vested and he received a total of 63,399 RDS B shares, with a value at vesting of £1,499,069. While the original award of 51,393 RDS B shares was reported in the 2016 Directors' Remuneration Report, it is included again here in the interest of transparency. The remaining 12,006 RDS B shares represent accrued dividends paid in accordance with the plan and the value of these at vesting was £238,882.

Payments below €5,000 are not reported as they are considered de minimis.

TSR PERFORMANCE AND CEO PAY PERFORMANCE GRAPHS

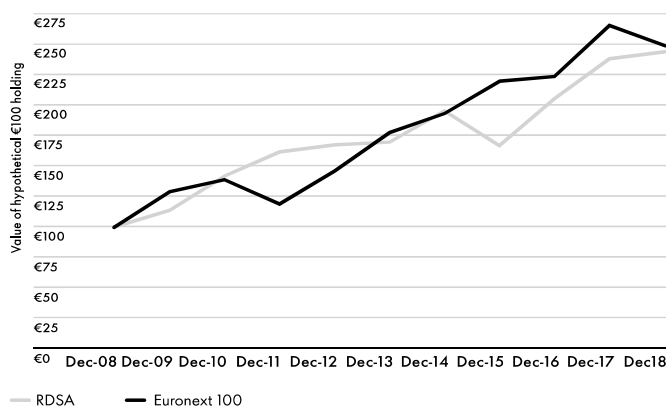
The graphs compare the TSR performance of the Company over the past nine financial years with that of the companies comprising the Euronext 100 and the FTSE 100 share indices. The Board regards these indices as appropriate broad market equity indices for comparison, as they are the leading market indices in the Company's home markets.

DIRECTORS' SCHEME INTERESTS

The table below shows the aggregate position for Directors' interests under share schemes at December 31. These are A shares for Ben van Beurden, and A ADSs for Jessica Uhl. During the period from December 31, 2018, to March 13, 2019, scheme interests have changed as a result of the vesting of the 2016 LTIP and DBP awards on March 1, 2019, and the 2019 LTIP awards made on February 1, 2019, as described on pages 135-136 and 128 respectively.

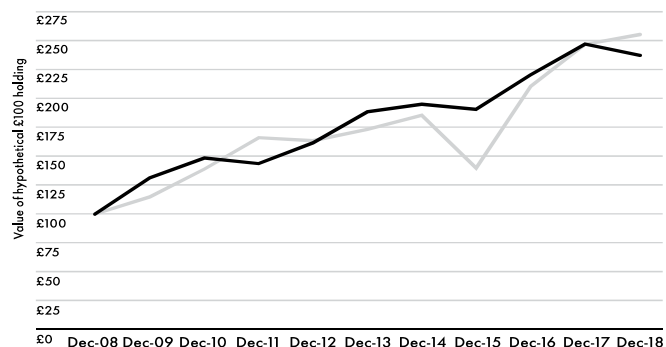
Historical TSR performance (RDSA)

Growth in the value of a hypothetical €100 holding over nine years
Euronext 100 comparison based on 30 trading day average values



Historical TSR performance (RDSB)

Growth in the value of a hypothetical £100 holding over nine years
FTSE 100 comparison based on 30 trading day average values



CEO PAY OUTCOMES

The following table sets out the single total figure of remuneration, and the annual bonus payout and long-term incentive (LTI) vesting rates compared with the respective maximum opportunity, for the CEO for the last ten years.

CEO pay outcomes

Year		Single total figure of remuneration CEO (€000)	Annual bonus payout against maximum opportunity	LTI vesting rates against maximum opportunity
2018	Ben van Beurden	20,138	79%	95%
2017	Ben van Beurden	8,909	81%	35%
2016	Ben van Beurden	8,593	66%	42%
2015	Ben van Beurden	5,576	98%	8%
2014	Ben van Beurden	24,198	94%	49%
2013	Peter Voser	8,456	44%	30%
2012	Peter Voser	18,246	83%	88%
2011	Peter Voser	9,941	90%	30%
2010	Peter Voser	10,611	100%	75%
2009	Peter Voser	6,228	50%	0%
2009	Jeroen van der Veer	3,748	66%	0%

Peter Voser stood down on December 31, 2013 and was succeeded by Ben van Beurden. Ben van Beurden's single figure for 2014 was impacted by the increase in pension accrual (€10.695 million) calculated under the UK reporting regulations and tax equalisation (€7.905 million) as a result of his promotion and prior assignment to the UK. Jeroen van der Veer stood down on July 1, 2009, and Peter Voser took over from that date. Only remuneration relating to their position as CEO is included.

CHANGE IN REMUNERATION OF CEO AND EMPLOYEES FROM 2017 TO 2018

The CEO data compares the remuneration of Ben van Beurden for 2018 with 2017. The comparator group consists of local employees in the Netherlands, the UK and the USA. This is considered to be a suitable employee comparator group because: these are countries with a significant Shell employee base; a large proportion of senior managers come from these countries; and REMCO considers remuneration levels in these countries when setting base salaries for Executive Directors.

Taxable benefits are those that align with the definition of taxable benefits applying in the respective country. In line with the "Single total figure of remuneration for Executive Directors" table, the annual bonus is included in the year in which it was earned.

Change in remuneration of CEO and employees

	CEO	Employees
Salaries	2.5%	2.3%
Taxable benefits [A]	8.2%	24.9%
Annual bonus	0.0%	18.5%

[A] The increase in taxable benefits is principally due to the buyout of a medical insurance allowance paid to Netherlands employees who received a one-off payment of €4,935 in 2018.

RELATIVE IMPORTANCE OF SPEND ON PAY

Distributions to shareholders by way of dividends and share buybacks and remuneration paid to or receivable by employees for the last five years are set out below, together with annual percentage changes.

Relative importance of spend on pay

Year	Dividends and share buybacks[A]		Spend on pay (all employees)[B]	
	\$ billion	Annual change	\$ billion	Annual change
2018	20.2	29%	13.4	-6%
2017	15.6	4%	14.3	-9%
2016	15.0	25%	15.7	-8%
2015	12.0	-18%	17.1	5%
2014	14.6	-14%	16.4	0%

[A] Dividends paid, which includes the dividends settled in shares via our Scrip Dividend Programme, and repurchases of shares as reported in the "Consolidated Statement of Changes in Equity".

[B] Employee costs, excluding redundancy costs, as reported in Note 26 to the "Consolidated Financial Statements".

Spend on pay can be compared with the major costs associated with generating income by referring to the "Consolidated Statement of Income". Over the last five years, the average spend on pay was 5% of the major costs of generating income. These costs are considered to be the sum of: purchases; production and manufacturing expenses; selling, distribution and administrative expenses; research and development; exploration; and depreciation, depletion and amortisation.

TOTAL PENSION ENTITLEMENTS (AUDITED)

During 2018, Ben van Beurden and Jessica Uhl accrued retirement benefits under defined benefit plans. The pension accrued under these plans at December 31, 2018, is set out below. The exchange rates used for conversion into euros and dollars are at December 31, 2018.

Accrued pension (audited)

	Thousand		
	Local	€	\$
Ben van Beurden [A]	€1,271	€1,271	\$1,453
Jessica Uhl [B]	\$1,231	€1,077	\$1,231

[A] The accrued retirement benefits are disclosed on a per annum basis. The normal retirement age for Ben van Beurden's defined benefit pension scheme increased from age 67 to age 68, effective January 1, 2018, due to changes in Dutch pension regulations. In accordance with all other Dutch employees similarly affected, his previously accrued pension benefits were adjusted on actuarial neutral terms to take account of the increase in retirement age. His accrued pension was €1,256,450 at December 31, 2017, after adjustment to take account of the increase in retirement age.

[B] Jessica Uhl has an annual choice of two accrual formulas with different forms of benefits, one in the form of a lifetime annuity and the other allows for a lump-sum payment. She elected to accrue benefits for 2018 under the latter and the eventual lump sum benefit is shown. She also has a deferred Dutch defined benefit pension plan, as a result of a prior Shell assignment on local Dutch terms and conditions. The age at which Jessica Uhl can receive any pension benefit without an actuarial reduction under this plan is 60. The value of the deferred pension benefit is €3,252 per annum.

The age at which Ben van Beurden can receive any pension benefit without actuarial reduction is 68 and for Jessica Uhl this is age 65 (in the US retirement plans). Any pension benefits on early retirement are reduced using actuarial factors to reflect early payment. No payments were made in 2018 regarding early retirement or in lieu of retirement benefits.

BEN VAN BEURDEN

Ben van Beurden is a member of the "Stichting Shell Pensioenfonds", the pension plan for Shell employees in the Netherlands who joined before July 2013 that provides benefits in defined benefit form. Ben van Beurden is also a member of the Shell net pay defined contribution pension plan in the Netherlands with effect from January 1, 2015. The contribution rates for Ben van Beurden are the same as those applicable to other employees in the Netherlands in his age bracket.

JESSICA UHL

Jessica Uhl is a member of the Shell US retirement benefit arrangements, which include the Shell Pension Plan, a defined benefit plan, and the Shell Provident Fund, a defined contribution plan. The contribution rates for Jessica Uhl are the same as those applicable to other US employees, however, unlike other US participants, Jessica Uhl's pensionable compensation does not include the annual bonus. She also has a deferred Dutch defined benefit pension plan, as a result of a prior Shell assignment on local Dutch terms and conditions.

EXTERNAL APPOINTMENTS

The Board considers external appointments to be valuable in broadening Executive Directors' knowledge and experience. The number of outside directorships is generally limited to one. Exceptions to this are considered in the final year of employment. The Board must explicitly approve such appointments. Executive Directors are allowed to retain any cash or share-based compensation they receive from such external board directorships.

STATEMENT OF VOTING AT 2018 AGM

The Company's 2018 AGM was held on May 22, 2018, in the Netherlands. The result of the poll in respect of Directors' remuneration was as follows:

Approval of Directors' Remuneration Report

Votes	Number	Percentage
For	3,886,764,832	74.78%
Against	1,311,138,457	25.22%
Total cast	5,197,903,289[A]	100.00%
Withheld [B]	41,918,978	

[A] Representing 62.31% of issued share capital.

[B] A vote "withheld" is not a vote under English law and is not counted in the calculation of the proportion of the votes "for" and "against" a resolution.

The result of the poll in respect of the Directors' Remuneration Policy approved at the 2017 AGM was as follows:

Approval of Directors' Remuneration Policy

Votes	Number	Percentage
For	4,064,279,529	92.34%
Against	337,361,835	7.66%
Total cast	4,401,641,364[A]	100.00%
Withheld [B]	37,303,341	

[A] Representing 53.53% of issued share capital.

[B] A vote "withheld" is not a vote under English law and is not counted in the calculation of the proportion of the votes "for" and "against" a resolution.

At our May 2018 Annual General Meeting, we received shareholder support of 74.78% for the Directors' Remuneration Report for the year ended December 31, 2017, which followed a vote of 92% support for our Remuneration Policy the prior year.

REMCO was deeply disappointed with this voting outcome and during 2018 engaged with shareholders to understand the reason for the outcome. Having analysed our voting results, we believe that more than 90% of our largest shareholders supported the Remuneration Report and this was reinforced in our engagement with them. No further specific action in relation to our largest shareholders in relation to this outcome was taken and we continue to engage with them on a regular basis.

A number of our smaller shareholders voted against the 2017 report and we met face to face with some of them in our recent shareholder engagement roadshow. It was clear that when we engage with shareholders, it helps to create a better understanding of our decisions and we are keen to reach deeper into our share register to engage with more shareholders on remuneration matters. For example, the REMCO Chair released a video, which can be found on the Shell investor relations website, in February 2019 to provide an explanation of some of the work done and decisions made by REMCO in the year. We will continue to work on ways to achieve this.

We also had a helpful and constructive meeting with the proxy agency that made an Against recommendation. We appreciate their desire for improved disclosures and the evolution of their views on our policy structure.

One of the most important points to emerge from these discussions was that we should have been clearer about why the tragic June 2017 incident in Pakistan involving a sub-contractor road tanker did not lead to a reduced bonus outcome. Further comments about this are in the REMCO Chair's statement.

DIRECTORS' EMPLOYMENT ARRANGEMENTS AND LETTERS OF APPOINTMENT

Executive Directors are employed for an indefinite period. Non-executive Directors, including the Chair, have letters of appointment. Details of Executive Directors' employment arrangements can be found in the Directors' Remuneration Policy on page 145. Further details of Non-executive Directors' terms of appointment can be found in the "Directors' Report" on page 93 and the "Corporate governance" report on page 97.

COMPENSATION OF DIRECTORS AND SENIOR MANAGEMENT

During the year ended December 31, 2018, Shell paid and/or accrued compensation totalling \$43 million (2017: \$46 million) to Directors and Senior Management for services in all capacities while serving as a Director or member of Senior Management, including \$3 million (2017: \$3 million) accrued to provide pension, retirement and similar benefits. The amounts stated are those recognised in Shell's income on an IFRS basis. See Note 27 to the "Consolidated Financial Statements". Personal loans or guarantees were not provided to Directors or Senior Management.

CEO PAY RATIO

The UK Companies (Miscellaneous Reporting) Regulations 2018 introduces a requirement for certain UK listed companies to publish the ratio of CEO pay to UK staff pay. Although not required to be published until reporting on the 2019 financial year, REMCO believes in transparency on remuneration matters and has chosen to start disclosing from this year:

Year	Option [A]	25 th Percentile pay ratio	Median pay ratio	75 th pay ratio
2018	A	202:1	143:1	92:1

[A] The calculation methodology used is Option A as defined in the Regulations. Under this approach, the full-time equivalent total remuneration for all UK employees for the relevant financial year is determined. Using this data, companies will rank the data and identify employees whose remuneration places them at median, 25th and 75th percentile. Three pay ratios are then calculated against CEO 'single figure' total remuneration.

Directors' Remuneration Policy

This section describes the Directors' Remuneration Policy (Policy) as published in the 2016 Directors' Remuneration Report which, following shareholder approval at the 2017 Annual General Meeting (AGM), came into effect from May 23, 2017, and will be effective until the 2020 AGM, unless a further policy is proposed by the Company and approved by shareholders in the meantime.

The Policy has evolved over time, to align with: Shell's strategy, market practice and shareholders' views. A consistent and competitive structure, which applies across the workforce, is also a core principle. This consistency allows for a culture of shared purpose and performance.

The Executive Directors' remuneration structure is made up of a fixed element of basic pay and the majority of the package is tied to two variable elements: the annual bonus (50% delivered in shares) and the Long-term Incentive Plan (LTIP). Variable pay outcomes are conditional on the successful execution of the operating plan in the short term and financial out-performance over the longer term. Furthermore, the award of shares under the bonus and LTIP, along with significant shareholding requirements, is intended to ensure executives build up a sizeable shareholding stake in Royal Dutch Shell plc (the Company) and experience the same outcomes as shareholders.

EXECUTIVE DIRECTORS

Executive Directors' remuneration policy table

Element	Purpose and link to strategy	Maximum opportunity	Operation and performance measurement
Base salary and pensionable base salary	Provides a fixed level of earnings to attract and retain Executive Directors.	We have retained a maximum of €2,000,000, for both base salary and pensionable base salary, in the context of current peer group base salary levels.	<p>Base salary and pensionable base salary (where different) are reviewed annually with salary adjustments effective from January 1 each year.</p> <p>In making salary determinations, the Remuneration Committee (REMCO) will consider:</p> <ul style="list-style-type: none"> the market positioning of the Executive Directors' compensation packages; comparison with Senior Management salaries; the employee context, and planned average salary increase for other employees across three major countries – the Netherlands, the UK and the USA; the experience, skills and performance of the Executive Director, or any change in the scope and responsibility of their role; general economic conditions, Shell's financial performance, and governance trends; and the impact of salary increases on pension benefits and other elements of the package. <p>For Executive Directors employed outside their base country, euro base salaries are translated into their home currencies for pension plan purposes. Pensionable base salaries are maintained in line with euro base salaries taking into account exchange rate fluctuations and other factors as determined by REMCO.</p>
Benefits	Provides benefits, in line with those applicable to the wider workforce, in order to attract and retain Executive Directors.	The maximum opportunity is the cost to the Company of providing the relevant benefit as specified in Shell's standard policies. These costs can vary.	<p>Benefits that Executive Directors typically receive include car allowances and transport to and from home and office, risk benefits (for example ill-health, disability or death-in-service), as well as employer contributions to insurance plans (such as medical). Precise benefits will depend on the Executive Director's specific circumstances such as nationality, country of residence, length of service, and family status. Post-retirement benefits such as healthcare may be applicable under their country-specific policies. Shell's mobility policies may apply, such as for relocation and tax return preparation support, as may tax equalisation related to expatriate employment prior to Board appointment, or in other limited circumstances to offset double taxation. REMCO may adjust the range and scope of the benefits offered in the context of developments for other employees in relevant countries. Personal loans or guarantees are not provided to Executive Directors.</p> <p>In relation to the maximum opportunity, and by way of example, maximum relocation and tax equalisation settlement benefits will be the grossed-up cost of meeting the specific Executive Director's costs incurred as a result of appointment and any associated relocation (in line with Shell's policy), and will depend on a variety of factors such as length of service, salary increase on appointment and the tax regime in place at the time.</p>

Executive Directors' remuneration policy table (continued)

Element	Purpose and link to strategy	Maximum opportunity	Operation and performance measurement
Annual bonus	<p>Rewards the delivery of short-term operational targets as derived from Shell's operating plan as well as individual contribution to Shell.</p> <p>To reinforce alignment with shareholder interests, 50% is delivered in cash and 50% is delivered in shares. Shares are subject to a three-year holding period, which applies beyond an Executive Director's tenure.</p>	<p>Maximum bonus (as a percentage of base salary):</p> <ul style="list-style-type: none"> Chief Executive Officer (CEO): 250% Other Executive Directors: 240% <p>Target levels (as a percentage of base salary):</p> <ul style="list-style-type: none"> CEO: 150% Other Executive Directors: 120% 	<ul style="list-style-type: none"> The bonus is determined by reference to performance from January 1 to December 31 each year. Annual bonus = base salary x target bonus % x scorecard result (0-2); adjusted for individual performance with a 0-1.2 multiplier. Taking the Shell operating plan into consideration, REMCO sets stretching scorecard targets and weightings which support the delivery of the strategy. Measures are related to financial performance, operational excellence and sustainable development. Indicative weightings are 30%, 50% and 20% respectively. This balance ensures that the achievement of short-term financial performance does not undermine future shareholder value creation. Stretching individual targets are also set. Scorecard targets will be disclosed in a subsequent Directors' Remuneration Report when they are no longer deemed to be commercially sensitive. Individual performance is reflected by adjusting the bonus outcome. Upward adjustment is capped at 20% and subject to the overall maximum bonus cap. The CEO's maximum bonus is asymmetrically capped at 250%. There is no limit to downward adjustment. There are no prescribed thresholds or minimum levels of performance that equate to a prescribed payment under the Policy and this structure can result in no bonus being awarded. The annual bonus is subject to malus provisions before it is delivered and to clawback provisions thereafter. REMCO retains the ability to adjust performance measure targets and weightings year by year within the overall target and maximum payouts approved in the Policy.
LTIP	<p>Rewards longer-term value creation linked to Shell's strategy. The measures predominantly focus on financial growth and increases in value compared with the other oil majors.</p> <p>To reinforce alignment with shareholder interests, shares delivered from vested LTIP awards are subject to a three-year holding period, which applies beyond an Executive Director's tenure.</p>	<p>Awards may be made up to a value of 400% of base salary.</p> <p>2017 Award levels:</p> <ul style="list-style-type: none"> CEO: 340% Other Executive Directors: 270% <p>Awards may vest at up to 200% of the shares originally awarded, plus dividends.</p>	<ul style="list-style-type: none"> Award levels are determined annually by REMCO and are set within the maximum approved in the Policy. Awards may vest between 0% and 200% of the initial award level depending on Shell's performance on either an absolute basis, or on a relative basis against the other oil majors. For 2017, performance is assessed over a three-year period based on absolute free cash flow (FCF), which is the sum of cash flow from operating activities and cash flow from investing activities (25%), and the following relative performance measures: total shareholder return (TSR) (25%), return on average capital employed (ROACE) growth (25%) and cash flow from operating activities growth (25%). Each measure can vest independently, but if the TSR measure does not result in vesting, then the total vesting level will be capped at 50% of the maximum payout. Although it is possible for no LTIP shares to vest, on current measures and weightings, 5% of the maximum LTIP award would vest if there was a threshold vesting outcome in respect of FCF and no vesting on the other measures. Additional shares are released representing the value of dividends payable on the vested shares, as if these had been owned from the award date. Following payment of taxes, delivered shares from LTIP awards must be held for a further three years to align with Shell's longer-term time horizon and strategy. The LTIP award is subject to malus provisions before it is delivered and to clawback provisions thereafter. REMCO may adjust or change the LTIP measures, targets and weightings to ensure continued alignment with Shell's strategy.

Executive Directors' remuneration policy table (continued)

Element	Purpose and link to strategy	Maximum opportunity	Operation and performance measurement
Pension	Provides a competitive retirement provision in line with the individual's base country benefits policy, to attract and retain Executive Directors.	By reference to pensionable base salary, pension accrual and contribution rates and other pensionable elements, as determined by the rules of the base country pension plan of which the Executive Director is a member.	Executive Directors' retirement benefits are maintained in line with those of the wider workforce in their base country. Only base salary is pensionable, unless country plan regulations specify otherwise. The rules of the relevant plans detail the pension benefits which members can receive on retirement (including on ill-health), death or leaving service. REMCO retains the right to amend the form of any Executive Director's pension arrangements where appropriate, for example in response to changes in legislation to ensure the original objective of this element of remuneration is preserved.
Shareholding	Aligns interests of Executive Directors with those of shareholders by creating a connection between individual wealth and Shell's long-term performance.	Shareholding (% of base salary): <ul style="list-style-type: none"> ▪ CEO: 700% ▪ Other Executive Directors: 400% 	Executive Directors are expected to build up their shareholding to the required level over a period of five years from appointment and, once reached, to maintain this level for the full period of their appointment. The intention is for the shareholding guideline to be reached through retention of vested shares from share plans. REMCO will monitor individual progress and retains the ability to adjust the guideline in special circumstances on an individual basis.

NOTES TO THE EXECUTIVE DIRECTORS' REMUNERATION POLICY TABLE

Benefits

Benefits for Executive Directors deemed taxable in the UK are included as taxable benefits in the single total figure of remuneration table. These elements may include transport to and from home and office, the provision of home security, and occasional business-required spouse travel, which are generally considered legitimate business expenses rather than components of remuneration.

Annual bonus

For the 2017 performance year, the scorecard framework will consist of cash flow from operating activities (30% weight), operational excellence (50% weight) and sustainable development (20% weight). REMCO believes it is important for annual variable pay to remain balanced, with operational and environmental components, complementing the LTIP's focus on longer-term financial outcomes. The same annual bonus scorecard approach applies to Senior Management and other senior executives, supporting consistency of remuneration and alignment of objectives.

For future years, the specific measures and weightings for the annual bonus scorecard will be reviewed annually by REMCO and adjusted accordingly to evolve with Shell's strategy and circumstances. The annual review will also consider the scorecard target and outcome history over a decade to ensure that the targets set remain stretching but realistic. REMCO retains the right to exercise its judgement to adjust the mathematical bonus scorecard outcome to ensure that the bonus scorecard outcome for Executive Directors reflects other aspects of Shell's performance which REMCO deems appropriate for the reported year. REMCO is aware that the simple application of arithmetic performance targets may lead to anomalies between business performance and shareholder experience and therefore careful consideration is given to formulaic outcomes. REMCO has a track record of using its discretion to make downward adjustments where appropriate.

2017 annual bonus scorecard measures and weightings

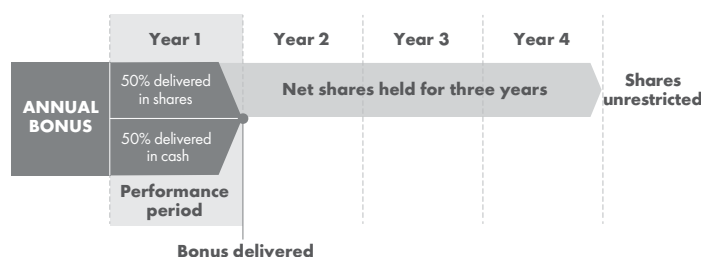
PERFORMANCE MEASURE AND WEIGHTING	LINK TO OPERATING PLAN
Cash flow from operating activities (30%)	This reflects our business performance.
Operational excellence (50%)	Project delivery: Indicator of our ability to deliver projects, on time, and on budget. Operations: Maximising oil and gas production, LNG liquefaction volumes, and the availability of refineries and chemical plants are indicators of the full and effective use of our resources; which in turn generate cash flow.
Sustainable development (20%)	Safety and environmental performance are both core to how we operate. Safety: Is implicit in all our activities. A safe work environment has been, and will always be, an important indicator of Shell's commitment to its employees and contractor staff. Environmental performance: We are managing Shell's carbon intensity as part of the long-term transition to a lower carbon energy system. Therefore greenhouse gas measures are now included.

REMCO strengthens the Executive Directors' individual accountability by increasing or decreasing their annual bonuses to take account of how well they have delivered against their individual performance targets. Shell operates this approach for most of its employees. These individual targets typically relate to qualitative differentiators not already covered by the scorecard. Examples for the Executive Directors have included management of transformative portfolio changes, portfolio development, and organisational and financial leadership. This individual performance element preserves consistency with the wider workforce and reinforces and drives a company-wide culture of performance and behaviour.

Directors' Remuneration Policy Continued

At the end of the one-year performance period, 50% of the annual bonus is delivered in cash and 50% is delivered in shares. Shares are subject to a three-year holding period, which remains in force beyond an Executive Director's tenure.

Bonus time horizon



Long-term Incentive Plan

The LTIP rewards longer-term performance linked to Shell's strategy, which includes cash generation and capital discipline, as well as value created for shareholders.

The LTIP measures are predominantly based on relative outperformance compared with the other oil majors, in line with our strategic intent to be a leader in the oil and gas industry. For 2017, the measures will consist of absolute FCF and relative growth compared with our peers based on the following: TSR, ROACE and cash flow from operating activities. REMCO will regularly review the measures, weightings and comparator group, and retains the right to adjust these to ensure that the LTIP continues to serve its intended purpose and level of challenge.

FCF performance is measured by aggregating annual absolute FCF performance over the three-year performance period and then comparing the outcome to the aggregate of our plan FCF targets over three years. The outstanding (maximum), target and threshold (minimum) levels are declared at the end of the performance period and will be the aggregate respective annual outstanding, target and threshold levels for each year of the performance period. A straight-line vesting schedule will apply for performance between threshold and outstanding. The target, along with the ranges for threshold and outstanding performance, is set by reference to our operating plan and is in line with our cash flow priorities, namely: to service and reduce debt, pay dividends, buy back shares and make future capital investments.

For relative measures, we measure and rank growth based on the data points at the end of the performance period compared with those at the beginning of the period, using publicly reported data. When comparing performance against the other oil majors, the relative performance ranking is as indicated in the table below.

2017 LTIP measures and vesting schedule

PERFORMANCE MEASURE AND WEIGHTING	LINK TO STRATEGY	VESTING SCHEDULE (% OF INITIAL LTIP AWARD)
Free cash flow (25%)	Recognition of the importance of generating cash after net capital expenditure to service and reduce debt, pay dividends, buy back shares and make future capital investments.	Maximum – 200% Target – 100% Threshold – 40% Below threshold – 0%
TSR (25%)	Assessment of actual wealth created for shareholders.	1st – 200% 2nd – 150% 3rd – 80% 4th or 5th – nil
ROACE growth (25%)	Indicator of capital discipline.	
Cash flow from operating activities growth (25%)	Source of capital expenditure commitments which support sustainable growth based on portfolio and cost management.	

TSR underpin

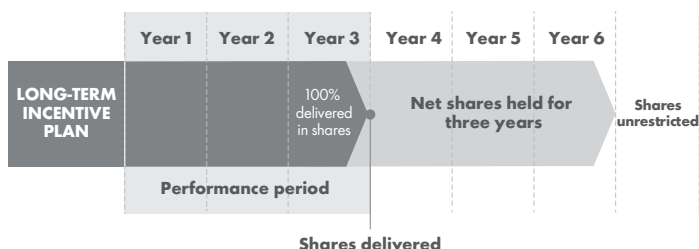
If the TSR ranking is fourth or fifth, the level of the award that can vest on the basis of the three other measures will be capped at 50% of the maximum payout for the LTIP.

Performance outcomes

REMCO retains discretion to adjust the mathematical outcome if it believes that this is distorted by circumstances which are unrelated to performance, for example, reporting changes, ranking clustering, or corporate events in the comparator group. Upward adjustment would only be considered after consultation with major shareholders. An explanation of any such adjustment would be set out in the relevant Directors' Remuneration Report.

LTIP performance is assessed over a three-year period. Vested shares from the LTIP are subject to a further three-year holding period post vesting, which remains in force beyond an Executive Director's tenure. This time horizon has been extended and is deemed to be suitable for incentive purposes, but is recognised as short relative to some of Shell's operations. However, REMCO believes that it provides for broad alignment with shareholder interests when coupled with significant shareholding requirements.

LTIP time horizon



Treatment of outstanding awards

Awards granted prior to the approval and implementation of this Policy and/or prior to an individual becoming an Executive Director will continue to vest and be delivered in accordance with the terms of the original award even if this is not consistent with the terms of this Policy.

As at March 7, 2017, this applies to Executive Directors Ben van Beurden and Simon Henry who each have outstanding awards under the LTIP and DBP. Jessica Uhl, who is appointed an Executive Director with effect from March 9, 2017, has outstanding awards under the LTIP.

Shareholding

REMCO believes significant shareholding by Executive Directors is an important way of ensuring that shareholders and Executive Directors share the same priorities. Shareholding is one of Shell's core remuneration principles as it creates a balanced connection between individual wealth and Shell's long-term performance. This will support effective governance and an ownership mindset. Significant shareholding requirements reflect the performance timescales of Shell and are aligned with absolute shareholder return.

The CEO is expected to build up a shareholding of seven times their base salary over five years from appointment. Other Executive Directors are expected to build up a shareholding of four times their base salary over the same period. In the event of an increase to the guideline multiple of salary, for every additional multiple of salary required, the director will have one extra year to reach the increased guideline, subject to a maximum of five years from the date of the change.

The holding periods for LTIP vested shares and shares delivered as part of the annual bonus continue to apply after Executive Directors leave employment. This is to ensure departing executives continue to have their interests aligned with those of shareholders.

DIFFERENCES FOR EXECUTIVE DIRECTORS FROM OTHER EMPLOYEES

The remuneration structure and approach to setting remuneration levels are consistent across Shell, with consideration given to location, seniority and responsibilities. However, a higher proportion of total remuneration is tied to variable pay for Executive Directors and members of Senior Management.

The salary for each Executive Director is determined based on the indicators in the "Executive Directors' remuneration policy table", which reflect the international nature of the Executive Directors' labour market. The salary for other employees is normally set on a country basis.

Executive Directors are eligible to receive the standard benefits and allowances provided to other staff. The provisions that are not generally available for other employees are described in "Benefits".

The methodology used for determining the annual bonus for Executive Directors is broadly consistent with the approach for Shell employees generally. However, the individual performance factor for Executive Directors is capped at 1.2 and the scorecard used for the majority of Shell staff may differ in the make-up and weighting of the metrics used. Like Executive Directors, members of Senior Management receive 50% of their annual bonus in shares.

Executive Directors are not eligible to receive new awards under employee share plans other than the LTIP, although awards previously granted will continue to vest in accordance with the terms of the original award. Selected employees participate in the Performance Share Plan (PSP). The operation of the PSP is similar to the LTIP, but currently differs, for example, in some performance measures and their relative weightings. As at March 2017, around 55,000 employees participate in one or more of Shell's global share plans and/or incentive plans, further supporting alignment with shareholder interests.

Executive Directors' retirement benefits are maintained in line with those of the wider workforce in their base country. There are no special pension arrangements exclusive to Executive Directors.

ILLUSTRATION OF POTENTIAL REMUNERATION OUTCOMES

The charts below represent estimates under three performance scenarios ("Minimum", "On-target", and "Maximum") of the potential remuneration outcomes for each Executive Director resulting from the application of 2017 base salaries to awards expected to be made in 2017 in accordance with the Policy.

Performance scenarios

SCENARIO	OUTCOME		
Minimum	Fixed remuneration includes 2017 base salaries, 2016 benefits (as reported in the single total figure of remuneration table), with an estimate for the incoming CFO, and a projection of 2017 pension for the CEO and incoming CFO. There is no annual bonus or vesting of the LTIP award.		
	Reflects fixed remuneration, plus on-target 2017 annual bonus and vesting of LTIP award, as percentages of base salary, as follows:		
		CEO	CFO
On-target	Annual incentive	150%	120%
	Long-term incentive	340%	270%
	Reflects fixed remuneration, plus maximum pay-out of 2017 annual bonus and vesting of 200% of original LTIP award, as percentages of base salary, as follows:		
Maximum		CEO	CFO
	Annual incentive	250%	240%
	Long-term incentive	680%	540%

The majority of Executive Directors' remuneration is delivered through variable pay elements, which are conditional on the achievement of stretching targets.

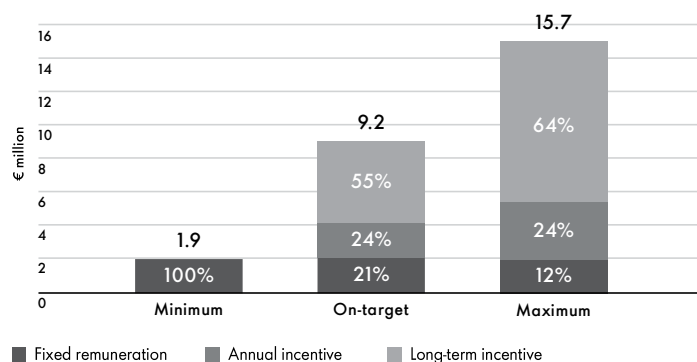
The scenario charts are based on future Policy award levels and are combined with projected single total figures of remuneration. The pay scenarios are forward-looking and only serve to illustrate the future Policy.

Directors' Remuneration Policy Continued

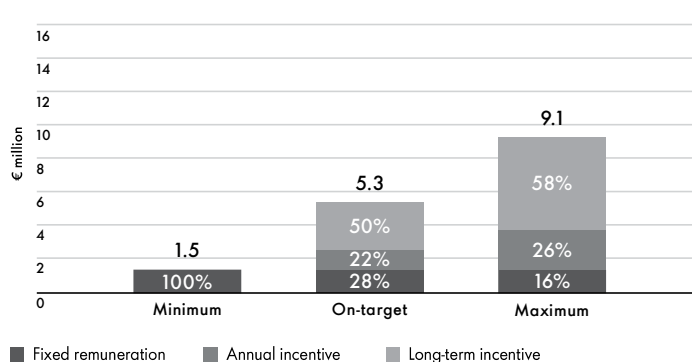
For simplicity, the scenarios assume no share price movement and exclude dividend accrual, for the portion of the bonus paid in shares and the LTIP, although dividend accrual during the performance and holding period

applies. The scenarios are based on the current CEO (Ben van Beurden) and incoming CFO (Jessica Uhl) roles.

CEO pay scenarios



CFO pay scenarios



NON-EXECUTIVE DIRECTORS

Non-executive Directors' remuneration policy table

Fee structure	Approach to setting fees	Other remuneration
<p>Non-executive Directors (NEDs) receive a fixed annual fee for their directorship. The size of the fee will differ based on the position on the Board: Chair of the Board fee or standard Non-executive Director fee.</p> <p>Additional annual fee(s) are payable to any director who serves as Senior Independent Director, a Board committee chair, or a Board committee member.</p> <p>A NED receives either a chair or member fee for each committee. This means that a chair of a committee does not receive both fees.</p> <p>NEDs receive an additional fee for any Board meeting involving intercontinental travel – except for one meeting a year held in a location other than The Hague.</p>	<p>The Chair's fee is determined by REMCO. The Board determines the fees payable to NEDs. The maximum aggregate annual fees will be within the limit specified by the Articles of Association and in accordance with the NEDs' responsibilities and time commitments.</p> <p>The Board reviews NED fees periodically to ensure that they are aligned with those of other major listed companies.</p>	<p>Business expenses incurred in respect of the performance of their duties as a NED will be paid or reimbursed by Shell. Such expenses could include transport between home and office and occasional business-required spouse travel. Where required, the Chair is offered Shell-provided accommodation in The Hague. REMCO has the discretion to offer other benefits to the Chair as appropriate to their circumstances. Where business expenses or benefits create a personal tax liability to the director, Shell may cover the associated tax.</p> <p>The Chair and the other NEDs cannot receive awards under any incentive or performance-based remuneration plans, and personal loans or guarantees are not granted to them.</p> <p>NEDs do not accrue any retirement benefits as a result of their non-executive directorships with Shell.</p> <p>NEDs are encouraged to hold shares with a value equivalent to 100% of their fixed annual fee and maintain that holding during their tenure.</p>

MALUS AND CLAWBACK

Variable pay awards may be made subject to adjustment events. At the discretion of REMCO, such an award may be adjusted before delivery (malus) or reclaimed after delivery (clawback) if an adjustment event occurs. Adjustment events will be specified in award documentation and it is intended that they will, for example, relate to restatement of financial results due to: non-compliance with a financial reporting requirement; or misconduct by an Executive Director or misconduct through their direction or non-direction. REMCO retains the right to alter the list of adjustment events in respect of future awards.

In addition, REMCO will retain discretion in assuring itself that there is satisfactory underlying performance before releasing any variable pay to Executive Directors and may withhold all or some of the bonus or shares awarded if it considers that the underlying performance (financial, environmental, safety or other) of Shell is inadequate.

RECRUITMENT EXECUTIVE DIRECTORS

REMCO determines the remuneration package for new Executive Director appointments. These appointments may involve external or internal recruitment or reflect a change in role of a current Executive Director.

When determining remuneration packages for new Executive Directors, REMCO will seek a balanced outcome which allows Shell to:

- attract and motivate candidates of the right quality;

- take into account the individual's current remuneration package and other contractual entitlements;
- seek a competitive pay position relative to our comparator group, without overpaying;
- encourage relocation if required; and
- honour entitlements (for example, variable remuneration) of internal candidates before their promotion to the Board.
- REMCO will follow the approach set out in the table below when determining the remuneration package for a new Executive Director.

Remuneration package

Component	Approach	Maximum
Ongoing remuneration	The salary, benefits, annual bonus, long-term incentives and pension benefits will be positioned and delivered within the framework of the Executive Directors' remuneration policy.	As stated in the "Executive Directors' remuneration policy table".
Compensation for the forfeiture of any awards under variable remuneration arrangements	To facilitate external recruitment, one-off compensation in consideration for forfeited awards under variable remuneration arrangements entered into with a previous employer may be required. REMCO will use its judgement to determine the appropriate level of compensation by matching the value of any lost awards under variable remuneration arrangements with the candidate's previous employer. This compensation may take the form of a one-off cash payment or an additional award under the LTIP. The compensation can alternatively be based on a newly created long-term incentive plan arrangement where the only participant is the new director.	An amount equal to the value of the forfeited variable remuneration awards, as assessed by REMCO. Consideration will be given to appropriate performance conditions, performance periods and clawback arrangements.
Replacement of forfeited entitlements other than any awards under variable remuneration arrangements	There may also be a need to compensate a new Executive Director in respect of forfeited entitlements other than any awards under variable remuneration arrangements. This could include, for example, pension or contractual entitlements, or other benefits. On recruitment, these entitlements may be replicated within the Executive Directors' remuneration policy or valued by REMCO and compensated in cash. In cases of internal promotion to the Board, any commitments made which cannot be effectively replaced within the Executive Directors' remuneration policy may, at REMCO's discretion, continue to be honoured.	An amount equal to the value of the forfeited entitlements, as assessed by REMCO.
Exceptional recruitment incentive	Apart from the ongoing annual remuneration package and any compensation in respect of the replacement of forfeited entitlements, there may be circumstances in which REMCO needs to offer a one-off recruitment incentive in the form of cash or shares to ensure the right external candidate is attracted. REMCO recognises the importance of internal succession planning but it must also have the ability to compete for talent with other global companies. The necessity and level of this incentive will depend on the individual's circumstances.	One times the LTIP award level, subject to the limits set out in the "Executive Directors' remuneration policy table".

NON-EXECUTIVE DIRECTORS

REMCO's approach to setting the remuneration package for NEDs is to offer fee levels and specific benefits (where appropriate) in line with the "Non-executive Directors' remuneration policy table" and subject to the Articles of Association. NEDs are not offered variable remuneration or retention awards.

When determining the benefits for a new Chair, the individual circumstances of the future Chair will be taken into account.

DIRECTORS' EMPLOYMENT ARRANGEMENTS AND LETTERS OF APPOINTMENT

Executive Directors are employed for an indefinite period. Executive Directors with the Netherlands as their base country will be employed on the basis of a contract of employment governed by Dutch employment law. For Executive Directors with a base country other than the Netherlands, REMCO will determine their employment arrangements based on a number of considerations, including Dutch immigration requirements and base country retirement benefits. NEDs, including the Chair, have letters of appointment. Executive Directors' employment arrangements and NEDs' letters of appointment are available for inspection at the AGM or on request. For further details on appointment and re-appointment of Directors, see the "Directors' Report" on page 93.

END OF EMPLOYMENT

EXECUTIVE DIRECTORS

Notice period

Employment arrangements of Executive Directors can generally end by either the employee or the employer providing one month's notice, or the applicable statutory notice period. For example, under Dutch law, the statutory notice period for the employer will vary in line with the length of service, with the maximum being four months' notice. Under Dutch law, termination payments are not linked to the contract's notice period.

The Netherlands statutory end-of-employment compensation With effect from July 1, 2015, new employment legislation in the Netherlands introduced statutory end-of-employment compensation. Under this legislation, every termination (other than following retirement or for cause) of a Dutch employment contract that has continued for a minimum of two years will give rise to an obligation to pay the departing employee transition compensation ("transitievergoeding"). The statutory compensation is capped at one times the annual salary, which is deemed to include

variable pay such as the annual bonus. Executive Directors are expected not to claim transition compensation or any other applicable statutory compensation over and above the agreed compensation for loss of office as set out in the "End of employment" table below.

Outstanding entitlements

In cases of resignation or dismissal for cause, fixed remuneration (base salary, benefits, and employer pension contributions) will cease on the last day of employment, variable remuneration elements will generally lapse and the Executive Director is not eligible for compensation for loss of office.

The information below generally applies to termination of employment by Shell giving notice, by mutual agreement, or in situations where the employment terminates because of retirement with Shell consent at a date other than the normal retirement date, redundancy or in other similar circumstances at REMCO's discretion.

End of employment

Provision	Policy
Compensation for loss of office	<p>For Executive Directors appointed prior to 2011, REMCO may offer a termination payment of up to one times annual pay (base salary plus target bonus).</p> <p>For Executive Directors appointed between January 1, 2011 and December 31, 2016, employment contracts include a cap on termination payments of one times annual pay (base salary plus target bonus). Delivery of compensation is mitigated by a contractual obligation for the Executive Director to seek alternative employment and the Company's ability to implement phased payment terms.</p> <p>For Executive Directors appointed on or after January 1, 2017, REMCO may offer a termination payment of up to one times base salary (target bonus will not be included). However, REMCO may be obligated to pay statutory compensation over and above the compensation for loss of office to a departing Executive Director who asserts a statutory claim thereto. Delivery of compensation is mitigated by a contractual obligation for the Executive Director to seek alternative employment and the Company's ability to implement phased payment terms.</p> <p>The reimbursement of standard end-of-employment benefits such as repatriation costs and outplacement support may also be included, as deemed reasonable by REMCO.</p> <p>REMCO may adjust the termination payment for any situation where a full payment is inappropriate, taking into consideration applicable law, corporate governance provisions and the best interests of the Company and shareholders as a whole.</p>
Annual bonus	<p>Any annual bonus in the year of departure is prorated based on service. Depending on the timing of the departure, REMCO may consider the latest scorecard position or defer payment until the full-year scorecard result is known.</p> <p>DBP shares and bonus delivered in shares represent the bonus which a participant has already earned and carry no further performance conditions; therefore, these shares will be unrestricted at the conclusion of the normal deferral or holding period respectively and no proration will apply.</p>
LTIP	<p>Outstanding awards are prorated on a monthly basis, by reference to the Executive Director's service within the performance period. They will generally survive the end of employment and will remain subject to the same vesting performance conditions, and malus and clawback provisions, as if the Executive Director had remained in employment. The three-year holding period will also remain in force for any awards made on or after January 1, 2017. If the participant dies before the end of the performance period, the award will vest at the target level on the date of death. In case of death after the end of the performance period, the award will vest as described in this Policy.</p>

NON-EXECUTIVE DIRECTORS

No payments for loss of office will be made to NEDs.

CONSIDERATION OF OVERALL PAY AND EMPLOYMENT CONDITIONS

When setting the Policy, no specific employee groups were consulted. However, Shell seeks to promote and maintain good relations with employee representative bodies as part of its employee engagement strategy, and consults on matters affecting employees and business performance as required.

When determining Executive Directors' remuneration structure and outcomes, REMCO reviews a set of information, including relevant reference points and trends, which includes internal data on employee remuneration (for example, employee relations matters in respect of remuneration and average salary increases applying in the Netherlands, UK and the USA). During the Policy review, pay and employment conditions of the wider Shell employee population were taken into account by adhering to the same performance, rewards and benefits philosophy for the Executive Directors, as well as overall benchmarking principles. Furthermore, any potential differences from other employees (see "Differences for Executive Directors from other employees") were taken into account when providing REMCO with advice in the formation of this Policy.

Dialogue between management and staff is important, with the annual Shell People Survey being one of the principal means of gathering employee views on a range of matters. The Shell People Survey includes questions inviting employees' views on their pay and benefit arrangements. The Company also encourages share ownership among employees, and many are shareholders who are able to participate in the vote on the Policy at the AGM.

REMCO is kept informed by the CEO, the Chief Human Resources & Corporate Officer and the Executive Vice President Remuneration, Benefits & Services on the bonus scorecard and any relevant remuneration matters affecting Senior Management and other senior executives, extending to multiple levels below the Board.

CONSIDERATION OF SHAREHOLDER VIEWS

REMCO engages with major shareholders on a regular basis throughout the year and this allows it to hear views on Shell's remuneration approach and test proposals when developing or evolving the Policy. Recent examples of REMCO responding to shareholder views include introducing greenhouse gas management to variable pay and setting FCF as an absolute measure in the LTIP performance conditions.

REMCO will review the Policy regularly to ensure it continues to reinforce Shell's long-term strategy and remains closely aligned with shareholders' interests.

ADDITIONAL POLICY STATEMENT

REMCO reserves the right to make payments outside the Policy in limited exceptional circumstances, such as for regulatory, tax or administrative purposes or to take account of a change in legislation or exchange controls, and only where REMCO considers such payments are necessary to give effect to the intent of the Policy.

Signed on behalf of the Board

/s/ Linda M. Szymanski

Linda M. Szymanski

Company Secretary

March 13, 2019

Financial Statements and Supplements

Independent Auditor's Report to the members of Royal Dutch Shell plc

REPORT ON THE FINANCIAL STATEMENTS

1. OUR OPINIONS AND CONCLUSIONS ARISING FROM OUR AUDIT

1.1 Our opinion on the financial statements

In our opinion, the financial statements of Royal Dutch Shell plc (the Parent Company) and its subsidiaries (collectively, Shell):

- give a true and fair view of the state of Shell's and of the Parent Company's affairs as at December 31, 2018, and of Shell's and the Parent Company's income for the year then ended;
- have been properly prepared both in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU) and IFRS as issued by the International Accounting Standards Board (IASB); and
- have been prepared in accordance with the requirements of the Companies Act 2006, and, as regards Shell's financial statements, Article 4 of the IAS Regulation.

1.2 Our opinion on other matters prescribed by the Companies Act 2006

In our opinion:

- the part of the Directors' Remuneration Report to be audited has been properly prepared in accordance with the Companies Act 2006; and
- based on the work undertaken in the course of our audit:
 - the information given in the Strategic Report and the Directors' Report for the financial year for which the financial statements are prepared is consistent with the financial statements; and
 - the Strategic Report and the Directors' Report have been prepared in accordance with applicable legal requirements.

1.3 Matters on which we are required to report by exception

Our confirmations that we have nothing to report by exception, in relation to those matters where we are required so to report, are set out in sections 8 and 9 below.

1.4 What we have audited

We have audited Royal Dutch Shell plc's financial statements for the year ended December 31, 2018, which are included in the Annual Report and Form 20-F (the Annual Report) and comprise:

Shell	Parent Company
Consolidated Balance Sheet as at December 31, 2018	Balance Sheet as at December 31, 2018
Consolidated Statement of Income for the year then ended	Statement of Income for the year then ended
Consolidated Statement of Comprehensive Income for the year then ended	Statement of Comprehensive Income for the year then ended
Consolidated Statement of Changes in Equity for the year then ended	Statement of Changes in Equity for the year then ended
Consolidated Statement of Cash Flows for the year then ended	Statement of Cash Flows for the year then ended
Related Notes 1 to 28 to the Consolidated Financial Statements, including a summary of significant accounting policies	Related Notes 1 to 14 to the Parent Company Financial Statements

The financial reporting framework that has been applied in the preparation of the financial statements is applicable law and both IFRS as adopted by the EU and IFRS as issued by the IASB.

2. BASIS FOR OUR OPINION

We conducted our audit in accordance with International Standards on Auditing (UK) (ISA (UK)) and applicable law. Our responsibilities under those standards are further described in the 'Auditor's responsibilities for the audit of the financial statements' section of our report below. We are independent of Shell and the Parent Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in the UK, including the Financial Reporting Council's Ethical Standard as applied to listed public interest entities, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

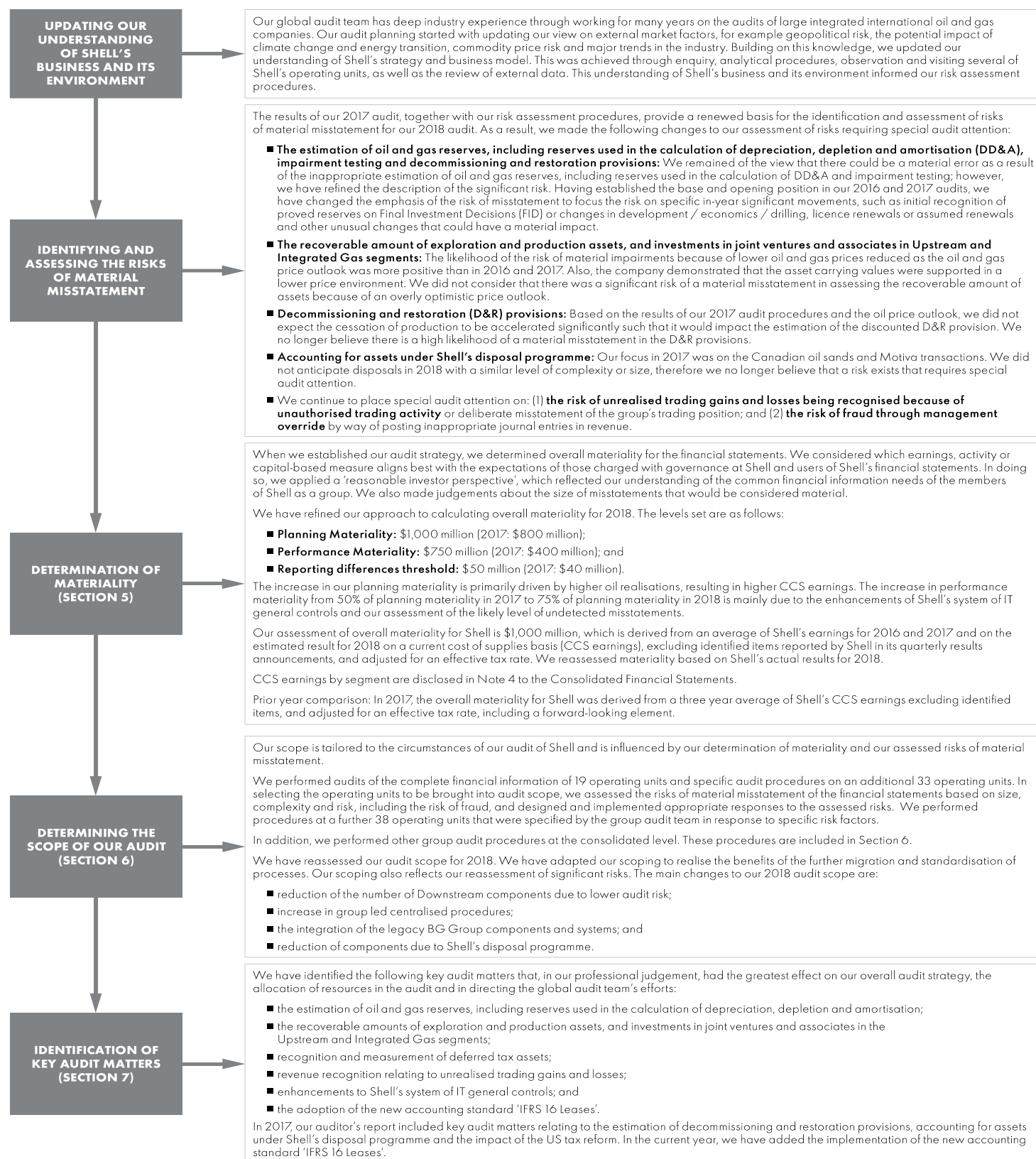
We believe that the audit evidence we have obtained during the planning, execution and conclusion of our audit is sufficient and appropriate to provide a suitable basis for our opinion.

3. OUR CONCLUSIONS RELATING TO PRINCIPAL RISKS, GOING CONCERN AND VIABILITY STATEMENT

We have nothing to report in respect of the following information in the Annual Report, in relation to which ISA (UK) requires us to report to you whether we have anything material to add or draw attention to:

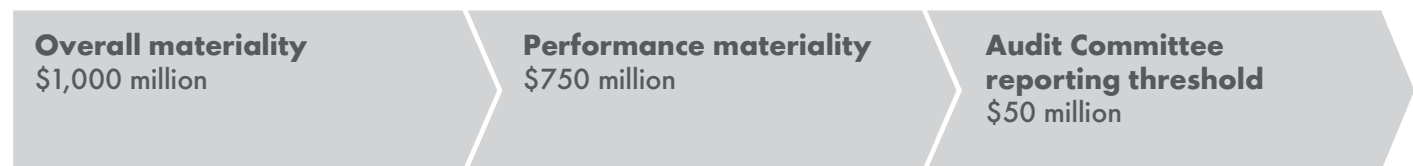
- the disclosures in the Annual Report set out on pages 15 to 20 that describe the principal risks and cross refer to where there are explanations of how the risks are being managed or mitigated;
- the Directors' confirmation set out on page 104 in the Annual Report that they have carried out a robust assessment of the principal risks facing the entity, including those that would threaten its business model, future performance, solvency or liquidity;
- the Directors' statement set out on pages 91 to 94 in the financial statements about whether they considered it appropriate to adopt the going concern basis of accounting in preparing them, and their identification of any material uncertainties to the entity's ability to continue to do so over a period of at least twelve months from the date of approval of the financial statements;
- whether the Directors' statement in relation to going concern required under the Listing Rules in accordance with Listing Rule 9.8.6R(3) is materially inconsistent with our knowledge obtained in the audit; or
- the Directors' explanation set out on pages 91 to 94 in the Annual Report as to how they have assessed the prospects of the entity, over what period they have done so and why they consider that period to be appropriate, and their statement as to whether they have a reasonable expectation that the entity will be able to continue in operation and meet its liabilities as they fall due over the period of their assessment, including any related disclosures drawing attention to any necessary qualifications or assumptions.

4. OVERVIEW OF OUR AUDIT APPROACH



5. OUR APPLICATION OF MATERIALITY

The scope of our work is influenced by our view of materiality. As we develop our audit strategy, we determine materiality at the overall level and at the individual account level (referred to as our 'performance materiality' (see below)).



Overall materiality

What we mean

We apply the concept of materiality both in planning and performing our audit, as well as in evaluating the effect of identified misstatements (including omissions) on our audit and in forming our audit opinion. For the purposes of determining whether or not Shell's financial statements are free from material misstatement (whether due to fraud or error), we define materiality as the magnitude of misstatements that, individually or in the aggregate, could reasonably be expected to influence the economic decisions of the users of these financial statements. We are required to establish a materiality level for the financial statements as a whole that is appropriate in the light of Shell's particular circumstances.

Our overall materiality provides a basis for identifying and assessing the risk of material misstatement and determining the nature and extent of audit procedures. Our evaluation of materiality requires professional judgement and necessarily takes into account qualitative as well as quantitative considerations. It also considers our assessment of the expectations of those charged with governance at Shell and users of Shell's financial statements. As required by auditing standards, we reassess materiality throughout the duration of the audit.

Level set

Group materiality

We set our preliminary overall materiality for Shell's Consolidated Financial Statements at \$1,000 million (2017: \$800 million). We kept this under review throughout the year and reassessed the appropriateness of our original assessment in the light of Shell's results and external market conditions. Based on this review, we did not find it necessary to revise our level of overall materiality.

Parent Company materiality

We determined materiality for the Parent Company to be \$2.6 billion (2017: \$2.5 billion), which is 1% (2017: 1%) of equity. Equity is an appropriate basis to determine materiality for an investment holding company and 1% is a typical percentage of equity to use to determine materiality. Any balances in the parent company financial statements that were relevant to our audit of the consolidated group were audited using an allocation of group performance materiality.

Our basis for determining materiality for 2018

Our assessment of overall materiality is \$1,000 million. This is derived from an average of Shell's earnings for 2016 and 2017 and on the estimated result for 2018 on a current cost of supplies basis (CCS earnings), excluding identified items reported by Shell in its quarterly results announcements, and adjusted for an effective tax rate. The \$1,000 million was determined by applying a percentage to the calculated average CCS earnings. When using an earnings-related measure to determine overall materiality, the norm is to apply a benchmark percentage of 5% of the pre-tax measure. In setting overall materiality, we applied a more prudent rate that was below the 5% benchmark. Our overall materiality is less than 3% of the 2018 income before taxation.

In determining materiality, auditing standards require us to use benchmark measures, such as pre-tax income, gross profit and total revenue. Nevertheless, we have to exercise considerable judgement, including which earnings, activity or capital based measure aligns best with the expectations of users of Shell's financial statements and the Audit Committee. In determining the most appropriate benchmark on which to base our materiality assessment, we have applied a 'reasonable investor perspective'. This reflects our understanding of the common financial information needs of Shell's investors as a group, which we believe is CCS earnings, excluding identified items. Shell's quarterly results announcements feature CCS earnings excluding identified items as the primary measure for earnings.

CCS earnings excluding identified items removes both the effects of changes in oil price on inventory carrying amounts and items disclosed as identified items that can significantly distort Shell's results in any one particular year. In our view, the use of CCS earnings excluding identified items allows investors to understand how management has performed despite the commodity price environment, as opposed to because of it. Furthermore, analyst forecasts predominantly feature CCS earnings, excluding identified items, as the basis for earnings. The analyst consensus data supports our judgement that CCS earnings, excluding identified items, is the key indicator of performance from a reasonable investor perspective.

The identified items, reported by Shell in its quarterly results announcements, were: net divestment gains (\$3.3 billion), net impairments (\$1.0 billion charge), fair value accounting of commodity derivatives and certain gas contracts (\$1.1 billion gain), redundancy and restructuring (\$0.2 billion charge), and the aggregate of other individually small items (net \$0.1 billion charge).

The identified items excluded in 2017 were: net divestment gains (\$1.6 billion), impairments (\$3.0 billion charge), fair value accounting of commodity derivatives and certain gas contracts (\$0.3 billion loss), redundancy and restructuring (\$0.4 billion charge), impact of exchange rate movements on tax balances (\$0.6 billion gain), impact arising from the US tax reform legislation (\$2.0 billion charge) and the aggregate of other individually small items (net \$0.2 billion charge). On the basis of our analysis of these factors, we concluded that we should focus on Shell's CCS earnings, excluding identified items reported by Shell in its quarterly results announcements, and adjusted for an effective tax rate. In 2017, we included a forward-looking element in the calculation of average earnings due to the low oil price environment. In the current year, however, we have not used a forward-looking view, as the oil price environment is more stable.

Performance materiality

What we mean	<p>Having established overall materiality, we determined 'performance materiality', which represents our tolerance for misstatement in an individual account. It is calculated as a percentage of overall materiality in order to reduce to an appropriately low level the probability that the aggregate of uncorrected and undetected misstatements exceeds overall materiality of \$1,000 million for Shell's financial statements as a whole.</p> <p>Once we determined our audit scope, we then assigned performance materiality to our various in-scope operating units. Our in-scope operating unit audit teams used this assigned performance materiality in performing their group audit procedures. The performance materiality allocation is dependent on the size of the operating unit, measured by its contribution of earnings to Shell, or other appropriate metric, and the risk associated with the operating unit.</p>
Level set	<p>On the basis of our risk assessment, our judgement was that performance materiality should be 75% (2017: 50%) of our overall materiality, namely \$750 million (2017: \$400 million). In assessing the appropriate level, we consider the nature, the number and impact of the audit differences identified in 2017 as well as the overall control environment. The increase in performance materiality is mainly due to the enhancements of Shell's system of IT general controls and our assessment of the likely level of undetected misstatements.</p> <p>In 2018, the range of performance materiality allocated to operating units was \$113 million to \$375 million (2017: \$40 million to \$260 million). This is set out in more detail in section 6 below.</p>

Audit difference reporting threshold

What we mean	<p>This is the amount below which identified misstatements are considered to be clearly trivial.</p> <p>The threshold is the level above which we collate and report audit differences to the Audit Committee. We also report differences below that threshold that, in our view, warrant reporting on qualitative grounds. We evaluate any uncorrected misstatements against both the quantitative measures of materiality discussed above and in the light of other relevant qualitative considerations in forming our opinion.</p>
Level set	<p>We agreed with the Audit Committee that we would report to the Committee all audit differences more than \$50 million (2017: \$40 million), as well as differences below that threshold that, in our view, warrant reporting on qualitative grounds.</p>

6. OUR SCOPE OF THE AUDIT OF SHELL'S FINANCIAL STATEMENTS

What we mean	<p>We are required to establish an overall audit strategy that sets the scope, timing and direction of our audit, and that guides the development of our audit plan. Audit scope comprises the physical locations, operating units, activities and processes to be audited that, in aggregate, are expected to provide sufficient coverage of the financial statements for us to express an audit opinion.</p>
Criteria for determining our audit scope	<p>Our assessment of audit risk and our evaluation of materiality determined our audit scope for each operating unit within Shell which, when taken together, enabled us to form an opinion on the financial statements under ISA (UK). Our audit effort was focused towards higher risk areas, such as management judgements and on operating units that are considered significant based upon size, complexity or risk.</p> <p>The factors that we considered when assessing the scope of the Shell audit, and the level of work to be performed at the operating units that are in scope for group reporting purposes, included the following:</p> <ul style="list-style-type: none"> the financial significance of an operating unit to Shell's earnings, total assets or total liabilities, including consideration of the financial significance of specific account balances or transactions; the significance of specific risks relating to an operating unit: history of unusual or complex transactions, identification of significant audit issues or the potential for, or a history of, material misstatements; the effectiveness of the control environment and monitoring activities, including entity-level controls; our assessment of locations that carry a higher than normal audit risk in relation to fraud, bribery or corruption; and; the findings, observations and audit differences that we noted as a result of our 2017 audit.
Selection of in-scope operating units	<p>We reassessed our audit scope for 2018 compared to 2017. In particular, we considered Shell's continued enhancement of their finance function and processes, which included the further standardisation and migration of processes to their business service centres (BSCs). This enabled us further to centralise our audit procedures and refocus our scope, reducing the audit involvement at a component level and the number of operating units in our audit scope. Also, our revised scope reflects our view of lower audit risk within Downstream, an increase in centralised audit procedures, the integration of legacy BG Group components and systems, and Shell's disposal programme. We kept our audit scope under review throughout the year to reflect changes in Shell's underlying business and risks; however, no significant changes were required.</p>

Full and specific scope

We selected 52 operating units (2017: 67) across 11 countries (2017: 12) based on their size or risk characteristics. We performed full scope audits of the complete financial information of 19 operating units (2017: 25). For 33 operating units (2017: 42) we performed specific scope audit procedures on individual account balances within the operating unit based on their size and risk profiles.

Specified

In addition to the 52 operating units (2017: 67) discussed above, we selected a further 38 operating units (2017: 47) where we performed procedures at the operating unit level that were specified by the group audit team in response to specific risk factors and in order to ensure that, at the overall group level, we reduced and appropriately covered the residual risk of error.

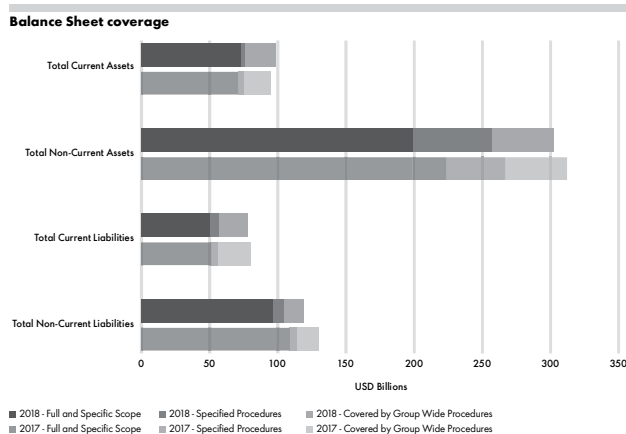
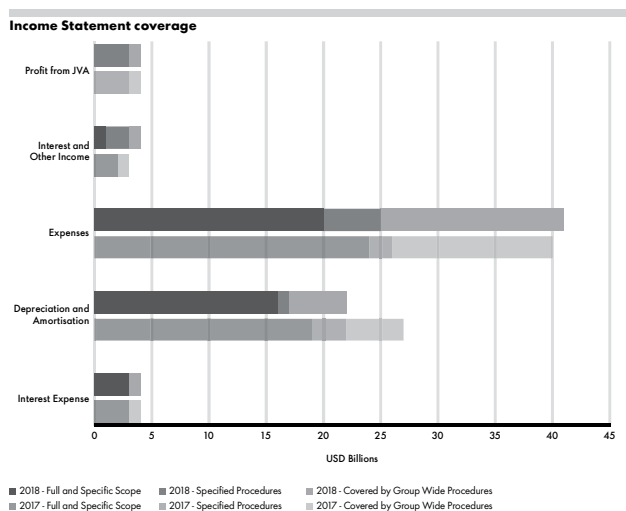
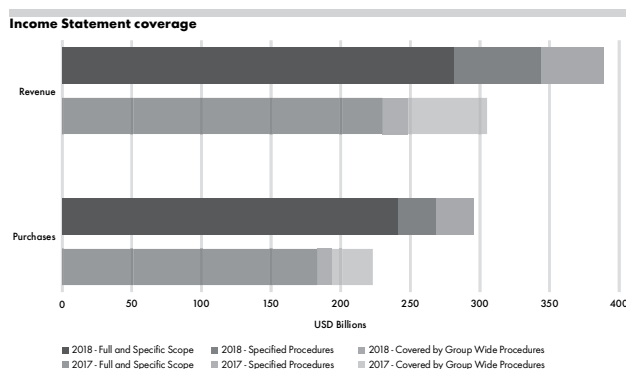
In addition, specified procedures were performed at the group level on a further 62 operating units. These procedures included, the testing of Shell's centralised activities addressing the implications of significant and complex accounting matters across all operating units, our centralised revenue and accounts receivable analytics programme, testing controls for the revenue and purchase to pay processes, including IT general and IT application controls, procedures over investments in securities, segment level impairment reviews, procedures over the forecasts as they relate to deferred tax assets recoverability and review of pension scheme assumptions.

Group wide procedures

For the remaining 637 operating units (2017: 688) we performed supplementary audit procedures, in relation to Shell's centralised group accounting and reporting processes. These included, but were not limited to, Shell's activities addressing the appropriate elimination of intercompany balances and, the completeness of provisions for litigation and other claims. We performed testing of both manual and consolidation journal entries through the year, homogeneous processes and controls at the BSCs, and testing of group wide IT systems. We performed disaggregated analytical reviews on each financial statement line item and also tested Shell's analytical procedures performed at a group, segment and function level.

In addition to this testing, we applied our Risk Scan analytics techniques, which consolidate internal and external data to identify potential risks of material misstatement. This allowed us to risk rate each of the 637 operating units whereby we identified 155 operating units where we believed that it was appropriate to carry out targeted testing. This included the audit of manual journal entries and/or the testing of payments to third party vendors to ensure that these had been approved in line with Shell's policies and had an appropriate business rationale.

Our coverage by full and specific, specified and group wide procedures is depicted below. The summary is by income statement accounts and balance sheet sub-totals. The dollar amounts shown for each line item represent 100% of the specific account balance. The 2017 comparative data is shown below on a basis consistent with the 2017 audit opinion. Overall, our full, specific and specified procedures accounted for 72% of Shell's absolute CCS earnings, excluding identified items reported by Shell in its quarterly results announcements and adjusted for an effective tax rate. The remaining CCS earnings were covered by group wide procedures.



Allocation of performance materiality to the in-scope operating units

The level of materiality that we applied in undertaking our audit work at the operating unit level was determined by applying a percentage of our total performance materiality. This percentage is based on the significance of the operating unit relative to Shell as a whole and our assessment of the risk of material misstatement at that operating unit. In 2018 the range of materiality applied at the operating unit level was \$113 million to \$375 million (2017: \$40 million to \$260 million). The operating units selected, together with the ranges of materiality applied, were:

	Countries	No. of operating units	Range of materiality applied \$ million
Full scope Segments			
Integrated Gas	Australia, Qatar	4	150-225
Upstream	Brazil, Nigeria, USA	4	150-225
Downstream	Germany, USA	3	150-225
Corporate	UK	1	150
Full scope Function			
Trading and supply	UK, USA, UAE, Barbados, Singapore, the Netherlands	7	281-375
Total full scope		19	
Specific scope Segments			
Upstream	Canada, Kazakhstan, Malaysia, UK	5	150
Downstream	Singapore, USA	6	150
Corporate	The Netherlands, Singapore, UK, USA	11	150
Specific scope Function			
Trading and supply	UK, USA, UAE, Canada, Singapore	11	113-150
Total specific scope		33	
Total full and specific scope		52	

Integrated group team structure

The overall audit strategy is determined by the Senior Statutory Auditor, Allister Wilson. During 2018 he visited five countries to meet with local Ernst & Young (EY) teams and Shell local management (in some cases more than once). The Senior Statutory Auditor is supported by 26 segment and function partners and associate partners, who are based in the Netherlands and the UK. They are responsible for directing, supervising and reviewing the work of EY global network firms operating under our instruction (local EY teams) to evaluate whether:

- the work was performed and documented to a sufficiently high standard;
- the local EY audit team demonstrated that they had challenged management sufficiently and had executed their audit procedures with a sufficient level of scepticism; and
- there is sufficient appropriate audit evidence to support the conclusions reached.

Involvement with local EY teams

Shell has centralised processes and controls over key areas within its BSCs. We have a central team who provide direct oversight, review, and coordination of our BSC audit teams. Our teams performed centralised testing in the BSCs for certain accounts, including revenue, cash and payroll. In establishing our overall approach to the group audit, we determined the type of work that needed to be undertaken at each of the operating units or BSCs by the group audit team or by auditors from other local EY teams.

The group audit team performed procedures directly on 62 of the in-scope operating units. For the operating units where the work was performed by local EY auditors, we determined the appropriate level of involvement of the group audit team to enable us to conclude that sufficient appropriate audit evidence had been obtained.

The group audit team interacted regularly with the local EY teams during each stage of the audit, were responsible for the scope and direction of the audit process and reviewed key working papers. This, together with the additional procedures performed at the group level, gave us sufficient appropriate audit evidence for our opinion on Shell's Consolidated Financial Statements. We maintained continuous dialogue with our local EY teams in addition to holding formal meetings quarterly to ensure that we were fully aware of their progress and results of their audit procedures.

Our local EY partners attended our global team audit planning meeting in November 2017. Also, during 2018, the Senior Statutory Auditor and other group audit partners and directors visited operating units across seven countries and each of Shell's BSCs. These visits included discussing the audit approach with the local EY teams and any issues arising from their work, meetings with local management, attending planning and closing meetings, and reviewing key audit working papers on risk areas. The visits also promote deeper engagement with our local EY audit teams, ensuring that a consistent and cohesive audit approach is adopted that drives a high-quality audit.

Countries visited

Australia, Malaysia, UK, Brazil, the Netherlands, USA, Nigeria

BSCs

India, Malaysia, Poland, Philippines

7. OUR ASSESSMENT OF KEY AUDIT MATTERS

As Shell's auditors, we are required to determine – from the matters communicated by us to the Audit Committee during the year – those matters that required significant attention from us in performing our audit of Shell's 2018 Consolidated Financial Statements. In making this determination we took the following into account:

- the risks that we believed were significant to our audit and therefore required special audit consideration;
- areas of higher assessed risk of material misstatement that influenced our audit focus;
- significant audit judgements relating to areas in Shell's Consolidated Financial Statements that involved significant management judgement, including accounting estimates that we identified as having high estimation uncertainty;
- the effect on our audit of significant events or transactions that occurred during the period; and
- those assessed risks of material misstatement that had the greatest effect on the allocation of resources in the audit and directing the efforts of the audit team.

On this basis, we have identified the following key audit matters that, in our professional judgement, were of most significance in our audit of Shell's 2018 Consolidated Financial Statements. These matters included those that had the greatest effect on: the overall strategy; the allocation of resources in the audit; and directing the efforts of the audit team. The key audit matters have been addressed in the context of the audit of Shell's Consolidated Financial Statements and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

The table below describes the key audit matters, a summary of our procedures carried out and our key observations that we communicated to the AC.

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Our key audit matters

Risk	Our response to the risk	Key observations communicated to the Shell Audit Committee
<p>The estimation of oil and gas reserves, including reserves used in the calculation of depreciation, depletion and amortisation (DD&A)</p> <p>At December 31, 2018, Shell reported 11,578 million barrels of oil equivalent of proved developed and undeveloped reserves. (2017: 12,233 million barrels of oil equivalent).</p> <p>The estimation of oil and gas reserves and resources is a significant area of judgement due to the technical uncertainty in assessing the quantities and complex contractual arrangements that dictate Shell's share of reserves and resources volumes. The estimates are based on internal or external experts' assessment of reserves in place, recovery factors and crude quality.</p> <p>In-year movements can result from revisions of previous estimates, reclassifications, improved recovery assumptions, extensions and discoveries and purchases and sales.</p> <p>The risk relates to significant in-year movements, or lack thereof, in the reserves and resources volumes that materially impact elements of the financial statements including DD&A, impairment testing and decommissioning and restoration provisions. In-year movements generally arise from new information, for example additional drilling results, production patterns, water-cut levels, export facilities and changes in development plans.</p>		
	<p>Our reserves team includes auditors with substantial oil and gas reserves expertise, valuation experience and relevant qualifications in energy economics.</p> <p>We carried out the following procedures:</p> <ul style="list-style-type: none"> ■ reconfirmed our understanding of Shell's oil and gas reserves estimation process; ■ tested compliance with significant controls in Shell's oil and gas reserves control framework; ■ confirmed that significant additions or reductions in SEC proved reserves had been made in the period in which the new information became available; ■ tested Shell's internal certification process and controls for technical and commercial experts responsible for reserves estimation; ■ tested the reasonableness of SEC proved undeveloped reserves recognised. Where volumes recognised remained undeveloped for more than five years from the date they were booked, or where development is not expected for at least five years, we ensured that Shell was still working towards development by corroborating with future development plans, including capital expenditure plans as appropriate; ■ where relevant, tested all inputs in the economic limit test for reserves determination, and satisfied ourselves that the economic limit test incorporates Shell's estimate of future CO₂ costs to reflect the potential impact of climate change and energy transition; ■ where reserves are recognised beyond current licence terms we obtained evidence to support the assumption that a licence will be renewed; and ■ where SEC proved developed reserves were not used for DD&A purposes, we challenged management's basis and obtained sufficient and appropriate evidence to ensure that the reserves base used was reasonable and better reflected the expected useful life of the field or facilities. <p>Our procedures were led by the group audit team, with input from our teams in Australia, Brazil, Canada, Kazakhstan, the Netherlands, Malaysia, Nigeria, Norway, Qatar, Russia, the UK and USA.</p>	<p>In January 2019 we communicated to the AC that, based on our testing performed, we had not identified any significant errors in the oil and gas reserves estimates and concluded that the inputs and assumptions used to estimate proved reserves were reasonable.</p>

Cross-reference: See the AC Report on page 114 for details on how the AC reviewed assurances for proved oil and gas reserves. Also, see Notes 2 and 8 to the "Consolidated Financial Statements", and Supplementary information – oil and gas (unaudited) on page 215.

Our key audit matters

Risk	Our response to the risk	Key observations communicated to the Shell Audit Committee
<p>The recoverable amounts of exploration and production assets, and investments in joint ventures and associates</p> <p>At December 31, 2018, Shell recognised \$167 billion of exploration and production assets within property, plant and equipment (PP&E) (2017: \$172 billion). Shell also recognised investments in joint ventures and associates of \$25 billion (2017: \$28 billion).</p> <p>Assets' operational performance and external factors could have a significant impact on the recoverable amounts of Shell's Upstream and Integrated Gas assets. Assessing the recoverable amount of an asset involves a significant amount of judgement. The most critical assumptions in forecasting future cash flows are management's view on the long-term oil and gas price outlook, the discount rate used, future expected production volumes and capital and operating expenditure.</p>	<p>Our procedures included testing for indicators of impairment and reversals of impairment and validating the appropriateness of the level at which the testing took place.</p> <p>We confirmed that Shell's asset impairment methodology was appropriate. Where impairment assessments were carried out, we tested the integrity of the models used. For those assets impaired previously, we evaluated the actual results versus the assumptions made and considered if reversals were required.</p> <p>For price assumptions, we corroborated future short and long-term commodity prices to consensus analysts' forecasts and those adopted by other international oil companies; we confirmed prices were used consistently across Shell and that pricing differentials were reasonable and appropriate and satisfied ourselves that Shell's long-term price assumptions incorporated the potential impact of climate change and energy transition.</p> <p>Our oil and gas valuations team tested the reasonableness of the discount rate used for impairment testing. For cash flow inputs we:</p> <ul style="list-style-type: none"> confirmed that operating expenditure profiles and capital costs to complete construction could be supported by approved operator budgets and management forecasts; confirmed that carbon pricing was included in cash flows, where applicable; reconciled reserves volumes in the impairment models and confirmed that the life-of-field assumptions were consistent with those applied in the decommissioning and restoration provision models; and performed sensitivity analyses on certain key variables in the base case cash flow models to understand the impact of changes in certain assumptions (including oil and gas prices, production and operating expenditure levels). <p>We assessed the reasonableness of the basis for the risking of the cash flows applied to each individual asset. In so doing, we considered the stage of the life of the asset, country risk and ensured consistency across similar fields.</p> <p>Where impairment tests were undertaken, we stress tested the models using different price scenarios and risked discount rates that we considered reasonable when taking account of the nature of the asset, its location, its stage of development and associated risks.</p> <p>The audit procedures were performed by our group audit team as well as our local audit teams in Australia, Brazil, Canada, Kazakhstan, Malaysia, Nigeria, Qatar, the UK and USA, which covered 79% of PP&E and investments in joint ventures and associates in Upstream and Integrated Gas segments.</p> <p>We also performed specified procedures over the recoverability of investments in joint ventures and associates in Australia, Brazil, Brunei, Canada, Iraq, the Netherlands, Nigeria, Qatar and Russia, which covered an additional 10% of investments in joint ventures and associates in the Upstream and Integrated Gas segments.</p>	<p>We reported that, on the basis of our analysis of future commodity prices used in the impairment models versus other international oil companies and consensus analysts' forecasts, there is strong external evidence to support the reasonableness of Shell's commodity price assumptions – both in the short and long term. We also confirmed that we were satisfied with Shell's approach to estimating future oil and gas prices was robust and appropriate.</p> <p>We confirmed that we were satisfied that the cash flows used in the impairment tests had been risked appropriately and that the discount rate applied was appropriate.</p> <p>We concluded that the impairments and impairment reversals recorded were appropriately determined.</p> <p>Where impairment tests were undertaken and no impairment was recorded, we performed specific procedures, including multi-dimensional sensitivity analysis on the key assumptions that drive the impairment analysis, and concluded that it was reasonable and supportable not to record an impairment charge.</p>

Cross-reference: See the AC Report on page 116 for details on how the AC considered impairments. Also, see Notes 2, 8 and 9 to the "Consolidated Financial Statements".

Our key audit matters

Risk	Our response to the risk	Key observations communicated to the Shell Audit Committee
Recognition and measurement of deferred tax assets (DTAs)		
<p>At December 31, 2018, Shell recognised gross DTAs totalling \$29 billion (2017: \$31 billion), which are recognised within two balance sheet line items, deferred tax assets and as an offset against deferred tax liabilities, depending on the overall tax position in a particular jurisdiction.</p> <p>Estimating DTAs requires significant judgement, including the timing of reversals of deferred tax liabilities (DTL) and the availability of future profits against which tax deductions represented by the DTAs can be offset.</p> <p>A significant proportion of DTA balances is supported by forecast future taxable profits, which are derived from Shell's commodity price assumptions and business plans. In some cases, the DTA will be utilised in a period substantially beyond the period of the operating plan.</p>	<p>We considered the expected timing of utilisation of the DTA including the relevant country tax laws that apply to the utilisation of tax losses. This included the ability to carry tax losses forward or back and any restrictions arising from ring fencing tax losses to particular projects.</p> <p>Our procedures depended on whether or not the DTAs were supported by the unwinding of taxable temporary differences, forecast taxable profits or tax planning opportunities that would be necessary to utilise tax losses. We assessed whether the forecast timing of the unwinding of taxable temporary differences were appropriate after considering the nature of the temporary difference and the relevant tax law.</p> <p>For DTAs that are supported by forecast taxable profits or tax planning opportunities, we:</p> <ul style="list-style-type: none"> ▪ stress tested the commodity price and/or other key assumptions that underpin Shell's assessment of forecast probable taxable profits; ▪ determined the extent to which sufficient probable taxable profits would arise in the period within which the related losses would be available for utilisation, considering for example limits on the length of time that losses can be carried forward (applicable to the USA, the Netherlands and China in particular) or if losses are ring fenced for tax purposes (including the UK and Nigeria); and ▪ considered whether the tax balances were calculated using appropriate, and substantively enacted, tax laws and rates. <p>For the tax planning strategies necessary to justify the recognition of the DTAs, we considered whether or not the planning was reasonable and in line with the current tax law, including satisfying ourselves that sufficient profits would be available in the appropriate periods.</p> <p>Our audit procedures over the recognition and valuation of DTAs were performed by our tax specialist teams in Australia, Brazil, Canada, Germany, Kazakhstan, Nigeria, Singapore, Qatar, the UK and USA, which covered 64% of the gross DTA balance. We also performed specified procedures over the recognition and valuation of DTAs in Canada, Denmark, Germany, Kazakhstan, the Netherlands, Norway and the USA, which covered an additional 22% of the gross DTA balance.</p>	<p>We reported our conclusions to the January 2019 meeting of the AC that we had challenged the robustness of the key management judgements and confirmed that we were satisfied that where DTAs recognised are based on income forecast to arise beyond Shell's planning horizon, we consider that there was sufficient future taxable profit that is probable to support the DTAs; however, we noted that a greater degree of judgement is required in recognising DTAs beyond Shell's planning horizon.</p> <p>We also reported to the AC that the DTAs were appropriately recognised and valued at the year end.</p>

Cross-reference: See the AC Report on page 116 for details on how the AC reviewed certain tax matters, in particular the recoverability of deferred tax assets. Also see Notes 2 and 16 to the "Consolidated Financial Statements".

Our key audit matters

Risk	Our response to the risk	Key observations communicated to the Shell Audit Committee
Revenue recognition relating to unrealised trading gains and losses <p>Shell's Trading and Supply function is integrated within the Downstream, Integrated Gas and Upstream segments and is spread across multiple regions. It is inherently complex and exposes Shell to risks that are not normally associated with core oil and gas activities. Whilst trading is not uncommon amongst international oil and gas companies, it does require a robust internal control environment.</p> <p>In our audit we have considered the risk of unrealised trading gains and losses being recognised because of unauthorised trading activity or deliberate misstatement of Shell's trading positions.</p> <p>The deliberate misstatement of Shell's trading positions or mismarking of positions could result in understated trading losses, overstated trading profits and/or individual bonuses being manipulated through inappropriate inter-period profit/loss allocations.</p>		
	<p>Our trading audit teams comprise of individuals who have significant experience of auditing both large commodity trading organisations and financial institutions.</p> <p>Our audit procedures focused on:</p> <ul style="list-style-type: none"> ■ investigations as to whether or not there were any breakdowns of trading controls or instances of rogue trading reported or known or suspected frauds; ■ testing controls across the trading and supply function, including IT general and IT application controls; ■ independently obtaining confirmation of a sample of open trading positions with brokers and counterparties, or performing alternative procedures as necessary; ■ performing valuation testing of open positions, including confirming the appropriateness of price curves used; ■ performing independent testing of valuation models, focusing on validating contract terms and key assumptions; and ■ testing the completeness of the amounts recorded in the financial statements through procedures to detect unrecorded liabilities as well as detailed cut-off procedures around sales, purchases, trade receivables and trade payables. <p>The audit procedures were performed principally by the group audit team and the UK and US component teams.</p> <p>In May 2018, the Senior Statutory Auditor and the Audit Partner responsible for the audit of Shell's Trading and Supply function accompanied the AC on its one-day visit of Shell's Trading and Supply office in London, and attended all discussions on a wide range of matters, including the external market and regulatory environments, market risk, credit risk, assurance and supervision and Brexit planning.</p>	<p>We confirmed that:</p> <ul style="list-style-type: none"> ■ the valuation of derivative contracts as at December 31, 2018 was appropriate; ■ our testing – through a combination of controls testing and expanded substantive audit procedures – satisfied us that the models used to value contracts were appropriate for the purposes of the valuations included in Shell's Consolidated Financial Statements; and ■ the unrealised gains and losses had been recorded appropriately; and ■ our completeness testing did not identify any unrecorded liabilities or significant cut-off issues.

Cross-reference: See Note 19 to the "Consolidated Financial Statements".

Our key audit matters

Risk	Our response to the risk	Key observations communicated to the Shell Audit Committee
<p>Recognition, measurement, presentation and disclosure of leases (IFRS 16)</p> <p>IFRS 16 is without doubt the most complex new standard that companies such as Shell have had to implement since the adoption of IFRS in 2005.</p> <p>Shell has a significant number of leases that are in scope for IFRS 16. The key complexities include:</p> <ul style="list-style-type: none"> ▪ how to apply IFRS 16 to joint arrangements, in particular where the operator enters into a lease on behalf of a joint operation; ▪ the determination of the appropriate discount rate to be used in capitalising Shell's operating leases; ▪ assessing the appropriate accounting for complex lease structures; and ▪ implementing an appropriate system platform that can accommodate the inevitable volume and complexity that a company like Shell would require. <p>Although the standard is being implemented in 2019, disclosures on the impact are included in these financial statements.</p>		
	<p>We have audited the impact of the implementation of the new leasing standard on Shell. Our audit procedures primarily focused on the following:</p> <ul style="list-style-type: none"> ▪ assessing the completeness of Shell's population of operating leases and that all leases were appropriately uploaded on Shell's lease accounting IT application; ▪ analysing the accounting for Shell's complex rig lease structures; ▪ assessing the appropriate incremental borrowing rate to be used in capitalising Shell's leases; ▪ testing the control framework around the IFRS 16 IT application adopted by Shell; and ▪ auditing the disclosures provided in the financial statements on the impact of IFRS 16. <p>The audit procedures to address this risk were performed principally by the group audit team.</p>	<p>We reported to the Audit Committee that the key complexities surrounding the implementation of IFRS 16 were the determination of the appropriate discount rates to be used in calculating Shell's lease liabilities and the implementation of the IT system that supports the accounting for the large population of leases. Also, we reported that we had engaged our oil and gas valuation specialists to assist in auditing the discount rates adopted by Shell.</p> <p>We reported further that, based on our audit procedures, we were satisfied that the overall additional lease liabilities and right of use assets as at January 1, 2019, were within an acceptable range, albeit the lower end. Accordingly, we confirmed that the disclosures in Note 3 to the Consolidated Financial Statements, on the adoption of IFRS 16 were appropriately prepared in accordance with the standard. Also, we reported that we were satisfied with the design and operating effectiveness of the controls surrounding the IT system that records the individual leases, including the input and output controls.</p>

Cross-reference: See the AC Report on page 116 for details on how the AC considered the IFRS 16 implementation. Also, see Note 3 to the "Consolidated Financial Statements".

Our key audit matters

Risk	Our response to the risk	Key observations communicated to the Shell Audit Committee
Enhancements to Shell's system of IT general controls <p>In 2018, Shell management devoted significant effort to enhance and standardise Shell's system of IT general controls (ITGCs), including the implementation of new global IT processes.</p> <p>During any period of significant process change, there is increased risk to the internal financial control environment. Consequently, in addition to the inherent risks associated with auditing the IT systems of a complex global organisation such as Shell, the audit team focused its procedures on the risks associated with the following change programmes:</p> <ul style="list-style-type: none"> ▪ further standardisation of Shell's user access management process; and ▪ implementation of Shell's enterprise wide IT change management process. 		
	<p>Our procedures focused on the key IT processes and controls over IT systems critical to our audit. These included: management of changes to systems and access to systems; and IT operations, such as problem and incident management, and back-up and restore.</p> <p>We updated our understanding of Shell's key IT applications and IT transitions that impacted our financial statement audits by carrying out walk-through tests. We identified 130 applications that were critical to our audit and therefore included in our audit scope. We also assessed the risk associated with any key business or IT changes and identified and tested application and IT dependent manual controls that we considered key to the business processes related to financial reporting.</p> <p>Our audit approach involved central testing of ITGCs that we considered important to the financial statements, including:</p> <ul style="list-style-type: none"> ▪ management of changes to systems; ▪ management of access to systems; and ▪ management of IT operations. <p>The audit procedures to address this risk were performed principally by the BSC and group audit teams.</p>	<p>Throughout 2018, we communicated to the AC the progress of our internal controls testing, including the testing of ITGCs.</p> <p>In January 2019, we confirmed that, through a combination of internal controls testing supplemented by targeted substantive audit procedures, we were satisfied that we had obtained sufficient and appropriate audit evidence over Shell's management of changes to systems, management of access to systems and IT operations for our financial statement audit.</p>

8. OTHER INFORMATION

The other information comprises the information included in the Annual Report set out on pages 1 to 147 and 215 to 236 including the Strategic Report, Governance and Additional Information sections, other than the financial statements and our auditor's report thereon. The Directors are responsible for the other information.

Our opinion on the financial statements does not cover the other information and, except to the extent otherwise explicitly stated in this report, we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated. If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether there is a material misstatement in the financial statements or a material misstatement of the other information. If, based on the work we have performed, we conclude that there is a material misstatement of the other information, we are required to report that fact.

We have nothing to report in this regard.

In this context, we also have nothing to report in regard to our responsibility to address specifically the following items in the other information and to report as uncorrected material misstatements of the other information where we conclude that those items meet the following conditions:

- *Fair, balanced and understandable set out on page 92* – the statement given by the Directors that they consider the Annual Report and financial statements taken as a whole is fair, balanced and understandable and provides the information necessary for shareholders to assess Shell's performance, business model and strategy, is materially inconsistent with our knowledge obtained in the audit; or
- *Audit Committee reporting set out on page 113 to 118* – the section describing the work of the AC does not appropriately address matters communicated by us to the AC; or
- *Directors' statement of compliance with the UK Corporate Governance Code set out on page 96* – the parts of the Directors' statement required under the Listing Rules relating to Shell's compliance with the UK Corporate Governance Code containing provisions specified for review by the auditor in accordance with Listing Rule 9.8.10R(2) do not properly disclose a departure from a relevant provision of the UK Corporate Governance Code.

9. MATTERS ON WHICH WE ARE REQUIRED TO REPORT BY EXCEPTION

In the light of the knowledge and understanding of Shell and the Parent Company, and its environment obtained in the course of our audit, we have not identified material misstatements in the Strategic Report or the Directors' Report.

We have nothing to report in respect of the following matters in relation to which the Companies Act 2006 requires us to report to you if, in our opinion:

- adequate accounting records have not been kept by the Parent Company, or returns adequate for our audit have not been received from branches not visited by us; or
- the Parent Company financial statements and the part of the Directors' Remuneration Report to be audited are not in agreement with the accounting records and returns; or
- certain disclosures of Directors' remuneration specified by law are not made; or
- we have not received all the information and explanations we require for our audit.

10. RESPONSIBILITIES OF DIRECTORS

As explained more fully in the statement of Directors' responsibilities set out on page 91, the Directors are responsible for the preparation of the Consolidated Financial Statements and for being satisfied that they give a true and fair view, and for such internal control as the Directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the Directors are responsible for assessing Shell and the Parent Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors either intend to liquidate Shell or the Parent Company or to cease operations, or have no realistic alternative but to do so.

11. AUDITOR'S RESPONSIBILITIES FOR THE AUDIT OF THE FINANCIAL STATEMENTS

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISA (UK) will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

12. EXPLANATION AS TO WHAT EXTENT THE AUDIT WAS CONSIDERED CAPABLE OF DETECTING IRREGULARITIES, INCLUDING FRAUD

The objectives of our audit, in respect to fraud, are; to identify and assess the risks of material misstatement of the financial statements due to fraud; to obtain sufficient appropriate audit evidence regarding the assessed risks of material misstatement due to fraud, through designing and implementing appropriate responses; and to respond appropriately to fraud or suspected fraud identified during the audit. However, the primary responsibility for the prevention and detection of fraud rests with both those charged with governance of the entity and management.

Our approach was as follows:

- We obtained an understanding of the legal and regulatory frameworks that are applicable to Shell and determined that the most significant are those that relate to the reporting framework (IFRS, Companies Act 2006, the UK Corporate Governance Code, the US Securities Exchange Act of 1934 and the Listing Rules of the UK Listing Authority) and the relevant tax compliance regulations in the jurisdictions in which Shell operates. In addition, we concluded that there are certain significant laws and regulations that may have an effect on the determination of the amounts and disclosures in the financial statements and those laws and regulations relating to health and safety, employee matters, environmental, and bribery and corruption practices.
- We understood how Shell is complying with those frameworks by making enquiries of management, internal audit, those responsible for legal and compliance procedures and the Company Secretary. We corroborated our enquiries through our review of Board minutes, papers provided to the AC and correspondence received from regulatory bodies and noted that there was no contradictory evidence.
- We assessed the susceptibility of Shell's Consolidated Financial Statements to material misstatement, including how fraud might occur, by embedding forensic specialists into our audit team. Our forensic specialists worked with the group audit team to identify the fraud risks across various parts of the business. In addition, we utilised internal and external information to perform a fraud risk assessment for each of the countries of operation. We considered the risk of fraud through management override and, in response, we incorporated data analytics across manual journal entries into our audit approach. We also considered the possibility of fraudulent or corrupt payments made through third parties and conducted detailed analytical testing on third party vendors in high risk jurisdictions. Where instances of risk behaviour patterns were identified through our data analytics, we performed additional audit procedures to address each identified risk. These procedures included testing of transactions back to source information and were designed to provide reasonable assurance that the financial statements were free from fraud or error. We also conducted specific audit procedures in relation to the risk of bribery and corruption across various countries of operation determined by a risk based process.
- Based on the results of our risk assessment we designed our audit procedures to identify non-compliance with such laws and regulations identified above. Our procedures involved journal entry testing, with a focus on journals meeting our defined risk criteria based on our understanding of the business; enquiries of legal counsel, group management, internal audit and all full and specific scope management; review of the volume and nature of complaints received by the whistleblowing hotline during the year and focused testing, as discussed in the key audit matters section 7 above.
- If any instance of non-compliance with laws and regulations were identified, these were communicated to the relevant local EY teams who performed sufficient and appropriate audit procedures supplemented by audit procedures performed at the group level. Where appropriate we consulted our forensic specialists.

A further description of our responsibilities for the audit of the financial statements is located on the Financial Reporting Council's website at <https://www.frc.org.uk/auditorsresponsibilities>. This description forms part of our auditor's report.

13. OTHER MATTERS WE ARE REQUIRED TO ADDRESS

Following the recommendation of the AC we were re-appointed by the Company's Annual General Meeting (AGM) on May 22, 2018, as auditor of the Company to hold office until the conclusion of the next AGM of the Company, and signed an engagement letter on May 22, 2018. Our total uninterrupted period of engagement is three years covering periods from our appointment through to the period ending December 31, 2018.

The non-audit services prohibited by the FRC's Ethical Standard were not provided to Shell or the Parent Company and we remain independent of Shell and the Parent Company in conducting the audit.

Our audit opinion is consistent with our additional report to the AC explaining the results of our audit.

14. USE OF OUR REPORT

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the Company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the Company and the Company's members as a body, for our audit work, for this report, or for the opinions we have formed.

/s/ Allister Wilson (Senior Statutory Auditor)

for and on behalf of Ernst & Young LLP,
Statutory Auditor
London
March 13, 2019

1. The maintenance and integrity of the Shell website are the responsibility of the Directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
2. Legislation in the UK governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

The report set out above is included for the purposes of Royal Dutch Shell plc's 2018 Annual Report and Accounts only and does not form part of Royal Dutch Shell plc's Annual Report on Form 20-F for 2018.

Report of Independent Registered Public Accounting Firm

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF ROYAL DUTCH SHELL PLC

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Royal Dutch Shell plc (the Company) as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the Consolidated Financial Statements). In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with International Financial Reporting Standards (IFRS) issued by the International Accounting Standards Board (IASB) and in conformity with IFRS as adopted by the European Union.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated March 13, 2019, expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2016.
London, United Kingdom
March 13, 2019

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF ROYAL DUTCH SHELL PLC

Opinion on Internal Control over Financial Reporting

We have audited Royal Dutch Shell plc's (the Company) internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Consolidated Financial Statements of the Company, and our report dated March 13, 2019, expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting as set out on page 104. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorisations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorised acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

London, United Kingdom

March 13, 2019

1. The maintenance and integrity of the Shell website are the responsibility of the Directors of Royal Dutch Shell plc; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
2. Legislation in the UK governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

The reports set out above are included for the purposes of Royal Dutch Shell plc's 2018 Annual Report on Form 20-F only and do not form part of Royal Dutch Shell plc's Annual Report on Accounts for 2018.

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Consolidated Financial Statements Continued

Consolidated Statement of Income

	Notes	2018	2017	\$ million 2016
Revenue	4	388,379	305,179	233,591
Share of profit of joint ventures and associates	9	4,106	4,225	3,545
Interest and other income	5	4,071	2,466	2,897
Total revenue and other income		396,556	311,870	240,033
Purchases		294,399	223,447	162,574
Production and manufacturing expenses		26,970	26,652	28,434
Selling, distribution and administrative expenses		11,360	10,509	12,101
Research and development		986	922	1,014
Exploration		1,340	1,945	2,108
Depreciation, depletion and amortisation	4	22,135	26,223	24,993
Interest expense	6	3,745	4,042	3,203
Total expenditure		360,935	293,740	234,427
Income before taxation		35,621	18,130	5,606
Taxation charge	16	11,715	4,695	829
Income for the period	4	23,906	13,435	4,777
Income attributable to non controlling interest		554	458	202
Income attributable to Royal Dutch Shell plc shareholders		23,352	12,977	4,575
Basic earnings per share (\$)	24	2.82	1.58	0.58
Diluted earnings per share (\$)	24	2.80	1.56	0.58

Consolidated Statement of Comprehensive Income

	Notes	2018	2017	\$ million 2016
Income for the period	4	23,906	13,435	4,777
Other comprehensive income/(loss), net of tax	22			
Items that may be reclassified to income in later periods:				
Currency translation differences		(3,172)	5,156	703
Unrealised gains/(losses) on securities		[A]	593	(214)
Debt instruments remeasurements		(15) [A]		
Cash flow hedging gains/(losses)		730	(552)	(617)
Net investment hedging losses		–	–	(2,024)
Deferred cost of hedging		(209) [A]		
Share of other comprehensive (loss)/income of joint ventures and associates	9	(10)	170	(28)
Total		(2,676)	5,367	(2,180)
Items that are not reclassified to income in later periods:				
Retirement benefits remeasurements		3,588	604	(3,817)
Equity instruments remeasurements		(153) [A]		
Share of other comprehensive income of joint ventures and associates	9	193 [A]		
Total		3,628	604	(3,817)
Other comprehensive income/(loss) for the period		952	5,971	(5,997)
Comprehensive income/(loss) for the period		24,858	19,406	(1,220)
Comprehensive income attributable to non-controlling interest		383	578	154
Comprehensive income/(loss) attributable to Royal Dutch Shell plc shareholders		24,475	18,828	(1,374)

[A] See Note 2 Significant accounting policies, judgements and estimates regarding the implementation of IFRS 9 *Financial Instruments*

Consolidated Balance Sheet

		\$ million	
	Notes	Dec 31, 2018	Dec 31, 2017
Assets			
Non-current assets			
Intangible assets	7	23,586	24,180
Property, plant and equipment	8	223,175	226,380
Joint ventures and associates	9	25,329	27,927
Investments in securities	10	3,074	7,222
Deferred tax	16	12,097	13,791
Retirement benefits	17	6,051	2,799
Trade and other receivables [A]	11	7,826	8,475
Derivative financial instruments [A]	19	574	919
		301,712	311,693
Current assets			
Inventories	12	21,117	25,223
Trade and other receivables [A]	11	42,431	44,565
Derivative financial instruments [A]	19	7,193	5,304
Cash and cash equivalents	13	26,741	20,312
		97,482	95,404
Total assets		399,194	407,097
Liabilities			
Non-current liabilities			
Debt	14	66,690	73,870
Trade and other payables [A]	15	2,735	3,447
Derivative financial instruments [A]	19	1,399	981
Deferred tax	16	14,837	13,007
Retirement benefits	17	11,653	13,247
Decommissioning and other provisions	18	21,533	24,966
		118,847	129,518
Current liabilities			
Debt	14	10,134	11,795
Trade and other payables [A]	15	48,888	51,410
Derivative financial instruments [A]	19	7,184	5,253
Taxes payable	16	7,497	7,250
Retirement benefits	17	451	594
Decommissioning and other provisions	18	3,659	3,465
		77,813	79,767
Total liabilities		196,660	209,285
Equity			
Share capital	20	685	696
Shares held in trust		(1,260)	(917)
Other reserves	22	16,615	16,932
Retained earnings		182,606	177,645
Equity attributable to Royal Dutch Shell plc shareholders		198,646	194,356
Non-controlling interest		3,888	3,456
Total equity		202,534	197,812
Total liabilities and equity		399,194	407,097

[A] With effect from 2018, current and non-current derivative assets and liabilities are no longer presented as part of Trade and other receivables and Trade and other payables, but separately disclosed on the Consolidated Balance Sheet to provide more insight. Comparatives were revised to align with the current year presentation.

Signed on behalf of the Board

/s/ Jessica Uhl

Jessica Uhl
Chief Financial Officer
March 13, 2019

Consolidated Statement of Changes in Equity

\$ million

	Equity attributable to Royal Dutch Shell plc shareholders					Non-controlling interest	Total equity
	Share capital (see Note 20)	Shares held in trust	Other reserves (see Note 22)	Retained earnings	Total		
At January 1, 2018 (as previously published)	696	(917)	16,932	177,645	194,356	3,456	197,812
Impact of IFRS 9 [A]	—	—	(138)	88	(50)	—	(50)
At January 1, 2018 (as revised)	696	(917)	16,794	177,733	194,306	3,456	197,762
Comprehensive income for the period	—	—	1,123	23,352	24,475	383	24,858
Transfer from other comprehensive income [B]	—	—	(971)	971	—	—	—
Dividends (see Note 23)	—	—	—	(15,675)	(15,675)	(586)	(16,261)
Repurchases of shares [C]	(11)	—	11	(4,519)	(4,519)	—	(4,519)
Share-based compensation [D] [E]	—	(343)	(342)	693	8	—	8
Other changes in non-controlling interest	—	—	—	51	51	635	686
At December 31, 2018	685	(1,260)	16,615	182,606	198,646	3,888	202,534
At January 1, 2017	683	(901)	11,298	175,566	186,646	1,865	188,511
Comprehensive income for the period	—	—	5,851	12,977	18,828	578	19,406
Dividends (see Note 23)	—	—	—	(15,628)	(15,628)	(406)	(16,034)
Scrip dividends (see Note 23)	13	—	(13)	4,751	4,751	—	4,751
Share-based compensation	—	(16)	(204)	(74)	(294)	—	(294)
Other changes in non-controlling interest	—	—	—	53	53	1,419	1,472
At December 31, 2017	696	(917)	16,932	177,645	194,356	3,456	197,812
At January 1, 2016	546	(584)	(17,186)	180,100	162,876	1,245	164,121
Comprehensive loss for the period	—	—	(5,949)	4,575	(1,374)	154	(1,220)
Dividends (see Note 23)	—	—	—	(14,959)	(14,959)	(180)	(15,139)
Scrip dividends (see Note 23)	17	—	(17)	5,282	5,282	—	5,282
Shares issued	120	—	33,930	—	34,050	—	34,050
Share-based compensation	—	(317)	520	141	344	—	344
Other changes in non-controlling interest	—	—	—	427	427	646	1,073
At December 31, 2016	683	(901)	11,298	175,566	186,646	1,865	188,511

[A] See Note 2 Significant Accounting Policies, Judgements and Estimates regarding the implementation of IFRS 9 *Financial Instruments*.

[B] The transfer mainly relates to the sale of Shell's shareholding in Malaysia LNG Tiga Sendirian Berhad (\$617 million) and the sale of shares in Canadian Natural Resources Limited (\$481 million) (see Note 22).

[C] The repurchase of shares recognised through retained earnings includes the aggregate maximum consideration Shell is contractually bound to under the current tranche of the buyback programme, plus associated stamp duty.

[D] The amendments to IFRS 2 *Share-based payment* became effective January 1, 2018. Following adoption of the amendments, components of share-based payments (related to tax) that were previously classified as cash-settled are now classified as equity-settled. This resulted in an increase of \$172 million in the share plan reserve within other reserves and a net increase of \$125 million in retained earnings (see Note 22).

[E] Includes a reclassification of \$503 million between Other reserves and Retained earnings, which relates to the unwinding of expired share options.

Consolidated Statement of Cash Flows

				\$ million
	Notes	2018	2017	2016
Income for the period	4	23,906	13,435	4,777
Adjustment for:				
Current tax	16	10,475	6,591	2,731
Interest expense (net)		2,878	3,365	2,752
Depreciation, depletion and amortisation	8	22,135	26,223	24,993
Exploration well write-offs [A]		449	897	834
Net gains on sale and revaluation of non-current assets and businesses		(3,265)	(1,640)	(2,141)
Share of profit of joint ventures and associates		(4,106)	(4,225)	(3,545)
Dividends received from joint ventures and associates		4,903	4,998	3,820
Decrease/(increase) in inventories		2,823	(2,079)	(5,658)
Decrease/(increase) in current receivables [A]		1,955	(2,577)	(4,127)
(Decrease)/increase in current payables [A]		(1,336)	2,406	1,359
Derivative financial instruments [A]		799	(1,039)	1,461
Deferred tax, retirement benefits, decommissioning and other provisions [A]		219	(4,300)	(1,588)
Other [A]		921	(98)	(619)
Tax paid		(9,671)	(6,307)	(4,434)
Cash flow from operating activities		53,085	35,650	20,615
Capital expenditure		(23,011)	(20,845)	(22,116)
Acquisition of BG Group plc, net of cash and cash equivalents acquired		—	—	(11,421)
Investments in joint ventures and associates		(880)	(595)	(1,330)
Proceeds from sale of property, plant and equipment and businesses		4,366	8,808	2,072
Proceeds from sale of joint ventures and associates		1,594	2,177	1,565
Interest received		823	724	470
Other		3,449 [B]	1,702 [C]	(203)
Cash flow from investing activities		(13,659)	(8,029)	(30,963)
Net decrease in debt with maturity period within three months		(396)	(869)	(360)
Other debt:				
New borrowings		3,977	760	18,144
Repayments		(11,912)	(11,720)	(6,710)
Interest paid		(3,574)	(3,550)	(2,938)
Change in non-controlling interest		678	293	1,110
Cash dividends paid to:				
Royal Dutch Shell plc shareholders	23	(15,675)	(10,877)	(9,677)
Non-controlling interest		(584)	(406)	(180)
Repurchases of shares		(3,947)	—	—
Shares held in trust: net purchases and dividends received		(1,115)	(717)	(160)
Cash flow from financing activities		(32,548)	(27,086)	(771)
Currency translation differences relating to cash and cash equivalents		(449)	647	(1,503)
Increase/(decrease) in cash and cash equivalents		6,429	1,182	(12,622)
Cash and cash equivalents at beginning of year		20,312	19,130	31,752
Cash and cash equivalents at end of year	13	26,741	20,312	19,130

[A] With effect from 2018 Exploration well write offs, previously presented under Other and changes in current and non current Derivative financial instruments previously presented under Decrease/increases in current receivables and payables and Other are shown separately. Prior years comparatives within Cash flow from operating activities have been revised to conform with the current year presentation.

Overall, the revisions do not have an impact on the previously published cash flow from operating activities.

[B] Includes \$3,307 million from the sale of shares in Canadian Natural Resources Limited, which were received in connection with the oil sands divestment.

[C] Includes \$2,635 million from the sale of Shell's interest in Woodside Petroleum Limited.

Notes to the Consolidated Financial Statements

1 BASIS OF PREPARATION

The Consolidated Financial Statements of Royal Dutch Shell plc (the Company) and its subsidiaries (collectively referred to as Shell) have been prepared in accordance with the provisions of the Companies Act 2006 (the Act) and Article 4 of the IAS Regulation, and therefore in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union. As applied to Shell, there are no material differences from IFRS as issued by the International Accounting Standards Board (IASB); therefore, the Consolidated Financial Statements have been prepared in accordance with IFRS as issued by the IASB.

As described in the accounting policies in Note 2, the Consolidated Financial Statements have been prepared under the historical cost convention except for certain items measured at fair value. Those accounting policies have been applied consistently in all periods, except for those accounting standards that were adopted from January 1, 2018 (see Note 2 below).

The Consolidated Financial Statements were approved and authorised for issue by the Board of Directors on March 13, 2019.

2 SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS AND ESTIMATES

This Note describes Shell's significant accounting policies, which are those relevant to an understanding of the Consolidated Financial Statements and includes the measurement bases used in their preparation. It allows an understanding as to how transactions, other events and conditions are reported. It also describes: (a) judgements, apart from those involving estimations, that management makes in applying the policies that have the most significant effect on the amounts recognised in the Consolidated Financial Statements; and (b) estimations, including assumptions about the future, that management makes in applying the policies. The sources of estimation uncertainty that have a significant risk of a material adjustment to the carrying amounts of assets and liabilities within the next financial year are specifically identified as a significant estimate.

The accounting policies applied are consistent with those of the previous financial years except for the adoption as from January 1, 2018 of IFRS 9 *Financial Instruments* (IFRS 9), IFRS 15 *Revenue from Contracts with Customers* (IFRS 15) and IFRS 2 *Share-based payment* (IFRS 2) amendments: Classification and measurement of share-based payment transactions.

IFRS 9 sets out the requirements for recognising and measuring financial assets, financial liabilities and certain contracts to buy or sell non-financial items. Furthermore, on a prospective basis the standard facilitates use of hedge accounting and results in different income recognition upon the sale of certain investments in securities. The adoption of IFRS 9 resulted in a decrease of \$83 million in equity at January 1, 2018, mainly representing the recognition of additional provisions for impairment of receivables under the expected credit loss model. In addition, changing the measurement basis from amortised cost to fair value for certain financial assets resulted in an increase of \$33 million in equity at January 1, 2018. Furthermore, a reclassification within equity between other reserves and retained earnings, primarily representing deferred cost of hedging, was recognised.

IFRS 15 provides a single model of accounting for revenue arising from contracts with customers based on the identification and satisfaction of performance obligations, and revenue from contracts with customers that is distinguished from other resources. For the adoption of IFRS 15 the modified retrospective transition approach was applied. Although the accounting for certain contracts, such as those with provisional pricing or take-or pay arrangements, and underlifts and overlifts, did change, no transition adjustment is presented as the adoption did not have a significant effect on Shell's accounting or disclosures.

The amendments to IFRS 2 became effective January 1, 2018. Following adoption of the amendments, components of share-based payments (related to tax) that were previously classified as cash-settled are now classified as equity-settled. This resulted in an increase of \$172 million in the share plan reserve within other reserves and a net increase of \$125 million in retained earnings.

NATURE OF THE CONSOLIDATED FINANCIAL STATEMENTS

The Consolidated Financial Statements are presented in US dollars (dollars) and comprise the financial statements of the Company and its subsidiaries, being those entities over which the Company has control, either directly or indirectly, through exposure or rights to their variable returns and the ability to affect those returns through its power over the entities. Information about subsidiaries at December 31, 2018, can be found in Exhibit 8.

Subsidiaries are consolidated from the date on which control is obtained until the date that such control ceases, using consistent accounting policies. All inter-company balances and transactions, including unrealised profits arising from such transactions, are eliminated. Unrealised losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. Non-controlling interest represents the proportion of income, other comprehensive income and net assets in subsidiaries that is not attributable to the Company's shareholders.

CURRENCY TRANSLATION

Foreign currency transactions are translated using the exchange rate at the dates of the transactions or valuation where items are re-measured. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at quarter-end exchange rates of monetary assets and liabilities denominated in foreign currencies (including those in respect of inter-company balances, unless related to loans of a long-term investment nature)

are recognised in income, except when recognised in other comprehensive income in respect of cash flow or net investment hedges, and presented within interest and other income or within purchases where not related to financing. Share capital issued in currencies other than the dollar is translated at the exchange rate at the date of issue.

On consolidation, assets and liabilities of non-dollar entities are translated to dollars at year-end rates of exchange, while their statements of income, other comprehensive income and cash flows are translated at quarterly average rates. The resulting translation differences are recognised as currency translation differences within other comprehensive income. Upon sale of all or part of an interest in, or upon liquidation of, an entity, the appropriate portion of cumulative currency translation differences related to that entity are generally recognised in income.

REVENUE RECOGNITION (from January 1, 2018)

Revenue from sales of oil, natural gas, chemicals and other products is recognised at the transaction price which Shell expects to be entitled to, after deducting sales taxes, excise duties and similar levies. For contracts that contain separate performance obligations the transaction price is allocated to those separate performance obligations by reference to their relative standalone selling prices.

Revenue is recognised when control of the products has been transferred to the customer. For sales by Integrated Gas and Upstream operations, this generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism; for sales by refining operations, it is either when the product is placed onboard a vessel or offloaded from the vessel, depending on the contractually agreed terms; and for sales of oil products and chemicals, it is either at the point of delivery or the point of receipt, depending on contractual conditions.

Revenue resulting from hydrocarbon production from properties in which Shell has an interest with partners in joint arrangements is recognised on the basis of Shell's volumes lifted and sold. Revenue resulting from the production of oil and natural gas under production-sharing contracts (PSCs) is recognised for those amounts relating to Shell's cost recoveries and Shell's share of the remaining production. Gains and losses on derivative contracts and the revenue and costs associated with other contracts that are classified as held for trading purposes are reported on a net basis in the Consolidated Statement of Income. Purchases and sales of hydrocarbons under exchange contracts that are necessary to obtain or reposition feedstocks for refinery operations are presented net in the Consolidated Statement of Income.

Revenue resulting from arrangements that are not considered contracts with customers is presented as revenue from other sources.

REVENUE RECOGNITION (prior to January 1, 2018)

Revenue from sales of oil, natural gas, chemicals and other products is recognised at the fair value of consideration received or receivable, after deducting sales taxes, excise duties and similar levies, when the significant risks and rewards of ownership have been transferred, which is when title passes to the customer. For sales by Integrated Gas and Upstream operations, this generally occurs when product is physically transferred into a vessel, pipe or other delivery mechanism; for sales by refining operations, it is either when product is placed onboard a vessel or offloaded from the vessel, depending on the contractually agreed terms; and for sales of oil products and chemicals, it is either at the point of delivery or the point of receipt, depending on contractual conditions.

Revenue resulting from hydrocarbon production from properties in which Shell has an interest with partners in joint arrangements is recognised on the basis of Shell's working interest (entitlement method). Revenue resulting from the production of oil and natural gas under production-sharing contracts (PSCs) is recognised for those amounts relating to Shell's cost recoveries and Shell's share of the remaining production. Gains and losses on derivative contracts and the revenue and costs associated with other contracts that are classified as held for trading purposes are reported on a net basis in the Consolidated Statement of Income. Purchases and sales of hydrocarbons under exchange contracts that are necessary to obtain or reposition feedstocks for refinery operations are presented net in the Consolidated Statement of Income.

RESEARCH AND DEVELOPMENT

Development costs that are expected to generate probable future economic benefits are capitalised as intangible assets. All other research and development expenditure is recognised in income as incurred.

EXPLORATION COSTS

Hydrocarbon exploration costs are accounted for under the successful efforts method: exploration costs are recognised in income when incurred, except that exploratory drilling costs, including in respect of operating leases, are included in property, plant and equipment pending determination of proved reserves. Exploration costs capitalised in respect of exploration wells that are more than 12 months old are written off unless: (a) proved reserves are booked; or (b) (i) they have found commercially producible quantities of reserves and (ii) they are subject to further exploration or appraisal activity in that either drilling of additional exploratory wells is under way or firmly planned for the near future or other activities are being undertaken to sufficiently progress the assessing of reserves and the economic and operating viability of the project.

PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLE ASSETS

Recognition

Property, plant and equipment comprise assets owned by Shell, assets held by Shell under finance leases and assets operated by Shell as contractor in PSCs. They include rights and concessions in respect of properties with proved reserves (proved properties) and with no proved reserves (unproved properties). Property, plant and equipment, including expenditure on major inspections, and intangible assets are initially recognised in the Consolidated Balance Sheet at cost where it is probable that they will generate future economic benefits. This includes capitalisation of decommissioning and restoration costs associated with provisions for asset retirement (see "Provisions"), certain development costs (see "Research and development") and the effects of associated cash flow hedges (see "Financial instruments (from January 1, 2018)") as applicable. The accounting for exploration costs is described separately (see "Exploration costs"). Intangible assets include goodwill, liquefied natural gas (LNG) off-take and sales contracts obtained through acquisition, software costs and trademarks. Interest is capitalised, as an increase in property, plant and equipment, on major capital projects during construction.

Property, plant and equipment and intangible assets are subsequently carried at cost less accumulated depreciation, depletion and amortisation (including any impairment). Gains and losses on sale are determined by comparing the proceeds with the carrying amounts of assets sold and are recognised in income, within interest and other income.

An asset is classified as held for sale if its carrying amount will be recovered principally through sale rather than through continuing use, which is when the sale is highly probable, and it is available for immediate sale. Assets classified as held for sale are measured at the lower of the carrying amount upon classification and the fair value less costs to sell.

Depreciation, depletion and amortisation

Property, plant and equipment related to hydrocarbon production activities are in principle depreciated on a unit-of-production basis over the proved developed reserves of the field concerned, other than assets whose useful lives differ from the lifetime of the field which are depreciated applying the straight-line method. However, for certain Upstream assets, the use for this purpose of proved developed reserves, which are determined using the SEC-mandated yearly average oil and gas prices, would result in depreciation charges for these assets which do not reflect the pattern in which their future economic benefits are expected to be consumed as, for example, it may result in assets with long-term expected lives being depreciated in full within one year. Therefore, in these instances, other approaches are applied to determine the reserves base for the purpose of calculating depreciation, such as using management's expectations of future oil and gas prices rather than yearly average prices, to provide a phasing of periodic depreciation charges that more appropriately reflects the expected utilisation of the assets concerned.

Rights and concessions in respect of proved properties are depleted on the unit-of-production basis over the total proved reserves of the relevant area. Where individually insignificant, unproved properties may be grouped and depreciated based on factors such as the average concession term and past experience of recognising proved reserves.

Property, plant and equipment held under finance leases and capitalised LNG off-take and sales contracts are depreciated or amortised over the term of the respective contract. Other property, plant and equipment and intangible assets are depreciated or amortised on a straight-line basis over their estimated useful lives, except for goodwill, which is not amortised. They include refineries and chemical plants (for which the useful life is generally 20 years), retail service stations (15 years), upgraders (30 years) and major inspection costs, which are depreciated over the estimated period before the next planned major inspection (three to five years).

On classification of an asset as held for sale, depreciation ceases.

Estimates of the useful lives and residual values of property, plant and equipment and intangible assets are reviewed annually and adjusted if appropriate.

Impairment

The carrying amount of goodwill is tested for impairment annually; in addition, assets other than unproved properties (see "Exploration costs") are tested for impairment whenever events or changes in circumstances indicate that the carrying amounts for those assets may not be recoverable. On classification as held for sale, the carrying amounts of property, plant and equipment and intangible assets are also reviewed. If assets are determined to be impaired, the carrying amounts of those assets are written down to their recoverable amount, which is the higher of fair value less costs to sell (see "Fair value measurements") and value in use.

Value in use is determined as the amount of estimated risk-adjusted discounted future cash flows. For this purpose, assets are grouped into cash-generating units based on separately identifiable and largely independent cash inflows. Estimates of future cash flows used in the evaluation of impairment of assets are made using management's forecasts of commodity prices, market supply and demand, product margins and, in the case of exploration and production assets, expected production volumes. The latter takes into account assessments of field and reservoir performance and includes expectations about both proved reserves and volumes that are expected to constitute proved reserves in the future (unproved volumes), which are risk-weighted utilising geological, production, recovery and economic projections. Cash flow estimates are risk-adjusted to reflect local conditions as appropriate and discounted at a rate based on Shell's marginal cost of debt.

Impairments, except those related to goodwill, are reversed as applicable to the extent that the events or circumstances that triggered the original impairment have changed.

Impairment losses and reversals are reported within depreciation, depletion and amortisation.

Judgements and estimates

Proved oil and gas reserves

Unit-of-production depreciation, depletion and amortisation charges are principally measured based on management's estimates of proved developed oil and gas reserves. Also, exploration drilling costs are capitalised pending the results of further exploration or appraisal activity, which may take several years to complete and before any related proved reserves can be booked.

Proved reserves are estimated by reference to available geological and engineering data and only include volumes for which access to market is assured with reasonable certainty. Yearly average oil and gas prices are applied in the determination of proved reserves. Estimates of proved reserves are inherently imprecise, require the application of judgement and are subject to regular revision, either upward or downward, based on new information such as from the drilling of additional wells, observation of long-term reservoir performance under producing conditions and changes in economic factors, including product prices, contract terms, legislation or development plans.

Changes to estimates of proved developed reserves affect prospectively the amounts of depreciation, depletion and amortisation charged and, consequently, the carrying amounts of exploration and production assets. It is expected, however, that in the normal course of business the diversity of the asset portfolio will limit the effect of such revisions. The outcome of, or assessment of plans for, exploration or appraisal activity may result in the related capitalised exploration drilling costs being recognised in income in that period.

Judgement is involved in determining when to use an alternative reserves base in order to appropriately reflect the expected utilisation of the assets concerned (see "Depreciation, depletion and amortisation").

Information about the carrying amounts of exploration and production assets and the amounts charged to income, including depreciation, depletion and amortisation and the quantitative impact of the use of an alternative reserve base, is presented in Note 8.

Impairment

For the purposes of determining whether impairment of assets has occurred, and the extent of any impairment loss or its reversal, the key assumptions management uses in estimating risk-adjusted future cash flows for value-in-use measures are future oil and gas prices, expected production volumes and refining margins appropriate to the local circumstances and environment. These assumptions and the judgements of management that are based on them are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates.

The determination of cash-generating units requires judgement. Changes in this determination could impact the calculation of value in use and therefore the conclusion on the recoverability of assets' carrying amounts when performing an impairment test.

Judgement, which is subject to change as new information becomes available, can be required in determining when an asset is classified as held for sale. A change in that judgement could result in impairment charges affecting income, depending on whether classification requires a write down of the asset to its fair value less costs to sell.

Significant estimate

Future price assumptions, presented in Note 8, tend to be stable because management does not consider short-term increases or decreases in prices as being indicative of long-term levels, but they are nonetheless subject to change. Expected production volumes, which comprise proved reserves and unproved volumes, are used for impairment testing because management believes this to be the most appropriate indicator of expected future cash flows. As discussed in "Proved oil and gas reserves" above, reserves estimates are inherently imprecise. Furthermore, projections about unproved volumes are based on information that is necessarily less robust than that available for mature reservoirs. Due to the nature and geographical spread of the business activity in which those assets are used, it is typically not practicable to estimate the likelihood or extent of impairments under different sets of assumptions for Shell overall.

Changes in assumptions could affect the carrying amounts of assets, and any impairment losses and reversals will affect income.

Information about the carrying amounts of assets and impairments is presented in Notes 7 and 8.

LEASES

Agreements under which payments are made to owners in return for the right to use an asset for a period are accounted for as leases. Leases that transfer substantially all the risks and rewards of ownership are recognised at the commencement of the lease term as finance leases within property, plant and

equipment and debt at the fair value of the leased asset or, if lower, at the present value of the minimum lease payments. Finance lease payments are apportioned between interest expense and repayments of debt. All other leases are classified as operating leases and the cost is recognised in income on a straight-line basis, except where capitalised as exploration drilling costs (see "Exploration costs").

JOINT ARRANGEMENTS AND ASSOCIATES

Arrangements under which Shell has contractually agreed to share control (see "Nature of the Consolidated Financial Statements" for the definition of control) with another party or parties are joint ventures where the parties have rights to the net assets of the arrangement, or joint operations where the parties have rights to the assets and obligations for the liabilities relating to the arrangement. Investments in entities over which Shell has the right to exercise significant influence but neither control nor joint control are classified as associates. Information about incorporated joint arrangements and associates at December 31, 2018, can be found in Exhibit 8.

Investments in joint ventures and associates are accounted for using the equity method, under which the investment is initially recognised at cost and subsequently adjusted for the Shell share of post-acquisition income less dividends received and the Shell share of other comprehensive income and other movements in equity, together with any loans of a long-term investment nature. Where necessary, adjustments are made to the financial statements of joint ventures and associates to bring the accounting policies used into line with those of Shell. In an exchange of assets and liabilities for an interest in a joint venture, the non-Shell share of any excess of the fair value of the assets and liabilities transferred over the pre-exchange carrying amounts is recognised in income. Unrealised gains on other transactions between Shell and its joint ventures and associates are eliminated to the extent of Shell's interest in them; unrealised losses are treated similarly but may also result in an assessment of whether the asset transferred is impaired.

Shell recognises its assets and liabilities relating to its interests in joint operations, including its share of assets held jointly and liabilities incurred jointly with other partners.

INVENTORIES

Inventories are stated at cost or net realisable value, whichever is lower. Cost comprises direct purchase costs (including transportation), and associated costs incurred in bringing inventories to their present condition and location, and is determined using the first-in, first-out (FIFO) method for oil, gas and chemicals and by the weighted average cost method for materials.

TAXATION

The charge for current tax is calculated based on the income reported by the Company and its subsidiaries, as adjusted for items that are non-taxable or disallowed and using rates that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is determined, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the Consolidated Balance Sheet and on unused tax losses and credits carried forward.

Deferred tax assets and liabilities are calculated using the enacted or substantively enacted rates that are expected to apply when an asset is realised or a liability is settled. They are not recognised where they arise on the initial recognition of goodwill or of an asset or liability in a transaction (other than in a business combination) that, at the time of the transaction, affects neither accounting nor taxable profit, or in respect of taxable temporary differences associated with subsidiaries, joint ventures and associates where the reversal of the respective temporary difference can be controlled by Shell and it is probable that it will not reverse in the foreseeable future.

Deferred tax assets are recognised to the extent that it is probable that future taxable profits will be available against which the deductible temporary differences, unused tax losses and credits carried forward can be utilised.

Income taxes are recognised in income except when they relate to items recognised in other comprehensive income, in which case the tax is recognised in other comprehensive income. Income tax assets and liabilities are presented separately in the Consolidated Balance Sheet except where there is a right of offset within fiscal jurisdictions and an intention to settle such balances on a net basis.

Judgements and estimates

Tax liabilities are recognised when it is considered probable that there will be a future outflow of funds to a taxing authority. In such cases, provision is made for the amount that is expected to be settled, where this can be reasonably estimated. A change in estimate of the likelihood of a future outflow and/or in the expected amount to be settled would be recognised in income in the period in which the change occurs. This requires the application of judgement as to the ultimate outcome, which can change over time depending on facts and circumstances. Judgements mainly relate to transfer pricing, including inter-company financing, interpretation of PSCs, expenditure deductible for tax purposes and taxation arising on disposal.

Deferred tax assets are recognised only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those assets are likely to reverse, and a judgement as to whether or not there will be sufficient taxable profits available to offset the assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability

change, there can be an increase or decrease in the amounts recognised in respect of deferred tax assets as well as in the amounts recognised in income in the period in which the change occurs.

Taxation information, including charges and deferred tax assets and liabilities, is presented in Note 16. Income taxes include taxes at higher rates levied on income from certain Integrated Gas and Upstream activities.

RETIREMENT BENEFITS

Benefits in the form of retirement pensions and healthcare and life insurance are provided to certain employees and retirees under defined benefit and defined contribution plans.

Obligations under defined benefit plans are calculated annually by independent actuaries using the projected unit credit method, which takes into account employees' years of service and, for pensions, average or final pensionable remuneration, and are discounted to their present value using interest rates of high-quality corporate bonds denominated in the currency in which the benefits will be paid and of a duration consistent with the plan obligations. Where plans are funded, payments are made to independently managed trusts; assets held by those trusts are measured at fair value. Defined benefit plan surpluses are recognised as assets to the extent that they are considered recoverable, which is generally by way of a refund or lower future employer contributions.

The amounts recognised in income in respect of defined benefit plans mainly comprise service cost and net interest. Service cost comprises principally the increase in the present value of the obligation for benefits resulting from employee service during the period (current service cost) and also amounts relating to past service and settlements or amendments of plans. Plan amendments are changes to benefits and are generally recognised when all legal and regulatory approvals have been received and the effects have been communicated to members. Net interest is calculated using the net defined benefit liability or asset matched against the discount rate yield curve at the beginning of each year for each plan. Remeasurements of the net defined benefit liability or asset resulting from actuarial gains and losses and the return on plan assets excluding the amount recognised in income are recognised in other comprehensive income.

For defined contribution plans, pension expense represents the amount of employer contributions payable for the period.

Significant judgements and estimates

Defined benefit obligations and plan assets, and the resulting liabilities and assets that are recognised, are subject to significant volatility as actuarial assumptions regarding future outcomes and market values change. Substantial judgement is required in determining the actuarial assumptions, which vary for the different plans to reflect local conditions but are determined under a common process in consultation with independent actuaries. The assumptions applied in respect of each plan are reviewed annually and adjusted where necessary to reflect changes in experience and actuarial recommendations.

Information about the amounts reported in respect of defined benefit pension plans, assumptions applicable to the principal plans and their sensitivity to changes are presented in Note 17.

PROVISIONS

Provisions are recognised at the balance sheet date at management's best estimate of the expenditure required to settle the present obligation. Non-current amounts are discounted at a rate intended to reflect the time value of money. The carrying amounts of provisions are regularly reviewed and adjusted for new facts or changes in law or technology.

Provisions for decommissioning and restoration costs, which arise principally in connection with hydrocarbon production facilities and pipelines, are measured on the basis of current requirements, technology and price levels; the present value is calculated using amounts discounted over the useful economic life of the assets. The liability is recognised (together with a corresponding amount as part of the related property, plant and equipment) once an obligation crystallises in the period when a reasonable estimate can be made. The effects of changes resulting from revisions to the timing or the amount of the original estimate of the provision are reflected on a prospective basis, generally by adjustment to the carrying amount of the related property, plant and equipment. However, where there is no related asset, or the change reduces the carrying amount to nil, the effect, or the amount in excess of the reduction in the related asset to nil, is recognised in income.

Redundancy provisions are recognised when a detailed formal plan identifies the business or part of the business concerned, the location and number of employees affected, a detailed estimate of the associated costs and an appropriate timeline, and the employees affected have been notified of the plan's main features.

Other provisions are recognised in income in the period in which an obligation arises and the amount can be reasonably estimated. Provisions are measured based on current legal requirements and existing technology where applicable. Recognition of any joint and several liability is based on management's best estimate of the final pro rata share of the liability. Provisions are determined independently of expected insurance recoveries. Recoveries are recognised when virtually certain of realisation.

Significant estimates

Estimates of provisions for future decommissioning and restoration costs are recognised and based on current legal and constructive requirements, technology and price levels. Because actual outflows can differ from estimates due to changes in laws, regulations, public expectations, technology, prices and conditions, and can take place many years in the future, the carrying amounts of provisions are regularly reviewed and adjusted to take account of such changes. The discount rate applied is reviewed annually.

Information about decommissioning and restoration provisions is presented in Note 18.

FINANCIAL INSTRUMENTS (from January 1, 2018)

Financial assets and liabilities are presented separately in the Consolidated Balance Sheet except where there is a legally enforceable right of offset and Shell has the intention to settle on a net basis or realise the asset and settle the liability simultaneously.

Financial Assets

Financial assets are classified at initial recognition and subsequently measured at amortised cost, fair value through other comprehensive income or fair value through profit or loss. The classification of financial assets is determined by the contractual cash flows and where applicable the business model for managing the financial assets.

A financial asset is measured at amortised cost, if the objective of the business model is to hold the financial asset in order to collect contractual cash flows and the contractual terms give rise to cash flows that are solely payments of principal and interest. It is initially recognised at fair value plus or minus transaction costs that are directly attributable to the acquisition or issue of the financial asset. Subsequently the financial asset is measured using the effective interest method less any impairment. Gains and losses are recognised in profit or loss when the asset is derecognised, modified or impaired.

All equity instruments and other debt instruments are recognised at fair value. For equity instruments, on initial recognition, an irrevocable election (on an instrument-by-instrument basis) can be made to designate these as at fair value through other comprehensive income instead of fair value through profit and loss. Dividends received on equity instruments are recognised as other income in profit or loss when the right of payment has been established, except when the company benefits from such proceeds as a recovery of part of the cost of the financial asset, in which case, such gains are recorded in other comprehensive income.

Investments in securities

Investments in securities ("securities") comprise equity and debt securities. Equity securities are carried at fair value. Generally, unrealised holding gains and losses are recognised in other comprehensive income. On sale, net gains and losses previously accumulated in other comprehensive income are transferred to retained earnings. Debt securities are generally carried at fair value with unrealised holding gains and losses recognised in other comprehensive income. On sale, net gains and losses previously accumulated in other comprehensive income are recognised in income.

Impairment of financial assets

The expected credit loss model is applied for recognition and measurement of impairments in financial assets measured at amortised cost or at fair value through other comprehensive income. The expected credit loss model also is applied for financial guarantee contracts to which IFRS 9 applies and are not accounted for at fair value through profit or loss. The loss allowance for the financial asset is measured at an amount equal to the 12-month expected credit losses. If the credit risk on the financial asset has increased significantly since initial recognition, the loss allowance for the financial asset is measured at an amount equal to the lifetime expected credit losses. Changes in loss allowances are recognised in profit and loss. For trade receivables, a simplified impairment approach is applied recognising expected lifetime losses from initial recognition.

Significant estimate

Receivables from governments may be large and subject to disputes. Recoverability is subject to uncertainty as to the settlement of amounts including tax, royalty, cost recovery and associated interest. Information about government receivables is presented in Note 11.

Financial Liabilities

Financial liabilities are measured at amortised cost, unless they are required to be measured at fair value through profit or loss, such as instruments held for trading, or Shell has opted to measure them at fair value through profit or loss. Debt and trade payables are recognised initially at fair value based on amounts exchanged, net of transaction costs, and subsequently at amortised cost except for fixed rate debt subject to fair value hedging which is remeasured for the hedged risk (see below). Interest expense on debt is accounted for using the effective interest method, and other than interest capitalised, is recognised in income. For financial liabilities that are measured under the fair value option, the change in the fair value related to own credit risk is recognised in other comprehensive income. The remaining fair value change is recognised to fair value through profit and loss.

Derivative contracts and hedges

Derivative contracts are used in the management of interest rate risk, foreign exchange risk, commodity price risk, and foreign currency cash balances. Derivatives that are not closely related to the host contract in terms of economic characteristics and risks of which the host contract is not a financial asset, are separated from their host contract and recognised at fair value with the associated gains and losses recognised in income.

Certain derivative contracts qualify and are designated either as a "fair value" hedge of the change in fair value of a recognised asset or liability or an unrecognised firm commitment or as a "cash flow" hedge for the change in cash flows to be received or paid relating to a recognised asset or liability or a highly probable forecast transaction.

A change in the fair value of a fair value hedge is recognised in income, together with the consequential adjustment to the carrying amount of the hedged item. The effective portion of a change in fair value of a derivative contract designated as a cash flow hedge is recognised in other comprehensive income until the hedged transaction occurs; any ineffective portion is recognised in income. Where the hedged item is a non-financial asset or liability, the amount in accumulated other comprehensive income is transferred to the initial carrying amount of the asset or liability (reclassified to the balance sheet); for other hedged items, the amount in accumulated other comprehensive income is reclassified to income when the hedged transaction affects income.

The effective portion of a change due to retranslation at quarter-end exchange rates in the carrying amount of debt and the principal amount of derivative contracts used to hedge net investments in foreign operations is recognised in other comprehensive income until the related investment is sold or liquidated; any ineffective portion is recognised in income.

All relationships between hedging instruments and hedged items are documented, as well as risk management objectives and strategies for undertaking hedge transactions. The effectiveness of hedges is also continually assessed and hedge accounting is discontinued when there is a change in the risk management strategy.

Unless designated as hedging instruments, contracts to sell or purchase non-financial items that can be settled net as if the contracts were financial instruments and that do not meet expected own use requirements (typically, forward sale and purchase contracts for commodities in trading operations), and contracts that are or contain written options, are recognised at fair value; associated gains and losses are recognised in income.

FINANCIAL INSTRUMENTS (prior to January 1, 2018)

Financial assets and liabilities are presented separately in the Consolidated Balance Sheet except where there is a legally enforceable right of offset and Shell has the intention to settle on a net basis or realise the asset and settle the liability simultaneously.

Financial assets

Investments in securities

Investments in securities (also referred to as "securities") comprise equity and debt securities classified on initial recognition as available-for-sale and are carried at fair value, except where their fair value cannot be measured reliably, in which case they are carried at cost, less any impairment. Unrealised holding gains and losses other than impairments are recognised in other comprehensive income, except for translation differences arising on foreign currency debt securities, which are recognised in income. On maturity or sale, net gains and losses previously deferred in accumulated other comprehensive income are recognised in income.

Interest income on debt securities is recognised in income using the effective interest method. Dividends on equity securities are recognised in income when receivable.

Cash and cash equivalents

Cash and cash equivalents comprise cash at bank and in hand, including offsetting bank overdrafts, short-term bank deposits, money market funds, reverse repos and similar instruments that have a maturity of three months or less at the date of purchase.

Trade receivables

Trade receivables are recognised initially at fair value based on amounts exchanged and subsequently at amortised cost less any impairment.

Significant estimate

Receivables from governments may be large and subject to disputes. Recoverability is subject to uncertainty as to the settlement of amounts including tax, royalty, cost recovery and associated interest. Information about government receivables is presented in Note 11.

Financial liabilities

Debt and trade payables are recognised initially at fair value based on amounts exchanged, net of transaction costs, and subsequently at amortised cost except for fixed rate debt subject to fair value hedging which is remeasured for the hedged risk (see below). Interest expense on debt is accounted for using the effective interest method and, other than interest capitalised, is recognised in income.

Derivative contracts and hedges

Derivative contracts are used in the management of interest rate risk, foreign exchange risk and commodity price risk, and in the management of foreign currency cash balances. These contracts are recognised at fair value.

Certain derivative contracts qualify and are designated either as a “fair value” hedge of the change in fair value of a recognised asset or liability or an unrecognised firm commitment or as a “cash flow” hedge of the change in cash flows to be received or paid relating to a recognised asset or liability or a highly probable forecast transaction.

A change in the fair value of a hedging instrument designated as a fair value hedge is recognised in income, together with the consequential adjustment to the carrying amount of the hedged item. The effective portion of a change in fair value of a derivative contract designated as a cash flow hedge is recognised in other comprehensive income until the hedged transaction occurs; any ineffective portion is recognised in income. Where the hedged item is a non-financial asset or liability, the amount in accumulated other comprehensive income is transferred to the initial carrying amount of the asset or liability (reclassified to the balance sheet); for other hedged items, the amount in accumulated other comprehensive income is reclassified to income when the hedged transaction affects income.

The effective portion of a change due to retranslation at quarter-end exchange rates in the carrying amount of debt and the principal amount of derivative contracts used to hedge net investments in foreign operations is recognised in other comprehensive income until the related investment is sold or liquidated; any ineffective portion is recognised in income.

All relationships between hedging instruments and hedged items are documented, as well as risk management objectives and strategies for undertaking hedge transactions. The effectiveness of hedges is also continually assessed and hedge accounting is discontinued when a hedge ceases to be highly effective.

Gains and losses on derivative contracts not qualifying and designated as hedges, including forward sale and purchase contracts for commodities in trading operations that may be settled by the physical delivery or receipt of the commodity, are recognised in income.

Unless designated as hedging instruments, contracts to sell or purchase non-financial items that can be settled net as if the contracts were financial instruments and that do not meet expected own use requirements (typically, forward sale and purchase contracts for commodities in trading operations), and contracts that are or contain written options, are recognised at fair value; associated gains and losses are recognised in income.

Derivatives embedded within contracts that are not already required to be recognised at fair value, and that are not closely related to the host contract in terms of economic characteristics and risks, are separated from their host contract and recognised at fair value; associated gains and losses are recognised in income.

FAIR VALUE MEASUREMENTS

Fair value measurements are estimates of the amounts for which assets or liabilities could be transferred at the measurement date, based on the assumption that such transfers take place between participants in principal markets and, where applicable, taking highest and best use into account.

Judgements and estimates

Where available, fair value measurements are derived from prices quoted in active markets for identical assets or liabilities. In the absence of such information, other observable inputs are used to estimate fair value. Inputs derived from external sources are corroborated or otherwise verified, as appropriate. In the absence of publicly available information, fair value is determined using estimation techniques that take into account market perspectives relevant to the asset or liability, in as far as they can reasonably be ascertained, based on predominantly unobservable inputs. For derivative contracts where publicly available information is not available, fair value estimations are generally determined using models and other valuation methods, the key inputs for which include future prices, volatility, price correlation, counterparty credit risk and market liquidity, as appropriate; for other assets and liabilities, fair value estimations are generally based on the net present value of expected future cash flows.

SHARE-BASED COMPENSATION PLANS

The fair value of share-based compensation expense arising from the Performance Share Plan (PSP) and the Long-term Incentive Plan (LTIP) – Shell's main equity-settled plans – is estimated using a Monte Carlo option pricing model and is recognised in income from the date of grant over the vesting period with a corresponding increase directly in equity. The model projects and averages the results for a range of potential outcomes for the vesting conditions, the principal assumptions for which are the share price volatility and dividend yields for Shell and four of its main competitors over the last three years and the last 10 years. Prior to the adoption of the IFRS 2 amendments, changes in the fair value of share-based compensation for cash-settled plans were recognised in income with a corresponding change in liabilities.

SHARES HELD IN TRUST

Shares in the Company, which are held by employee share ownership trusts and trust-like entities, are not included in assets but are reflected at cost as a deduction from equity as shares held in trust.

ACQUISITIONS AND SALES OF INTERESTS IN A BUSINESS

Assets acquired and liabilities assumed when control is obtained over a business, and when an interest or an additional interest is acquired in a joint operation which is a business, are recognised at their fair value at the date of the acquisition; the amount of the purchase consideration above this value is recognised as goodwill. When control is obtained, any non-controlling interest is recognised as the proportionate share of the identifiable net assets. The

acquisition of a non-controlling interest in a subsidiary and the sale of an interest while retaining control are accounted for as transactions within equity. The difference between the purchase consideration or sale proceeds after tax and the relevant proportion of the non-controlling interest, measured by reference to the carrying amount of the interest's net assets at the date of acquisition or sale, is recognised in retained earnings as a movement in equity attributable to Royal Dutch Shell plc shareholders.

CONSOLIDATED STATEMENT OF INCOME PRESENTATION

Purchases reflect all costs related to the acquisition of inventories and the effects of the changes therein, and include associated costs incurred in conversion into finished or intermediate products. Production and manufacturing expenses are the costs of operating, maintaining and managing production and manufacturing assets. Selling, distribution and administrative expenses include direct and indirect costs of marketing and selling products.

3 CHANGES TO IFRS NOT YET ADOPTED

IFRS 16 Leases was issued in 2016 to replace IAS 17 Leases and is required to be adopted by 2019. Under the new standard all lease contracts, with limited exceptions, are recognised in financial statements by way of right-of-use assets and corresponding lease liabilities. Shell will apply the modified retrospective approach, which means that the cumulative effect of initially applying the standard is recognised at the date of initial application and there is no restatement of comparative information. Compared with the existing accounting for operating leases, application of the standard will have a significant impact on the classification of expenditures and consequently the classification of cash flow from operating activities, cash flow from investing activities and cash flow from financing activities. It will also impact the timing of expenses recognised in the statement of income. No impact is expected in relation to lease contracts previously classified as finance leases. The adoption of the new standard at January 1, 2019, is expected to have a negligible impact on equity following the recognition of lease liabilities of approximately \$16.0 billion and additional right of use assets of approximately \$15.6 billion and reclassifications mainly related to pre-paid leases and onerous contract provisions previously recognised.

IFRS 17 Insurance contracts was issued in 2017 and will become effective for annual reporting periods beginning on or after January 1, 2021. The IFRS 17 model combines a current balance sheet measurement of insurance contracts with recognition of profit over the period that services are provided. The general model in the standard requires insurance contract liabilities to be measured using probability-weighted current estimates of future cash flows, an adjustment for risk, and a contractual service margin representing the profit expected from fulfilling the contracts. Effects of changes in the estimates of future cash flows and the risk adjustment relating to future services are recognised over the period services are provided rather than immediately in profit or loss. Shell is in the process evaluating the initial impact of this pronouncement.

4 SEGMENT INFORMATION

General Information

Shell is an international energy company engaged in the principal aspects of the oil and gas industry and reports its business through the segments: Integrated Gas, Upstream, Downstream, and Corporate.

The Integrated Gas segment covers liquefied natural gas activities and the conversion of natural gas into gas-to-liquids fuels and other products, as well as the New Energies portfolio. It includes natural gas exploration and extraction and the operation of the upstream and midstream infrastructure necessary to deliver gas to market. It markets and trades natural gas, LNG, electricity and carbon-emission rights and also markets and sells LNG as a fuel for heavy-duty vehicles and marine vessels.

Upstream combines the following two operating segments: 1) Upstream, which is engaged in the exploration for and extraction of crude oil, natural gas and natural gas liquids, and the marketing and transportation of oil and gas, and 2) Oil Sands, which is engaged in the extraction of bitumen from mined oil sands and conversion into synthetic crude oil. These operating segments have similar economic characteristics because their earnings are significantly dependent on crude oil and natural gas prices and production volumes.

The Downstream segment is engaged in oil products and chemicals manufacturing, marketing and trading activities, that turns crude oil and other feedstocks into a range of products which are moved and marketed around the world for domestic, industrial and transport use.

The Corporate segment covers the non-operating activities supporting Shell, comprising Shell's holdings and treasury organisation, its self-insurance activities and its headquarters and central functions.

Basis of Segmental Reporting

Sales between segments are based on prices generally equivalent to commercially available prices. Third-party revenue and non-current assets information by geographical area are based on the country of operation of the group subsidiaries that report this information. Separate disclosure is provided for the UK as this is Shell's country of domicile.

Segment earnings are presented on a current cost of supplies basis (CCS earnings), which is the earnings measure used by the Chief Executive Officer for the purposes of making decisions about allocating resources and assessing performance. On this basis, the purchase price of volumes sold during the period is based on the current cost of supplies during the same period after making allowance for the tax effect. CCS earnings therefore exclude the effect of changes in the oil price on inventory carrying amounts.

Information by segment on a current cost of supplies basis is as follows:

					\$ million
2018	Integrated Gas	Upstream	Downstream	Corporate	Total
CCS earnings	11,444	6,798	7,601	(1,479)	24,364
Revenue:					
Third party	43,764	9,892	334,680	43	388,379 [A]
Inter-segment	4,853	37,841	5,358	—	
Share of profit/(loss) of joint ventures and associates (CCS basis)	2,273	285	1,785	(222)	4,121
Interest and other income, of which:	2,230	600	345	896	4,071
Interest income	—	—	—	772	772
Net gains on sale and revaluation of non-current assets and businesses	2,231	712	302	20	3,265
Depreciation, depletion and amortisation charge, of which:	4,850	13,006	4,064	215	22,135
Impairment losses	200	1,065	424	7	1,696 [B]
Impairment reversals	—	1,265	—	—	1,265 [C]
Interest expense	221	609	71	2,844	3,745
Taxation charge/(credit) (CCS basis)	2,795	8,791	1,515	(1,270)	11,831

[A] Includes \$3,348 million of revenue from sources other than from contracts with customers, which mainly comprises the impact of fair value accounting of commodity derivatives

[B] Impairment losses comprise Property, plant and equipment (\$1,515 million) and Intangible assets (\$181 million).

[C] See Note 8.

					\$ million
2017	Integrated Gas	Upstream	Downstream	Corporate	Total
CCS earnings	5,078	1,551	8,258	(2,416)	12,471
Revenue:					
Third party	32,674	7,723	264,731	51	305,179
Inter-segment	3,978	32,469	4,248	—	
Share of profit/(loss) of joint ventures and associates (CCS basis)	1,714	623	1,956	(129)	4,164
Interest and other income, of which:	687	1,188	154	437	2,466
Interest income	—	—	—	677	677
Net gains on sale and revaluation of non-current assets and businesses	301	1,189	136	14	1,640
Depreciation, depletion and amortisation charge, of which:	4,965	17,303	3,877	78	26,223
Impairment losses	302	4,118	385	—	4,805 [A]
Impairment reversals	10	605	—	—	615 [B]
Interest expense	248	744	109	2,941	4,042
Taxation charge/(credit) (CCS basis)	790	2,409	1,783	(636)	4,346

[A] Impairment losses comprise Property, plant and equipment (\$4,572 million) and Intangible assets (\$233 million).

[B] See Note 8.

2016					\$ million
	Integrated Gas	Upstream	Downstream	Corporate	Total
CCS earnings	2,529	(3,674)	6,588	(1,751)	3,692
Revenue:					
Third party	25,282	6,412	201,823	74	233,591
Inter-segment	3,908	26,524	1,727	—	
Share of profit/(loss) of joint ventures and associates (CCS basis)	1,116	222	2,244	(182)	3,400
Interest and other income, of which:	765	839	851	442	2,897
Interest income	—	—	—	451	451
Net gains on sale and revaluation of non-current assets and businesses	507	867	765	2	2,141
Depreciation, depletion and amortisation charge, of which:	4,509	16,779	3,681	24	24,993
Impairment losses	72	1,274	588	6	1,940 [A]
Impairment reversals	—	—	38	—	38 [B]
Interest expense	247	852	91	2,013	3,203
Taxation charge/(credit) (CCS basis)	1,254	(938)	1,008	(839)	485

[A] Impairment losses comprise Property, plant and equipment (\$1,931 million) and Intangible assets (\$9 million).

[B] See Note 8.

Reconciliation of CCS earnings to income for the period

	2018	2017	2016
CCS earnings	24,364	12,471	3,692
Current cost of supplies adjustment:			
Purchases	(559)	1,252	1,284
Taxation	116	(349)	(344)
Share of profit of joint ventures and associates	(15)	61	145
	(458)	964	1,085
Income for the period	23,906	13,435	4,777

Information by geographical area is as follows:

2018					\$ million
	Europe	Asia, Oceania, Africa	USA	Other Americas	Total
Third-party revenue, by origin	118,960 [A]	153,716 [B]	89,876	25,827	388,379
Intangible assets, property, plant and equipment, joint ventures and associates at December 31	38,617 [C]	117,127	59,625	56,721	272,090

[A] Includes \$54,659 million that originated from the UK.

[B] Includes \$89,811 million that originated from Singapore.

[C] Includes \$21,863 million located in the UK.

2017					\$ million
	Europe	Asia, Oceania, Africa	USA	Other Americas	Total
Third-party revenue, by origin	100,609 [A]	114,683 [B]	66,854	23,033	305,179
Intangible assets, property, plant and equipment, joint ventures and associates at December 31	41,416 [C] [D]	122,345	55,898 [D]	58,828	278,487

[A] Includes \$49,370 million that originated from the UK.

[B] Includes \$62,046 million that originated from Singapore.

[C] Includes \$22,734 million located in the UK.

[D] The USA geographical allocation has increased by \$1,604 million with a corresponding decrease in Europe.

2016

\$ million

	Europe	Asia, Oceania, Africa	USA	Other Americas	Total
Third-party revenue, by origin	81,573 [A]	87,635 [B]	44,615	19,768	233,591
Intangible assets, property, plant and equipment, joint ventures and associates at December 31	42,265 [C] [D]	121,618	62,066 [D]	67,371	293,320

[A] Includes \$38,490 million that originated from the UK.

[B] Includes \$42,533 million that originated from Singapore.

[C] Includes \$24,015 million located in the UK.

[D] The USA geographical allocation has increased by \$1,636 million with a corresponding decrease in Europe.

5 INTEREST AND OTHER INCOME

	2018	2017	2016
Interest income	772	677	451
Dividend income (from investments in equity securities)	104	375	264
Net gains on sale and revaluation of non-current assets and businesses	3,265	1,640	2,141
Net foreign exchange (losses)/gains on financing activities	(174)	(453)	343
Other	104	227	(302)
Total	4,071	2,466	2,897

In 2018, net gains on sale of non-current assets and businesses arose mainly in respect of gains on the sale of Integrated Gas assets in Thailand, Malaysia, Oman and New Zealand, as well as Upstream assets in Iraq and Malaysia and a Downstream divestment in Argentina partially offset by a charge related to the disposal of our Upstream assets in Ireland.

In 2017, net gains on sale of non-current assets and businesses arose mainly in respect of gains on the sale of Upstream assets in the UK and the USA as well as Downstream assets in Australia and Saudi Arabia, partly offset by a loss on the Motiva transaction. Net foreign exchange losses on financing activities in 2017 includes a charge of \$545 million from the release of cumulative currency translation differences following the restructuring of funding for our North America businesses.

In 2016, net gains on sale of non-current assets and businesses arose mainly in respect of Upstream assets in North America and Downstream assets in Denmark and Japan. In addition, in respect of a decrease in Shell's interest in Woodside Petroleum Limited, a revaluation gain of \$293 million was recognised and a gain of \$358 million on the related release of cumulative currency translation differences was recognised in net foreign exchange gains on financing activities. Other mainly relates to the write down of an investment in securities.

Other net foreign exchange losses of \$210 million in 2018 (2017: \$47 million; 2016: \$49 million) were included in purchases.

6 INTEREST EXPENSE

	2018	2017	2016
Interest incurred and similar charges	3,550	3,448	2,732
Less: interest capitalised	(876)	(622)	(725)
Other net losses on fair value hedges of debt	169	114	4
Accretion expense	902	1,102	1,192
Total	3,745	4,042	3,203

The rate applied in determining the amount of interest capitalised in 2018 was 4% (2017: 3%; 2016: 3%).

7 INTANGIBLE ASSETS

2018					\$ million
	Goodwill	LNG off-take and sales contracts	Other	Total	
Cost					
At January 1	14,154	10,429	6,106	30,689	
Additions	331	—	659	990	
Sales, retirements and other movements	(75)	(64)	(253)	(392)	
Currency translation differences	(72)	—	(120)	(192)	
At December 31	14,338	10,365	6,392	31,095	
Depreciation, depletion and amortisation, including impairments					
At January 1	492	2,432	3,585	6,509	
Charge for the year	173	925	370	1,468	
Sales, retirements and other movements	(21)	(64)	(275)	(360)	
Currency translation differences	(22)	—	(86)	(108)	
At December 31	622	3,293	3,594	7,509	
Carrying amount at December 31	13,716	7,072	2,798	23,586	

2017					\$ million
	Goodwill	LNG off-take and sales contracts	Other	Total	
Cost					
At January 1	13,592	10,429	5,085	29,106	
Additions	784	—	786	1,570	
Sales, retirements and other movements	(261)	—	37	(224)	
Currency translation differences	39	—	198	237	
At December 31	14,154	10,429	6,106	30,689	
Depreciation, depletion and amortisation, including impairments					
At January 1	605	1,475	3,059	5,139	
Charge for the year	—	957	612	1,569	
Sales, retirements and other movements	(136)	—	(241)	(377)	
Currency translation differences	23	—	155	178	
At December 31	492	2,432	3,585	6,509	
Carrying amount at December 31	13,662	7,997	2,521	24,180	

Goodwill at December 31, 2018, principally related to the acquisition of BG Group plc (BG) in 2016, allocated to Integrated Gas (\$4,897 million) and Upstream (\$6,013 million) at the operating segment level, and to Pennzoil-Quaker State Company (\$1,609 million), a lubricants business in the Downstream segment based largely in North America. Information on annual impairment testing is included in Note 8.

8 PROPERTY, PLANT AND EQUIPMENT

2018						\$ million
	Exploration and production		Manufacturing, supply and distribution	Other	Total	
	Exploration and evaluation	Production				
Cost						
At January 1	22,510	292,256	86,948	22,355	424,069	
Additions	3,514	12,596	6,438	1,594	24,142	
Sales, retirements and other movements	(4,443)	(19,643)	(667)	(814)	(25,567)	
Currency translation differences	(400)	(4,828)	(1,484)	(1,095)	(7,807)	
At December 31	21,181	280,381	91,235	22,040	414,837	
Depreciation, depletion and amortisation, including impairments						
At January 1	5,060	137,525	44,483	10,621	197,689	
Charge for the year	(979) [A]	16,551	4,000	1,095	20,667	
Sales, retirements and other movements	(608)	(19,631)	(1,353)	(756)	(22,348)	
Currency translation differences	(186)	(2,753)	(912)	(495)	(4,346)	
At December 31	3,287	131,692	46,218	10,465	191,662	
Carrying amount at December 31	17,894	148,689	45,017	11,575	223,175	

[A] Includes an impairment reversal for assets in North America.

2017						\$ million
	Exploration and production		Manufacturing, supply and distribution	Other	Total	
	Exploration and evaluation	Production				
Cost						
At January 1	25,376	302,532	77,286	20,063	425,257	
Additions	2,319	15,347	8,148	1,352	27,166	
Sales, retirements and other movements	(5,651) [A]	(33,133) [A]	(1,427)	(655)	(40,866)	
Currency translation differences	466	7,510	2,941	1,595	12,512	
At December 31	22,510	292,256	86,948	22,355	424,069	
Depreciation, depletion and amortisation, including impairments						
At January 1	6,363	133,600	39,673	9,523	189,159	
Charge for the year	778	19,155	3,705	1,016	24,654	
Sales, retirements and other movements	(2,300)	(19,615)	(763)	(701)	(23,379)	
Currency translation differences	219	4,385	1,868	783	7,255	
At December 31	5,060	137,525	44,483	10,621	197,689	
Carrying amount at December 31	17,450	154,731	42,465	11,734	226,380	

[A] \$1,065 million has been reclassified from Exploration and evaluation to Production.

Sales, retirements and other movements in 2018 include sales of interests in Thailand, Ireland, Argentina and Norway. In Thailand, Shell sold its 22.22% interest in the Bangkot field and adjoining acreage offshore Thailand. In Ireland, Shell sold its 45% interest in the Corrib gas venture. The Buenos Aires Refinery was sold as part of the Argentina Downstream business together with other businesses, as well as the supply and distribution activities. In Norway, Shell sold its 44.56% operated interest in the Draugen field and 12% non-operated interest in the Gjøa field.

The carrying amount at December 31, 2018, included \$33,451 million (2017: \$42,121 million) of assets under construction. This amount excludes exploration and evaluation assets. The carrying amount at December 31, 2018, also included \$705 million of assets classified as held for sale (2017: \$986 million).

The carrying amount of exploration and production assets at December 31, 2018, included rights and concessions in respect of proved and unproved properties of \$15,860 million (2017: \$14,839 million). Exploration and evaluation assets principally comprise rights and concessions in respect of unproved properties and capitalised exploration drilling costs.

The carrying amount of assets at December 31, 2018, for which an alternative reserves base was applied in the calculation of the depreciation charge (see Note 2), was \$5,838 million (2017: \$18,115 million). If no alternative reserves base had been used, the pre-tax depreciation charge for the year ended December 31, 2018, would have been \$1,003 million higher (2017: \$5,558 million, 2016: \$9,181 million).

Contractual commitments for the purchase of property, plant and equipment at December 31, 2018, amounted to \$4,783 million (2017: \$4,504 million). In addition, Shell has other commitments for future expenditure that, when incurred, are also expected to be recognised as additions to property, plant and equipment, such as the majority of operating lease payments in respect of drilling and ancillary equipment (see Note 14).

Carrying amount of property, plant and equipment held under finance leases [A]			\$ million
	Dec 31, 2018	Dec 31, 2017	
Exploration and production	6,299	8,399	
Manufacturing, supply and distribution	3,149	3,151	
Other	200	272	
Total	9,648	11,822	

[A] See Note 14.

Impairments			\$ million
	2018	2017	2016
Impairment losses [A]			
Exploration and production	1,066	4,187	1,324
Manufacturing, supply and distribution	441	376	567
Other	8	9	40
Total	1,515	4,572	1,931
Impairment reversals [A]			
Exploration and production	1,265	615	—
Manufacturing, supply and distribution	—	—	36
Other	—	—	2
Total	1,265	615	38

[A] See Note 4.

Impairment losses in 2018 were mainly in Upstream, and principally related to the disposal of Shell's interests in Norway and Ireland and related to assets in the Gulf of Mexico. Impairment reversals were mainly related to assets in North America. Impairment losses in 2017 were mainly in Upstream, and principally related to the disposal of interests in Canada and interests in Ireland classified as held for sale. Impairment losses in 2016 were mainly triggered by asset performance, disposals and project cancellations. They related primarily in Upstream to shale and deep-water properties in North and South America and in Downstream to disposals and assets held for sale in the refining portfolio.

For impairment testing purposes, the respective carrying amounts of property, plant and equipment and intangible assets were compared with their value in use. Cash flow projections used in the determination of value in use were made using management's forecasts of commodity prices, market supply and demand, product margins and expected production volumes (see Note 2). These cash flows were adjusted for the risks specific to the assets, and therefore these risks were not included in the determination of the discount rate applied. The nominal pre-tax rate applied in 2018 was 6% (2017: 6%; 2016: 6%).

Oil and gas price assumptions applied for impairment testing are reviewed and, where necessary, adjusted on a periodic basis. Reviews include comparison with available market data and forecasts that reflect developments in demand such as global economic growth, technology efficiency, policy

measures and, in supply, consideration of investment and resource potential, cost of development of new supply, and behaviour of major resource holders. The near-term commodity price assumptions applied in impairment testing in 2018 were as follows:

Commodity price assumptions [A]

	2019	2020	2021
Brent crude oil (\$/b)	65	65	70
Henry Hub natural gas (\$/MMBtu)	3.25	3.50	3.50

[A] Money of the day.

For periods after 2021, the real terms long-term price assumptions applied were \$70 per barrel (/b) (2017: \$70/b after 2020) for Brent crude oil and \$3.50 per million British thermal units (/MMBtu) (2017: \$3.50/MMBtu after 2020) for Henry Hub natural gas.

Capitalised exploration drilling costs

	\$ million		
	2018	2017	2016
At January 1	6,981	7,910	7,835
Additions pending determination of proved reserves	2,588	1,708	1,762
Amounts charged to expense	(449)	(897)	(834)
Reclassifications to productive wells on determination of proved reserves	(2,461)	(1,894) [A]	(1,187)
Other movements	(30)	154	334
At December 31	6,629	6,981 [A]	7,910

[A] \$912 million of capitalised exploration drilling costs has been reclassified from Exploration and evaluation to Production.

	Projects		Wells	
	Number	\$ million	Number	\$ million
Between 1 and 5 years	44	3,645	180	2,670
Between 6 and 10 years	12	1,059	143	1,766
Between 11 and 15 years	4	238	16	441
Between 16 and 20 years	—	—	3	65
Total	60	4,942	342	4,942

Exploration drilling costs capitalised for periods greater than one year at December 31, 2018, analysed according to the most recent year of activity, are presented in the table above. They comprise \$1,342 million relating to 17 projects where drilling activities were under way or firmly planned for the future and \$3,600 million relating to 43 projects awaiting development concepts.

9 JOINT VENTURES AND ASSOCIATES

Shell share of comprehensive income of joint ventures and associates

	2018			2017			2016		
	Joint ventures	Associates	Total	Joint ventures	Associates	Total	Joint ventures	Associates	Total
Income for the period	1,307	2,799	4,106	2,102	2,123	4,225	2,332	1,213	3,545
Other comprehensive income/(loss) for the period	172	11	183	164	6	170	78	(106)	(28)
Comprehensive income for the period	1,479	2,810	4,289	2,266	2,129	4,395	2,410	1,107	3,517

Carrying amount of interests in joint ventures and associates

	Dec 31, 2018			Dec 31, 2017		
	Joint ventures	Associates	Total	Joint ventures	Associates	Total
Net assets	14,263	11,066	25,329	15,052	12,875	27,927

Transactions with joint ventures and associates

	2018	2017	\$ million 2016
Sales and charges to joint ventures and associates	8,270	13,121	24,214
Purchases and charges from joint ventures and associates	11,212	10,680	13,859

These transactions principally comprise sales and purchases of goods and services in the ordinary course of business. Related balances outstanding at December 31, 2018, and 2017, are presented in Notes 11 and 15.

Other arrangements in respect of joint ventures and associates

	Dec 31, 2018	\$ million Dec 31, 2017
Commitments to make purchases from joint ventures and associates [A]	1,254	1,371
Commitments to provide debt or equity funding to joint ventures and associates	638	1,216

[A] Commitments to make purchases from joint ventures and associates mainly relate to contracts associated with raw materials and transportation capacity.

10 INVESTMENTS IN SECURITIES**Investment in securities**

	Dec 31, 2018	\$ million Dec 31, 2017
Equity securities:	1,823	5,976
Equity securities at fair value through other comprehensive income	1,823	
Debt securities:	1,251	1,246
Debt securities at amortised cost	8	
Debt securities at fair value through other comprehensive income	953	
Debt securities at fair value through profit and loss	290	
Total	3,074	7,222
At fair value		
Measured by reference to prices in active markets for identical assets	1,873	5,776
Measured using predominantly unobservable inputs	1,193	1,268
Total	3,066	7,044
At cost	8	178
Total	3,074	7,222

Equity securities at December 31, 2018, principally comprised interests below 5%, in various investments. Shell's 8% share in Canadian Natural Resources Limited and 15% interest in Malaysia LNG Tiga Sendirian Berhad were disposed of in 2018. Their carrying amounts at December 31, 2017, were \$3,506 million and \$722 million respectively. Debt securities principally comprised a portfolio required to be held by Shell's internal insurance entities as security for their activities.

Investments in securities measured using predominantly unobservable inputs [A]

	2018	\$ million 2017
At January 1	1,268	1,233
Gains/(losses) recognised in other comprehensive income	212	(108)
Other movements	(287) [B]	143
At December 31	1,193	1,268

[A] Based on expected dividend flows, adjusted for country and other risks as appropriate and discounted to their present value.

[B] Other movements mainly relates to the disposal of the interest in Malaysia LNG Tiga Sendirian Berhad, partly offset by investments made in securities during 2018.

11 TRADE AND OTHER RECEIVABLES

	Dec 31, 2018		Dec 31, 2017	
	Current	Non-current	Current	Non-current
Trade receivables	27,541	—	30,721	—
Other receivables	8,543	4,823	9,036	5,525
Amounts due from joint ventures and associates	992	1,183	868	1,327
Prepayments and deferred charges	5,355	1,820	3,940	1,623
Total	42,431	7,826	44,565	8,475

The fair value of financial assets included above approximates the carrying amount and was determined from predominantly unobservable inputs.

Other receivables at December 31, 2018, include receivables from certain governments in their capacity as joint arrangement partners, of \$1,449 million (2017: \$2,265 million), after provisions for impairments, that are overdue in part or in full. Recoverability and timing thereof is subject to uncertainty, however, the ultimate risk of default on the carrying amount is considered to be low. Other receivables also include income tax (see Note 16) and other tax receivables.

Provisions for impairments deducted from trade and other receivables amounted to \$790 million at December 31, 2018 (2017: \$881 million).

Allowance for expected credit losses - trade receivables					\$ million
	Not overdue	Overdue 1-30 days	Overdue 31-180 days	Overdue more than 180 days	Total
Expected loss rate	0.0014% - 0.0799%	0.0393% - 1.548%	0.1752% - 14.8524%	0.7592% - 28.037%	
Gross carrying amount	25,835	892	541	539	27,807
Loss allowance provision	(2)	(2)	(7)	(12)	(23)
Net carrying amount at December 31, 2018	25,833	890	534	527	27,784
Net carrying amount at December 31, 2017	28,719	1,154	480	368	30,721

The Company uses a provision matrix to calculate expected credit losses (ECLs) for trade receivables. The provision matrix is initially based on the Company's historical observed default rates. The Company will calibrate the matrix to adjust the historical credit loss experience with forward-looking information.

A loss allowance provision of \$243 million was established, in addition to all other impairments to trade receivables as at December 31, 2018, that are outside of the provision matrix calculations.

12 INVENTORIES

	Dec 31, 2018	Dec 31, 2017
Oil, gas and chemicals	19,516	22,962
Materials	1,601	2,261
Total	21,117	25,223

Inventories at December 31, 2018, include write-downs to net realisable value of \$1,473 million (2017: \$253 million).

13 CASH AND CASH EQUIVALENTS

	\$ million
	Dec 31, 2018
	Dec 31, 2017
Cash	4,034
Short-term bank deposits	3,655
Money market funds, reverse repos and other cash equivalents	19,052
Total	26,741
	20,312

Included in cash and cash equivalents at December 31, 2018, were amounts totalling \$257 million (2017: \$120 million) subject to currency controls or other legal restrictions. Information about credit risk is presented in Note 19.

14 DEBT AND LEASE ARRANGEMENTS

DEBT

	\$ million
	Dec 31, 2018
	Dec 31, 2017
	Total
	Total
Short-term debt	693
Long-term debt due within 1 year	8,419
Current debt	9,112
Non-current debt	53,686
Total	62,798
	14,026
	76,824
	70,141
	15,524
	85,665

Net debt

	\$ million
	Current debt
	Non-current debt
	Derivative financial instruments [A]
	Cash and cash equivalents (see Note 13)
	Net debt [A]
At January 1, 2018	(11,795)
Cash flow	10,392
Finance lease additions	(51)
Other movements	(8,939)
Currency translation differences and foreign exchange gains/(losses)	259
At December 31, 2018	(10,134)
At January 1, 2017	(9,484)
Cash flow	11,457
Finance lease additions	(56)
Other movements	(13,232)
Currency translation differences and foreign exchange gains/(losses)	(480)
At December 31, 2017	(11,795)

[A] With effect from 2018, the net debt calculation includes the fair value of derivative financial instruments used to hedge foreign exchange and interest rate risks relating to debt and associated collateral balances. Derivative financial instruments at December 31, 2018, includes \$72 million representing collateral on debt-related derivatives. Prior year comparatives have been revised to reflect the change in the net debt calculation.

Management's financial strategy is to manage Shell's assets and liabilities with the aim that, across the business cycle, "cash in" at least equals "cash out" while maintaining a strong balance sheet.

Gearing, defined as net debt (total debt less cash and cash equivalents) as a percentage of total capital (net debt plus total equity), is a key measure of Shell's capital structure. Across the business cycle, management aims to manage gearing within a range of 0-30%. At December 31, 2018, gearing was 20.3% (2017: 25.0%, as revised).

Gearing	\$ million, except where indicated	
	Dec 31, 2018	Dec 31, 2017
Net debt	51,428	65,944 [A]
Total equity	202,534	197,812
Total capital	253,962	263,756 [A]
Gearing	20.3%	25.0% [A]

[A] As revised, following the revision of the net debt calculation from 2018.

Management's priorities for applying Shell's cash are the servicing and reduction of debt commitments, payment of dividends, followed by a balance of capital investment and share buybacks. Management's policy is to grow the dollar dividend through time, in line with its view of Shell's underlying earnings and cash flow.

Shell has access to international debt capital markets via two commercial paper (CP) programmes, a Euro medium-term note (EMTN) programme and a US universal shelf (US shelf) registration. Issuances under the CP programmes are supported by a committed credit facility and cash.

Borrowing facilities and amounts undrawn	\$ million			
	Facility		Amount undrawn	
	Dec 31, 2018	Dec 31, 2017	Dec 31, 2018	Dec 31, 2017
CP programmes	20,000	20,000	20,000	19,659
EMTN programme	unlimited	unlimited	N/A	N/A
US shelf registration	unlimited	unlimited	N/A	N/A
Committed credit facility	8,840	8,500	8,840	8,500

Under the CP programmes, Shell can issue debt of up to \$10 billion with maturities not exceeding 270 days and \$10 billion with maturities not exceeding 397 days. The EMTN programme is updated each year, most recently in August 2018. No debt was issued under this programme in 2018 (2017: \$nil issued). The US shelf registration provides Shell with the flexibility to issue debt securities, ordinary shares, preferred shares and warrants. The registration is updated every three years and was last updated in December 2017. During 2018, debt totalling \$3 billion (2017: nil) was issued under the registration. The committed credit facility is available at pre-agreed margins and expires in 2020. The terms and availability are not conditional on Shell's financial ratios or its financial credit ratings.

In addition, other subsidiaries have access to undrawn short-term bank facilities totalling \$3,035 million at December 31, 2018 (2017: \$3,409 million).

Interest rate swaps have been entered into against certain fixed rate debt affecting the effective interest rate on these balances (see Note 19).

The following tables compare contractual cash flows for debt excluding finance lease liabilities at December 31, with the carrying amount in the Consolidated Balance Sheet. Contractual amounts reflect the effects of changes in foreign exchange rates; differences from carrying amounts reflect the effects of discounting, premiums and, where hedge accounting is applied, fair value adjustments. Interest is estimated assuming interest rates applicable to variable rate debt remain constant and there is no change in aggregate principal amounts of debt other than repayment at scheduled maturity, as reflected in the table.

2018	\$ million							
	Contractual payments						Difference from carrying amount	Carrying amount
	Less than 1 year	Between 1 and 2 years	Between 2 and 3 years	Between 3 and 4 years	Between 4 and 5 years	5 years and later		
Bonds	8,163	5,900	4,993	4,458	4,312	33,162	60,988	181
Bank and other borrowings	945	39	209	50	27	359	1,629	—
Total (excluding interest)	9,108	5,939	5,202	4,508	4,339	33,521	62,617	181
Interest	1,780	1,555	1,426	1,319	1,244	14,406	21,730	

2017

\$ million

	Contractual payments						Difference from carrying amount	Carrying amount
	Less than 1 year	Between 1 and 2 years	Between 2 and 3 years	Between 3 and 4 years	Between 4 and 5 years	5 years and later		
Commercial paper	341	—	—	—	—	—	5	346
Bonds	8,989	8,306	5,900	5,047	4,620	35,037	131	68,030
Bank and other borrowings	1,321	43	127	56	180	36	2	1,765
Total (excluding interest)	10,651	8,349	6,027	5,103	4,800	35,073	138	70,141
Interest	1,957	1,688	1,457	1,328	1,221	15,293		

The fair value of debt excluding finance lease liabilities at December 31, 2018, was \$64,708 million (2017: \$74,650 million), mainly determined from the prices quoted for those securities.

LEASE ARRANGEMENTS

Finance lease liabilities mainly relate to contracts in Upstream and Integrated Gas for floating production, storage and offloading units, subsea equipment and power generation. Finance lease liabilities are secured on the leased assets. Operating lease contracts are, in Upstream and Integrated Gas, principally for drilling and ancillary equipment, service vessels, LNG vessels and land and buildings; in Downstream, principally for tankers, storage capacity and retail sites; and in Corporate, principally for land and buildings.

The future minimum lease payments for finance and operating leases and the present value of future minimum finance lease payments at December 31, by payment date are as follows:

2018

\$ million

	Finance leases			Operating leases
	Future minimum lease payments	Interest	Present value of future minimum lease payments	Future minimum lease payments [A]
Less than 1 year	2,061	1,039	1,022	4,784
Between 1 and 5 years	7,508	3,391	4,117	11,575
5 years and later	13,370	4,483	8,887	7,860
Total	22,939	8,913	14,026	24,219

[A] Includes \$5,348 million in respect of drilling and ancillary equipment.

2017

\$ million

	Finance leases			Operating leases
	Future minimum lease payments	Interest	Present value of future minimum lease payments	Future minimum lease payments [A] [B]
Less than 1 year	2,274	1,190	1,084	4,909
Between 1 and 5 years	8,246	3,887	4,359	12,415
5 years and later	15,043	4,962	10,081	7,961
Total	25,563	10,039	15,524	25,285

[A] Includes \$6,473 million in respect of drilling and ancillary equipment.

[B] Revised following a reassessment of contracts

Future minimum lease payments at December 31, 2018 are stated before deduction of amounts expected to be received under non-cancellable sub-leases of \$273 million (2017: \$336 million) in respect of finance leases and \$507 million (2017: \$300 million) in respect of operating leases.

Operating lease expense in 2018 was \$4,354 million (2017: \$4,822 million; 2016: \$5,063 million).

15 TRADE AND OTHER PAYABLES

	\$ million			
	Dec 31, 2018		Dec 31, 2017	
	Current	Non-current	Current	Non-current
Trade payables	30,351	—	33,196	—
Other payables	5,597	2,413	5,767	3,090
Amounts due to joint ventures and associates	2,851	33	2,021	29
Accruals and deferred income	10,089	289	10,426	328
Total	48,888	2,735	51,410	3,447

The fair value of financial liabilities included above approximates the carrying amount and was determined from predominantly unobservable inputs.

Other payables include amounts due to joint arrangement partners and in respect of other project-related items.

Information about offsetting, collateral and liquidity risk is presented in Note 19.

16 TAXATION

Taxation charge	\$ million		
	2018	2017	2016
Current tax:			
Charge in respect of current period	10,415	7,204	3,936
Adjustments in respect of prior periods	60	(613)	(1,205)
Total	10,475	6,591	2,731
Deferred tax:			
Relating to the origination and reversal of temporary differences, tax losses and credits	1,438	(4,102)	(2,688)
Relating to changes in tax rates and legislation	(157)	2,004 [A]	(200)
Adjustments in respect of prior periods	(41)	202	986
Total	1,240	(1,896)	(1,902)
Total taxation charge	11,715	4,695	829

[A] Mainly in respect of the US Tax Cuts and Jobs Act (the Act).

Adjustments in respect of prior periods relate to events in the current period and reflect the effects of changes in rules, facts or other factors compared with those used in establishing the current tax position or deferred tax balance in prior periods.

Reconciliation of applicable tax charge/(credit) at statutory tax rates to taxation charge			\$ million
	2018	2017	2016
Income before taxation	35,621	18,130	5,606
Less: share of profit of joint ventures and associates	(4,106)	(4,225)	(3,545)
Income before taxation and share of profit of joint ventures and associates	31,515	13,905	2,061
Applicable tax charge/(credit) at statutory tax rates	11,444	4,532	(344)
Adjustments in respect of prior periods	19	(411)	(219)
Tax effects of:			
Income not subject to tax at statutory rates	(1,783)	(1,852)	(1,740)
Expenses not deductible for tax purposes	1,379	2,423	2,066
(Recognition)/derecognition of deferred tax assets	(381)	(957)	1,575
Deductible items not expensed	(371)	(584)	(516)
Taxable income not recognised	312	251	509
Changes in tax rates and legislation	(157)	2,004	(200)
Other	1,253	(711)	(302)
Taxation charge	11,715	4,695	829

The weighted average of statutory tax rates was 36% in 2018 (2017: 33%; 2016: (17)%). Compared to 2017, the increase in the rate reflects a higher proportion of earnings in the Upstream segment, subject to relatively higher tax rates than earnings in Downstream and Integrated Gas. The negative rate in 2016 (tax credit on pre-tax income) was mainly due to losses incurred in jurisdictions with a higher weighted average statutory tax rate than jurisdictions in which profits were made.

Other tax-reconciling items include \$819 million relating to the impact of movements in the Brazilian real, Australian dollar and Argentinian peso on deferred tax positions (2017: (\$585) million, 2016: (\$607) million).

Taxes payable			\$ million
	Dec 31, 2018	Dec 31, 2017	
Income taxes	3,990	4,062	
Sales taxes, excise duties and similar levies	3,507	3,188	
Total	7,497	7,250	

Included in other receivables at December 31, 2018 (see Note 11), was income tax receivable of \$1,042 million (2017: \$933 million).

2018 - Deferred tax

\$ million

	Decommissioning and other provisions	Property, plant and equipment	Tax losses and credits carried forward	Retirement benefits	Other	Total
Deferred tax asset						
At January 1, 2018	6,182	3,379	13,684	3,868	4,144	31,257
(Charge)/credit to income	166	345	(553)	14	119	91
Currency translation differences	(177)	(32)	(462)	(93)	(42)	(806)
Other	(269)	26	(502)	(479)	12	(1,212)
At December 31, 2018	5,902	3,718	12,167	3,310	4,233	29,330
Deferred tax liability						
At January 1, 2018	—	(26,904)	—	(742)	(2,827)	(30,473)
(Charge)/credit to income	—	(1,751)	—	180	240	(1,331)
Currency translation differences	—	409	—	24	36	469
Other	—	475	—	(1,136)	(74)	(735)
At December 31, 2018	—	(27,771)	—	(1,674)	(2,625)	(32,070)
Net deferred tax liability at December 31, 2018						(2,740)
Deferred tax asset/liability as presented in the balance sheet at December 31, 2018						
Deferred tax asset						12,097
Deferred tax liability						(14,837)

2017 - Deferred tax

\$ million

	Decommissioning and other provisions	Property, plant and equipment	Tax losses and credits carried forward	Retirement benefits	Other [A]	Total
Deferred tax asset						
At January 1, 2017	7,733	3,510	16,600	5,053	4,374	37,270
(Charge)/credit to income	(1,853)	189	(2,732)	(493)	(265)	(5,154)
Currency translation differences	269	49	554	216	78	1,166
Other	33	(369)	(738)	(908)	(43)	(2,025)
At December 31, 2017	6,182	3,379	13,684	3,868	4,144	31,257
Deferred tax liability						
At January 1, 2017	—	(33,963)	—	(582)	(3,574)	(38,119)
(Charge)/credit to income	—	6,437	—	(129)	742	7,050
Currency translation differences	—	(711)	—	(63)	(70)	(844)
Other	—	1,333	—	32	75	1,440
At December 31, 2017	—	(26,904)	—	(742)	(2,827)	(30,473)
Net deferred tax asset at December 31, 2017						784
Deferred tax asset/liability as presented in the balance sheet at December 31, 2017						
Deferred tax asset						13,791
Deferred tax liability						(13,007)

[A] Reclassified from the Other category to Tax losses carried forward to align with current year presentation.

The presentation in the balance sheet takes into consideration the offsetting of deferred tax assets and deferred tax liabilities within the same tax jurisdiction, where this is permitted. The overall deferred tax position in a particular tax jurisdiction determines if a deferred tax balance related to that jurisdiction is presented within deferred tax assets or deferred tax liabilities.

Other movements in deferred tax assets and liabilities principally relate to acquisitions, sales of non-current assets and businesses, and amounts recognised in other comprehensive income, which in 2017 included amounts in respect of the Act.

The amount of deferred tax assets dependent on future taxable profits not arising from the reversal of existing deferred tax liabilities, and which relate to tax jurisdictions, where Shell has suffered a loss in the current or preceding year, was \$9,979 million at December 31, 2018 (2017: \$12,452 million). It is considered probable based on business forecasts that such profits will be available.

Unrecognised taxable temporary differences associated with undistributed retained earnings of investments in subsidiaries, joint ventures and associates amounted to \$3,951 million (2017: \$3,746 million).

Unrecognised deductible temporary differences, unused tax losses and credits carried forward amounted to \$34,910 million at December 31, 2018 (2017: \$34,773 million) including amounts of \$27,604 million (2017: \$28,016 million) that are subject to time limits for utilisation of five years or later, or are not time limited.

17 RETIREMENT BENEFITS

Retirement benefits are provided through a number of funded and unfunded defined benefit plans and defined contribution plans, the most significant of which are in the Netherlands, UK and USA. Benefits comprise principally pensions; retirement healthcare and life insurance are also provided in certain countries.

Retirement benefit expense	\$ million		
	2018	2017	2016
Defined benefit plans:			
Current service cost, net of plan participants' contributions	1,494	1,500	1,527
Interest expense on obligations	2,282	2,309	2,643
Interest income on plan assets	(2,087)	(2,019)	(2,358)
Other	(221)	(404)	(116)
Total	1,468	1,386	1,696
Defined contribution plans	410	429	485
Total retirement benefit expense	1,878	1,815	2,181

Retirement benefit expense is presented principally within production and manufacturing expenses and selling, distribution and administrative expenses in the Consolidated Statement of Income. Interest income on plan assets is calculated using the same rate as that applied to the related defined benefit obligations for each plan to determine interest expense.

Remeasurements	\$ million		
	2018	2017	2016
Actuarial gains/(losses) on obligations:			
Due to changes in financial assumptions [A]	8,186	(4,495)	(11,391)
Due to experience adjustments [B]	(268)	37	642
Due to changes in demographic assumptions [C]	(459)	933	809
Total	7,459	(3,525)	(9,940)
Return on plan assets (shortage)/in excess of interest income	(2,312)	4,942	5,106
Other movements	66	50	18
Total remeasurements	5,213	1,467	(4,816)

[A] Primarily relates to changes in the discount rate assumptions.

[B] Experience adjustments arise from differences between the actuarial assumptions made in respect of the year and actual outcomes.

[C] Primarily relates to updates in mortality assumptions.

Defined benefit plans		\$ million
	Dec 31, 2018	Dec 31, 2017
Obligations	(91,856)	(104,285)
Plan assets	85,803	93,243
Net liability	(6,053)	(11,042)
Retirement benefits in the Consolidated Balance Sheet:		
Non-current assets	6,051	2,799
Non-current liabilities	(11,653)	(13,247)
Current liabilities	(451)	(594)
Total	(6,053)	(11,042)

Defined benefit plan obligations		\$ million, except where indicated
	2018	2017
At January 1	104,285	94,405
Current service cost	1,491	1,550
Interest expense	2,282	2,309
Actuarial (gains)/losses	(7,459)	3,525
Benefit payments	(4,435)	(4,579)
Other movements	(360)	(949)
Currency translation differences	(3,948)	8,024
At December 31	91,856	104,285
Comprising:		
Funded pension plans	83,276	94,903
Weighted average duration	17 years	19 years
Unfunded pension plans	4,359	4,824
Weighted average duration	13 years	12 years
Other unfunded plans	4,221	4,558
Weighted average duration	12 years	13 years

Defined benefit plan assets		\$ million, except where indicated	
		2018	2017
At January 1		93,243	81,276
Return on plan assets (shortage)/in excess of interest income		(2,312)	4,942
Interest income		2,087	2,019
Employer contributions		763	1,804
Plan participants' contributions		47	50
Benefit payments		(4,123)	(4,294)
Other movements		(102)	(245)
Currency translation differences		(3,800)	7,691
At December 31		85,803	93,243
Comprising:			
Quoted in active markets:			
Equities		24%	32%
Debt securities		53%	45%
Real estate		1%	1%
Investment funds		0%	1%
Other		1%	1%
Other:			
Equities		8%	7%
Debt securities		3%	3%
Real estate		6%	6%
Investment funds		3%	3%
Other		0%	1%
Cash		1%	0%

Long-term investment strategies of plans are generally determined by the relevant pension plan trustees using a structured asset liability modelling approach to define the asset mix that best meets the objectives of optimising returns within agreed risk levels while maintaining adequate funding levels. The value of the plan assets was impacted by the reduced return on investments globally.

Employer contributions to defined benefit pension plans are based on actuarial valuations in accordance with local regulations and are estimated to be \$0.9 billion in 2019.

Additional contributions to the Netherlands defined benefit pension plan would be required if the 12-month rolling average local funding percentage falls below 105% for six months or more. At the most recent (2018) funding valuation the local funding percentage was above this level. There are no set minimum statutory funding requirements for the UK plans. Under an agreement with the trustee of the main UK defined benefit plan, Shell will provide additional contributions if the funding position falls below a certain level, although this is currently not anticipated. For the US plans, under the Pension Protection Act there are minimum required contribution levels; forecast contributions are expected to exceed these.

The principal assumptions applied in determining the present value of defined benefit obligations and their bases were as follows:

- rates of increase in pensionable remuneration, pensions in payment and healthcare costs: historical experience and management's long-term expectation;
- discount rates: prevailing long-term AA corporate bond yields, chosen to match the currency and duration of the relevant obligation; and
- mortality rates: published standard mortality tables for the individual countries concerned adjusted for Shell experience where statistically significant.

The weighted averages for those assumptions and related sensitivity information at December 31 are presented below. Sensitivity information indicates by how much the defined benefit obligations would increase or decrease if a given assumption were to increase or decrease with no change in other assumptions.

\$ million, except where indicated					
	Assumptions used			Effect of using alternative assumptions	
	Increase/(decrease) in defined benefit obligations		Range of assumptions		
	2018	2017		2018	2017
Rate of increase in pensionable remuneration	4.1%	4.7%	-1% to +1%	(1,576) to 1,819	(2,150) to 2,782
Rate of increase in pensions in payment	1.8%	1.9%	-1% to +1%	(8,304) to 10,104	(10,120) to 12,662
Rate of increase in healthcare costs	6.3%	6.6%	-1% to +1%	(410) to 496	(451) to 551
Discount rate for pension plans	2.9%	2.5%	-1% to +1%	15,606 to (12,078)	19,042 to (14,567)
Discount rate for healthcare plans	4.2%	3.5%	-1% to +1%	536 to (436)	599 to (483)
Expected age at death for persons aged 60:					
Men	87 years	87 years	-1 year to +1 year	(1,538) to 1,583	(1,906) to 2,022
Women	89 years	89 years	-1 year to +1 year	(1,436) to 1,476	(1,720) to 1,828

18 DECOMMISSIONING AND OTHER PROVISIONS

						\$ million
	Decommissioning and restoration	Legal	Environmental	Redundancy	Other	Total
At January 1, 2018						
Current	817	423	287	758	1,180	3,465
Non-current	19,767	1,095	1,218	560	2,326	24,966
	20,584	1,518	1,505	1,318	3,506	28,431
Additions	418	196	191	535	1,070	2,410
Amounts charged against provisions	(497)	(200)	(212)	(504)	(887)	(2,300)
Accretion expense	755	17	17	15	48	852
Disposals	(1,781) [A]	(14)	(11)	(3)	(49)	(1,858)
Remeasurements and other movements	(1,065)	(47)	(130)	(367)	(122)	(1,731)
Currency translation differences	(481)	(10)	(22)	(35)	(64)	(612)
	(2,651)	(58)	(167)	(359)	(4)	(3,239)
At December 31, 2018						
Current	876	213	264	491	1,815	3,659
Non-current	17,057	1,247	1,074	468	1,687	21,533
	17,933	1,460	1,338	959	3,502	25,192
At January 1, 2017						
Current	797	500	296	831	1,360	3,784
Non-current	24,368	1,066	1,186	564	2,434	29,618
	25,165	1,566	1,482	1,395	3,794	33,402
Additions	1,168	390	496	756	988	3,798
Amounts charged against provisions	(491)	(327)	(173)	(618)	(1,207)	(2,816)
Accretion expense	897	61	20	13	47	1,038
Disposals	(2,807)	(2)	(4)	(18)	(71)	(2,902)
Remeasurements and other movements	(4,245)	(190)	(352)	(301)	(178)	(5,266)
Currency translation differences	897	20	36	91	133	1,177
	(4,581)	(48)	23	(77)	(288)	(4,971)
At December 31, 2017						
Current	817	423	287	758	1,180	3,465
Non-current	19,767	1,095	1,218	560	2,326	24,966
	20,584	1,518	1,505	1,318	3,506	28,431

[A] Mainly related to disposal of interests in New Zealand and Thailand.

The amount and timing of settlement in respect of these provisions are uncertain and dependent on various factors that are not always within management's control. The discount rate applied at December 31, 2018 was 4% (2017: 4%).

Reviews of estimated future decommissioning and restoration costs and the discount rate applied are carried out annually. In 2018, there was a decrease of \$982 million (2017: \$3,980 million) in the provision resulting from changes in cost estimates, reported within remeasurements and other movements.

Of the decommissioning and restoration provision at December 31, 2018, an estimated \$3,490 million is expected to be utilised between one to five years, \$2,173 million within six to 10 years, and the remainder in later periods.

Other provisions include amounts recognised in respect of employee benefits and onerous contracts.

19 FINANCIAL INSTRUMENTS

Financial instruments in the Consolidated Balance Sheet includes investments in securities (see Note 10), cash and cash equivalents (see Note 13), debt (see Note 14) and derivative contracts.

RISKS

In the normal course of business, financial instruments of various kinds are used for the purposes of managing exposure to interest rate, foreign exchange and commodity price movements.

Treasury standards are applicable to all subsidiaries and each subsidiary is required to adopt a treasury policy consistent with these standards. These policies cover: financing structure; interest rate and foreign exchange risk management; insurance; counterparty risk management; and use of derivative contracts. Wherever possible, treasury operations are carried out through specialist regional organisations without removing from each subsidiary the responsibility to formulate and implement appropriate treasury policies.

Apart from forward foreign exchange contracts to meet known commitments, the use of derivative contracts by most subsidiaries is not permitted by their treasury policy.

Other than in exceptional cases, the use of external derivative contracts is confined to specialist trading and central treasury organisations that have appropriate skills, experience, supervision, control and reporting systems.

Shell's operations expose it to market, credit and liquidity risk, as described below.

Market risk

Market risk is the possibility that changes in interest rates, foreign exchange rates or the prices of crude oil, natural gas, LNG, refined products, chemical feedstocks, power and carbon-emission rights will adversely affect the value of assets, liabilities or expected future cash flows.

Interest rate risk

Most debt is raised from central borrowing programmes. Shell's policy continues to be to have debt principally denominated in dollars and to maintain a largely floating interest rate exposure profile; however, Shell has issued a significant amount of fixed rate debt in recent years, taking advantage of historically low interest rates available in US debt markets. As a result, a substantial portion of the debt portfolio at December 31, 2018, is at fixed rates and this reduces Shell's exposure to the dollar LIBOR interest rate.

The financing of most subsidiaries is structured on a floating-rate basis and, except in special cases, further interest rate risk management is discouraged.

On the basis of the floating rate net debt position at December 31, 2018, (both issued and hedged), and assuming other factors (principally foreign exchange rates and commodity prices) remained constant and that no further interest rate management action was taken, an increase in interest rates of 1% would have decreased 2018 income before taxation by \$37 million (2017: \$174 million, based on the floating rate position at December 31, 2017).

The carrying amounts and maturities of debt and borrowing facilities are presented in Note 14. Interest expense is presented in Note 6.

Foreign exchange risk

Many of the markets in which Shell operates are priced, directly or indirectly, in dollars. As a result, the functional currency of most Integrated Gas and Upstream entities and those with significant cross-border business is the dollar. For Downstream entities, the functional currency is typically the local currency. Consequently, Shell is exposed to varying levels of foreign exchange risk when an entity enters into transactions that are not denominated in its functional currency, when foreign currency monetary assets and liabilities are translated at the balance sheet date and as a result of holding net investments in operations that are not dollar-functional. Each entity is required to adopt treasury policies that are designed to measure and manage its foreign exchange exposures by reference to its functional currency.

Foreign exchange gains and losses arise in the normal course of business from the recognition of receivables and payables and other monetary items in currencies other than an entity's functional currency. Foreign exchange risk may also arise in connection with capital expenditure. For major projects, an assessment is made at the final investment decision stage whether to hedge any resulting exposure.

Assuming other factors (principally interest rates and commodity prices) remained constant and that no further foreign exchange risk management action were taken, a 10% appreciation against the dollar at December 31 of the main currencies to which Shell is exposed would have the following effects:

	\$ million			
	Increase/(decrease) in income before taxation		Increase in net assets	
	2018	2017	2018	2017
10% appreciation against the dollar of:				
Canadian dollar	(40)	(43)	1,245	1,111
Euro	65	130	1,190	1,086
Australian dollar	(109)	(24)	835	786
Sterling	(46)	(77)	779	632

The above sensitivity information was calculated by reference to carrying amounts of assets and liabilities at December 31 only. The effect on income before taxation arises in connection with monetary balances denominated in currencies other than an entity's functional currency; the effect on net assets arises principally from the translation of assets and liabilities of entities that are not dollar-functional.

Foreign exchange gains and losses included in income are presented in Note 5.

Commodity price risk

Certain subsidiaries have a mandate to trade crude oil, natural gas, LNG, refined products, chemical feedstocks, power and carbon-emission rights, and to use commodity derivative contracts (forwards, futures, swaps and options) as a means of managing price and timing risks arising from this trading activity. In effecting these transactions, the entities concerned operate within procedures and policies designed to ensure that risks, including those relating to the default of counterparties, are managed within authorised limits.

Risk management systems are used for recording and valuing instruments. Commodity price risk exposure is monitored, and the acceptable level of exposure determined, by market risk committees. There is regular reviewing of mandated trading limits by senior management, daily monitoring of market risk exposure using value-at-risk (VAR) techniques, daily monitoring of trading positions against limits, and marking-to-fair value of trading exposures with a department independent of traders reviewing the market values applied. Although trading losses can and do occur, the nature of the trading portfolio and its management are considered adequate mitigants against the risk of significant losses.

VAR techniques based on variance/covariance or Monte Carlo simulation models are used to make a statistical assessment of the market risk arising from possible future changes in market values over a 24-hour period and within a 95% confidence level. The calculation of potential changes in fair value takes into account positions, the history of price movements and the correlation of these price movements. Models are regularly reviewed against actual fair value movements to ensure integrity is maintained. The VAR year-end positions in respect of commodities traded in active markets, which are presented in the table below, are calculated on a diversified basis in order to reflect the effect of offsetting risk within combined portfolios.

Value-at-risk (pre-tax)	\$ million	
	Dec 31, 2018	Dec 31, 2017
Global oil	28	25
North America gas and power	11	11
Europe gas and power	3	3
Carbon-emission rights	2	1

Credit risk

Policies are in place to ensure that sales of products are made to customers with appropriate creditworthiness. These policies include detailed credit analysis and monitoring of trading partners against counterparty credit limits. Credit information is regularly shared between business and finance functions, with dedicated teams in place to quickly identify and respond to cases of credit deterioration. Mitigation measures are defined and implemented for high-risk business partners and customers, and include shortened payment terms, collateral or other security posting and vigorous collections. In addition, policies limit the amount of credit exposure to any individual financial institution. There are no material concentrations of credit risk, with individual customers or geographically, and there has been no significant level of counterparty default in recent years.

Surplus cash is invested in a range of short-dated, secure and liquid instruments including short-term bank deposits, money market funds, reverse repos and similar instruments. The portfolio of these investments is diversified to avoid concentrating risk in any one instrument, country or counterparty. Management

monitors the investments regularly and adjusts the investment portfolio in light of new market information where necessary to ensure credit risk is effectively diversified.

In commodity trading, counterparty credit risk is managed within a framework of credit limits with utilisation being regularly reviewed. Credit risk exposure is monitored and the acceptable level is determined by a credit committee. Credit checks are performed by a department independent of traders, and are undertaken before contractual commitment. Where appropriate, netting arrangements, credit insurance, prepayments and collateral are used to manage specific risks.

Shell routinely enters into offsetting, master netting and similar arrangements with trading and other counterparties to manage credit risk. Where there is a legally enforceable right of offset under such arrangements and Shell has the intention to settle on a net basis or realise the asset and settle the liability simultaneously, the net asset or liability is recognised in the Consolidated Balance Sheet, otherwise assets and liabilities are presented gross. These amounts, as presented net and gross within trade and other receivables, trade and other payables and derivative financial instruments in the Consolidated Balance Sheet at December 31, were as follows:

2018						\$ million
	Amounts offset			Amounts not offset		Net amounts
	Gross amounts before offset	Amounts offset	Net amounts as presented	Cash collateral received/pledged	Other offsetting instruments	
Assets:						
Within trade receivables	12,697	8,340	4,358	62	221	4,075
Within derivative financial instruments	12,323	6,353	5,970	437	2,653	2,880
Liabilities:						
Within trade payables	12,931	8,264	4,667	97	221	4,349
Within derivative financial instruments	12,227	5,044	7,183	1,115	2,653	3,415

2017						\$ million
	Amounts offset			Amounts not offset		Net amounts
	Gross amounts before offset	Amounts offset	Net amounts as presented	Cash collateral received/pledged	Other offsetting instruments	
Assets:						
Within trade receivables	10,642	6,486	4,156	42	51	4,063
Within derivative financial instruments	6,987	2,387	4,600	186	2,326	2,088
Liabilities:						
Within trade payables	10,442	6,486	3,956	41	51	3,864
Within derivative financial instruments	7,315	2,392	4,923	300	2,326	2,297

Amounts not offset principally relate to contracts where the intention to settle on a net basis was not clearly established at December 31.

The carrying amount of financial assets pledged as collateral for liabilities or contingent liabilities at December 31, 2018, presented within trade and other receivables, was \$3,094 million (2017: \$1,890 million). The carrying amount of collateral held at December 31, 2018, presented within trade and other payables, was \$535 million (2017: \$282 million). Collateral mainly relates to initial margins held with commodity exchanges and over-the-counter counterparty variation margins.

Liquidity risk

Liquidity risk is the risk that suitable sources of funding for Shell's business activities may not be available. Management believes that it has access to sufficient debt funding sources (capital markets), and to undrawn committed borrowing facilities to meet foreseeable requirements. Information about borrowing facilities is presented in Note 14.

DERIVATIVE CONTRACTS AND HEDGES

Derivative contracts are used principally as hedging instruments, however, because hedge accounting is not always applied, movements in the carrying amounts of derivative contracts that are recognised in income are not always matched in the same period by the recognition of the income effects of the related hedged items.

Carrying amounts, maturities and hedges

The carrying amounts of derivative contracts at December 31, designated and not designated as hedging instruments for hedge accounting purposes, were as follows:

							\$ million
2018	Assets			Liabilities			Net
	Designated	Not designated	Total	Designated	Not designated	Total	
Interest rate swaps	86	3	89	174	14	188	(99)
Forward foreign exchange contracts	—	331	331	33	264	297	34
Currency swaps and options	186	26	212	1,202	203	1,405	(1,193)
Commodity derivatives	—	6,864	6,864	—	6,637	6,637	227
Other contracts	—	271	271	—	56	56	215
Total	272	7,495	7,767	1,409	7,174	8,583	(816)

							\$ million
2017	Assets			Liabilities			Net
	Designated	Not designated	Total	Designated	Not designated	Total	
Interest rate swaps	—	16	16	165	34	199	(183)
Forward foreign exchange contracts	22	403	425	—	591	591	(166)
Currency swaps and options	483	208	691	815	76	891	(200)
Commodity derivatives	—	4,929	4,929	—	4,428	4,428	501
Other contracts	—	162	162	—	125	125	37
Total	505	5,718	6,223	980	5,254	6,234	(11)

Net losses before tax on derivative contracts, excluding realised commodity contracts and those accounted for as hedges, were \$1,818 million in 2018 (2017: \$1,321 million losses; 2016: \$414 million gains).

Certain contracts, mainly to hedge price risk relating to forecast commodity transactions which mature in 2019-2021, were designated in cash flow hedging relationships. The net carrying amount of commodity derivative contracts designated as cash flow hedging instruments at December 31, 2018, was an asset of \$120 million (2017: \$620 million liability) (see Note 22), and was presented after the offset of related margin balances maintained with exchanges.

Certain interest rate and currency swaps were designated in fair value hedges, principally in respect of debt for which the net carrying amount of the related derivative contracts, net of accrued interest, at December 31, 2018, was a liability of \$1,242 million (2017: \$826 million).

In the course of trading operations, certain contracts are entered into for delivery of commodities that are accounted for as derivatives. The resulting price exposures are managed by entering into related derivative contracts. These contracts are managed on a fair value basis and the maximum exposure to liquidity risk is the undiscounted fair value of derivative liabilities.

For a minority of commodity derivative contracts, carrying amounts cannot be derived from quoted market prices or other observable inputs, in which case fair value is estimated using valuation techniques such as Black-Scholes, option spread models and extrapolation using quoted spreads with assumptions developed internally based on observable market activity.

Other contracts include certain contracts that are held to sell or purchase commodities and others containing embedded derivatives, which are required to be recognised at fair value because of pricing or delivery conditions, even though they were entered into to meet operational requirements. These contracts are expected to mature in 2019-2025, with certain contracts having early termination rights (for either party). Valuations are derived from quoted market prices.

The contractual maturities of derivative liabilities at December 31 compare with their carrying amounts in the Consolidated Balance Sheet as follows:

2018									
									\$ million
	Contractual maturities							Difference from carrying amount [A]	Carrying amount
	Less than 1 year	Between 1 and 2 years	Between 2 and 3 years	Between 3 and 4 years	Between 4 and 5 years	5 years and later	Total		
Interest rate swap	101	68	20	1	1	1	192	(4)	188
Forward foreign exchange contracts	177	(24)	33	(1)	(5)	(15)	165	132	297
Currency swaps and options	605	265	474	405	198	1,715	3,662	(2,257)	1,405
Commodity derivatives	4,733	978	422	213	138	382	6,866	(229)	6,637
Other contracts	58	—	—	—	—	—	58	(2)	56
Total	5,674	1,287	949	618	332	2,083	10,943	(2,360)	8,583

[A] Mainly related to the effect of discounting.

2017									
									\$ million
	Contractual maturities							Difference from carrying amount [A]	Carrying amount
	Less than 1 year	Between 1 and 2 years	Between 2 and 3 years	Between 3 and 4 years	Between 4 and 5 years	5 years and later	Total		
Interest rate swap	59	67	56	18	1	3	204	(5)	199
Forward foreign exchange contracts	315	37	14	3	2	(39)	332	259	591
Currency swaps and options	541	343	140	304	194	879	2,401	(1,510)	891
Commodity derivatives	3,002	754	305	122	74	263	4,520	(92)	4,428
Other contracts	87	48	—	—	—	—	135	(10)	125
Total	4,004	1,249	515	447	271	1,106	7,592	(1,358)	6,234

[A] Mainly related to the effect of discounting.

Fair value measurements

The net carrying amounts of derivative contracts held at December 31, categorised according to the predominant source and nature of inputs used in determining the fair value of each contract, were as follows:

2018					\$ million
	Prices in active markets for identical assets/liabilities	Other observable inputs	Unobservable inputs		Total
Interest rate swaps	—	(99)	—		(99)
Forward foreign exchange contracts	—	34	—		34
Currency swaps and options	—	(1,193)	—		(1,193)
Commodity derivatives	(52)	431	(152)		227
Other contracts	—	90	125		215
Total	(52)	(737)	(27)		(816)

2017

\$ million

	Prices in active markets for identical assets/liabilities	Other observable inputs	Unobservable inputs	Total
Interest rate swaps	—	(183)	—	(183)
Forward foreign exchange contracts	—	(166)	—	(166)
Currency swaps and options	—	(200)	—	(200)
Commodity derivatives	36	302	163	501
Other contracts	—	(97)	134	37
Total	36	(344)	297	(11)

Net carrying amounts of derivative contracts measured using predominantly unobservable inputs

\$ million

	2018	2017 [A]
At January 1	297	468
Net (losses)/gains recognised in revenue	(258)	372
Purchases	461	252
Sales	(540)	(562)
Recategorisations (net)	18	(248)
Currency translation differences	(5)	15
At December 31	(27)	297

[A] Following a review of fair-valued commodity swaps, options, futures and forwards unobservable inputs in 2018, the movement of net carrying amounts of derivative contracts measured using predominantly unobservable inputs was revised. This revision did not result in a change in the opening and closing balances. The revised values for 2017 were provided for comparability purposes.

Included in net losses recognised in revenue in 2018 were unrealised net losses totalling \$36 million relating to assets and liabilities held at December 31, 2018 (2017: \$39 million gains).

20 SHARE CAPITAL**Issued and fully paid ordinary shares of €0.07 each [A]**

	Number of shares		Nominal value (\$ million)		
	A	B	A	B	Total
At January 1, 2018	4,597,136,050	3,745,486,731	387	309	696
Repurchase of shares	(125,246,754)	—	(11)	—	(11)
At December 31, 2018	4,471,889,296	3,745,486,731	376	309	685
At January 1, 2017	4,428,903,813	3,745,486,731	374	309	683
Scrip dividends	168,232,237	—	13	—	13
At December 31, 2017	4,597,136,050	3,745,486,731	387	309	696

[A] Share capital at December 31, 2018, and 2017, also included 50,000 issued and fully paid sterling deferred shares of £1 each.

At the Company's Annual General Meeting (AGM) on May 22, 2018, the Board was authorised to allot ordinary shares in the Company, and to grant rights to subscribe for or to convert any security into ordinary shares in the Company, up to an aggregate nominal amount of €194 million (representing 2,771 million ordinary shares of €0.07 each), and to list such shares or rights on any stock exchange. This authority expires at the earlier of the close of business on August 22, 2019, and the end of the AGM to be held in 2019, unless previously renewed, revoked or varied by the Company in a general meeting.

At the May 22, 2018 AGM, shareholders granted the Company the authority to repurchase up to 10% of its issued ordinary shares (excluding any treasury shares), renewing the authority granted by shareholders at previous AGMs. The authority will expire at the earlier of the close of business on August 22, 2019, and the end of the Company's AGM to be held in 2019. Ordinary shares purchased by the Company pursuant to this authority will either be cancelled or held in treasury. Treasury shares are shares in the Company that are owned by the Company itself. The minimum price, exclusive of expenses, which may be paid for an ordinary share is €0.07. The maximum price, exclusive of expenses, which may be paid for an ordinary share is the higher of: (i) an amount equal to 5% above the average market value for an ordinary share for the five business days immediately preceding the date of the purchase; and (ii) the higher of the price of the last independent trade and the highest current independent bid on the trading markets where the purchase is carried out.

21 SHARE-BASED COMPENSATION PLANS AND SHARES HELD IN TRUST

Share-based compensation expense

	2018	2017	2016
			\$ million
Equity-settled	531	422	488
Cash-settled	— [A]	380	205
Total	531	802	693

[A] As from 2018 components of share-based payments (related to tax) that were previously classified as cash-settled are classified as equity-settled (see Note 2). On an incidental basis awards may be cash settled, where an equity settlement is not possible under local regulations.

The principal share-based employee compensation plans are the PSP and LTIP. Awards of shares and American Depositary Shares (ADSs) of the Company under the PSP and LTIP are granted upon certain conditions to eligible employees. The actual amount of shares that may vest ranges from 0% to 200% of the awards, depending on the outcomes of prescribed performance conditions over a three-year period beginning on January 1 of the award year. Shares and ADSs vest for nil consideration.

Share awards under the PSP and LTIP

	Number of A shares (million)	Number of B shares (million)	Number of A ADSs (million)	Weighted average remaining contractual life (years)
At January 1, 2018	33	12	9	0.9
Granted	10	4	3	
Vested	(12)	(4)	(4)	
Forfeited	(1)	—	—	
At December 31, 2018	30	12	8	1.0
At January 1, 2017	36	12	10	1.0
Granted	10	4	3	
Vested	(12)	(4)	(4)	
Forfeited	(1)	—	—	
At December 31, 2017	33	12	9	0.9

Other plans offer employees opportunities to acquire shares and ADSs of the Company or receive cash benefits measured by reference to the Company's share price.

Shell employee share ownership trusts and trust-like entities purchase the Company's shares in the open market to meet delivery commitments under employee share plans. At December 31, 2018, they held 19.6 million A shares (2017: 15.2 million), 7.1 million B shares (2017: 2.9 million) and 5.9 million A ADSs (2017: 5.9 million).

22 OTHER RESERVES

Other reserves attributable to Royal Dutch Shell plc shareholders

\$ million

	Merger reserve	Share premium reserve	Capital redemption reserve	Share plan reserve	Accumulated other comprehensive income	Total
At January 1, 2018 (as previously reported)	37,298	154	84	1,440	(22,044)	16,932
Impact of IFRS 9 implementation	—	—	—	—	(138)	(138)
At January 1, 2018 (as revised)	37,298	154	84	1,440	(22,182)	16,794
Other comprehensive income attributable to Royal Dutch Shell plc shareholders	—	—	—	—	1,123	1,123
Transfer from other comprehensive income	—	—	—	—	(971)	(971)
Repurchase of shares	—	—	11	—	—	11
Share-based compensation	—	—	—	(342) [A] [B]	—	(342)
At December 31, 2018	37,298	154	95	1,098	(22,030)	16,615
At January 1, 2017	37,311	154	84	1,644	(27,895)	11,298
Other comprehensive loss attributable to Royal Dutch Shell plc shareholders	—	—	—	—	5,851	5,851
Scrip dividends	(13)	—	—	—	—	(13)
Share-based compensation	—	—	—	(204)	—	(204)
At December 31, 2017	37,298	154	84	1,440	(22,044)	16,932
At January 1, 2016	3,398	154	84	1,658	(22,480)	(17,186)
Other comprehensive loss attributable to Royal Dutch Shell plc shareholders	—	—	—	—	(5,949)	(5,949)
Scrip dividends	(17)	—	—	—	—	(17)
Shares issued	33,930	—	—	—	—	33,930
Share-based compensation	—	—	—	(14)	534	520
At December 31, 2016	37,311	154	84	1,644	(27,895)	11,298

[A] Includes a reclassification of \$503 million between the Share plan reserve and Retained earnings, which relates to the unwinding of expired share options.

[B] The amendments to IFRS 2 *Share-based payment* became effective January 1, 2018. Following adoption of the amendments, components of share-based payments (related to tax) that were previously classified as cash-settled are now classified as equity-settled. This resulted in an increase of \$172 million in the share plan reserve and a net increase of \$125 million in retained earnings.

The merger reserve and share premium reserve were established as a consequence of the Company becoming the single parent company of Royal Dutch Petroleum Company and The "Shell" Transport and Trading Company, p.l.c., now The Shell Transport and Trading Company Limited, in 2005. The increase in the merger reserve in 2016 in respect of the shares issued represents the difference between the fair value and the nominal value of the shares issued for the acquisition of BG. The capital redemption reserve was established in connection with repurchases of shares of the Company. The share plan reserve is in respect of equity-settled share-based compensation plans (see Note 21). The movement represents the net of the charge for the year and the release as a result of vested awards and is after deduction of tax of \$71 million in 2018 (2017: \$11 million; 2016: \$nil).

Accumulated other comprehensive income comprises the following:

Accumulated other comprehensive income attributable to Royal Dutch Shell plc shareholders								\$ million
	Currency translation differences	Unrealised gains/(losses) on securities	Debt instruments remeasurements	Cash flow hedging gains/(losses)	Deferred cost of hedging	Retirement benefits remeasurements	Equity instrument remeasurements	Total
At January 1, 2018 (as previously reported)	(8,735)	1,969	—	(633)	—	(14,645)	—	(22,044)
Impact of IFRS 9 implementation	—	(1,969)	(6)	6	(144)	—	1,975	(138)
At January 1, 2018 (as revised)	(8,735)	—	(6)	(627)	(144)	(14,645)	1,975	(22,182)
Recognised in other comprehensive income	(3,794)	—	(15)	50	(362)	5,213	(147)	945
Reclassified to income	651	—	—	722	95	—	—	1,468
Reclassified to the balance sheet	—	—	—	(30)	—	—	—	(30)
Reclassified to retained earnings	—	—	—	—	—	137	(1,108)	(971)
Tax on amounts recognised/reclassified	(29)	—	—	(12)	58	(1,625)	(6)	(1,614)
Total, net of tax	(3,172)	—	(15)	730	(209)	3,725	(1,261)	(202)
Share of joint ventures and associates	(25)	—	—	14	—	1	193	183
Other comprehensive income/(loss) for the period	(3,197)	—	(15)	744	(209)	3,726	(1,068)	(19)
Less: non-controlling interest	185	—	—	—	—	(13)	(1)	171
Attributable to Royal Dutch Shell plc shareholders	(3,012)	—	(15)	744	(209)	3,713	(1,069)	152
At December 31, 2018	(11,747)	—	(21)	117 [B]	(353)	(10,932)	906	(22,030)
At January 1, 2017	(13,831)	1,321	—	(144)	—	(15,241)	—	(27,895)
Recognised in other comprehensive income	4,513	796	—	(467)	—	1,467	—	6,309
Reclassified to income	610	(211)	—	(87)	—	—	—	312
Reclassified to the balance sheet	—	—	—	(18)	—	—	—	(18)
Tax on amounts recognised/reclassified	33	8	—	20	—	(863)	—	(802)
Total, net of tax	5,156	593	—	(552)	—	604	—	5,801
Share of joint ventures and associates	53	55	—	63	—	(1)	—	170
Other comprehensive loss for the period	5,209	648	—	(489)	—	603	—	5,971
Less: non-controlling interest	(113)	—	—	—	—	(7)	—	(120)
Attributable to Royal Dutch Shell plc shareholders	5,096	648	—	(489)	—	596	—	5,851
At December 31, 2017	(8,735)	1,969	—	(633) [B]	—	(14,645)	—	(22,044)
At January 1, 2016	(12,940)	1,409	—	473	—	(11,422)	—	(22,480)
Recognised in other comprehensive income	(1,023) [A]	(204)	—	(727)	—	(4,816)	—	(6,770)
Reclassified to income	(277)	1	—	(939)	—	—	—	(1,215)
Reclassified to the balance sheet	—	—	—	1,044 [C]	—	—	—	1,044
Tax on amounts recognised/reclassified	(21)	(11)	—	5	—	999	—	972
Total, net of tax	(1,321)	(214)	—	(617)	—	(3,817)	—	(5,969)
Share of joint ventures and associates	(154)	126	—	—	—	—	—	(28)
Other comprehensive income/(loss) for the period	(1,475)	(88)	—	(617)	—	(3,817)	—	(5,997)
Less: non-controlling interest	50	—	—	—	—	(2)	—	48
Attributable to Royal Dutch Shell plc shareholders	(1,425)	(88)	—	(617)	—	(3,819)	—	(5,949)
Reclassification in respect of shares held in trust	534	—	—	—	—	—	—	534
At December 31, 2016	(13,831)	1,321	—	(144)	—	(15,241)	—	(27,895)

[A] Includes losses of \$2,024 million arising on net investment hedges.

[B] See Note 19.

[C] Mainly relating to the acquisition of BG.

23 DIVIDENDS

Interim dividends	\$ million		
	2018	2017	2016
A shares:			
Cash: \$1.88 per share (2017: \$1.88; 2016: \$1.88)	8,605	4,919	4,545
Scrip: none (2017: \$1.88; 2016: \$1.88 per share)	–	3,558	3,491
Total – A shares	8,605	8,477	8,036
B shares:			
Cash: \$1.88 per share (2017: \$1.88; 2016: \$1.88)	7,070	5,958	5,132
Scrip: none (2017: \$1.88; 2016: \$1.88 per share)	–	1,193	1,791
Total – B shares	7,070	7,151	6,923
Total	15,675	15,628	14,959

In addition, on January 31, 2019, the Directors announced a further interim dividend in respect of 2018 of \$0.47 per A share and \$0.47 per B share. The total dividend is estimated to be \$3,848 million and is payable on March 25, 2019, to shareholders on the register at February 15, 2018. The Scrip Dividend Programme has been cancelled with effect from the fourth quarter 2017 interim dividend.

Dividends on A shares are by default paid in euros, although holders may elect to receive dividends in sterling. Dividends on B shares are by default paid in sterling, although holders may elect to receive dividends in euros. Dividends on ADSs are paid in dollars.

24 EARNINGS PER SHARE

	2018	2017	2016
Income attributable to Royal Dutch Shell plc shareholders (\$ million)	23,352	12,977	4,575
Weighted average number of A and B shares used as the basis for determining:			
Basic earnings per share (million)	8,282.8	8,223.4	7,833.7
Diluted earnings per share (million)	8,348.7	8,299.0	7,891.7

Basic earnings per share are calculated by dividing the income attributable to Royal Dutch Shell plc shareholders for the year by the weighted average number of A and B shares outstanding during the year. The weighted average number of shares outstanding excludes shares held in trust.

Diluted earnings per share are based on the same income figures. The weighted average number of shares outstanding during the year is increased by dilutive shares related to share-based compensation plans.

Earnings per share are identical for A and B shares.

25 LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

GENERAL

In the ordinary course of business, Shell subsidiaries are subject to a number of contingencies arising from litigation and claims brought by governmental, including tax authorities, and private parties. The operations and earnings of Shell subsidiaries continue, from time to time, to be affected to varying degrees by political, legislative, fiscal and regulatory developments, including those relating to the protection of the environment and indigenous groups in the countries in which they operate. The industries in which Shell subsidiaries are engaged are also subject to physical risks of various types.

The amounts claimed in relation to such events and, if such claims against Shell were successful, the costs of implementing the remedies sought in the various cases could be substantial. Based on information available to date and taking into account that in some cases it is not practicable to estimate the possible magnitude or timing of any resultant payments, management believes that the foregoing are not expected to have a material adverse impact on Shell's Consolidated Financial Statements. However, there remains a high degree of uncertainty around these contingencies, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition.

In certain divestment transactions, liabilities related to dismantling and restoration are de-recognised upon transfer of these obligations to the buyer. For certain of these obligations Shell has issued guarantees to third parties and continues to be liable in case that the primary obligator is not able to meet its obligation. These potential obligations arising from issuance of these guarantees are assessed to be remote.

PESTICIDE LITIGATION

Shell Oil Company (SOC), along with another agricultural chemical pesticide manufacturer and several distributors, has been sued by public and quasi-public water purveyors alleging responsibility for groundwater contamination caused by applications of chemical pesticides. There are approximately 45 such cases currently pending. These suits assert various theories of strict liability and negligence, and seek to recover actual damages, including drinking well treatment and remediation costs. Most assert claims for punitive damages. While the Company continues to vigorously defend these lawsuits, a new environmental regulatory standard became effective in the State of California, where a majority of the suits are pending. The new standard requires public water systems state wide to perform quarterly or monthly sampling of their drinking water sources for a chemical contained in certain pesticides, beginning in January 2018. Water systems deemed out of compliance with the new five parts per trillion regulatory standard must take corrective action to resolve the exceedance or take the potable water source out of service. In response to this new regulatory standard, the Company is monitoring the sampling results to determine the number of wells potentially impacted. Based on the claims asserted and SOC's track record, with regard to amounts paid to resolve varying claims, management does not expect the outcome of these lawsuits pending at December 31, 2018, to have a material adverse impact on Shell. However, there remains a high degree of uncertainty regarding the potential outcome of some of these pending lawsuits, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition.

CLIMATE CHANGE LITIGATION

In the USA, 12 lawsuits have been filed by several municipalities and one state against oil and gas companies, including Royal Dutch Shell plc. The plaintiffs seek damages for claimed harm to their public and private infrastructure from rising sea levels allegedly due to climate change caused by the defendants' fossil fuel products. A similar suit has been filed by a crab fishing industry group claiming harm to their fisheries as a result of alleged ocean-related impacts of climate change. Management believes the outcome of these matters should be resolved in a manner favourable to Shell, however, there remains a high degree of uncertainty regarding the ultimate outcome of these lawsuits, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition.

BRAZIL TAX

Pursuant to Law 7.183/2015 issued by the State of Rio de Janeiro (RJ State) and effective March 2016, a value-added levy has been imposed on oil extraction in the RJ State. The company understands that the obligations arising from this law are not legally sustainable and Shell obtained two separate favorable injunctions suspending the enforcement of the law in March and October 2016, respectively. Both injunctions remain in effect and the matter is currently pending before the Tribunal de Justiça do Rio de Janeiro, the local RJ State Court of Appeal. In addition, and as this is an industry-wide issue, the Brazilian Association of Oil and Gas Exploration and Production Companies, of which Shell is a member of, filed a suit in February 2016 before the Supremo Tribunal Federal, the Brazilian Supreme Court, challenging the constitutionality of the law. This matter is currently pending with the Supreme Court. Should Shell be required to pay such a levy, it could result in a total liability of approximately \$3 billion as at end 2018.

NIGERIAN LITIGATION

Shell subsidiaries and associates operating in Nigeria are parties to various environmental and contractual disputes brought in the courts of Nigeria, England and the Netherlands. These disputes are at different stages in litigation, including at the appellate stage, where judgements have been rendered against Shell entities. If taken at face value, the aggregate amount of these judgements could be seen as material. Management, however, believes that the outcomes of these matters will ultimately be resolved in a manner favourable to Shell. However, there remains a high degree of uncertainty regarding these cases, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition.

The authorities in various countries are investigating Shell Nigeria Exploration and Production Company Ltd.'s (SNEPCO's) investment in Nigerian oil block OPL 245 and the 2011 settlement of litigation pertaining to that block with regard to potential anti-bribery, anti-corruption and anti-money laundering laws.

On January 27, 2017, the Nigeria Federal High Court issued an Interim Order of Attachment for Oil Prospecting Licence 245 (OPL 245), pending the conclusion of the investigation. SNEPCO applied for and was granted a discharge of this order on constitutional and procedural grounds. Also in Nigeria, in March 2017 criminal charges alleging official corruption and conspiracy to commit official corruption were filed against SNEPCO, one current Shell employee and third parties including ENI SpA and one of its subsidiaries. Those proceedings are ongoing. In March 2017, parties alleging to be shareholders of Malabu Oil and Gas Company Ltd. (Malabu) filed two actions to challenge the 2011 settlement and the award of OPL 245 to SNEPCO and an ENI SpA subsidiary by the Federal Government of Nigeria. Those proceedings are also ongoing. On May 8, 2018, Human Environmental Development Agenda (HEDA) sought permission from the Federal High Court of Nigeria to apply for an order to direct the Attorney General of the Federation to revoke OPL 245 on grounds that the entire Malabu transaction in relation to the OPL is unconstitutional, illegal and void as it was obtained through fraudulent and corrupt practice. On October 4, 2018, SNEPCO was joined as a defendant in the HEDA action. Those proceedings are ongoing. In March 2016, the Nigeria House of Representatives (HoR) announced it was going to conduct a third investigation into OPL 245. SNEPCO sought and was granted an interlocutory injunction preventing the HoR from investigating SNEPCO, as such an investigation was beyond the legal powers of the HoR and the matter was under judicial consideration. On July 2, 2018, the court issued a decision in favour of SNEPCO granting all the reliefs sought including a declaration that the HoR does not have powers to investigate the OPL 245 award and a perpetual injunction to restrain the HoR from continuing with the investigations or compelling SNEPCO's participation in the investigations. On December 12, 2018, the Federal Republic of Nigeria issued a claim form in the UK against RDS and six subsidiaries, ENI SpA and two of its subsidiaries, Malabu as well as two other entities for the amount of \$1,092 million plus damages for having participated in a fraudulent and corrupt scheme leading to the acquisition by Shell and ENI corporate defendants in 2011 of OPL 245.

The Shell entities have yet to be served with the proceedings. On February 14, 2017, Royal Dutch Shell plc received a notice of request for indictment from the Milan public prosecutor with respect to this matter. On December 20, 2017, Royal Dutch Shell plc along with four former Shell employees including one former executive were remanded to trial in Milan. On May 14, 2018, a trial commenced in the Court of Milan and is ongoing. On September 18, 2018, RDS was joined to the proceedings as the civilly responsible party (responsabile civile) for the damages caused by the alleged illegal acts of the four former Shell employees. Three other Shell entities (Shell UK Ltd, SPDC and SEPA) also joined the proceedings but were denied status as responsabile civile for their respective former employees at this phase of the proceedings. Based on Shell's review of the Prosecutor of Milan's file and all the information and facts currently available to Shell, management does not believe that there is a basis to convict Shell in Milan. Furthermore, management is not aware of any evidence to convict any former or current Shell employee in Milan. On September 20, 2018, a guilty judgement was filed by the Milan Judge of the Preliminary Hearing in a separate OPL 245 fast track trial of two individuals, neither of whom worked on behalf of Shell. That decision is under appeal.

In February 2019, we were informed by the Dutch Public Prosecutor's Office (DPP) that they are nearing the conclusion of their investigation and are preparing to prosecute Royal Dutch Shell plc for criminal charges directly or indirectly related to the 2011 settlement of disputes over OPL 245 in Nigeria. Investigations by authorities in other jurisdictions are ongoing.

There remains a high degree of uncertainty around the OPL 245 matters and contingencies discussed above, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition. Accordingly, at this time, it is not practicable to estimate the magnitude and timing of any possible obligations or payments. Any violation of the US Foreign Corrupt Practices Act or other relevant anti-bribery, anti-corruption or anti-money laundering legislation could have a material adverse effect on Royal Dutch Shell plc's earnings, cash flows and financial condition.

26 EMPLOYEES

Employee costs	\$ million		
	2018	2017	2016
Remuneration	10,167	10,855	11,985
Social security contributions	810	844	867
Retirement benefits (see Note 17)	1,878	1,815	2,181
Share-based compensation (see Note 21)	531	802	693
Total [A]	13,386	14,316	15,726

[A] Excludes employees seconded to joint ventures and associates.

Average employee numbers	Thousand		
	2018	2017 [C]	2016 [C]
Integrated Gas	8	8	9
Upstream	14	16	18
Downstream	37	40	46
Corporate [A]	20	19	18
Total [B]	79	83	91

[A] Includes all employees working in business service centres irrespective of the segment they support.

[B] Excludes employees seconded to joint ventures and associates (2018: 3,000 employees, 2017: 3,000 employees, 2016: 4,000 employees).

[C] As revised.

27 DIRECTORS AND SENIOR MANAGEMENT

Remuneration of Directors of the Company

	2018	2017	\$ million 2016
Emoluments	12	11	10
Value of released awards under long-term incentive plans	20	5	8
Employer contributions to pension plans	1	1	1

Emoluments comprise salaries and fees, annual bonuses (for the period for which performance is assessed) and other benefits. The value of released awards under long-term incentive plans for the period is in respect of the performance period ending in that year. In 2018, retirement benefits were accrued in respect of qualifying services under defined benefit plans by two Directors.

Further information on the remuneration of the Directors can be found in the Directors' Remuneration Report on pages 119-147.

Directors and Senior Management expense

	2018	2017	\$ million 2016
Short-term benefits	26	23	21
Retirement benefits	3	3	3
Share-based compensation	14	17	15
Termination and related amounts	—	3	4
Total	43	46	43

Directors and Senior Management comprise members of the Executive Committee and the Non-executive Directors of the Company.

Short-term benefits comprise salaries and fees, annual bonuses delivered in cash and shares (for the period for which performance is assessed), other benefits and employer social security contributions. Prior to 2017, these included the 50% of annual bonuses delivered in cash, and share-based compensation included the appropriate proportion of the deferred element (under the Deferred Bonus Plan). Following shareholder approval at the 2017 AGM, the Deferred Bonus Plan has been removed and 50% of the bonus is delivered in shares subject to a three-year holding period.

28 AUDITOR'S REMUNERATION

	2018	2017	\$ million 2016
Fees in respect of the audit of the Consolidated and Parent Company Financial Statements, including audit of consolidation returns	31	27	32
Other audit fees, principally in respect of audits of accounts of subsidiaries	16	21	17
Total audit fees	47	48	49
Audit-related fees	5	4	2
Fees in respect of other non-audit services	1	1	1
Total	53	53	52

In addition, the auditor provided audit services to retirement benefit plans for employees of subsidiaries. Remuneration paid by those benefit plans amounted to \$1 million in 2018 (2017: \$1 million, 2016: \$1 million).

Classification of auditor's remuneration under US Securities and Exchange Commission rules

For US reporting purposes, the total auditor's remuneration of \$53 million (2017: \$53 million, 2016: \$52 million) is categorised as follows: audit \$50 million (2017: \$50 million, 2016: \$51 million), audit-related \$2 million (2017: \$2 million, 2016: \$1 million), and all other fees \$1 million (2017: \$1 million, 2016: nil).

Supplementary information – oil and gas (unaudited)

The information set out on pages 215-236 is referred to as “unaudited” as a means of clarifying that it is not covered by the audit opinion of the independent registered public accounting firm that has audited and reported on the “Consolidated Financial Statements”.

PROVED RESERVES

Proved reserves estimates are calculated pursuant to the US Securities and Exchange Commission (SEC) Rules and the Financial Accounting Standard Board’s Topic 932. Proved reserves can be either developed or undeveloped. The definitions used are in accordance with the SEC Rule 4-10 (a) of Regulation S-X. We include proved reserves associated with future production that will be consumed in operations.

Proved reserves shown are net of any quantities of crude oil or natural gas that are expected to be (or could be) taken as royalties in kind. Proved reserves outside North America include quantities that will be settled as royalties in cash. Proved reserves include certain quantities of crude oil or natural gas that will be produced under arrangements that involve Shell subsidiaries, joint ventures and associates in risks and rewards but do not transfer title of the product to those entities.

Subsidiaries’ proved reserves at December 31, 2018, were divided into 78% developed and 22% undeveloped on a barrel of oil equivalent basis. For the Shell share of joint ventures and associates, the proved reserves at December 31, 2018, were divided into 89% developed and 11% undeveloped on a barrel of oil equivalent basis.

Proved reserves are recognised under various forms of contractual agreements. Shell’s proved reserves volumes at December 31, 2018, present in agreements such as production-sharing contracts (PSC), tax/variable royalty contracts or other forms of economic entitlement contracts, where the Shell share of reserves can vary with commodity prices, were 2,181 million barrels of crude oil and natural gas liquids, and 13,832 thousand million standard cubic feet (scf) of natural gas.

Proved reserves cannot be measured exactly because estimation of reserves involves subjective judgement (see “Risk factors” on page 16 and our “Proved reserves assurance process” below). These estimates remain subject to revision and are unaudited supplementary information.

PROVED RESERVES ASSURANCE PROCESS

A central group of reserves experts, who on average have around 30 years’ experience in the oil and gas industry, undertake the primary assurance of the proved reserves bookings. This group of experts is part of the Resources Assurance and Reporting (RAR) organisation within Shell. A Vice President with 33 years’ experience in the oil and gas industry currently heads the RAR organisation. He is a member of the Society of Petroleum Engineers, Society of Petroleum Evaluation Engineers and holds a BA in mathematics from Oxford University and an MEng in Petroleum Engineering from Heriot Watt University. The RAR organisation reports directly to an Executive Vice President of Finance, who is a member of the Upstream Reserves Committee (URC). The URC is a multidisciplinary committee consisting of senior representatives from the Finance, Legal, Projects & Technology and Upstream organisations. The URC reviews and endorses all major (larger than 20 million barrels of oil equivalent) proved reserves bookings and endorses the total aggregated proved reserves. Final approval of all proved reserves bookings remains with Shell’s Executive Committee, and where all proved reserves bookings are reviewed by Shell’s Audit Committee. The Internal Audit function also provides secondary assurance through audits of the control framework.

CRUDE OIL, NATURAL GAS LIQUIDS, SYNTHETIC CRUDE OIL AND BITUMEN

Shell subsidiaries' proved reserves of crude oil, natural gas liquids (NGLs), synthetic crude oil and bitumen at the end of the year; their share of the proved reserves of joint ventures and associates at the end of the year; and the changes in such reserves during the year are set out on pages 217-219. Significant changes in these proved reserves are discussed below, where 'revisions and reclassifications' are changes based on new information that resulted from development drilling, production history, and changes in economic factors.

PROVED RESERVES 2018-2017

Shell subsidiaries

Europe

The net increase of 94 million barrels in revisions and reclassifications was mainly in the UK and Denmark.

Asia

The net increase of 227 million barrels in revisions and reclassifications was mainly in Oman and Kazakhstan. The sale of minerals in place of 52 million barrels occurred in Iraq (West Qurna) and Oman (Mukhaizna).

USA

The net increase of 81 million barrels in revisions and reclassifications was mainly in Mars and Ursa in the Gulf of Mexico. The increase of 179 million barrels in extensions and discoveries was mainly in Vito in the Gulf of Mexico and in the Permian Basin.

South America

The net increase of 139 million barrels in extensions and discoveries was in Mero (Brazil) and Vaca Muerta (Argentina).

PROVED RESERVES 2017-2016

Shell subsidiaries

Europe

The net increase of 61 million barrels in revisions and reclassifications resulted from field performance studies and development activities in Denmark, Norway and the UK. The sale of minerals in place of 50 million barrels occurred in the UK.

Asia

The net increase of 153 million barrels in revisions and reclassifications was mainly in Oman and Malaysia. The increase of 95 million barrels in extensions and discoveries was in Kazakhstan and Malaysia.

USA

The net increase of 235 million barrels in revisions and reclassifications resulted from field performance studies and development activities in respect of Stones and Mars in the Gulf of Mexico, and the Permian Basin. The increase of 242 million barrels in extensions and discoveries was in the Permian Basin, and Appomattox and Vicksburg in the Gulf of Mexico.

Canada

The sale of minerals in place of 1,992 million barrels in synthetic crude oil resulted from the sale of our 60% interest in the Athabasca Oil Sands Project (AOSP) and our in-situ and undeveloped oil sands interests. The purchase of minerals in place of 664 million barrels in synthetic crude oil resulted from the separate acquisition of a 50% controlling interest in Marathon Oil Canada Corporation, which has a 20% interest in the AOSP.

Shell share of joint ventures and associates

Asia

The net increase of 76 million barrels in revisions and reclassifications was mainly in Brunei.

Proved developed and undeveloped reserves 2018

Million barrels

					North America			South					
	Europe	Asia	Oceania	Africa	USA		Canada	America					Total
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	All products
Shell subsidiaries													
At January 1	356	1,482	132	463	899	22	649	—	946	4,300	649	—	4,949
Revisions and reclassifications	94	227	14	18	81	7	32	—	48	489	32	—	521
Improved recovery	—	27	—	—	—	—	—	—	14	41	—	—	41
Extensions and discoveries	2	3	—	—	179	6	—	—	139	329	—	—	329
Purchases of minerals in place	—	—	—	—	—	—	—	—	3	3	—	—	3
Sales of minerals in place	(14)	(52)	(8)	—	(2)	—	—	—	—	(76)	—	—	(76)
Production [A]	(70)	(185)	(9)	(61)	(140)	(13)	(20)	—	(122)	(600)	(20)	—	(620)
At December 31	368	1,502	129	420	1,017	23	661	—	1,027	4,486	661	—	5,147
Shell share of joint ventures and associates													
At January 1	12	301	—	—	—	—	—	—	—	313	—	—	313
Revisions and reclassifications	(2)	(2)	—	—	—	—	—	—	—	(4)	—	—	(4)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and discoveries	—	18	—	—	—	—	—	—	—	18	—	—	18
Purchases of minerals in place	—	—	—	—	—	—	—	—	—	—	—	—	—
Sales of minerals in place	—	—	—	—	—	—	—	—	—	—	—	—	—
Production	(1)	(37)	—	—	—	—	—	—	—	(38)	—	—	(38)
At December 31	9	281	—	—	—	—	—	—	—	290	—	—	290
Total	377	1,783	129	420	1,017	23	661	—	1,027	4,776	661	—	5,437
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31	—	—	—	—	—	—	331	—	—	—	331	—	331

[A] Includes 1 million barrels consumed in operations for synthetic crude oil.

Proved developed reserves 2018

Million barrels

	Geographical distribution												Total
	Europe	Asia	Oceania	Africa	North America			South America					
					USA		Canada	America					
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	All products
Shell subsidiaries													
At January 1	250	1,364	46	373	569	21	649	—	651	3,274	649	—	3,923
At December 31	243	1,318	108	335	629	21	661	—	634	3,288	661	—	3,949
Shell share of joint ventures and associates													
At January 1	11	253	—	—	—	—	—	—	—	264	—	—	264
At December 31	8	251	—	—	—	—	—	—	—	259	—	—	259

Proved undeveloped reserves 2018

Million barrels

					North America			South America					Total
	Europe	Asia	Oceania	Africa	USA		Canada						
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	
Shell subsidiaries													
At January 1	106	118	86	90	330	1	—	—	295	1,026	—	—	1,026
At December 31	124	185	21	85	388	2	—	—	394	1,199	—	—	1,199
Shell share of joint ventures and associates													
At January 1	1	48	—	—	—	—	—	—	—	49	—	—	49
At December 31	1	30	—	—	—	—	—	—	—	31	—	—	31

Proved developed and undeveloped reserves 2017

Million barrels

					North America				South America				Total	
	Europe	Asia	Oceania	Africa	USA		Canada		America					
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen		All products
Shell subsidiaries														
At January 1	435	1,386	128	529	491	18	2,014	2	992	3,979	2,014	2	5,995	
Revisions and reclassifications	61	153	13	23	235	8	(3)	2	38	531	(3)	2	530	
Improved recovery	—	35	—	—	38	—	—	—	—	73	—	—	73	
Extensions and discoveries	—	95	—	—	242	7	—	—	30	374	—	—	374	
Purchases of minerals in place	—	—	—	—	2	—	664	—	—	2	664	—	666	
Sales of minerals in place	(50)	—	—	(14)	—	—	(1,992)	(2)	—	(64)	(1,992)	(2)	(2,058)	
Production [A]	(90)	(187)	(9)	(75)	(109)	(11)	(34)	(2)	(114)	(595)	(34)	(2)	(631)	
At December 31	356	1,482	132	463	899	22	649	—	946	4,300	649	—	4,949	
Shell share of joint ventures and associates														
At January 1	7	256	—	—	—	—	—	—	—	263	—	—	263	
Revisions and reclassifications	6	76	—	—	—	—	—	—	—	82	—	—	82	
Improved recovery	—	3	—	—	—	—	—	—	—	3	—	—	3	
Extensions and discoveries	—	1	—	—	—	—	—	—	—	1	—	—	1	
Purchases of minerals in place	—	—	—	—	—	—	—	—	—	—	—	—	—	
Sales of minerals in place	—	—	—	—	—	—	—	—	—	—	—	—	—	
Production	(1)	(35)	—	—	—	—	—	—	—	(36)	—	—	(36)	
At December 31	12	301	—	—	—	—	—	—	—	313	—	—	313	
Total	368	1,783	132	463	899	22	649	—	946	4,613	649	—	5,262	
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31														
	—	—	—	—	—	—	325	—	—	—	325	—	325	

[A] Includes 1 million barrels consumed in operations for synthetic crude oil.

Proved developed reserves 2017

Million barrels

					North America				South America				Total
	Europe	Asia	Oceania	Africa	USA		Canada						
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	
Shell subsidiaries													
At January 1	257	1,184	36	461	437	14	1,387	2	543	2,932	1,387	2	4,321
At December 31	250	1,364	46	373	569	21	649	—	651	3,274	649	—	3,923
Shell share of joint ventures and associates													
At January 1	4	215	—	—	—	—	—	—	—	219	—	—	219
At December 31	11	253	—	—	—	—	—	—	—	264	—	—	264

Proved undeveloped reserves 2017

Million barrels

					North America				South America			Total	
	Europe	Asia	Oceania	Africa	USA		Canada	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen		
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil						
Shell subsidiaries													
At January 1	178	202	92	68	54	4	627	—	449	1,047	627	—	1,674
At December 31	106	118	86	90	330	1	—	—	295	1,026	—	—	1,026
Shell share of joint ventures and associates													
At January 1	3	41	—	—	—	—	—	—	—	44	—	—	44
At December 31	1	48	—	—	—	—	—	—	—	49	—	—	49

Proved developed and undeveloped reserves 2016

Million barrels

	North America							South America				Total	
	Europe	Asia	Oceania	Africa	USA		Canada		America				
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil		Bitumen
Shell subsidiaries													
At January 1	417	1,286	126	579	560	22	1,941	3	56	3,046	1,941	3	4,990
Revisions and reclassifications	24	100	9	21	17	3	33	4	86	260	33	4	297
Improved recovery	—	22	—	—	2	—	—	—	—	24	—	—	24
Extensions and discoveries	—	4	—	—	20	6	96	—	—	30	96	—	126
Purchases of minerals in place	85	175	2	14	—	—	—	—	931	1,207	—	—	1,207
Sales of minerals in place	(5)	—	—	—	(5)	(2)	—	—	—	(12)	—	—	(12)
Production [A]	(86)	(201)	(9)	(85)	(103)	(11)	(56)	(5)	(81)	(576)	(56)	(5)	(637)
At December 31	435	1,386	128	529	491	18	2,014	2	992	3,979	2,014	2	5,995
Shell share of joint ventures and associates													
At January 1	11	290	12	—	—	—	—	—	—	313	—	—	313
Revisions and reclassifications	(3)	1	(11)	—	—	—	—	—	—	(13)	—	—	(13)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and discoveries	—	1	—	—	—	—	—	—	—	1	—	—	1
Purchases of minerals in place	—	—	—	—	—	—	—	—	—	—	—	—	—
Sales of minerals in place	—	—	—	—	—	—	—	—	—	—	—	—	—
Production	(1)	(36)	(1)	—	—	—	—	—	—	(38)	—	—	(38)
At December 31	7	256	—	—	—	—	—	—	—	263	—	—	263
Total	442	1,642	128	529	491	18	2,014	2	992	4,242	2,014	2	6,258
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31													
	—	—	—	4	—	—	—	—	—	4	—	—	4

[A] Includes 2 million barrels consumed in operations for synthetic crude oil.

Proved developed reserves 2016

Million barrels

					North America				South America			Total	
	Europe	Asia	Oceania	Africa	USA		Canada		America				
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil		Bitumen
Shell subsidiaries													
At January 1	220	972	36	437	455	20	1,405	3	44	2,184	1,405	3	3,592
At December 31	257	1,184	36	461	437	14	1,387	2	543	2,932	1,387	2	4,321
Shell share of joint ventures and associates													
At January 1	5	204	9	—	—	—	—	—	—	218	—	—	218
At December 31	4	215	—	—	—	—	—	—	—	219	—	—	219

Proved undeveloped reserves 2016

Million barrels

					North America				South America				Total	
	Europe	Asia	Oceania	Africa	USA		Canada							
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen		All products
Shell subsidiaries														
At January 1	197	314	90	142	105	2	536	—	12	862	536	—	1,398	
At December 31	178	202	92	68	54	4	627	—	449	1,047	627	—	1,674	
Shell share of joint ventures and associates														
At January 1	6	86	3	—	—	—	—	—	—	95	—	—	95	
At December 31	3	41	—	—	—	—	—	—	—	44	—	—	44	

NATURAL GAS

Shell subsidiaries' proved reserves of natural gas at the end of the year, their share of the proved reserves of joint ventures and associates at the end of the year, and the changes in such reserves during the year are set out on pages 222-224. Significant changes in these proved reserves are discussed below. Volumes are not adjusted to standard heat content. Apart from integrated projects, volumes of gas are reported on an "as-sold" basis. The price used to calculate future revenue and cash flows from proved gas reserves is the contract price or the 12-month average on "as-sold" volumes. Volumes associated with integrated projects are those measured at a designated transfer point between the upstream and downstream portions of the integrated project. Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

PROVED RESERVES 2018-2017

Shell subsidiaries

Europe

The net increase of 1,183 thousand million scf in revisions and reclassifications was mainly in Norway, the UK, Denmark and Germany.

Asia

The net decrease of 483 thousand million scf in revisions and reclassifications was mainly in Qatar, Malaysia and Kazakhstan. The increase of 354 thousand million scf in extensions and discoveries was in Malaysia.

Oceania

The net increase of 1,438 thousand million scf in revisions and reclassifications was mainly in the Surat Basin, Jansz-lo and Gorgon (all Australia).

Africa

The net increase of 896 thousand million scf in revisions and reclassifications was mainly in Gbaran, Assa North, Forcaddos-Yokri (Nigeria) and Sapphire (Egypt).

USA

The net decrease of 296 thousand million scf in revisions and reclassifications was mainly in Tioga. The increase of 283 thousand million scf in extensions and discoveries was mainly in the Permian Basin.

Shell share of joint ventures and associates

Europe

The net decrease of 3,653 thousand million scf in revisions and reclassifications was mainly in Groningen (the Netherlands).

Groningen: The decrease of 3,673 thousand million scf is as a result of the Dutch cabinet's announcement on March 29, 2018, about its aspiration to end Groningen production by 2030, and an agreement signed by Shell, ExxonMobil and the Dutch government in June 2018. The proved reserves are aligned with the new regulatory framework and the updated production outlook issued in November 2018 by the Dutch Ministry of Economic Affairs.

PROVED RESERVES 2017-2016

Shell subsidiaries

Europe

The sale of minerals in place of 224 thousand million scf was mainly the UK fields: Elgin-Franklin, Everest, J-Area, Lomond and Erskine.

Asia

The net increase of 979 thousand million scf in revisions and reclassifications resulted from field performance updates and development activities in Kazakhstan and Malaysia. The increase of 549 thousand million scf in extensions and discoveries was mainly in China and Kazakhstan.

Oceania

The net decrease of 574 thousand million scf in revisions and reclassifications resulted from field performance updates and development activities. There was a decrease of 958 thousand million scf in the Surat Basin and an increase of 384 thousand million scf from Jansz-lo, Prelude, Gorgon (all Australia) and Maui (New Zealand). The purchases of minerals in place of 204 thousand million scf were in the Surat Basin.

Africa

The net increase of 287 thousand million scf in revisions and reclassifications resulted from field performance updates and development activities, mainly in Kolo Creek in Nigeria.

USA

The net increase of 958 thousand million scf in revisions and reclassifications resulted from field performance updates and development activities in Tioga, East Texas, North Louisiana and the Permian Basin. The increase of 1,163 thousand million scf in extensions and discoveries was mainly in Tioga, the Permian Basin, and Appomattox and Kaikias in the Gulf of Mexico.

Canada

The net increase of 412 thousand million scf in revisions and reclassifications resulted from field performance studies and development activities in Groundbirch, Waterton and Fox Creek. The increase of 205 thousand million scf in extensions and discoveries was in Groundbirch and Fox Creek.

Shell share of joint ventures and associates

Europe

The net decrease of 1,027 thousand million scf in revisions and reclassifications was mainly in the Netherlands, due to further reassessment of Groningen compression.

Asia

The net increase of 652 thousand million scf in revisions and reclassifications resulted from field performance studies and development activities in Brunei and Russia.

Proved developed and undeveloped reserves 2018

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	3,100	11,822	7,978	2,082	2,569	1,272	1,501	30,324
Revisions and reclassifications	1,183	(483)	1,438	896	(296)	(153)	181	2,766
Improved recovery	—	—	—	—	—	—	7	7
Extensions and discoveries	3	354	—	—	283	131	65	836
Purchases of minerals in place	—	—	—	—	—	—	14	14
Sales of minerals in place	(192)	(157)	(232)	—	(32)	—	—	(613)
Production [A]	(494)	(906)	(757)	(434)	(377)	(261)	(258)	(3,487)
At December 31	3,600	10,631	8,427	2,544	2,147	989	1,509	29,847
Shell share of joint ventures and associates								
At January 1	5,125	4,964	19	—	—	—	—	10,108
Revisions and reclassifications	(3,653)	62	25	—	—	—	—	(3,566)
Improved recovery	—	—	—	—	—	—	—	—
Extensions and discoveries	—	5	—	—	—	—	—	5
Purchases of minerals in place	—	—	—	—	—	—	—	—
Sales of minerals in place	(37)	—	—	—	—	—	—	(37)
Production [B]	(273)	(450)	(20)	—	—	—	—	(743)
At December 31	1,163	4,581	24	—	—	—	—	5,768
Total	4,763	15,212	8,451	2,544	2,147	989	1,509	35,615
Reserves attributable to non-controlling interest in								
Shell subsidiaries at December 31	—	—	—	—	—	—	—	—

[A] Includes 245 thousand million standard cubic feet consumed in operations.

[B] Includes 41 thousand million standard cubic feet consumed in operations.

Proved developed reserves 2018

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	2,978	11,460	5,026	1,493	1,652	859	1,225	24,693
At December 31	2,658	10,092	5,820	1,573	1,706	721	1,238	23,808
Shell share of joint ventures and associates								
At January 1	5,055	4,275	19	—	—	—	—	9,349
At December 31	1,136	3,938	24	—	—	—	—	5,099

Proved undeveloped reserves 2018

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	122	362	2,952	589	917	413	276	5,631
At December 31	942	539	2,607	971	441	268	271	6,039
Shell share of joint ventures and associates								
At January 1	70	689	—	—	—	—	—	759
At December 31	27	643	—	—	—	—	—	670

Proved developed and undeveloped reserves 2017

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	3,741	11,073	9,051	2,225	675	844	1,650	29,259
Revisions and reclassifications	197	979	(574)	287	958	412	45	2,304
Improved recovery	—	66	—	—	74	—	—	140
Extensions and discoveries	2	549	—	—	1,163	205	6	1,925
Purchases of minerals in place	—	—	204	—	3	43	27	277
Sales of minerals in place	(224)	—	—	(7)	(11)	(6)	—	(248)
Production [A]	(616)	(845)	(703)	(423)	(293)	(226)	(227)	(3,333)
At December 31	3,100	11,822	7,978	2,082	2,569	1,272	1,501	30,324
Shell share of joint ventures and associates								
At January 1	6,497	4,754	31	—	—	—	—	11,282
Revisions and reclassifications	(1,027)	652	9	—	—	—	—	(366)
Improved recovery	—	1	—	—	—	—	—	1
Extensions and discoveries	—	11	—	—	—	—	—	11
Purchases of minerals in place	—	—	—	—	—	—	—	—
Sales of minerals in place	—	—	—	—	—	—	—	—
Production [B]	(345)	(454)	(21)	—	—	—	—	(820)
At December 31	5,125	4,964	19	—	—	—	—	10,108
Total	8,225	16,786	7,997	2,082	2,569	1,272	1,501	40,432
Reserves attributable to non-controlling interest in								
Shell subsidiaries at December 31	—	2	—	—	—	—	—	2

[A] Includes 215 thousand million standard cubic feet consumed in operations.

[B] Includes 41 thousand million standard cubic feet consumed in operations.

Proved developed reserves 2017

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	3,437	10,569	3,966	1,618	563	458	1,172	21,783
At December 31	2,978	11,460	5,026	1,493	1,652	859	1,225	24,693
Shell share of joint ventures and associates								
At January 1	5,240	4,110	31	—	—	—	—	9,381
At December 31	5,055	4,275	19	—	—	—	—	9,349

Proved undeveloped reserves 2017

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	304	504	5,085	607	112	386	478	7,476
At December 31	122	362	2,952	589	917	413	276	5,631
Shell share of joint ventures and associates								
At January 1	1,257	644	—	—	—	—	—	1,901
At December 31	70	689	—	—	—	—	—	759

Proved developed and undeveloped reserves 2016

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	3,848	10,692	5,411	2,236	754	955	43	23,939
Revisions and reclassifications	92	554	(177)	51	(95)	41	66	532
Improved recovery	—	10	—	—	—	—	—	10
Extensions and discoveries	4	162	—	2	200	180	3	551
Purchases of minerals in place	419	576	4,330	327	151	—	1,734	7,537
Sales of minerals in place	(7)	—	—	—	(7)	(63)	—	(77)
Production [A]	(615)	(921)	(513)	(391)	(328)	(269)	(196)	(3,233)
At December 31	3,741	11,073	9,051	2,225	675	844	1,650	29,259
Shell share of joint ventures and associates								
At January 1	7,538	5,363	535	—	—	—	—	13,436
Revisions and reclassifications	(636)	(197)	(464)	—	—	—	—	(1,297)
Improved recovery	—	—	—	—	—	—	—	—
Extensions and discoveries	—	35	—	—	—	—	—	35
Purchases of minerals in place	—	—	—	—	—	—	—	—
Sales of minerals in place	—	—	—	—	—	—	—	—
Production [B]	(405)	(447)	(40)	—	—	—	—	(892)
At December 31	6,497	4,754	31	—	—	—	—	11,282
Total	10,238	15,827	9,082	2,225	675	844	1,650	40,541
Reserves attributable to non-controlling interest in								
Shell subsidiaries at December 31	—	3	—	2	—	—	—	5

[A] Includes 197 thousand million standard cubic feet consumed in operations.

[B] Includes 44 thousand million standard cubic feet consumed in operations.

Proved developed reserves 2016

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	3,471	9,920	1,234	1,386	572	636	37	17,256
At December 31	3,437	10,569	3,966	1,618	563	458	1,172	21,783
Shell share of joint ventures and associates								
At January 1	5,933	4,301	420	—	—	—	—	10,654
At December 31	5,240	4,110	31	—	—	—	—	9,381

Proved undeveloped reserves 2016

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	377	772	4,177	850	182	319	6	6,683
At December 31	304	504	5,085	607	112	386	478	7,476
Shell share of joint ventures and associates								
At January 1	1,605	1,062	115	—	—	—	—	2,782
At December 31	1,257	644	—	—	—	—	—	1,901

STANDARDISED MEASURE OF DISCOUNTED FUTURE CASH FLOWS

The SEC Form 20-F requires the disclosure of a standardised measure of discounted future net cash flows, relating to proved reserves quantities and based on a 12-month unweighted arithmetic average sales price, calculated on a first-day-of-the-month basis, with cost factors based on those at the end of each year, currently enacted tax rates and a 10% annual discount factor. In our view, the information so calculated does not provide a reliable measure of future cash flows from proved reserves, nor does it permit a realistic comparison to be made of one entity with another because the assumptions used cannot reflect the varying circumstances within each entity. In addition, a substantial but unknown proportion of future real cash flows from oil and gas production activities is expected to derive from reserves which have already been discovered, but which cannot yet be regarded as proved.

STANDARDISED MEASURE OF DISCOUNTED FUTURE CASH FLOWS RELATING TO PROVED RESERVES AT DECEMBER 31

2018 - Shell subsidiaries								\$ million
	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	50,392	122,037	72,355	36,080	68,546	34,719	74,417	458,545
Future production costs	18,400	32,773	22,219	13,237	32,533	17,378	42,301	178,842
Future development costs	8,649	12,301	11,598	4,672	11,486	4,674	6,991	60,370
Future tax expenses	12,603	30,994	5,899	12,805	1,948	3,257	7,764	75,271
Future net cash flows	10,739	45,969	32,639	5,366	22,578	9,411	17,360	144,062
Effect of discounting cash flows at 10%	3,024	20,957	12,130	572	5,039	6,446	6,048	54,217
Standardised measure of discounted future net cash flows	7,715	25,012	20,509	4,794	17,539	2,964	11,312	89,845
Non-controlling interest included	—	1	—	—	—	1,638	—	1,639

2018 - Shell share of joint ventures and associates								\$ million
	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	5,260	44,327	104	—	—	—	—	49,691
Future production costs	2,712	20,886	80	—	—	—	—	23,677
Future development costs	1,083	6,726	36	—	—	—	—	7,844
Future tax expenses	1,136	7,128	1	—	—	—	—	8,265
Future net cash flows	329	9,588	(13)	—	—	—	—	9,904
Effect of discounting cash flows at 10%	(76)	2,759	(8)	—	—	—	—	2,675
Standardised measure of discounted future net cash flows	405	6,829	(5) [A]	—	—	—	—	7,229

[A] While proved reserves are economically producible at the 2018 yearly average price, the standardised measure of discounted future net cash flows was negative for those proved reserves at December 31, 2018, due to addition of overhead, tax and abandonment costs and ongoing commitments post production of proved reserves.

2017 - Shell subsidiaries								\$ million
	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	34,902	94,535	51,052	29,276	49,389	32,576	50,620	342,350
Future production costs	15,672	30,894	18,264	11,496	29,505	20,242	30,924	156,997
Future development costs	7,852	12,558	14,062	4,920	14,200	5,115	6,210	64,917
Future tax expenses	5,747	18,048	1,169	9,064	2,177	2,509	4,888	43,602
Future net cash flows	5,631	33,035	17,557	3,796	3,507	4,710	8,598	76,834
Effect of discounting cash flows at 10%	825	15,115	5,773	(9)	(796)	3,077	2,325	26,310
Standardised measure of discounted future net cash flows	4,806	17,920	11,784	3,805	4,303	1,633	6,273	50,524
Non-controlling interest included	—	1	—	—	—	870	—	871

2017 - Shell share of joint ventures and associates

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	22,725	37,954	69	—	—	—	—	60,748
Future production costs	17,442	17,592	54	—	—	—	—	35,088
Future development costs	1,051	7,605	64	—	—	—	—	8,720
Future tax expenses	1,803	5,172	—	—	—	—	—	6,975
Future net cash flows	2,429	7,585	(49)	—	—	—	—	9,965
Effect of discounting cash flows at 10%	1,008	1,862	(14)	—	—	—	—	2,856
Standardised measure of discounted future net cash flows	1,421	5,723	(35) [A]	—	—	—	—	7,109

[A] While proved reserves are economically producible at the 2017 yearly average price, the standardised measure of discounted future net cash flows was negative for those proved reserves at December 31, 2017, due to addition of overhead, tax and abandonment costs and ongoing commitments post production of proved reserves.

2016 - Shell subsidiaries

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	33,837	71,019	49,872	26,422	20,239	71,652	41,999	315,040
Future production costs	17,276	25,793	22,842	12,302	17,114	54,966	21,780	172,073
Future development costs	11,630	12,481	16,795	5,533	7,894	11,948	15,053	81,334
Future tax expenses	824	9,059	1,734	5,427	561	1,327	3,700	22,632
Future net cash flows	4,107	23,686	8,501	3,160	(5,330)	3,411	1,466	39,001
Effect of discounting cash flows at 10%	351	10,663	2,889	(231)	(3,423)	2,129	(1,095)	11,283
Standardised measure of discounted future net cash flows	3,756	13,023	5,612	3,391	(1,907) [A]	1,282	2,561	27,718
Non-controlling interest included	—	—	—	(65) [A]	—	—	—	(65)

[A] While proved reserves are economically producible at the 2016 yearly average price, the standardised measure of discounted future net cash flows was negative for those proved reserves at December 31, 2016, due to addition of overhead, tax and abandonment costs and ongoing commitments post production of proved reserves.

2016 - Shell share of joint ventures and associates

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	26,224	28,000	88	—	—	—	—	54,312
Future production costs	18,163	14,060	65	—	—	—	—	32,288
Future development costs	1,367	7,588	41	—	—	—	—	8,996
Future tax expenses	2,526	3,280	—	—	—	—	—	5,806
Future net cash flows	4,168	3,072	(18)	—	—	—	—	7,222
Effect of discounting cash flows at 10%	2,363	692	(9)	—	—	—	—	3,046
Standardised measure of discounted future net cash flows	1,805	2,380	(9) [A]	—	—	—	—	4,176

[A] While proved reserves are economically producible at the 2016 yearly average price, the standardised measure of discounted future net cash flows was negative for those proved reserves at December 31, 2016, due to addition of overhead, tax and abandonment costs and ongoing commitments post production of proved reserves.

CHANGE IN STANDARDISED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED RESERVES

2018				\$ million
	Shell subsidiaries	Shell share of joint ventures and associates	Total	
At January 1	50,524	7,109	57,633	
Net changes in prices and production costs	58,128	6,156	64,284	
Revisions of previous reserves estimates	15,265	(1,447)	13,818	
Extensions, discoveries and improved recovery	8,936	532	9,468	
Purchases and sales of minerals in place	(3,401)	(20)	(3,421)	
Development cost related to future production	(3,876)	(308)	(4,184)	
Sales and transfers of oil and gas, net of production costs	(38,014)	(4,858)	(42,872)	
Development cost incurred during the year	10,724	666	11,390	
Accretion of discount	7,060	994	8,054	
Net change in income tax	(15,501)	(1,595)	(17,096)	
At December 31	89,845	7,229	97,074	

2017				\$ million
	Shell subsidiaries	Shell share of joint ventures and associates	Total	
At January 1	27,718	4,176	31,894	
Net changes in prices and production costs	34,190	3,952	38,142	
Revisions of previous reserves estimates	13,769	1,931	15,700	
Extensions, discoveries and improved recovery	3,901	79	3,980	
Purchases and sales of minerals in place	(2,068)	—	(2,068)	
Development cost related to future production	(4,823)	461	(4,362)	
Sales and transfers of oil and gas, net of production costs	(27,544)	(3,652)	(31,196)	
Development cost incurred during the year	14,262	536	14,798	
Accretion of discount	3,844	630	4,474	
Net change in income tax	(12,725)	(1,004)	(13,729)	
At December 31	50,524	7,109	57,633	

2016

\$ million

	Shell subsidiaries	Shell share of joint ventures and associates	Total
At January 1	25,881	10,963	36,844
Net changes in prices and production costs	(21,506)	(6,942)	(28,448)
Revisions of previous reserves estimates	6,175	(1,328)	4,847
Extensions, discoveries and improved recovery	1,268	(17)	1,251
Purchases and sales of minerals in place	24,279	—	24,279
Development cost related to future production	(15,327)	(150)	(15,477)
Sales and transfers of oil and gas, net of production costs	(19,657)	(3,087)	(22,744)
Development cost incurred during the year	15,403	854	16,257
Accretion of discount	4,376	1,363	5,739
Net change in income tax	6,826	2,520	9,346
At December 31	27,718	4,176	31,894

OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES CAPITALISED COSTS

The aggregate amount of property, plant and equipment and intangible assets, excluding goodwill, relating to oil and gas exploration and production activities, and the aggregate amount of the related depreciation, depletion and amortisation at December 31, are shown in the tables below.

SHELL SUBSIDIARIES

	2018	2017
Cost		
Proved properties [A]	265,489	277,067 [B]
Unproved properties	21,256	22,642 [B]
Support equipment and facilities	6,404	6,112
	293,149	305,821
Depreciation, depletion and amortisation		
Proved properties [A]	126,641	132,823
Unproved properties	3,362	5,193
Support equipment and facilities	3,424	3,436
	133,427	141,452
Net capitalised costs	159,722	164,369

[A] Includes capitalised asset decommissioning and restoration costs and related depreciation.

[B] Includes reclassification of \$1,065 million from Exploration and Evaluation assets to Production assets related to 2017.

SHELL SHARE OF JOINT VENTURES AND ASSOCIATES

	2018	2017
\$ million		
Cost		
Proved properties [A]	44,331	43,394 [B]
Unproved properties	2,591	2,637 [C]
Support equipment and facilities	4,399	4,527 [D]
	51,321	50,558
Depreciation, depletion and amortisation		
Proved properties [A]	31,702	30,015 [E]
Unproved properties	—	— [F]
Support equipment and facilities	2,586	2,431 [G]
	34,288	32,446
Net capitalised costs	17,033	18,112

[A] Includes capitalised asset decommissioning and restoration costs and related depreciation.

[B] The balance revised to include correction of \$1,024 million related to 2017 (2017 balance \$42,370 million).

[C] The balance revised to include correction of \$20 million related to 2017 (2017 balance \$2,657 million).

[D] The balance revised to include correction of \$75 million related to 2017 (2017 balance \$4,452 million).

[E] The balance revised to include correction of \$1,829 million related to 2017 (2017 balance \$31,844 million).

[F] The balance revised to include correction of \$20 million related to 2017 (2017 balance \$20 million).

[G] The balance revised to include correction of \$711 million related to 2017 (2017 balance \$3,142 million).

OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES COSTS INCURRED

Costs incurred during the year in oil and gas property acquisition, exploration and development activities, whether capitalised or charged to income currently, are shown in the tables below. Finance leases are excluded. Development costs include capitalised asset decommissioning and restoration costs (including increases or decreases arising from changes to cost estimates or to the discount rate applied to the obligations) and exclude costs of acquiring support equipment and facilities, but include depreciation thereon.

SHELL SUBSIDIARIES

2018	\$ million							
	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Other[A]		
Acquisition of properties								
Proved	3	3	—	596	44	—	—	646
Unproved	2	6	—	76	44	310	486	924
Exploration	384	182	49	188	1,912	251	502	3,468 [B]
Development	1,452	1,102	1,632	962	4,052	505	2,095	11,800

[A] Comprises Canada, Honduras and Mexico.

[B] Includes \$1,581 million of Shales-related exploration activities. In 2018, we participated in 234 Shales productive exploratory wells with proved reserves allocated (Shell share: 118 wells).

2017	\$ million							
	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Other[A]		
Acquisition of properties								
Proved	—	—	—	10	—	2,246	19	2,275
Unproved	—	12	—	18	141	320	57	548
Exploration	329	135	38	138	1,354	235	600	2,829
Development	776	840	2,493	371	4,123	722	1,671	10,996

[A] Comprises Canada, Honduras and Mexico.

2016 [A]

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Other[B]		
Acquisition of properties								
Proved	1,978	4,709	6,917	926	132	—	28,803	43,465
Unproved	280	—	2	357	87	20	102	848
Exploration	338	400	34	247	1,043	415	574	3,051
Development	2,289	1,982	3,352	1,087	3,497	701	1,788	14,696

[A] Includes \$44,127 million of related costs incurred on acquisition of BG.

[B] Comprises Canada, Honduras and Mexico.

SHELL SHARE OF JOINT VENTURES AND ASSOCIATES

Joint ventures and associates did not incur costs in the acquisition of oil and gas properties in 2018, 2017 or 2016.

2018

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Exploration	—	90	14	—	—	—	—	104
Development	229	1,026	79	—	—	—	—	1,334

2017

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Exploration	3	82	8	—	—	—	—	93
Development	(22) [A]	660	58	—	—	—	—	696

[A] Includes a revision of decommissioning and restoration provisions.

2016

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Exploration	33	57	101	—	—	—	—	191
Development	99	2,173	273	—	—	—	—	2,545

OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES EARNINGS

The results of operations for oil and gas producing activities are shown in the tables below. Taxes other than income tax include cash-paid royalties to governments outside North America.

SHELL SUBSIDIARIES

2018								
\$ million								
	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Other[A]		
Revenue								
Third parties	1,875	3,364	1,389	2,401	2,165	507	1,023	12,724
Sales between businesses	6,705	11,284	4,683	3,586	7,716	1,946	7,154	43,074
Total	8,580	14,648	6,072	5,987	9,881	2,453	8,177	55,798
Production costs excluding taxes	2,262	2,143	1,073	1,093	2,573	1,069	1,401	11,614
Taxes other than income tax	122	841	199	328	83	—	2,767	4,340
Exploration	277	149	78	144	341	114	237	1,340
Depreciation, depletion and amortisation	2,684	2,301	1,571	1,394	4,543	(346)	3,271	15,418
Other costs/(income)	947	(180)	(514)	609	447	667	849	2,825
Earnings before taxation	2,288	9,394	3,665	2,419	1,894	949	(348)	20,261
Taxation charge/(credit)	2,047	4,851	893	902	550	236	1,162	10,641
Earnings after taxation	241	4,543	2,772	1,517	1,344	713	(1,510)	9,620

[A] Comprises Canada, Honduras and Mexico.

2017								
\$ million								
	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Other[A]		
Revenue								
Third parties	1,193	2,708	1,414	1,872	1,080	339	689	9,295
Sales between businesses	7,120	9,061	2,400	3,218	5,119	2,938	5,245	35,101
Total	8,313	11,769	3,814	5,090	6,199	3,277	5,934	44,396
Production costs excluding taxes	2,509	2,469	1,110	1,365	2,558	1,571	1,218	12,800
Taxes other than income tax	89	556	119	287	98	1	1,691	2,841
Exploration	243	245	42	129	868	142	276	1,945
Depreciation, depletion and amortisation	2,560	2,892	1,777	1,863	3,410	3,886	3,374	19,762
Other costs/(income)	(157)	1,073	(382)	145	114	1,050	469	2,312
Earnings before taxation	3,069	4,534	1,148	1,301	(849)	(3,373)	(1,094)	4,736
Taxation (credit)/charge	1,689	2,969	(202)	(361)	363	(1,486)	(294)	2,678
Earnings after taxation	1,380	1,565	1,350	1,662	(1,212)	(1,887)	(800)	2,058

[A] Comprises Canada, Honduras and Mexico.

2016

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Other[A]		
Revenue								
Third parties	969	2,656	1,069	1,380	643	41	476	7,234
Sales between businesses	5,816	7,284	1,438	3,138	3,960	3,789	2,980	28,405
Total	6,785	9,940	2,507	4,518	4,603	3,830	3,456	35,639
Production costs excluding taxes	2,565	2,212	805	1,468	3,348	2,230	865	13,493
Taxes other than income tax	66	421	83	194	70	—	790	1,624
Exploration	250	408	70	356	438	291	295	2,108
Depreciation, depletion and amortisation	3,270	3,304	1,130	2,018	4,372	1,953	2,881	18,928
Other costs/(income)	1,925	1,606	(700)	356	40	680	(173)	3,734
Earnings before taxation	(1,291)	1,989	1,119	126	(3,665)	(1,324)	(1,202)	(4,248)
Taxation charge/(credit)	(311)	1,918	559	431	(1,351)	(377)	(1,032)	(163)
Earnings after taxation	(980)	71	560	(305)	(2,314)	(947)	(170)	(4,085)

[A] Comprises Canada, Honduras and Mexico.

SHELL SHARE OF JOINT VENTURES AND ASSOCIATES

Oceania included Shell's 14% share of Woodside from January 2016 to April 2016, when its accounting classification was changed from an associate to an investment in securities. Woodside is a publicly-listed company on the Australian Securities Exchange for which we have limited access to data; accordingly, the numbers are estimated.

2018

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Third-party revenue	1,395	5,884	79	—	—	—	—	7,358
Total	1,395	5,884	79	—	—	—	—	7,358
Production costs excluding taxes	307	674	105	—	—	—	—	1,086
Taxes other than income tax	82	1,259	4	—	—	—	—	1,345
Exploration	5	45	—	—	—	—	—	50
Depreciation, depletion and amortisation	318	1,016	163	—	—	—	—	1,497
Other costs/(income)	595	615	(26)	—	—	—	—	1,184
Earnings before taxation	88	2,275	(167)	—	—	—	—	2,196
Taxation charge	7	975	—	—	—	—	—	982
Earnings after taxation	81	1,300	(167)	—	—	—	—	1,214

2017

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Third-party revenue	1,646	4,503	58	—	—	—	—	6,207
Total	1,646	4,503	58	—	—	—	—	6,207
Production costs excluding taxes	337	729	93	—	—	—	—	1,159
Taxes other than income tax	631	705	4	—	—	—	—	1,340
Exploration	7	57	4	—	—	—	—	68
Depreciation, depletion and amortisation	188	1,654	40	—	—	—	—	1,882
Other costs/(income)	(83)	511	(60)	—	—	—	—	368
Earnings before taxation	566	847	(23)	—	—	—	—	1,390
Taxation charge	173	197	—	—	—	—	—	370
Earnings after taxation	393	650	(23)	—	—	—	—	1,020

2016

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Third-party revenue	1,705	3,708	197	—	—	—	—	5,610
Total	1,705	3,708	197	—	—	—	—	5,610
Production costs excluding taxes	383	705	123	—	—	—	—	1,211
Taxes other than income tax	706	456	7	—	—	—	—	1,169
Exploration	36	25	27	—	—	—	—	88
Depreciation, depletion and amortisation	208	1,663	237	—	—	—	—	2,108
Other costs/(income)	(11)	401	(28)	—	—	—	—	362
Earnings before taxation	383	458	(169)	—	—	—	—	672
Taxation charge	91	23	8	—	—	—	—	122
Earnings after taxation	292	435	(177)	—	—	—	—	550

ACREAGE AND WELLS

The tables below reflect acreage and wells of Shell subsidiaries, joint ventures and associates. The term "gross" refers to the total activity in which Shell subsidiaries, joint ventures and associates have an interest. The term "net" refers to the sum of the fractional interests owned by Shell subsidiaries plus the Shell share of joint ventures and associates' fractional interests. Data below are rounded to the nearest whole number.

Oil and gas acreage (at December 31)

Thousand acres

	2018				2017				2016			
	Developed		Undeveloped		Developed		Undeveloped		Developed		Undeveloped	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Europe [A]	6,228	1,958	15,443	6,913	6,463	2,071	14,119	6,187	6,556	2,197	18,216	10,241
Asia	22,087	7,885	31,676	15,433	25,975	9,139	35,305	18,730	26,003	9,199	58,463	36,298
Oceania	3,202	1,220	15,662	10,298	3,296	1,255	22,406	13,985	1,939	822	37,876	24,109
Africa	4,666	1,940	38,874	22,732	4,663	1,938	33,453	20,811	5,083	2,315	41,517	29,152
North America - USA	1,541	952	2,133	1,635	1,936	1,134	2,718	1,937	2,002	1,197	4,151	2,577
North America - Mexico	—	—	5,178	3,885	—	—	—	—	—	—	—	—
North America - Canada	1,108	752	1,681	1,193	953	651	15,818 [B]	14,468 [B]	976	670	25,253 [C]	18,865 [C]
South America	1,490	710	10,352	6,725	1,302	606	9,338	6,196	1,315	547	17,759	14,643
Total	40,322	15,416	120,999	68,814	44,588	16,794	133,157	82,314	43,874	16,947	203,235	135,885

[A] Includes Greenland.

[B] Corrected from 16,714 (15,005 net).

[C] Corrected from 26,149 (19,402 net).

Number of productive wells [A] (at December 31)

	2018				2017				2016			
	Oil		Gas		Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Europe	1,077	277	1,201	379	1,156	303	1,235	392	1,215	321	1,232	403
Asia	7,498	2,750	331	189	9,279 [B]	3,067 [B]	682 [C]	269 [C]	9,157 [D]	3,089 [D]	632 [E]	251 [E]
Oceania	—	—	3,411	1,924	—	—	3,499	1,926	—	—	3,257	1,734
Africa	478	189	195	132	380	155	180	122	662	289	191	127
North America - USA	15,224	7,745	1,479	672	15,408	7,817	1,636	717	15,532	7,892	3,046	2,136
North America - Canada	1	1	936	846	—	—	892	794	283	283	941	781
South America	119	53	62	41	111	47	55	32	73	28	50	26
Total	24,397	11,015	7,615	4,183	26,334	11,389	8,179	4,252	26,922	11,902	9,349	5,458

[A] The number of productive wells with multiple completions (more than one formation producing into the same well bore) at December 31, 2018, was 1,132 gross (489 net); 2017: 1,696 gross, corrected from 1,946 gross (636 net, corrected from 761); 2016: 1,456 gross, corrected from 1,721 gross (554 net, corrected from 686 net).

[B] Corrected from 9,410 (3,132 net).

[C] Corrected from 711 (283 net).

[D] Corrected from 9,261 (3,141 net).

[E] Corrected from 656 (263 net).

Number of net productive wells and dry holes drilled

	2018		2017		2016	
	Productive	Dry	Productive	Dry	Productive	Dry
Exploratory [A]						
Europe	1	2	—	1	—	—
Asia	9	10	3	5	2	4
Oceania	—	—	2	—	—	—
Africa	6	6	2	3	4	2
North America - USA	104	4	9	6	40	2
North America - Canada	14	—	30	5	—	—
South America	6	7	6	—	—	—
Total	140	29	52	20	46	8
Development						
Europe	4	—	5	—	10	1
Asia	222	—	312	4	265	—
Oceania	41	—	63	—	184	—
Africa	24	1	24	3	15	—
North America - USA	276	—	237	—	137	—
North America - Canada	53	—	56	1	50	—
South America	5	—	1	—	3	—
Total	625	1	698	8	664	1

[A] Productive wells are wells with proved reserves allocated. Wells in the process of exploratory drilling are excluded and presented separately below.

Number of wells in the process of exploratory drilling [A]

2018

	At January 1		Wells in the process of drilling at January 1 and allocated proved reserves during the year		Wells in the process of drilling at January 1 and determined as dry during the year		New wells in the process of drilling at December 31		At December 31	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Europe	22	11	(1)	—	(4)	(2)	2	1	19	10
Asia	71	25	(23)	(8)	(4)	(1)	24	9	68	25
Oceania	47 [B]	15 [B]	(5)	(1)	—	—	3	1	45	15
Africa	42	27	—	—	(4)	(3)	9	7	47	31
North America - USA	212 [C]	137 [C]	(122)	(68)	(4)	(2)	65	29	151	96
North America - Canada	7 [D]	7 [D]	(7)	(7)	—	—	—	—	—	—
South America	46	20	(14)	(6)	(16)	(7)	20	12	36	19
Total	447	242	(172)	(90)	(32)	(15)	123	59	366	196

[A] Wells in the process of exploratory drilling includes wells pending further evaluation.

[B] Corrected from 50 (17 net).

[C] Corrected from 214 (138 net).

[D] Corrected from 5 (5 net).

Number of wells in the process of development drilling

2018

	At January 1		At December 31	
	Gross	Net	Gross	Net
Europe	7	2	5	2
Asia	73 [A]	28 [A]	36	14
Oceania	1	—	3	1
Africa	—	—	5	5
North America - USA	143 [B]	96 [B]	64	33
North America - Canada	21	18	17	17
South America	7 [C]	2 [C]	9	4
Total	252	146	139	76

[A] Corrected from 75 (29 net).

[B] Corrected from 144 (97 net).

[C] Corrected from 12 (3 net).

In addition to the present activities mentioned above, the following recovery methods are operational in the following countries: water flooding (Brazil (including water alternating gas), Brunei, Denmark, Egypt, Malaysia, Nigeria, Norway, Oman, Russia, the UK and the USA); gas injection (Brunei, Kazakhstan, Malaysia, Nigeria and Oman); steam injection (the Netherlands, Oman and the USA), and polymer flooding (Oman).

Parent Company Financial Statements

The Parent Company Financial Statements have not been audited in accordance with the standards of the Public Company Accounting Oversight Board (United States).

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Parent Company Financial Statements Continued

Statement of Income			\$ million
	Notes	2018	2017
Dividend income		23,278	10,958
Interest and other income	3	141	49
Administrative expenses		(43)	(53)
Interest and other expense	3	(222)	(26)
Income before taxation		23,154	10,928
Taxation charge/(credit)	6	44	(23)
Income for the period		23,110	10,951

Statement of Comprehensive Income			\$ million
		2018	2017
Income for the period		23,110	10,951
Comprehensive income for the period		23,110	10,951

Balance Sheet			\$ million
	Notes	Dec 31, 2018	Dec 31, 2017
Assets			
Non-current assets			
Investments in subsidiaries	4	256,920	256,882
Deferred tax	6	355	598
		257,275	257,480
Current assets			
Amounts due from subsidiaries	13	9,263	5,022
Cash and cash equivalents		3	3
		9,266	5,025
Total assets		266,541	262,505
Liabilities			
Non-current liabilities			
Accounts payable and accrued liabilities	5	—	332
		—	332
Current liabilities			
Accounts payable and accrued liabilities	5	4,862	4,333
		4,862	4,333
Total liabilities		4,862	4,665
Equity			
Share capital	8	685	696
Other reserves	9	235,536	235,366
Retained earnings		25,458	21,778
Total equity		261,679	257,840
Total liabilities and equity		266,541	262,505

Signed on behalf of the Board

/s/ Jessica Uhl

Jessica Uhl

Chief Financial Officer
March 13, 2019

Statement of Changes in Equity

					\$ million
	Notes	Share capital	Other reserves	Retained earnings	Total equity
At January 1, 2018		696	235,366	21,778	257,840
Comprehensive income for the period		—	—	23,110	23,110
Dividends	10	—	—	(15,675)	(15,675)
Repurchase of shares	8	(11)	11	(4,519)	(4,519)
Share-based compensation [A]	9	—	159	764	923
At December 31, 2018		685	235,536	25,458	261,679
At January 1, 2017		683	235,573	21,088	257,344
Comprehensive income for the period		—	—	10,951	10,951
Dividends	10	—	—	(15,628)	(15,628)
Scrip dividends	10	13	(13)	4,751	4,751
Share-based compensation	9	—	(194)	616	422
At December 31, 2017		696	235,366	21,778	257,840

[A] The amendments to IFRS 2 *Share-based payment* became effective January 1, 2018. Following adoption of the amendments, components of share-based payments (related to tax) that were previously classified as cash-settled are now classified as equity-settled. This resulted in an increase of \$172 million in the share plan reserve within other reserves and an increase of \$150 million in retained earnings.

Statement of Cash Flows

	Notes	2018	2017
Income for the period		23,110	10,951
Adjustment for:			
Dividend income		(23,278)	(10,958)
Tax		44	(23)
Interest income		(141)	(24)
Interest expense		156	26
Share-based compensation		16	25
Increase in working capital		(3,796)	(333)
Cash flow from operating activities		(3,889)	(336)
Dividends received		23,278	10,958
Interest received		141	24
Share-based compensation		248	258
Cash flow from investing activities		23,667	11,240
Cash dividends paid	10	(15,675)	(10,877)
Shares repurchased	8	(3,947)	—
Interest and other expenses paid		(156)	(26)
Cash flow from financing activities		(19,778)	(10,903)
Change in cash and cash equivalents		—	1
Cash and cash equivalents at beginning of the year		3	2
Cash and cash equivalents at end of the year		3	3

Notes to the Parent Company Financial Statements

1 BASIS OF PREPARATION

The Financial Statements of Royal Dutch Shell plc (the Company) have been prepared in accordance with the provisions of the Companies Act 2006 (the Act) and with International Financial Reporting Standards (IFRS) as adopted by the European Union. As applied to the Company, there are no material differences from IFRS as issued by the International Accounting Standards Board (IASB); therefore, the Financial Statements have been prepared in accordance with IFRS as issued by the IASB.

As described in the accounting policies in Note 2, the Financial Statements have been prepared under the historical cost convention except for certain items measured at fair value. Those accounting policies have been applied consistently in all periods, except for IFRS 2 *Share-based payment* where amendments to the standard were adopted from January 1, 2018.

The Financial Statements were approved and authorised for issue by the Board of Directors on March 13, 2019.

The preparation of financial statements in conformity with IFRS requires the use of certain accounting estimates. It also requires management to exercise its judgement in the process of applying the Company's accounting policies. Actual results may differ from those estimates.

The financial results of the Company are included in the Consolidated Financial Statements on pages 167-214. The financial results of the Company incorporate the results of the Dividend Access Trust (the Trust), the financial statements of which are presented on pages 251-255.

The Company's principal activity is being the parent company for Shell, as described in Note 1 to the Consolidated Financial Statements.

2 SIGNIFICANT ACCOUNTING POLICIES

The Company's accounting policies follow those of Shell as set out in Note 2 to the Consolidated Financial Statements. The following are Company-specific policies.

PRESENTATION AND FUNCTIONAL CURRENCY

The Company's presentation and functional currency is US dollars (dollars).

INVESTMENTS

Investments in subsidiaries are stated at cost, net of any impairment. Investments are tested for impairment whenever events or changes in circumstances indicate that the carrying amounts for those investments may not be recoverable. For the purposes of determining whether impairment of investments in subsidiaries has occurred, and the extent of any impairment loss or its reversal, the key assumptions management uses in estimating risk-adjusted future cash flows for value-in-use measures include future oil and gas prices, expected production volumes and refining margins appropriate to the local circumstances and environment. These assumptions and the judgements of management that are based on them are subject to change as new information becomes available. Cash flow estimates are risk-adjusted to reflect local conditions as appropriate and discounted at a rate based on Shell's marginal cost of debt. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Future price assumptions are presented in Note 8 to the Consolidated Financial Statements.

The original cost of the Company's investment in Royal Dutch Petroleum Company (Royal Dutch) was based on the fair value of the shares transferred to the Company by the former shareholders of Royal Dutch in exchange for A shares in the Company during the public exchange offer in 2005. The original cost of the Company's investment in The "Shell" Transport and Trading Company, p.l.c., now The Shell Transport and Trading Company Limited (Shell Transport), was the fair value of the shares held by the former shareholders of The "Shell" Transport and Trading Company, p.l.c. transferred in consideration for the issuance of B shares as part of the Scheme of Arrangement in 2005. The Company's investments in Royal Dutch and Shell Transport now represent an investment in Shell Petroleum N.V. (Shell Petroleum); this change had no impact on the cost of investments in subsidiaries.

DIVIDEND INCOME

Dividends are recognised on a paid basis unless the dividend has been confirmed by a general meeting of Shell Petroleum, in which case income is recognised on the date at which receipt is deemed virtually certain.

SHARE-BASED COMPENSATION PLANS

The fair value of share-based compensation for equity-settled plans granted to employees of subsidiaries under the Company's plans is recognised as an investment in subsidiaries from the date of grant over the vesting period with a corresponding increase in equity. Before the adoption of amendments to IFRS 2 *Share-based payment* from January 1, 2018, the changes in the fair value of share-based compensation for cash-settled plans relating to employees of subsidiaries were recognised as an investment in subsidiaries with a corresponding change in liabilities.

In the year of vesting of a plan, the costs for the actual deliveries are charged to the relevant employing subsidiaries. This is recognised as a realisation of the investment originally booked. If the actual vesting costs are higher than the cumulatively recognised share-based compensation charge, the difference is recognised in income.

See Note 21 to the Consolidated Financial Statements for information on the Company's principal plan.

TAXATION

The Company is tax-resident in the Netherlands. For the assessment of corporate income tax in the Netherlands, the Company and certain of its subsidiaries form a fiscal unit, in respect of which the Company recognises any current tax receivable or payable (and deferred tax asset or liability) for the fiscal unit as a whole to the extent such balances have been settled between the Company and other members of the fiscal unit at the balance sheet date.

The Company's tax charge or credit recognised in income is calculated at the statutory tax rate prevailing in the Netherlands for current tax and statutory tax rate substantively enacted in the Netherlands for deferred tax.

3 INTEREST AND OTHER INCOME/EXPENSE

	\$ million	
	2018	2017
Interest and other income:		
Interest income	141	24
Foreign exchange gains	—	25
Total	141	49
Interest and other expenses:		
Interest expense	(156)	(26)
Foreign exchange losses	(66)	—
Total	(222)	(26)

4 INVESTMENTS IN SUBSIDIARIES

	\$ million	
	2018	2017
At January 1	256,882	256,583
Share-based compensation	512	779
Recovery of vested share-based compensation	(474)	(480)
At December 31	256,920	256,882

5 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	Dec 31, 2018		Dec 31, 2017	
	Current	Non-current	Current	Non-current
Amounts due to subsidiaries (see Note 13)	3,934	—	3,859	—
Accruals and other liabilities	614	—	318	332
Withholding tax payable	311	—	153	—
Unclaimed dividends	3	—	3	—
Total	4,862	—	4,333	332

Accruals and other liabilities at December 31, 2018, principally comprise commitments for share repurchases undertaken on the Company's behalf under irrevocable, non-discretionary arrangements.

Accruals and other liabilities at December 31, 2017, were principally in respect of cash-settled share-based compensation.

6 TAXATION

Taxation charge/(credit)	\$ million	
	2018	2017
Deferred tax:		
Relating to the origination and reversal of temporary differences	33	—
Relating to changes in tax rates and legislation	11	—
Adjustments in respect of prior periods	—	(23)
Taxation charge/(credit)	44	(23)

In 2018, deferred tax relating to changes in tax rates and legislation was in respect of announced reductions in corporation tax rates in the Netherlands.

Reconciliation of applicable tax charge at statutory tax rate to taxation charge/(credit)	\$ million	
	2018	2017
Income before taxation	23,154	10,928
Applicable tax charge at the statutory tax rate of 25.0% (2017: 25.0%)	5,789	2,732
Adjustments in respect of prior periods	—	(23)
Tax effects of:		
Income not subject to tax at statutory rates	(5,820)	(2,744)
Expenses not deductible for tax purposes	20	6
Other	55	6
Taxation charge/(credit)	44	(23)

Taxes payable are reported within accounts payable and accrued liabilities (see Note 5).

Deferred tax assets	\$ million	
	2018	2017
At January 1	598	352
Recognised in income	(44)	23
Other movements	(199)	223
At December 31	355	598

Deferred tax assets are recognised in respect of credits carried forward and in respect of tax losses, amounting to \$240 million at December 31, 2018 (2017: \$476 million), which are available for relief against future taxable profits for up to nine years from the year in which the losses were incurred.

7 FINANCIAL INSTRUMENTS

The adoption of IFRS 9 *Financial Instruments* in 2018 has had no significant impact on the Company's accounting or disclosures.

Financial assets and liabilities measured at amortised cost in the Company's Balance Sheet comprise amounts due from subsidiaries (see Note 13) and certain amounts reported within accounts payable and accrued liabilities (see Note 5). The fair value of financial assets and liabilities at December 31, 2018, and 2017, approximates their carrying amount.

Information on financial risk management is presented in Note 19 to the Consolidated Financial Statements. Foreign currency derivatives are used by the Company to manage foreign exchange risk, which arises when certain transactions are denominated in a currency that is not the Company's functional currency. There were no derivative financial instruments held at December 31, 2018, or 2017.

8 SHARE CAPITAL

Issued and fully paid ordinary shares of €0.07 each [A]

	Number of shares		Nominal value (\$ million)		
	A	B	A	B	Total
At January 1, 2018	4,597,136,050	3,745,486,731	387	309	696
Repurchase of shares	(125,246,754)	—	(11)	—	(11)
At December 31, 2018	4,471,889,296	3,745,486,731	376	309	685
At January 1, 2017	4,428,903,813	3,745,486,731	374	309	683
Scrip dividends	168,232,237	—	13	—	13
At December 31, 2017	4,597,136,050	3,745,486,731	387	309	696

[A] Share capital at December 31, 2018, and 2017, also included 50,000 issued and fully paid sterling deferred shares of £1 each.

At the Company's Annual General Meeting (AGM) on May 22, 2018, the Board was authorised to allot ordinary shares in the Company, and to grant rights to subscribe for or to convert any security into ordinary shares in the Company, up to an aggregate nominal amount of €194 million (representing 2,771 million ordinary shares of €0.07 each), and to list such shares or rights on any stock exchange. This authority expires at the earlier of the close of business on August 22, 2019, and the end of the AGM to be held in 2019, unless previously renewed, revoked or varied by the Company in a general meeting.

At the May 22, 2018 AGM, shareholders granted the Company the authority to repurchase up to 10% of its issued ordinary shares (excluding any treasury shares), renewing the authority granted by the shareholders at previous AGMs. The authority will expire at the earlier of the close of business on August 22, 2019, and the end of the AGM of the Company to be held in 2019. Ordinary shares purchased by the Company pursuant to this authority will either be cancelled or held in treasury. Treasury shares are shares in the Company which are owned by the Company itself. The minimum price, exclusive of expenses, which may be paid for an ordinary share is €0.07. The maximum price, exclusive of expenses, which may be paid for an ordinary share is the higher of: (i) an amount equal to 5% above the average market value for an ordinary share for the five business days immediately preceding the date of the purchase; and (ii) the higher of the price of the last independent trade and the highest current independent bid on the trading venues where the purchase is carried out.

A shares repurchased in 2018 under the Company's share buyback programme were all cancelled.

B shares rank equally in all respects with A shares except for the dividend access mechanism described below. The Company, Shell Transport and BG Group Limited (BG), can procure the termination of the dividend access mechanism at any time. Upon such termination, B shares will form one class with A shares ranking equally in all respects and A and B shares will be known as ordinary shares without further distinction.

The sterling deferred shares are redeemable only at the discretion of the Company for £1 each and carry no voting rights. There are no further rights to participate in profits or assets, including the right to receive dividends. Upon winding up or liquidation, the shares carry a right to repayment of paid-up nominal value, ranking ahead of A and B shares.

For information on the number of shares in the Company held by Shell employee share ownership trusts and trust-like entities to meet delivery commitments under employee share plans, see Note 21 to the Consolidated Financial Statements.

DIVIDEND ACCESS MECHANISM FOR B SHARES

General

Dividends paid on A shares have a Dutch source for tax purposes and are subject to Dutch withholding tax.

It is the expectation and the intention, although there can be no certainty, that holders of B shares will receive dividends through the dividend access mechanism. Any dividends paid on the dividend access shares will have a UK source for UK and Dutch tax purposes. There will be no Dutch withholding tax on such dividends. From April 2016, there were changes to the taxation of dividends for individual shareholders resident in the UK. The dividend tax credit was abolished, and a tax-free dividend allowance introduced.

Description of dividend access mechanism

Shell Transport and BG have each issued a dividend access share to Computershare Trustees (Jersey) Limited as Trustee. Pursuant to a declaration of trust, the Trustee will hold any dividends paid in respect of the dividend access shares on trust for the holders of B shares and will arrange for prompt disbursement of such dividends to holders of B shares. Interest and other income earned on unclaimed dividends will be for the account of Shell Transport and BG and any dividends which are unclaimed after 12 years will revert to Shell Transport and BG once forfeited. Holders of B shares will not have any interest in either dividend access share and will not have any rights against Shell Transport and BG as issuers of the dividend access shares. The only assets held on trust for the benefit of the holders of B shares will be dividends paid to the Trustee in respect of the dividend access shares.

The declaration and payment of dividends on the dividend access shares will require board action by Shell Transport and BG (as applicable) and will be subject to any applicable limitations in law or in the Shell Transport or BG (as appropriate) articles of association in effect. In no event will the aggregate amount of the dividend paid by Shell Transport and BG under the dividend access mechanism for a particular period exceed the aggregate of the dividend announced by the Board of the Company on B shares in respect of the same period (after giving effect to currency conversions).

In particular, under their respective articles of association, Shell Transport and BG are each only able to pay a dividend on their respective dividend access shares which represents a proportional amount of the aggregate of any dividend announced by the Company on the B shares in respect of the relevant period, where such proportions are calculated by reference to, in the case of Shell Transport, the number of B shares in existence prior to completion of the Company's acquisition of BG and, in the case of BG, the number of B shares issued as part of the acquisition, in each case as against the total number of B shares in issue immediately following completion of the acquisition of BG.

Operation of the dividend access mechanism

If, in connection with the announcement of a dividend by the Company on B shares, the Board of Shell Transport and/or the Board of BG elects to declare and pay a dividend on their respective dividend access shares to the Trustee, the holders of B shares will be beneficially entitled to receive their share of those dividends pursuant to the declaration of trust (and arrangements will be made to ensure that the dividend is paid in the same currency in which they would have received a dividend from the Company).

If any amount is paid by Shell Transport or BG by way of a dividend on the dividend access shares and paid by the Trustee to any holder of B shares, the dividend which the Company would otherwise pay on B shares will be reduced by an amount equal to the amount paid to such holders of B shares by the Trustee.

The Company will have a full and unconditional obligation, in the event that the Trustee does not pay an amount to holders of B shares on a cash dividend payment date (even if that amount has been paid to the Trustee), to pay immediately the dividend announced on B shares. The right of holders of B shares to receive distributions from the Trustee will be reduced by an amount equal to the amount of any payment actually made by the Company on account of any dividend on B shares.

If for any reason no dividend is paid on the dividend access shares, holders of B shares will only receive dividends from the Company directly. Any payment by the Company will be subject to Dutch withholding tax (unless an exemption is obtained under Dutch law or under the provisions of an applicable tax treaty).

The Dutch tax treatment of dividends paid under the dividend access mechanism has been confirmed by the Dutch Revenue Service in an agreement ("vaststellingsovereenkomst") with the Company and N.V. Koninklijke Nederlandsche Petroleum Maatschappij (Royal Dutch Petroleum Company) dated October 26, 2004, as supplemented and amended by an agreement between the same parties dated April 25, 2005, and a final settlement agreement in connection with the acquisition of BG dated November 9, 2015. The agreements state, among other things, that dividend distributions on the dividend access shares by Shell Transport and/or BG will not be subject to Dutch withholding tax provided that the dividend access mechanism is structured and operated substantially as set out above.

The Company may not extend the dividend access mechanism to any future issuances of B shares without prior consultation with the Dutch Revenue Service.

Accordingly, the Company would not expect to issue additional B shares unless confirmation from the Dutch Revenue Service was obtained or the Company were to determine that the continued operation of the dividend access mechanism was unnecessary. Any further issue of B shares is subject to advance consultation with the Dutch Revenue Service.

The dividend access mechanism may be suspended or terminated at any time by the Company's Directors or the Directors of Shell Transport or BG, for any reason and without financial recompense. This might, for instance, occur in response to changes in relevant tax legislation.

9 OTHER RESERVES

					\$ million
	Merger reserve	Share premium reserve	Capital redemption reserve	Share plan reserve	Total
At January 1, 2018	234,231	154	84	897	235,366
Repurchase of shares	—	—	11	—	11
Share-based compensation	—	—	—	159	159
At December 31, 2018	234,231	154	95	1,056	235,536
At January 1, 2017	234,244	154	84	1,091	235,573
Scrip dividends	(13)	—	—	—	(13)
Share-based compensation	—	—	—	(194)	(194)
At December 31, 2017	234,231	154	84	897	235,366

The merger reserve was established as a consequence of the Company becoming the single parent company of Royal Dutch and Shell Transport and represented the difference between the cost of the investment in those companies and the nominal value of shares issued in exchange for those investments as required by the prevailing legislation at that time, section 131 of the Companies Act 1985. On February 15, 2016, the Company acquired all shares in BG Group plc by means of a Scheme of Arrangement under Part 26 of the Act, via the issuance of 218.7 million A shares and 1,305.1 million B shares and cash payments. This resulted in an increase in the merger reserve, representing the difference between the fair value and the nominal value of the shares issued by the Company.

On January 6, 2006, loan notes were converted into 4,827,974 A shares. The difference between the carrying value of the loan notes and the nominal value of the new shares issued was credited to the share premium reserve. The capital redemption reserve was established in connection with repurchases of shares of the Company. The share plan reserve is in respect of equity-settled share-based compensation plans (see Note 21 to the Consolidated Financial Statements) and movement in share-based compensation for the year is the net of the charge to equity, the release as a result of vested awards and the impact of amendments to IFRS 2 *Share-based payment*.

10 DIVIDENDS

See Note 23 to the Consolidated Financial Statements.

11 LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

See Note 25 to the Consolidated Financial Statements.

12 DIRECTORS AND SENIOR MANAGEMENT

See Note 27 to the Consolidated Financial Statements for the remuneration of Directors of the Company. In 2018, the Company recognised \$24 million (2017: \$25 million) in administrative expenses for the compensation of Directors and Senior Management.

13 RELATED PARTIES

Information about the Company's subsidiaries, and whether these are held directly or indirectly, and other related undertakings (all of which are held indirectly), at December 31, 2018, is set out in Exhibit 8.

	\$ million			
	Amounts due from subsidiaries		Amounts due to subsidiaries (see Note 5)	
	2018	2017	2018	2017
Shell Petroleum	–	4,502	550	672
Shell Treasury Centre Limited	9,260	518	–	–
Shell Corporate Services Switzerland AG	–	–	3,384	–
Shell Treasury Luxembourg Sarl	–	–	–	3,164
Other	3	2	–	23
Total	9,263	5,022	3,934	3,859

The amount due from Shell Petroleum at December 31, 2018 is \$nil (2017: \$4,502 million). Interest was calculated at US LIBOR less 0.210% (2017: US LIBOR less 0.058%) and interest income in 2018 was \$134 million (2017: \$19 million).

The amount due from Shell Treasury Centre Limited (STCL) comprises call deposits in dollars, sterling and euros. Interest is calculated at US LIBOR less 0.210% (2017: US LIBOR less 0.058%) on dollar balances, at GBP LIBOR less 0.190% (2017: GBP LIBOR less 0.137%) on sterling balances and at Euro Overnight Index Average (EONIA) less 0% (2017: EONIA less 0.1%) on euro balances, unless this results in a negative interest rate in which case no interest is earned. Net interest income in 2018 from STCL was \$7 million (2017: \$5 million).

In 2018, the Company transferred an interest-bearing receivable and an interest-bearing payable at fair value, equal to the carrying amount of the balances at transfer date, from Shell Treasury Luxembourg Sarl (STLB) to Shell Corporate Services Switzerland AG (SCSS). The net amount due to STLB at December 31, 2018, is \$nil (2017: interest-bearing receivable of €1,289 million and an interest-bearing payable of \$4,707 million). Interest on euro balances was calculated at EONIA less 0% (2017: EONIA less 0.1%) unless this resulted in a negative interest rate in which case no interest was earned. Interest on dollar balances was calculated at US LIBOR (2017: US LIBOR). Net interest expense on these balances in 2018 was \$89 million (2017: \$26 million).

The net amount due to SCSS at December 31, 2018, which is repayable on demand, comprises an interest-bearing receivable of €4,690 million (2017: €nil) and an interest-bearing payable of \$8,746 million (2017: \$nil). Interest on euro balances is calculated at EONIA less 0% (2017: EONIA less 0.1%) unless this results in a negative interest rate in which case no interest is earned. Interest on dollar balances is calculated at US LIBOR (2017: US LIBOR). Net interest expense on these balances in 2018 was \$67 million (2017: \$nil).

OTHER TRANSACTIONS AND BALANCES

The Company periodically enters into forward and spot foreign currency contracts with Treasury companies, which are subsidiaries. There were no open foreign currency contracts at December 31, 2018, or 2017.

The Company settles general and administrative expenses of the Trust, including the auditor's remuneration.

The Company has guaranteed contractual payments totalling \$53,357 million at December 31, 2018 (2017: \$58,527 million), and related interest, in respect of listed debt issued by Shell International Finance B.V.

14 AUDITOR'S REMUNERATION

See Note 28 to the Consolidated Financial Statements.

Independent Auditor's Report to Computershare Trustees (Jersey) Limited as Trustee of the Royal Dutch Shell Dividend Access Trust and the Board of Directors of Royal Dutch Shell plc

TO COMPUTERSHARE TRUSTEES (JERSEY) LIMITED AS TRUSTEE OF THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST AND THE BOARD OF DIRECTORS AND SHAREHOLDERS OF ROYAL DUTCH SHELL PLC

Opinion on the Financial Statements

We have audited the non-statutory financial statements of the Royal Dutch Shell Dividend Access Trust (the Financial Statements) for the year ended December 31, 2018 which comprise the Statement of Income, the Statement of Comprehensive Income, the Balance Sheet, the Statement of Changes in Equity, the Statement of Cash Flows and the related notes 1 to 8. The financial reporting framework that has been applied in their preparation is International Financial Reporting Standards (IFRS) as adopted by the European Union (EU) and IFRS as issued by the International Accounting Standards Board (IASB).

In our opinion the Financial Statements:

- give a true and fair view of the Royal Dutch Shell Dividend Access Trust's (the Trust) affairs as at December 31, 2018 and of its income for the year then ended; and
- have been properly prepared both in accordance with IFRS as adopted by the EU and IFRS as issued by the IASB.

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (UK) (ISAs (UK)). Our responsibilities under those standards are further described in the "Auditor's responsibilities for the audit of the financial statements" section of our report below. We are independent of the Trust in accordance with the ethical requirements that are relevant to our audit of the Financial Statements in the UK, including the Financial Reporting Council's Ethical Standard, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Conclusions relating to going concern

We have nothing to report in respect of the following matters in relation to which the ISAs (UK) require us to report to you where:

- the Trustee of Royal Dutch Shell Dividend Access Trust's (the Trustee) use of the going concern basis of accounting in the preparation of the Financial Statements is not appropriate; or
- the Trustee has not disclosed in the Financial Statements any identified material uncertainties that may cast significant doubt about the Trust's ability to continue to adopt the going concern basis of accounting for a period of at least twelve months from the date of approval of the Financial Statements.

Other information

The other information comprises the information included in the annual report, other than the Financial Statements and our auditor's report thereon. The Board of Directors of Royal Dutch Shell plc, (the Directors) are responsible for the other information.

Our opinion on the Financial Statements does not cover the other information and, we do not express any form of assurance conclusion thereon.

In connection with our audit of the Financial Statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the Financial Statements or our knowledge obtained in the audit or otherwise appears to be materially misstated. If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether there is a material misstatement in the Financial Statements or a material misstatement of the other information. If, based on the work we have performed, we conclude that there is a material misstatement of the other information, we are required to report that fact.

We have nothing to report in this regard.

Responsibilities of the Trustee

The Trustee is responsible for the preparation of the Financial Statements and for being satisfied that they give a true and fair view, and for such internal control as the Trustee determines is necessary to enable the preparation of Financial Statements that are free from material misstatement, whether due to fraud or error.

In preparing the Financial Statements, the Trustee is responsible for assessing the Trust's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Trustee either intends to liquidate the Trust or to cease operations, or have no realistic alternative but to do so. The Trustee is also required to: present fairly the financial position, financial performance and cash flows of the Trust; select suitable accounting policies in accordance with IAS 8: Accounting Policies, Changes in Accounting Estimates and Errors and then apply them consistently; present information, including accounting policies, in a manner that provides relevant, reliable, comparable and understandable

Independent Auditor's Report to Computershare Trustees (Jersey) Limited as Trustee of the Royal Dutch Shell Dividend Access Trust and the Board of Directors of Royal Dutch Shell plc

Continued

information; make judgements that are reasonable; provide additional disclosures when compliance with the specific requirements in IFRS as adopted by the EU and as issued by the IASB is insufficient to enable users to understand the impact of particular transactions, other events and conditions on the Trust's financial position and financial performance; and state whether the Financial Statements have been prepared in accordance with IFRS as adopted by the EU and as issued by the IASB.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the Financial Statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs (UK) will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these Financial Statements.

A further description of our responsibilities for the audit of the Financial Statements is located on the Financial Reporting Council's website at <https://www.frc.org.uk/auditorsresponsibilities>. This description forms part of our auditor's report.

Use of our report

This report is made solely to the Directors as a body, in accordance with our engagement letter dated November 6, 2018. Our audit work has been undertaken so that we might state to the Trustee and the Directors those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the Trust and the Trustee and the Directors as a body, for our audit work, for this report, or for the opinions we have formed.

/s/ Ernst & Young LLP
London
March 13, 2019

1. The maintenance and integrity of the Shell website are the responsibility of the Directors of Royal Dutch Shell plc; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
2. Legislation in the UK governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

The report set out above is included for the purposes of Royal Dutch Shell plc's Annual Report and Accounts for 2018 only and does not form part of Royal Dutch Shell plc's Annual Report on Form 20-F for 2018.

Report of Independent Registered Public Accounting Firm

TO COMPUTERSHARE TRUSTEES (JERSEY) LIMITED AS TRUSTEE OF THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST AND THE BOARD OF DIRECTORS AND SHAREHOLDERS OF ROYAL DUTCH SHELL PLC

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Royal Dutch Shell Dividend Access Trust (the Trust) as of December 31, 2018 and 2017, the related statements of income, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the "Financial Statements"). In our opinion, the Financial Statements present fairly, in all material respects, the financial position of the Trust at December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board and in conformity with IFRS as adopted by the European Union.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Trust's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated March 13, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Trustee of the Trust (the Trustee) and the management of Royal Dutch Shell plc (the management). Our responsibility is to express an opinion on the Trust's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Trust in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Trust's auditor since 2016.

London, United Kingdom

March 13, 2019

TO COMPUTERSHARE TRUSTEES (JERSEY) LIMITED AS TRUSTEE OF ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST AND THE BOARD OF DIRECTORS AND SHAREHOLDERS OF ROYAL DUTCH SHELL PLC

Opinion on Internal Control over Financial Reporting

We have audited Royal Dutch Shell Dividend Access Trust's (the Trust) internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Financial Statements of the Trust, and our report dated March 13, 2019, expressed an unqualified opinion thereon.

Basis for Opinion

The Trustee of the Trust (the Trustee) and the management of Royal Dutch Shell plc (the Management) are responsible for maintaining effective internal control over financial reporting and for their assessment of the effectiveness of internal control over financial reporting included in the accompanying Trustee's and Management's Report on Internal Control over Financial Reporting set out on page 104. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Trust in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP
London, United Kingdom
March 13, 2019

1. The maintenance and integrity of the Shell website are the responsibility of the Directors of Royal Dutch Shell plc; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
2. Legislation in the UK governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

The report set out above is included for the purposes of Royal Dutch Shell plc's Annual Report on Form 20-F for 2018 only and do not form part of Royal Dutch Shell plc's Annual Report and Accounts for 2018.

Royal Dutch Shell Dividend Access Trust Financial Statements

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Royal Dutch Shell Dividend Access Trust Financial Statements *Continued*

Statement of Income

	2018	2017	£ million 2016
Dividend income	5,328	4,567	3,879
Income before taxation and for the period	5,328	4,567	3,879

Statement of Comprehensive Income

	2018	2017	£ million 2016
Income for the period	5,328	4,567	3,879
Comprehensive income for the period	5,328	4,567	3,879

Balance Sheet

	Notes	Dec 31, 2018	£ million Dec 31, 2017
Assets			
Current assets			
Cash and cash equivalents		3	2
Total assets		3	2
Liabilities			
Current liabilities			
Unclaimed dividends	4	3	2
Total liabilities		3	2
Equity			
Capital account	5	—	—
Revenue account		—	—
Total equity		—	—
Total liabilities and equity		3	2

Signed on behalf of Computershare Trustees (Jersey) Limited
as Trustee of the Royal Dutch Shell Dividend Access Trust

/s/ Karen Kurys

Karen Kurys

March 13, 2019

/s/ Martin Fish

Martin Fish

Statement of Changes in Equity

	Notes	Capital account	Revenue account	£ million Total equity
At January 1, 2018		—	—	—
Comprehensive income for the period		—	5,328	5,328
Distributions made	6	—	(5,328)	(5,328)
At December 31, 2018		—	—	—
At January 1, 2017		—	—	—
Comprehensive income for the period		—	4,567	4,567
Distributions made	6	—	(4,567)	(4,567)
At December 31, 2017		—	—	—
At January 1, 2016		—	—	—
Comprehensive income for the period		—	3,879	3,879
Distributions made	6	—	(3,879)	(3,879)
At December 31, 2016		—	—	—

Statement of Cash Flows

	2018	2017	£ million 2016
Income for the period	5,328	4,567	3,879
Adjustment for:			
Dividends received	(5,328)	(4,567)	(3,879)
Cash flow from operating activities	—	—	—
Dividends received	5,328	4,567	3,879
Cash flow from investing activities	5,328	4,567	3,879
Cash distributions made	(5,327)	(4,567)	(3,879)
Cash flow from financing activities	(5,327)	(4,567)	(3,879)
Change in cash and cash equivalents	1	—	—
Cash and cash equivalents at January 1	2	2	2
Cash and cash equivalents at December 31	3	2	2

Notes to the Royal Dutch Shell Dividend Access Trust Financial Statements

1 THE TRUST

The Royal Dutch Shell Dividend Access Trust (the Trust) was established on May 19, 2005, by The "Shell" Transport and Trading Company, p.l.c., now The Shell Transport and Trading Company Limited (Shell Transport), and Royal Dutch Shell plc (the Company). The Trust is governed by the applicable laws of England and Wales and is resident and domiciled in Jersey. The Trust is not subject to taxation. The Trustee of the Trust is Computershare Trustees (Jersey) Limited, registration number 92182 (the Trustee), Queensway House, Hilgrove Street, St Helier, Jersey, JE1 1ES. The Trust was established as part of a dividend access mechanism.

Shell Transport and BG Group Limited (BG), have each issued a dividend access share to the Trustee. Following the announcement of a dividend by the Company on the B shares, Shell Transport and BG may declare a dividend on their dividend access shares.

The primary purposes of the Trust are to receive, on behalf of the B shareholders of the Company and in accordance with their respective holdings of B shares in the Company, any amounts paid by way of dividend on the dividend access shares and to pay such amounts to the B shareholders on the same pro rata basis. The Trust is not subject to significant market risk, credit risk or liquidity risk.

The Trust shall not endure for a period in excess of 80 years from May 19, 2005, being the date on which the Trust Deed was executed.

2 THE BASIS OF PREPARATION

The Financial Statements of the Trust have been prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union. As applied to the Trust, there are no material differences from IFRS as issued by the International Accounting Standards Board (IASB); therefore, the Financial Statements have been prepared in accordance with IFRS as issued by the IASB.

The Financial Statements have been prepared under the historical cost convention. The accounting policies described in Note 3 have been applied consistently in all periods presented.

The Financial Statements were approved and authorised for issue by the Trustee on March 13, 2019.

The financial results of the Trust are included in the Consolidated and Parent Company Financial Statements on pages 167-214 and pages 237-246 respectively.

3 SIGNIFICANT ACCOUNTING POLICIES

The Trust's accounting policies follow those of Shell as set out in Note 2 to the Consolidated Financial Statements. The following are Trust-specific policies. The adoption of IFRS 9 *Financial Instruments* in 2018 has had no significant impact on the Trust's accounting or disclosures.

PRESENTATION AND FUNCTIONAL CURRENCY

The Trust's presentation and functional currency is sterling. The Trust's dividend income and dividends paid are principally in sterling.

DIVIDEND INCOME

Dividends on the dividend access shares are recognised on a paid basis unless the dividend has been confirmed by a general meeting of Shell Transport or BG, in which case income is recognised on the date on which receipt is deemed virtually certain.

DISTRIBUTIONS MADE

Amounts are recorded as distributed once a wire transfer or cheque is issued. To the extent that cheques expire or are returned unrepresented, the Trust records a liability for unclaimed dividends and a corresponding amount of cash.

4 UNCLAIMED DIVIDENDS

Unclaimed dividends of £2,816,655 (2017: £2,302,549) include any dividend cheque payments that have not been presented within 12 months, have expired or have been returned unrepresented. Dividends which are unclaimed after 12 years will revert to Shell Transport and BG once forfeited.

5 CAPITAL ACCOUNT

The capital account is represented by the dividend access share of 25 pence settled in the Trust by Shell Transport and the dividend access share of 10 pence settled in the Trust by BG. There have been no changes in the capital account in the current or prior year.

6 DISTRIBUTIONS MADE

Distributions are made to the B shareholders of the Company in accordance with the Trust Deed. See Note 23 to the Consolidated Financial Statements for information about dividends per share. Any wire transfers that are not completed are replaced by cheques.

7 RELATED PARTIES

The Trust received dividend income of £3,470 million (2017: £2,970 million; 2016: £2,533 million) in respect of the dividend access share from Shell Transport and £1,858 million (2017: £1,597 million; 2016: £1,346 million) in respect of the dividend access share from BG. The Trust made distributions of £5,328 million (2017: £4,567 million; 2016: £3,879 million) to the B shareholders of the Company.

The Company pays the general and administrative expenses of the Trust, including the auditor's remuneration.

8 AUDITOR'S REMUNERATION

Auditor's remuneration for 2018 audit services was £33,750 (2017: £33,750; 2016: £33,750).

Additional Information

Shareholder information

Royal Dutch Shell plc (the Company) was incorporated in England and Wales on February 5, 2002, as a private company under the Companies Act 1985, as amended. On October 27, 2004, the Company was re-registered as a public company limited by shares and changed its name from Forthdeal Limited to Royal Dutch Shell plc. The Company is registered at Companies House, Cardiff, under company number 4366849, and at the Chamber of Commerce, The Hague, under company number 34179503. The Legal Entity Identifier (LEI) issued by the London Stock Exchange is 21380068P1DRHJM8KU70. The business address for the Directors and Senior Management is Carel van Bylandtlaan 30, 2596 HR, The Hague, The Netherlands.

The Company is resident in the Netherlands for Dutch and UK tax purposes and its primary objective is to carry on the business of a holding company. It is not directly or indirectly owned or controlled by another corporation or by any government and does not know of any arrangements that may result in a change of control of the Company.

NATURE OF TRADING MARKET

The Company has two classes of ordinary shares: A and B shares. The principal trading market for A shares is Euronext Amsterdam and the principal trading market for B shares is the London Stock Exchange. Ordinary shares are traded in registered form.

A and B American Depositary Shares (ADSs) are listed on the New York Stock Exchange [A]. A depositary receipt is a certificate that evidences ADSs. Depositary receipts are issued, cancelled and exchanged at the office of JP Morgan Chase Bank, N.A., 383 Madison Avenue, New York, New York 10179, USA, as depositary (the Depositary), under a deposit agreement between the Company, the Depositary and the holders of ADSs [B]. Each ADS represents two €0.07 shares of Royal Dutch Shell plc deposited under the agreement. More information relating to ADSs is given on page 259.

[A] At February 15, 2019, 444,857,258 A ADSs and 323,849,655 B ADSs were outstanding, representing 20% and 17% of the respective share capital class, held by 5,410 and 926 holders of record with an address in the USA, respectively. In addition to holders of ADSs, at February 15, 2019, 25,537 A shares and 949,113 B shares of €0.07 each were outstanding, representing 0.000% and 0.011% of the respective share capital class, held by 314 and 3,095 holders of record registered with an address in the USA, respectively.

[B] JP Morgan Chase Bank, N.A. were appointed as Depositary with effect from November 1, 2018, in succession to The Bank of New York Mellon, 101 Barclay Street, New York, NY 10286, USA.

Listing information

	A shares	B shares
Ticker symbol London	RDSA	RDSB
Ticker symbol Amsterdam	RDSA	RDSB
Ticker symbol New York (ADS [A])	RDS.A	RDS.B
ISIN Code	GB00B03MLX29	GB00B03MM408
CUSIP	G7690A100	G7690A118
SEDOL Number London	B03MLX2	B03MM40
SEDOL Number Euronext	B09CBL4	B09CBN6
Weighting on FTSE at 31/12/18	6.17%	5.16%
Weighting on AEX at 31/12/18	16.17%	not included

[A] Each A ADS represents two A shares of €0.07 each and each B ADS represents two B shares of €0.07 each.

SHARE CAPITAL

The issued and fully paid share capital of the Company at February 15, 2019, was as follows:

Share capital

	Issued and fully paid	
	Number	Nominal value
Ordinary shares of €0.07 each		
A shares	4,441,269,079	€310,888,836
B shares	3,745,486,731	€262,184,071
Sterling deferred shares of £1 each	50,000	£50,000

The Directors may only allot new ordinary shares if they have authority from shareholders to do so. The Company seeks to renew this authority annually at its Annual General Meeting (AGM). Under the resolution passed at the Company's 2018 AGM, the Directors were granted authority to allot ordinary shares up to an aggregate nominal amount equivalent to approximately one-third of the issued ordinary share capital of the Company (in line with the guidelines issued by institutional investors).

The following is a summary of the material terms of the Company's ordinary shares, including brief descriptions of the provisions contained in the Articles of Association (the Articles) and applicable laws of England and Wales in effect on the date of this document. This summary does not purport to include complete statements of these provisions:

- upon issuance, A and B shares are fully paid and free from all liens, equities, charges, encumbrances and other interest of the Company and not subject to calls of any kind;
- all A and B shares rank equally for all dividends and distributions on ordinary share capital; and
- A and B shares are admitted to the Official List of the UK Financial Conduct Authority and to trading on the market for listed securities of the London Stock Exchange. A and B shares are also admitted to trading on Euronext Amsterdam. A and B ADSs are listed on the New York Stock Exchange.

At December 31, 2018, trusts and trust-like entities holding shares for the benefit of employee share plans of Shell held (directly and indirectly) 38 million shares of the Company with an aggregate market value of \$1,128 million and an aggregate nominal value of €3 million.

SIGNIFICANT SHAREHOLDINGS

The Company's A and B shares have identical voting rights, and accordingly the Company's major shareholders do not have different voting rights.

SIGNIFICANT DIRECT SHAREHOLDINGS

Direct holdings of 3% or more of A and B shares combined held by registered members representing the interests of underlying investors at December 31, 2018, are given below.

Direct shareholdings

	A shares		B shares		Total	
	Number	%	Number	%	Number	%
Euroclear Nederland	1,795,621,266	40.15	15,022,439	0.40	1,810,643,705	22.03
Guaranty (Nominees) Limited	883,221,124	19.75	635,818,258	16.98	1,519,039,382	18.49
State Street Nominees Limited	172,015,005	3.85	191,471,980	5.11	363,486,985	4.42
Chase Nominees Limited	60,547,031	1.35	260,984,315	6.97	321,531,346	3.91

SIGNIFICANT INDIRECT SHAREHOLDINGS

Interests of investors with 3% or more of A and B shares combined at December 31, 2018, are given below.

Indirect shareholdings

	A shares		B shares		Total	
	Number	%	Number	%	Number	%
BlackRock, Inc.	334,842,363	7.49	256,790,694	6.86	591,633,057	7.20
The Capital Group Companies, Inc.	66,006,890	1.48	401,977,309	10.73	467,984,199	5.70
The Vanguard Group, Inc.	199,027,711	4.45	132,605,115	3.54	331,632,826	4.04

NOTIFICATION OF MAJOR SHAREHOLDINGS

The Company did not receive any notifications pursuant to Disclosure Guidance and Transparency Rule (DTR) 5 during the year.

Investor

	A shares		B shares		Total[B]	
	Number	%	Number	%	Number	%
BlackRock, Inc. [A]	277,045,557	6.10	218,422,847	5.83	495,468,404	5.97

[A] The information provided is derived from the most recent notification, received in 2017. This includes the percentage figures shown, which align with the issued capital as at the date of notification.

[B] Excludes financial instruments according to Art. 13(1)(a) of Directive 2004/109/EC (DTR 5.3.1.1 (a)) and financial instruments with similar economic effect according to Art. 13(1)(b) of Directive 2004/109/EC (DTR 5.3.1.1 (b)).

The Company did not receive any notifications pursuant to DTR 5 in the period from December 31, 2018, to February 15, 2019, (being a date not more than one month prior to the date of the Company's Notice of Annual General Meeting).

DIVIDENDS

The following tables show the dividends on each class of share and each class of ADS for the years 2014 - 2018.

A and B shares					\$
	2018	2017	2016	2015	2014
Q1	0.47	0.47	0.47	0.47	0.47
Q2	0.47	0.47	0.47	0.47	0.47
Q3	0.47	0.47	0.47	0.47	0.47
Q4	0.47	0.47	0.47	0.47	0.47
Total announced in respect of the year	1.88	1.88	1.88	1.88	1.88

A shares					€ [A]
	2018	2017	2016	2015	2014
Q1	0.40	0.42	0.42	0.42	0.35
Q2	0.40	0.39	0.42	0.42	0.36
Q3	0.41	0.40	0.44	0.43	0.38
Q4	0.42	0.38	0.44	0.42	0.43
Total announced in respect of the year	1.64	1.59	1.72	1.69	1.53
Amount paid during the year	1.60	1.65	1.70	1.71	1.42

[A] Euro equivalent, rounded to the nearest euro cent.

B shares					Pence [A]
	2018	2017	2016	2015	2014
Q1	35.18	37.12	32.98	30.75	28.03
Q2	36.50	36.28	35.27	30.92	29.09
Q3	36.77	35.02	37.16	31.07	30.16
Q4	35.94	33.91	38.64	32.78	31.20
Total announced in respect of the year	144.39	142.33	144.05	125.52	118.48
Amount paid during the year	142.36	147.06	138.19	123.94	114.16

[A] Sterling equivalent.

A and B ADSs					\$
	2018	2017	2016	2015	2014
Q1	0.94	0.94	0.94	0.94	0.94
Q2	0.94	0.94	0.94	0.94	0.94
Q3	0.94	0.94	0.94	0.94	0.94
Q4	0.94	0.94	0.94	0.94	0.94
Total announced in respect of the year	3.76	3.76	3.76	3.76	3.76
Amount paid during the year	3.76	3.76	3.76	3.76	3.72

METHOD OF HOLDING SHARES OR AN INTEREST IN SHARES

There are several ways in which Royal Dutch Shell plc registered shares or an interest in these shares can be held, including:

- directly as registered shares either in uncertificated form or in certificated form in a shareholder's own name;
- indirectly through Euroclear Nederland (in respect of which the Dutch Securities Giro Act ("Wet giraal effectenverkeer") is applicable);
- through the Royal Dutch Shell Corporate Nominee Service;
- through another third-party nominee or intermediary company; and
- as a direct or indirect holder of either an A or a B ADS with the Depositary

AMERICAN DEPOSITARY SHARES

Effective November 1, 2018, J.P. Morgan Chase Bank, N.A. serves as successor depositary for our ADS programme. A copy of the Form of Amended and Restated Deposit Agreement with J.P. Morgan Chase Bank, N.A. ("Depositary") was filed with the SEC as an Exhibit to our Form F-6 filed on October 19, 2018 ("Deposit Agreement").

The Depositary is the registered shareholder of the shares underlying the A or B ADSs and enjoys the rights of a shareholder under the Articles. Holders of ADSs will not have shareholder rights. The rights of the holder of an A or a B ADS are specified in the Deposit Agreement with the Depositary and are summarised below.

The Depositary will receive all cash dividends and other cash distributions made on the deposited shares underlying the ADSs and, where possible and on a reasonable basis, will distribute such dividends and distributions to holders of ADSs. Rights to purchase additional shares will also be made available to the Depositary who may make such rights available to holders of ADSs. All other distributions made on the Company's shares will be distributed by the Depositary in any means that the Depositary thinks is equitable and practical. The Depositary may deduct its fees and expenses and the amount of any taxes owed from any payments to holders and it may sell a holder's deposited shares to pay any taxes owed. The Depositary is not responsible if it decides that it is unlawful or impractical to make a distribution available to holders of ADSs.

The Depositary will notify holders of ADSs of shareholders' meetings of the Company and will arrange to deliver voting materials to such holders of ADSs if requested by the Company. Upon request by a holder, the Depositary will endeavour to appoint such holder as proxy in respect of such holder's deposited shares entitling such holder to attend and vote at shareholders' meetings. Holders of ADSs may also instruct the Depositary to vote their deposited securities and the Depositary will try, as far as practical and lawful, to vote deposited shares in accordance with such instructions. The Company cannot ensure that holders will receive voting materials or otherwise learn of an upcoming shareholders' meeting in time to ensure that holders can instruct the Depositary to vote their shares.

Upon payment of appropriate fees, expenses and taxes: (i) shareholders may deposit their shares with the Depositary and receive the corresponding class and amount of ADSs; and (ii) holders of ADSs may surrender their ADSs to the Depositary and have the corresponding class and amount of shares credited to their account.

Further, subject to certain limitations, holders may, at any time, cancel ADSs and withdraw their underlying shares or have the corresponding class and amount of shares credited to their account.

FEES PAID BY HOLDERS OF ADSs

The Depositary collects its fees for delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal or from intermediaries acting for them. The Depositary collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of distributable property to pay the fees. The Depositary may generally refuse to provide fee-attracting services until its fees for those services are paid. See page 260.

PAYMENTS BY DEPOSITARY TO THE COMPANY

J.P. Morgan Chase Bank, N.A., as Depositary, has agreed to share with the Company portions of certain fees collected, less ADS programme expenses paid by the Depositary. For example, these expenses include the Depositary's annual programme fees, transfer agency fees, custody fees, legal expenses, postage and envelopes for mailing annual and interim financial reports, printing and distributing dividend cheques, electronic filing of US federal tax information, mailing required tax forms, stationery, postage, facsimile and telephone calls and the standard out-of-pocket maintenance costs for the ADSs. From January 1, 2018, to February 15, 2019, the Company received \$2,832,296 from the former depositary and \$nil from the Depositary.

DIVIDEND REINVESTMENT PLAN

Equiniti Financial Services Limited, part of the same group of companies as the Company's Registrar, Equiniti Limited, operates a Dividend Reinvestment Plan ("DRIP") which enables RDS shareholders to elect to have their dividend payments used to purchase RDS shares of the same class as those already held by them. More information can be found at www.shareview.co.uk/info/drip or by contacting Equiniti.

ABN AMRO Bank N.V. and JP Morgan Chase Bank N.A. also operate dividend reinvestment options. More information can be found by contacting the relevant provider.

Persons depositing or withdrawing shares must pay:	For:
\$5.00 or less per 100 ADSs (or portion of 100 ADSs)	Issuance of ADSs, including those resulting from a distribution of shares, rights or other property; Cancellation of ADSs for the purpose of their withdrawal, including if the deposit agreement terminates; and Distribution of securities to holders of deposited securities by the Depositary to ADS registered holders.
Registration and transfer fees	Registration and transfer of shares on the share register to or from the name of the Depositary or its agent when they deposit or withdraw shares.
Expenses of the Depositary	Cable, telex and facsimile transmissions (when expressly provided in the deposit agreement); and Converting foreign currency into dollars.
Taxes and other governmental charges the Depositary or the custodian has to pay on any ADS or share underlying an ADS, for example, share transfer taxes, stamp duty or withholding taxes	As necessary.

In addition to the above, the Depositary may charge: (i) a dividend fee of \$5.00 or less per 100 ADSs (or portion of 100 ADSs) for cash dividends or issuance of ADSs resulting from share dividends and (ii) an administrative fee of \$5.00 or less per 100 ADSs (or portion of 100 ADSs) per calendar year. The Company and Depositary have agreed not to charge these fees at this time.

EXCHANGE CONTROLS AND OTHER LIMITATIONS AFFECTING SECURITY HOLDERS

Other than restrictions affecting those individuals, entities, government bodies, corporations or agencies that are subject to European Union (EU) sanctions, for example, regarding Syria, and those sanctions adopted by the government of the UK, and the general EU prohibition to transfer funds to and from North Korea, we are not aware of any other legislative or other legal provision currently in force in the UK, the Netherlands or arising under the Articles restricting remittances to holders of the Company's ordinary shares who are non-residents of the UK, or affecting the import or export of capital.

TAXATION GENERAL

The Company is incorporated in England and Wales and tax-resident in the Netherlands. As a tax resident of the Netherlands, it is generally required by Dutch law to withhold tax at a rate of 15% on dividends on its ordinary shares and ADSs, subject to the provisions of any applicable tax convention or domestic law. Depending on their particular circumstances, non-Dutch tax-resident holders may be entitled to a full or partial refund of Dutch withholding tax. The following sets forth the operation of other provisions on dividends on the Company's various ordinary shares and ADSs to UK and US holders, as well as certain other tax rules pertinent to holders. Holders should consult their own tax adviser if they are uncertain as to the tax treatment of any dividend.

DIVIDENDS PAID ON THE DIVIDEND ACCESS SHARES

There is no Dutch withholding tax on dividends on B shares or B ADSs, provided that such dividends are paid on the dividend access shares pursuant to the dividend access mechanism (see "Dividend access mechanism for B shares" on page 108). Dividends paid on the dividend

access shares are treated as UK-source for tax purposes and there is no UK withholding tax on them.

In 2018, all dividends with respect to B shares and B ADSs were paid on the dividend access shares pursuant to the dividend access mechanism.

DUTCH WITHHOLDING TAX

When Dutch withholding tax applies on dividends paid to a US holder (that is, dividends on A shares or A ADSs, or on B shares or B ADSs that are not paid on the dividend access shares pursuant to the dividend access mechanism), the US holder will be subject to Dutch withholding tax at the rate of 15%. A US holder who is entitled to the benefits of the 1992 Double Taxation Convention (the Convention) between the USA and the Netherlands as amended by the protocol signed on March 8, 2004, will be entitled to a reduction in the Dutch withholding tax, either by way of a full or a partial exemption at source or by way of a partial refund or a credit as follows:

- if the US holder is an exempt pension trust as described in article 35 of the Convention, or an exempt organisation as described in article 36 thereof, the US holder will be exempt from Dutch withholding tax; or
- if the US holder is a company that holds directly at least 10% of the voting power in the Company, the US holder will be subject to Dutch withholding tax at a rate not exceeding 5%.

In general, the entire dividend (including any amount withheld) will be dividend income to the US holder and the withholding tax will be treated as a foreign income tax that is eligible for credit against the US holder's income tax liability or a deduction subject to certain limitations. A "US holder" includes, but is not limited to, a citizen or resident of the USA, or a corporation or other entity organised under the laws of the USA or any of its political subdivisions.

When Dutch withholding tax applies on dividends paid to UK tax-resident holders (that is, dividends on A shares or A ADSs, or on B shares or B ADSs that are not paid on the dividend access shares pursuant to the dividend access mechanism), the dividend will typically be subject to withholding tax at a rate of 15%. Such UK tax-resident holder may be entitled to a credit (not repayable) for withholding tax against their UK tax liability. However,

certain corporate shareholders are, subject to conditions, exempt from UK tax on dividends. Withholding tax suffered cannot be offset against such exempt dividends. UK tax-resident holders should also be entitled to claim a refund of one-third of the Dutch withholding tax from the Dutch tax authorities in reliance on the tax convention between the Netherlands and the UK. Pension plans meeting certain defined criteria can, however, be entitled to claim a full refund or exemption at source of the dividend tax withheld. Also, UK tax-resident corporate shareholders holding at least a 5% shareholding and meeting other defined criteria are exempted at source from dividend tax.

For holders who are tax-resident in any other country, the availability of a whole or partial exemption or refund of Dutch withholding tax is governed by Dutch tax law and/or the tax convention, if any, between the Netherlands and the country of the holder's residence.

There may be other grounds on which holders who are tax-resident in the UK, the USA or any other country can obtain a full or partial refund of the Dutch withholding tax, depending on their particular circumstances; see "Taxation: General" above.

DUTCH CAPITAL GAINS TAXATION

Capital gains on the sale of shares of a Dutch tax-resident company by a US holder are generally not subject to taxation by the Netherlands unless the US holder has a permanent establishment therein and the capital gain is derived from the sale of shares that are part of the business property of the permanent establishment.

DUTCH SUCCESSION DUTY AND GIFT TAXES

Shares of a Dutch tax-resident company held by an individual who is not a resident or a deemed resident of the Netherlands will generally not be subject to succession duty in the Netherlands on the individual's death.

A gift of shares of a Dutch tax-resident company by an individual who is not a resident or a deemed resident of the Netherlands is generally not subject to Dutch gift tax.

UK STAMP DUTY AND STAMP DUTY RESERVE TAX

Sales or transfers of the Company's ordinary shares within a clearance service (such as Euroclear Nederland) or of the Company's ADSs within the ADS depositary receipts system will not give rise to a stamp duty reserve tax (SDRT) liability and should not in practice require the payment of UK stamp duty.

The transfer of the Company's ordinary shares to a clearance service (such as Euroclear Nederland) or to an issuer of depositary shares (such as ADSs) will generally give rise to a UK stamp duty or SDRT liability at the rate of 1.5% of consideration given or, if none, of the value of the shares. A sale of the Company's ordinary shares that are not held within a clearance service (for example, settled through the UK's CREST system of paperless transfers) will generally be subject to UK stamp duty or SDRT at the rate of 0.5% of the amount of the consideration, normally paid by the purchaser.

CAPITAL GAINS TAX

For the purposes of UK capital gains tax, the market values [A] of the shares of the former public parent companies of the Royal Dutch/Shell Group at the relevant dates were:

	£	
	March 31, 1982	July 20, 2005
Royal Dutch Petroleum Company (N.V. Koninklijke Nederlandsche Petroleum Maatschappij) which ceased to exist on December 21, 2005	1.1349	17.6625
The "Shell" Transport and Trading Company, p.l.c. which delisted on July 19, 2005	1.4502	Not applicable

[A] Restated where applicable to reflect all capitalisation issues since the relevant date. This includes the change in the capital structure in 2005, when Royal Dutch Shell plc became the single parent company of Royal Dutch Petroleum Company and of The "Shell" Transport and Trading Company, p.l.c., now The Shell Transport and Trading Company Limited, and one share in Royal Dutch Petroleum Company was exchanged for two Royal Dutch Shell plc A shares and one share in The "Shell" Transport and Trading Company, p.l.c. was exchanged for 0.287333066 Royal Dutch Shell plc B shares.

Section 13(R) of the US Securities Exchange Act of 1934 disclosure

In accordance with our General Business Principles and Code of Conduct, Shell seeks to comply with all applicable international trade laws including applicable sanctions and embargoes.

The activities listed below have been conducted outside the USA by non-US affiliates of Royal Dutch Shell plc. None of the payments disclosed below were made in US dollars, nor are any of the balances disclosed below held in US dollars; however, for disclosure purposes, all have been converted into US dollars at the appropriate exchange rate. We do not believe that any of the transactions or activities listed below violated US sanctions.

In 2018, we settled a receivable of \$10.5 million with the National Iranian Oil Company (NIOC) associated with our previous upstream activities conducted prior to the imposition of European Union sanctions against a payable for freight and ancillary services in relation to oil cargoes purchased in 2016. The net payable of \$1.0 million was paid to NIOC in March 2018.

In 2017, we entered into a technology licence agreement with Petrochemical Industries Design and Engineering Company (PIDEC) to provide licence and engineering services to Abadan Oil Refinery Company (AORC) in relation to Cansolv sulphur dioxide (SO₂) scrubbing technology, as well as a separate end-user licence agreement with AORC for a continuing licence for the Cansolv SO₂ technology once PIDEC's work at Abadan has been completed. In addition, a separate agreement was signed at the same time between Shell, the Iran branch of Shell Development B.V. (SDI) and PIDEC, for the arrangement of payments due under the licence and engineering agreement to be made to SDI in Iran. In 2018, these agreements generated gross revenue of \$691,768 and an estimated net profit of \$438,131. At December 31, 2018, we have a receivable outstanding of \$691,768. In October 2018, we sent notices of termination with respect to these two agreements.

In addition, at December 31, 2018, we have a receivable of \$1.2 million outstanding with Hamedan Ibn Sina Petrochemical Company associated with a technology licence agreement signed in 2016. In October 2018, we sent notice of suspension with respect to this agreement.

In May 2018, we agreed to extend the term of a memorandum of understanding (MOU) originally signed in 2016 with the NIOC to cover a joint review of a number of oil and gas opportunities. This amendment extends the term of the MOU to August 6, 2018. There was no gross revenue or net profit associated with this transaction.

In 2018, we received gross revenue of \$228,441 into our account at Karafarin Bank from Bank Mellat in relation to advisory services provided to Marun Petrochemical Company, pursuant to an advisory agreement entered into in June 2017. No net profit was associated with these services in 2018.

In October 2018, we paid \$2.1 million to National Iranian Tanker Company pursuant to a charter party agreement entered into in May 2017. This payment constituted full settlement of all obligations under the charter party agreement.

In 2018, we paid \$18,812 for the clearance of overflight permits for Shell aircraft over Iranian airspace, and \$6,352 for handling costs, to the Iranian Civil Aviation Authority. There was no gross revenue or net profit associated with these transactions. On occasion, our aircraft may be routed over Iran and therefore these payments may continue in the future.

In 2018, Shell employees met with Iranian officials in Iran. In relation to these travelling Shell employees, \$6,336 was paid to Iranian authorities for visas and \$688 for exit fees; \$190 was paid to Bimeh Insurance Company for travel insurance; and \$853 was paid to Iranian airlines for flight tickets. Additionally, \$246 visa costs were incurred by non-US affiliates. We also discovered \$294 in visa costs for Shell employees and \$142 visa costs incurred by non-US affiliates in relation to 2017 that were not previously disclosed. Using an agent, CIBT Visumdienst B.V, we also paid a \$62 consular fee to an Iranian embassy. There was no gross revenue or net profit associated with these transactions. We have ceased these discussions and do not expect similar payments in the future.

In 2018, we provided downstream retail services to the Iranian Embassy in Switzerland and to the International Islamic Liquidity Management Corporation in Malaysia. These transactions generated gross revenue of \$4,064 and an estimated net profit of \$236 in Switzerland and \$979 gross revenue and an estimated net profit of \$57 in Malaysia. We have no contractual agreements with these parties.

We maintain accounts with Karafarin Bank, where our cash deposits (balance of \$5.0 million at December 31, 2018) generated non-taxable interest income of \$0.3 million in 2018, and we paid \$351 in bank charges. We have made payments amounting to \$1.4 million through our account in Karafarin Bank to a variety of non-sanctioned parties.

Non-GAAP measures reconciliations

These non-GAAP measures, also known as alternative performance measures, are financial measures other than those defined in International Financial Reporting Standards which Shell considers provide useful information.

EARNINGS ON A CURRENT COST OF SUPPLIES BASIS

Segment earnings are presented on a current cost of supplies basis (CCS earnings), which is the earnings measure used by the Chief Executive Officer for the purposes of making decisions about allocating resources and assessing performance. On this basis, the purchase price of volumes sold during the period is based on the current cost of supplies during the same period after making allowance for the tax effect. CCS earnings therefore exclude the effect of changes in the oil price on inventory carrying amounts. The current cost of supplies adjustment does not impact Cash flow from operating activities in the "Consolidated Statement of Cash Flows".

Reconciliation of CCS earnings to income for the period

	\$ million		
	2018	2017	2016
Earnings on a current cost of supplies basis (CCS earnings)	24,364	12,471	3,692
Attributable to non-controlling interest	(531)	(390)	(159)
Earnings on a current cost of supplies basis attributable to			
Royal Dutch Shell plc shareholders	23,833	12,081	3,533
Current cost of supplies adjustment	(458)	964	1,085
Non-controlling interest	(23)	(68)	(43)
Income attributable to			
Royal Dutch Shell plc shareholders	23,352	12,977	4,575
Non-controlling interest	554	458	202
Income for the period	23,906	13,435	4,777

CAPITAL INVESTMENT

Capital investment is a measure used to make decisions about allocating resources and assessing performance.

Capital investment reconciliation

	\$ million		
	2018	2017	2016
Capital expenditure [A]	23,011	20,845	22,116
Capital investment related to the acquisition of BG Group plc	—	—	52,904
Investments in joint ventures and associates [A]	880	595	1,330
Exploration expense, excluding exploration wells written off	889	1,048	1,274
Finance leases	452	1,074	2,343
Other	(453)	444	(90)
Capital investment	24,779	24,006	79,877
Of which			
Integrated Gas	4,460	3,827	26,214
Upstream	12,525	13,648	47,507
Downstream	7,564	6,416	6,057
Corporate	230	115	99

[A] Included within Cash flow from investing activities in the "Consolidated Statement of Cash Flows".

DIVESTMENTS

Divestments is a measure used to monitor the progress of our divestment programme. This measure comprises proceeds from sale of property, plant and equipment and businesses, joint ventures and associates, and other Integrated Gas, Upstream and Downstream investments in equity securities, adjusted onto an accruals basis and for any share consideration received or contingent consideration initially recognised upon the related divestment, as well as proceeds from sale of interests in entities while retaining control (for example, proceeds from sale of interests in Shell Midstream Partners, L.P.).

Divestments reconciliation

	\$ million		
	2018	2017	2016
Proceeds from sale of property, plant and equipment and businesses [A]	4,366	8,808	2,072
Proceeds from sale of joint ventures and associates [A]	1,594	2,177	1,565
Share and contingent consideration [B]	194	3,046	275
Proceeds from sale of interests in entities while retaining control [C]	673	278	1,108
Other	275	3,031 [D]	(36)
Divestments	7,102	17,340	4,984
Of which			
Integrated Gas	3,124	3,077	352
Upstream	2,198	11,542	1,726
Downstream	1,718	2,703	2,889
Corporate	62	18	17

[A] Included within Cash flow from investing activities in the "Consolidated Statement of Cash Flows".

[B] With effect from 2017, this is valued at the date of the related divestment. In future periods, the proceeds from any disposal of shares received as divestment consideration, and proceeds from realisation of contingent consideration, will be included in Cash flow from investing activities. In 2017, it mainly comprised \$2,829 million for shares in Canadian Natural Resources Limited (CNRL) received as partial consideration in the oil sands divestment. In 2018, these shares were sold for \$3,307 million.

[C] Included within "Change in non-controlling interest" in Cash flow from financing activities in the "Consolidated Statement of Cash Flows".

[D] Includes proceeds of \$2,635 million from the sale of shares in Woodside Petroleum Limited.

Non-GAAP measures reconciliations **Continued**

OPERATING EXPENSES

Operating expenses is a measure of Shell's cost management performance, comprising items from the "Consolidated Statement of Income" as follows.

Operating expenses	\$ million		
	2018	2017	2016
Production and manufacturing expenses	26,970	26,652	28,434
Selling, distribution and administrative expenses	11,360	10,509	12,101
Research and development	986	922	1,014
Total	39,316	38,083	41,549
Of which			
Integrated Gas	6,014	5,471	6,479
Upstream	12,157	12,656	14,501
Downstream	20,743	19,583	19,681
Corporate	402	373	888

RETURN ON AVERAGE CAPITAL EMPLOYED

Return on average capital employed (ROACE) measures the efficiency of our utilisation of the capital that we employ. In this calculation, ROACE is defined as income for the period, adjusted for after-tax interest expense, as a percentage of the average capital employed for the period. Capital employed consists of total equity, current debt and non-current debt.

Calculation of return on average capital employed

	\$ million		
	2018	2017	2016
Income for the period	23,906	13,435	4,777
Interest expense after tax	2,513	2,995	2,730
Income before interest expense	26,419	16,430	7,507
Capital employed - opening	283,477	280,988	222,500
Capital employed - closing	279,358	283,477	280,988
Capital employed - average	281,417	282,233	251,744
ROACE	9.4%	5.8%	3.0%

FREE CASH FLOW

Free cash flow is used to evaluate cash available for financing activities, including dividend payments, after investment in maintaining and growing our business. It is defined as follows.

Free cash flow	\$ million		
	2018	2017	2016
Cash flow from operating activities	53,085	35,650	20,615
Cash flow from investing activities	(13,659)	(8,029)	(30,963)
Free cash flow	39,426	27,621	(10,348)

Index to the Exhibits

Exhibit No.	Description	Page
1.1	Memorandum of Association of Royal Dutch Shell plc, together with a special resolution of Royal Dutch Shell plc dated May 18, 2010, (incorporated by reference to Exhibit 4.12 to the Registration Statement on Form F-3 (No. 333-177588) of Royal Dutch Shell plc filed with the US Securities and Exchange Commission on October 28, 2011).	
1.2	Articles of Association of Royal Dutch Shell plc, together with a special resolution of Royal Dutch Shell plc dated May 18, 2010, (incorporated by reference to Exhibit 4.11 to the Registration Statement on Form F-3 (No. 333-177588) of Royal Dutch Shell plc filed with the US Securities and Exchange Commission on October 28, 2011).	
2.1	Amended and Restated Dividend Access Trust Deed dated December 22, 2015, (incorporated by reference to Exhibit 2 to the Annual Report for the fiscal year ended December 31, 2015, on Form 20-F (File No. 001-32575) of Royal Dutch Shell plc filed with the US Securities and Exchange Commission on March 10, 2016).	
2.2	Senior Debt Securities Indenture among Shell International Finance B.V., as issuer, Royal Dutch Shell plc, as guarantor, and Deutsche Bank Trust Company Americas, as trustee, dated June 27, 2006, (incorporated by reference to Exhibit 4.3 to the Registration Statement on Form F-3ASR (No. 333-222005) of Royal Dutch Shell plc filed with the US Securities and Exchange Commission on December 12, 2017).	
4.1	Shell Provident Fund Regulations and Trust Agreement, as amended (incorporated by reference to Exhibit 4.7 to the Post-Effective Amendment to Registration Statement on Form S-8 (No. 333-126715) of Royal Dutch Shell plc filed with the US Securities and Exchange Commission on June 18, 2007).	
4.2	Form of Director Indemnity Agreement (incorporated by reference to Exhibit 4.3 to the Annual Report for the fiscal year ended December 31, 2005, on Form 20-F (File No. 001-32575) of Royal Dutch Shell plc filed with the US Securities and Exchange Commission on March 13, 2006).	
4.3	Form of contract of employment for Executive Directors (incorporated by reference to Exhibit 4.5 to the Annual Report for fiscal year ended December 31, 2013, on Form 20-F (File No. 001-32575) of Royal Dutch Shell plc filed with the US Securities and Exchange Commission on March 13, 2014).	
4.4	Form of Letter of appointment for Non-executive Directors.	
7.1	Calculation of Return on Average Capital Employed (ROACE) (incorporated by reference to page 263 herein).	
7.2	Calculation of gearing (incorporated by reference to page 27 and Note 14 to the Consolidated Financial Statements on page 191 herein).	
8.1	Significant Shell subsidiaries at December 31, 2018.	E1
12.1	Section 302 Certification of Royal Dutch Shell plc.	E20
12.2	Section 302 Certification of Royal Dutch Shell plc.	E21
13.1	Section 906 Certification of Royal Dutch Shell plc.	E22
99.1	Consent of Ernst & Young LLP, London, United Kingdom.	E23
99.2	Consent of Ernst & Young LLP, London, United Kingdom, relating to the Royal Dutch Shell Dividend Access Trust.	E24
101	Interactive data files.	

Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorised the undersigned to sign the Annual Report on Form 20-F on its behalf.

Royal Dutch Shell plc

/s/ Ben van Beurden

Ben van Beurden

Chief Executive Officer

March 13, 2019

Exhibit 8.1

SIGNIFICANT SUBSIDIARIES AND OTHER RELATED UNDERTAKINGS (AUDITED)

Significant subsidiaries and other related undertakings at December 31, 2018, are set out below. Significant subsidiaries are shaded and each meets the threshold specified under Rule 1-02(w) of Regulation S-X. Shell's percentage of share capital is shown to the nearest whole number. All subsidiaries have been included in the "Consolidated Financial Statements" on pages 167-214, and those held directly by the Company are marked with the footnote [a]. A number of the entities listed are dormant or not yet operational. Entities that are proportionately consolidated are identified by the footnote [b]. Shell-owned shares are ordinary (voting) shares unless identified with one of the following annotations against the company name: [c] Membership interest; [d] Partnership capital; [e] Non-redeemable; [f] Ordinary, Membership interest; [g] Ordinary, Non-redeemable; [h] Ordinary, Partnership capital; [i] Ordinary, Redeemable; [j] Ordinary, Redeemable, Non-redeemable; and [k] Redeemable, Non-redeemable.

Company by country of incorporation	Address of registered office	%
ARGENTINA		
O & G Developments Ltd S.A.	Av. Pte. Roque Sáenz Peña 788, 4th floor, Buenos Aires, 1383	100
AUSTRALIA		
Arrow Energy Holdings Pty Ltd	Level 39, 111 Eagle Street, Brisbane, QLD 4000	50
Austen & Butta Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
BC 789 Holdings Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
BG CPS Pty Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
BNG (Surat) Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Condamine 1 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Condamine 2 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Condamine 3 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Condamine 4 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Condamine Power Station Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Fuelink Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
New South Oil Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
North West Shelf LNG Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
OME Resources Australia Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Petroleum Resources [Thailand] Pty. Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
Provident & Pensions Holdings Proprietary Limited	Shell House, 562 Wellington Street, Perth, WA 6000	100
Pure Energy Resources Pty Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
QCLNG Operating Company Pty Ltd [i]	Level 30, 275 George Street, Brisbane, QLD 4000	75
QCLNG Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC (B7) Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC (Exploration) Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC (Infrastructure) Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Common Facilities Company Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 2 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 3 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 4 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 5 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 6 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 7 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 8 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 9 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Midstream Holdings Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Midstream Investments Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Midstream Land Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Midstream Limited Partnership	Level 42, Bourke Place, 600 Bourke Street, Melbourne, VIC 3000	100
QGC Midstream Services Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Northern Forestry Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Pty Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Sales Qld Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Train 1 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Train 1 Tolling Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Train 1 UJV Manager Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Train 2 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Train 2 Tolling No.2 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Train 2 Tolling Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Train 2 UJV Manager Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Upstream Finance Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Upstream Holdings Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Upstream Investments Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Upstream Limited Partnership	Level 42, Bourke Place, 600 Bourke Street, Melbourne, VIC 3000	100
Queensland Gas Company Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100

Company by country of incorporation	Address of registered office	%
Roma Petroleum Pty Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
SASF Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
SGA (Queensland) Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
SGAI Pty Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
Shell Australia FLNG Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Australia Lubricants Production Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Australia Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Australia Services Company Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Custodian Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Development (PSC19) Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Development (PSC20) Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Energy Australia Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Shell Energy Holdings Australia Limited	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Energy Investments Australia Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Global Solutions Australia Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell New Energies Australia Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Shell Tankers Australia Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Starzap Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Sunshine 685 Pty Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
Sunshine Gas Pty Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
Trident LNG Shipping Services Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Trident Shipping Services Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Walloons Coal Seam Gas Company Pty Limited [i]	Level 30, 275 George Street, Brisbane, QLD 4000	75
AUSTRIA		
Salzburg Fuelling GmbH	Innsbrucker Bundesstrasse 95, Salzburg, 5020	33
Shell Austria Gesellschaft mbH	Tech Gate, Donau-City-Str. 1, Vienna, 1220	100
Shell Brazil Holding GmbH	Tech Gate, Donau-City-Str. 1, Vienna, 1220	100
Shell China Holding GmbH	Schulhof 6/1, Vienna, 1010	100
TBG Tanklager Betriebsgesellschaft m.b.H.	Rettenlackstrasse 3, Salzburg, 5020	50
Transalpine Ölleitung in Österreich GmbH	Kienburg 11, Matrei in Osttirol, 9971	19
BAHAMAS		
Shell E & P Ireland Offshore Inc.	P.O. Box N4805, St. Andrew's Court, Frederick Street Steps, Nassau	100
BARBADOS		
Shell Trinidad and Tobago Resources SRL	One Welches, Welches, St. Thomas, BB22025	100
Shell Western Supply and Trading Limited	GTC Corporate Services Limited, Sassoon House, Shirley Street & Victoria Avenue, Nassau	100
BELGIUM		
Belgian Shell S.A.	Cantersteen 47, Brussels, 1000	100
CRI Catalyst Company Belgium N.V.	Panterschipstraat 331, Gent, 9000	100
Ethylene Pijpleiding Maatschappij (Belgie) N.V.	Kantersteen 47, Brussels, 1000	100
New Market Belgium S.A.	Cantersteen 47, Brussels, 1000	100
The New Motion Belgium Sprl	Regentlaan 37-40, Brussels, 1000	100
BERMUDA		
Egypt LNG Shipping Limited	Clarendon House, 2 Church Street, Hamilton, HM 11	25
Gas Investments & Services Company Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	85
Kuwait Shell Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Pecten Middle East Services Company Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Pecten Somalia Company Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Qatar Shell GTL Limited	4th Floor, Cedar House, 41 Cedar Ave, Hamilton, HM 12	100
Sakhalin Energy Investment Company Ltd	Clarendon House, 2 Church Street, Third Floor, Hamilton, HM 11	28
Shell Australia Natural Gas Shipping Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Bermuda (Overseas) Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Deepwater Borneo Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell EP International Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Exploration and Production Guyana Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Holdings (Bermuda) Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell International Trading Middle East Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Markets (Middle East) Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Mexico Exploration and Production Investment Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Offshore Central Gabon Ltd	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Oman Trading Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Overseas Holdings (Oman) Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Petroleum (Malaysia) Ltd	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Saudi Arabia (Refining) Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell South Syria Exploration Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Trading (M.E.) Private Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Trust (Bermuda) Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Trust (U.K. Property) Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Solen Insurance Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100

Company by country of incorporation	Address of registered office	%
Solen Life Insurance Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
BRAZIL		
BG Comercio e Importacao Ltda.	Av. República do Chile 330, 23º andar, Torre 2, Centro, Rio de Janeiro, 20031-170	100
BG do Brasil Ltda.	Av. República do Chile 330, 23º andar, Torre 2, sala 2309, Centro, Rio de Janeiro, 20031-170	100
BG Petroleo & Gas Brasil Ltda	Av. República do Chile 330, 23º andar (parte) - Torre 2, sala 2309, Centro, Rio de Janeiro, 20031-170	100
Fusus Comercio e Participacoes Ltda.	Calçada das Orquideas 40, 1 E 2 Andares, Centro Comercial 1, Alphaville, Barueri - SP, 06453-017	100
Icolub - Industria de Lubrificantes S.A.	Praia Intendente Bittencourt, 2 (Parte), Ilha do Governador, Rio de Janeiro, 21930-030	100
Marlim Azul Energia S.A.	Av. Paulista, 1274, 8º andar, Conjunto 23, Sala B, Bela Vista, São Paulo, 01310-100	30
Novus Industria De Lubrificantes Ltda	Praia Intendente Bittencourt nº 2 a 8N, Ribeira, Rio de Janeiro, 21930-030	99
Pecten do Brasil Servicos de Petroleo Ltda	Av. das Americas 4200, Bloco 6, 4th Floor (parte), Barra da Tijuca, Rio de Janeiro, 22640-102	100
Raizen Combustíveis S.A.	Victor Civita, 77, Block 1, Edifício: Rio Office Park, 4 floor, Barra da Tijuca, Rio de Janeiro, 22775-044	50
Raizen Energia S.A.	Av. Brigadeiro Faria Lima, 4100, 11th floor, part V, Itaim Bibi, São Paulo, 04538-132	50
Seapros Ltda.	Av. das Americas 4200, Bloco 6, sala 301 (parte), Barra da Tijuca, Rio de Janeiro, 22640-102	100
Shell Brasil Participações Ltda.	Av. Brigadeiro Faria Lima, 3311, Conj 81 Sala 02, Itam Bibi, São Paulo, 04538-133	100
Shell Brasil Petroleo Ltda.	Av. das Americas 4200, Bloco 6, salas 101, 201, 301, 401, 501, Barra da Tijuca, Rio de Janeiro, 22640-102	100
Shell Energy do Brasil Ltda	Av. das Americas 4200, Bloco 6, sala 501 (parte), Barra da Tijuca, Rio de Janeiro, 22640-102	100
BRUNEI		
Brunei LNG Sendirian Berhad	Lumut, Seria, KC2935	25
Brunei Shell Marketing Company Sendirian Berhad	Brunei Shell Petroleum Company, Sendirian Berhad, Seria, KB2933	50
Brunei Shell Petroleum Company Sendirian Berhad	Jalan Utara, Panaga, Seria, KB2933	50
Brunei Shell Tankers Sendirian Berhad	Jalan Utara, Panaga, Seria, KB2933	25
Shell Borneo Sendirian Berhad	c/o BSP Head Office, NDCO Block, Ground Floor, Jalan Utara, Panaga Seria, KB 3534	100
BULGARIA		
Shell Bulgaria Ead	48, Sitnyakovo Blvd., Serdika Offices, 8th floor, Sofia, 1505	100
CAMBODIA		
Angkor Resources Company Limited	186C, Street No 155, N/A - Tual Tumpung Muoy, Chamkamom, Phnom Penh	49
CANADA		
10084751 Canada Limited	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
1745844 Alberta Ltd.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	50
3095381 Nova Scotia Company	Suite 1300, 1969 Upper Water Street, Purdy's Wharf Tower II, Halifax, Nova Scotia, B3J 3R7	100
6581528 Canada Ltd.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
7026609 Canada Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
7645929 Canada Limited	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Alberta Products Pipe Line Ltd.	5305 McCall Way N.E., Calgary, Alberta, T2E 7N7	20
BG Canada Ltd.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
BlackRock Ventures Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Cansolv Technologies Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Coral Cibola Canada Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Criterion Catalysts & Technologies Canada, Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
FP Solutions Corporation	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	33
LNG Canada Development Inc. [b]	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	40
Sable Offshore Energy Inc.	1701 Hollis Street, Suite 1400, Halifax, Nova Scotia, B3J 3M8	33
SCL Pipeline Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
SFJ Inc.	199 Bay Street, Suite 5300, Commerce Court West, Toronto, Ontario, M5L 1B9	50
Shell Americas Funding (Canada) Limited	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Canada BROS Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Canada Energy [c]	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Canada Limited	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Canada OP Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Canada Products	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Canada Resources [c]	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Canada Services Limited	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Chemicals Canada [c]	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Energy Merchants Canada Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Energy North America (Canada) Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Global Solutions Canada Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Quebec Limitée	400 boul de Maisonneuve Ouest, Montreal, Quebec, H3A 1L4	100
Shell Trading Canada [c]	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Sun-Canadian Pipe Line Company Limited	830 Highway No. 6 North, Flamborough, Ontario, L0R 2H0	45
Trans-Northern Pipelines Inc.	45 Vogel Road, Suite 310, Richmond Hill, Ontario, L4B 3P6	33
CAYMAN ISLANDS		
Beryl North Sea Limited	Sterling Trust (Cayman) Limited, Whitehall House, 238 North Church Street, P.O. Box 1043, George Town, KY1-1102	100
BG Egypt S.A.	5th Floor, Bermuda House, Dr. Roy's Drive, George Town, Grand Cayman, KY1-1102	100
BG Exploration and Production India Limited	Campbells, Floor 4, Willow House, Cricket Square, Grand Cayman, KY1-9010	100
Gas Resources Limited	Caribbean Management Ltd, 5th Floor, Bermuda House, 36C Dr. Roy's Drive, Grand Cayman, KY1-1102	100
Schiehallion Oil & Gas Limited	Sterling Trust (Cayman) Limited, Whitehall House, 238 North Church Street, P.O. Box 1043, George Town, KY1-1102	100
Shell Bolivia Corporation	Zephyr House, 122 Mary Street, P.O. Box 2570, George Town, Grand Cayman, KY1-1103	100
Shell North Sea Holdings Limited	Maples Corporate Services Limited, Ugland House, P.O. Box 309, Grand Cayman, KY1-1104	100

Company by country of incorporation	Address of registered office	%
CHILE		
Shell Chile S.A.	C/O Carey y Cia Abogados, Miraflores 222, Piso 28, Santiago	100
CHINA		
Beijing Shell Petroleum Company Ltd.	Unit 1101-1104, level 11, Building 1, No. 19 Chaoyang Park Road, Chaoyang District, Beijing, 100125	49
Cansolv Technologies (Beijing) Company Limited	Unit 09, Level 31, No. 16 Building, No. 1 Jian Guo Men Wai Avenue, Chaoyang District, Beijing, 100004	100
Chongqing Doyen Shell Petroleum and Chemical Co. Ltd.	No. 196, Shuang Yuan Street, Beibei Zone, Chongqing, 400700	49
CNOOC and Shell Petrochemicals Company Limited	Dayawan Petrochemical Industrial Park, Huizhou, Guangdong, 516086	50
Fujian Xiangyu and Shell Petroleum Company Limited	Unit 604, 6/F, Building C, No. 3 Yunan Fourth Road, FTPZ Xiamen Sub-zone (Tariff-free Zone), Xiamen, 361000	49
Hangzhou Natural Gas Company Limited	10/F, Meiqi Mansion, No. 30 Tianmushan Road, Hangzhou, 310007	25
Infineum (China) Co. Ltd.	No. 1 Dongxin Road, Jiangsu Yangtze River International, Chemical Industry Park, Zhangjiagang, Jiangsu	50
Jiangsu Shell Energy Company Limited	Room 1001, 10/F, Unit 3, No. 198 Hexi Street, Jianye District, Nanjing, 210019	100
Shell (Beijing) Real Estate Consulting Ltd.	Unit 01, 32/F, No. 16 Building, No. 1 Courtyard, Jian Guo Men Wai Avenue, Chaoyang District, Beijing, 100004	100
Shell (China) Limited	30/F Unit 01-02, No. 16 Building, No. 1 Courtyard, Jian Guo Men Wai Avenue, Chaoyang District, Beijing, 100004	100
Shell (China) Projects & Technology Limited	Unit 01-08, Level 31, No. 16 Building, No. 1 Jian Guo Men Wai Avenue, Chaoyang District, Beijing, 100004	100
Shell (Shanghai) Petroleum Company Limited	Room 522, The British Road No. 38, China (Shanghai) Pilot Free Trade Zone, Shanghai, 200131	100
Shell (Shanghai) Technology Limited	Building 4, Jin Chuang Building, No. 4560, Jin Ke Road, Pilot Free Trade Zone, Shanghai	100
Shell (Tianjin) Lubricants Company Limited	North to Gang Bei Road and east to Hai Gang Road, Nangang Industrial Zone, Tianjin Economic-Technological Development Area, Tianjin, 300280	100
Shell (Tianjin) Oil and Petrochemical Company Limited	No. 286 Nansan Road, Tianjin Harbour Nanjiang Dev. Zone, Tanggu, Binhai NewDistrict, Tianjin, 300452	100
Shell (Zhejiang) Petroleum Trading Limited	No. 1 Wangjiaba, Xinmiaozi Village, Puyuan Town, Tongxiang, Jiaxing, Zhejiang, 314502	100
Shell (Zhuhai) Lubricants Company Limited	Nanjin Wan, Gaolan Dao, Zhuhai Harbour Industrial Zone, Guangdong, 519050	100
Shell Energy (China) Limited	Room 530, 5th Floor, Building 1, No. 239 Gang'ao Road, China (Shanghai) Free Trade Zone, Shanghai, 200137	100
Shell North China Petroleum Group Co., Ltd.	5th Floor, Administrative Commission Building, Wuqing Development Area, No.18, Fuyuan Road, Wuqing District, Tianjin, 300203	49
Shell Petroleum (Taizhou) Company Limited	Room 2027, No. 103 Tongxin North Road, Jinqing Town, Luqiao District, Taizhou, Zhejiang, 318059	100
Shell Road Solutions (Zhenjiang) Co. Ltd	No. 68 Xianiejia, Dagang, Zhenjiang New District, Zhenjiang, 212132	100
Shell Road Solutions Xinyue (Foshan) Co. Ltd.	Baisha, Hekou, Sanshui District, Foshan, Guangdong, 528133	60
Sinopec and Shell (Jiangsu) Petroleum Marketing Company Limited	No. 100, Xingang Dadao, Nanjing Economic and Technological Development Zone, Nanjing, Jiangsu, 210000	40
Suzhou Liyuan Retail Site Management Co., Ltd.	No. 358 Zhuhui Road, Suzhou, 215000	50
Yanchang and Shell (Guangdong) Petroleum Co., Ltd.	39th Floor as Planning-designed (41st Floor as Self-designated), Leatop Plaza, No. 32 East Zhujiang Road, Zhujiang New Town, Tianhe District, Guangzhou	49
Yanchang and Shell (Sichuan) Petroleum Company Limited	23F, Yanlord Square, Section 2, Renmin South Road, Chengdu, Sichuan, 610016	45
Yanchang and Shell Petroleum Company Limited	19F, Building C, City Gateway, No. 1 Jinye Road, Hi-Tech Zone, Xi'an, 710075	45
Zhejiang Shell Fuels Company Limited	Room 2103, North Tower, Yefeng Modern Center, No. 161, Shaoxing Road, Xiacheng District, Hangzhou City (Zhejiang Province), 310004	100
Zhejiang Shell Oil and Petrochemical Company Limited	The Port of Zhapu, Jiaxing Municipality, Zhejiang, 314201	100
Zhejiang Transfar and Shell Energy Company Limited	Rm 1503, Building 2, Plaza of ZBA, No. 939 Minhe Road, Ningwei Street, Xiaoshan District, Hangzhou, Zhejiang, Hangzhou, 311215	49
COLOMBIA		
C.I. Shell Comercializadora Colombia, S.A.S	Calle 90 No. 19 - 41, Oficina 702- Edificio Quantum, Bogotá, 452	100
Shell Colombia S.A.	Calle 90 No. 19 - 41, Oficina 702- Edificio Quantum, Bogotá, 452	100
COOK ISLANDS		
Branstone (International) Limited [i]	Bermuda House, Tutakimoo Road, Rarotonga	100
CÔTE D'IVOIRE		
Cote d'Ivoire GNL	14, Blvd Carde, Imm. Les Heveas, Plateau, Abidjan, BP V 194	13
CYPRUS		
Rosneft-Shell Caspian Ventures Limited [g]	Metochiou str, 37, Agios Andreas, Nicosia, CY-1101	49
CZECH REPUBLIC		
Shell Czech Republic a.s.	Antala Staska 2027/77, Praha 4, 140 00	100
DENMARK		
A/S Dansk Shell	Egeskovvej 265, Fredericia, 7000	100
Shell EP Holdingselskab Danmark ApS	Midtermolen 3, 4, Copenhagen, 2100	100
Shell Olie-og Gasudvinding Danmark Pipelines ApS	Midtermolen 3, 4, Copenhagen, 2100	100
TetraSpar Demonstrator ApS	Bredgade 30, København K, 1260	33
EGYPT		
Alam El Shawish Petroleum Company [b]	127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958	20
Badr Petroleum Company [b]	127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958	50
Burullus Gas Company S.A.E. [b]	28 Road 270, Maadi, Cairo	25
El Behera Natural Gas Liquefaction Company S.A.E.	City of Rashid, El Behera Governorate	36
IDKU Natural Gas Liquefaction Company S.A.E.	City of Rashid, El Behera Governorate	38
Obaiyed Petroleum Company [b]	127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958	50
Rashid Petroleum Company S.A.E. [b]	38 Street No. 270, Maadi, Cairo	40
Shell Egypt Trading	Business View Building, No. 79, 90 Street (South), Fifth Settlement- New Cairo, Cairo, 11835	100
Shell Lubricants Egypt	Business View Building, No. 79, 90 Street (South), Fifth Settlement- New Cairo, Cairo, 11835	100
Sitra Petroleum Company [b]	127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958	50
The Egyptian LNG Company S.A.E.	City of Rashid, El Behera Governorate	36
The Egyptian Operating Company for Natural Gas Liquefaction Projects S.A.E.	City of Rashid, El Behera Governorate	36

Company by country of incorporation	Address of registered office	%
Tiba Petroleum Company [b]	127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958	26
West Sitra Petroleum Company [b]	127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958	50
FINLAND		
Shell Aviation Finland Oy	Teknobulevardi 3-5, Vantaa, 01530	100
FRANCE		
Avitair SAS	Tour Pacific, 11/13 Cours Valmy - La Défense, Puteaux, 92800	100
Groupeement d'Exploitation du Dépôt de Réception Chennevières	Chemin de Livry, Dépôt de Chennevières, Chennevières-lès-Louvres, 95380	11
[b] [c]		
Groupeement Pétrolier Aviation SNC	Aéroport Roissy Charles de Gaulle, Zone de Frêt 1, 3 Rue des Vignes, Tremblay-en-France, 93290	20
Infineum France	Chemin départemental 54, Berre-L'Etang, 13130	50
Service Aviation Paris SNC	Orly Sud No. 144 - Bat. 438, Orly Aerogares, 94541	33
Shell Retraites SAS	Tour Pacific, 11/13 Cours Valmy - La Défense, Puteaux, 92800	100
Société de Gestion Mobilière et Immobilière SAS	Tour Pacific, 11/13 Cours Valmy - La Défense, Puteaux, 92800	100
Société des Pétroles Shell SAS	Tour Pacific, 11/13 Cours Valmy - La Défense, Puteaux, 92800	100
Ste du Pipeline Sud Européen S.A.	7-9, Rue des Freres Morane, Paris Cedex 15, 75738	21
The New Motion France SAS	15 Avenue du Centre, Guyancourt, 78280	100
GERMANY		
AGES Maut System GmbH & Co. KG	Berghausener Straße 96, Langenfeld, 40764	25
BEB Erdgas und Erdoel GmbH & Co. KG [b]	Riethorst 12, Hannover, 30659	50
BEB Holding GmbH [b]	Caffamacherreihe 5, Hamburg, 20355	50
Carissa Einzelhandel- und Tankstellenservice GmbH & Co. KG	Willinghusener Weg 5 D-E, Oststeinbek, 22113	100
Carissa Verwaltungsgesellschaft mbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
CRI Catalyst Leuna GmbH	Am Haupttor, Bau 8322, Leuna, 06237	100
CRI Deutschland GmbH	Am Haupttor, Bau 8322, Leuna, 06237	100
Deutsche Infineum GmbH & Co. KG	Neusser Landstraße 16, Köln, 50735	50
Deutsche Shell GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Deutsche Shell Holding GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Deutsche Transalpine Oelleitung GmbH	Paul Wassermann Str. 3, Munich, 81829	19
Erdoel-Raffinerie Deurag-Nerag GmbH	Riethorst 12, Hannover, 30659	50
euroShell Deutschland GmbH & Co. KG	Suhrenkamp 71 - 77, Hamburg, 22335	100
euroShell Deutschland Verwaltungsgesellschaft mbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
FBG Ferngasbeteiligungsgesellschaft mbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
H2 Mobility Deutschland GmbH and Co. KG	Linienstrasse 160, Berlin, 10115	28
H2 Mobility Deutschland Verwaltungs GmbH	Linienstrasse 160, Berlin, 10115	28
HRDS und SPNV Deutschland Oil GmbH & Co. KG	Suhrenkamp 71 - 77, Hamburg, 22335	100
HRDS und SPNV Deutschland Verwaltungsges. mbH	Suhrenkamp 71 - 77, Hamburg, 22335	90
Infineum Deutschland Verwaltungsgesellschaft mbH	Neusser Landstraße 16, Köln, 50735	50
Mineraloelraffinerie Oberrhein Verwaltungs GmbH	DEA-Scholven-Str., Karlsruhe, 76187	32
Nord-West Oelleitung GmbH [b]	Zum Oelhafen 207, Wilhelmshaven, 26384	20
Oberrheinische Mineraloelwerke GmbH [b]	DEA-Scholven-Str., Karlsruhe, 76187	42
OLF Deutschland GmbH [b]	Suhrenkamp 71 - 77, Hamburg, 22335	50
PCK Raffinerie GmbH [b]	Passower Chaussee 111, Schwedt/Oder, 16303	38
Rheinland Kraftstoff GmbH	Auf dem Schollbruch 24-26, Gelsenkirchen, 45899	100
Rhein-Main-Rohrleitungstransportgesellschaft mbH [b]	Godorfer Hauptstrasse 186, Köln, 50997	63
Shell Deutschland Additive GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell Deutschland Oil GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell Energy Deutschland GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell Erdgas Beteiligungsgesellschaft mbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell Erdgas Marketing GmbH & Co. KG	Suhrenkamp 71 - 77, Hamburg, 22335	75
Shell Erdoel und Erdgas Exploration GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell Exploration and Development Libya GmbH I	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell Exploration and Production Colombia GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell Exploration and Production Libya GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell Exploration et Production du Maroc GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell Exploration New Ventures One GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell Exploration und Produktion Deutschland GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell Global Solutions (Deutschland) GmbH	Hohe-Schaar-Straße 36, Hamburg, 21107	100
Shell Hydrogen Deutschland GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell Offshore Exploration und Produktion Deutschland GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell PrivatEnergie GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell Tunisia Offshore GmbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
Shell Verwaltungsgesellschaft für Erdgasbeteiligungen mbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
SPNV Deutschland Beteiligungsges. mbH	Suhrenkamp 71 - 77, Hamburg, 22335	100
The New Motion Deutschland GmbH	c/o Mindspace, Friedrichstraße 68, Berlin, 10117	100
Tiramizoo GmbH	Prannerstr. 2-4, Munich, 80333	21
Wasserbeschaffungsverband Wesseling-Hersel	Bruehler Str. 95, Wesseling	35
GIBRALTAR		
Shell LNG Gibraltar Limited	57/63 Line Wall Road, P.O. Box 199, Gibraltar	51

Company by country of incorporation	Address of registered office	%
GREECE		
Shell & MOH Aviation Fuels A.E.	151 Kifisias Ave., Marousi, Athens, 15124	51
GREENLAND		
Shell Greenland A/S	Aqquinsersuaq 48A, P.O. Box 1728, Nuuk, 3900	100
GUAM		
Shell Guam Inc.	643 Chalan San Antonio, Suite 100, Tamuning, GU 96911	100
HONG KONG		
AFSC Operations Limited	3 Scenic Road, Chek Lap Kok, Lantau	11
AFSC Refuelling Limited	3 Scenic Road, Chek Lap Kok, Lantau	11
Branstone Company Limited	35/F AIA Kowloon Tower, Landmark East, 100 How Ming Street, Kwun Tong (Kowloon)	100
Fulmart Limited	35/F AIA Kowloon Tower, Landmark East, 100 How Ming Street, Kwun Tong (Kowloon)	100
Hong Kong Response Limited	Esso Tsing Yi Terminal, Lot 46 Tsing Yi Road, Tsing Yi Island, New Territories	25
Ocean Century Tf Limited [i]	35/F AIA Kowloon Tower, Landmark East, 100 How Ming Street, Kwun Tong (Kowloon)	100
Shell Developments (HK) Limited [i]	35/F AIA Kowloon Tower, Landmark East, 100 How Ming Street, Kwun Tong (Kowloon)	100
Shell Hong Kong Limited	35/F AIA Kowloon Tower, Landmark East, 100 How Ming Street, Kwun Tong (Kowloon)	100
Shell Korea Limited	35/F AIA Kowloon Tower, Landmark East, 100 How Ming Street, Kwun Tong (Kowloon)	100
Shell Macau Limited	35/F AIA Kowloon Tower, Landmark East, 100 How Ming Street, Kwun Tong (Kowloon)	100
HUNGARY		
Shell Hungary Trading close Company Limited by shares	Bocskai út 134-146., Budapest, 1113	100
INDIA		
BG India Energy Private Limited	3-C World Trade Tower, New Barakhamba Lane, New Delhi, 110001	100
BG India Energy Services Private Limited	3-C World Trade Tower, New Barakhamba Lane, New Delhi, 110001	100
BG India Energy Solutions Private Limited	3-C World Trade Tower, New Barakhamba Lane, New Delhi, 110001	100
BG LNG Regas India Private Limited	3-C World Trade Tower, New Barakhamba Lane, New Delhi, 110001	100
Hazira LNG Private Limited	101-103 Abhijeet-II, Mithakhali Circle, Ahmedabad 380 006, Gujarat, 380006	100
Hazira Port Private Limited	101-103 Abhijeet-II, Mithakhali Circle, Ahmedabad 380 006, Gujarat, 380006	100
Pennzoil Quaker State India Limited	Plot No. T-5, MIDC, Talaja Industrial Area, Tal-Panvel, Raigad District, Maharashtra (Mumbai), 410208	100
Shell Energy Marketing and Trading India Private Limited	2nd floor, Campus 4A, RMZ Millenia Business Park II, 143 Dr MGR Road, Kandhanchavady, Perungudi, Chennai, TN 600096	100
Shell India Markets Private Limited	2nd floor, Campus 4A, RMZ Millenia Business Park II, 143 Dr MGR Road, Kandhanchavady, Perungudi, Chennai, TN 600096	100
Shell MRPL Aviation Fuels and Services Limited	102, Prestige Sigma, Vittal Mallya Road, Bangalore, 560001	50
INDONESIA		
PT. Gresik Distribution Terminal	Talavera Office Park 22-26th Floor, Jl. Letjen. TB Simatupang Kav. 22-26, Jakarta Selatan, Jakarta, 12430	100
PT. Shell Indonesia	Talavera Office Park 22-26th Floor, Jl. Letjen. TB Simatupang Kav. 22-26, Jakarta Selatan, Jakarta, 12430	100
PT. Shell Manufacturing Indonesia	Talavera Office Park 22-26th Floor, Jl. Letjen. TB Simatupang Kav. 22-26, Jakarta Selatan, Jakarta, 12430	100
PT. Shell Solar Indonesia	Talavera Office Park 22-26th Floor, Jl. Letjen. TB Simatupang Kav. 22-26, Jakarta Selatan, Jakarta, 12430	100
IRAQ		
Basrah Gas Company	Khor Al Zubair, Basrah	44
IRELAND		
Asiatic Petroleum Company (Dublin) Limited	1st Floor, Temple Hall, Temple Road, Blackrock, Co. Dublin, A94 K3K0	100
Irish Shell Trust Designated Activity Company	1st Floor, Temple Hall, Temple Road, Blackrock, Co. Dublin, A94 K3K0	100
Shell and Topaz Aviation Ireland Limited	Suite 7 Northwood House, Northwood Business Park, Santry, Dublin, 9	50
ISLE OF MAN		
Petrolon Europe Limited	First Names House, Victoria Road, Douglas, IM2 4DF	100
Petrolon International Limited	First Names House, Victoria Road, Douglas, IM2 4DF	100
Shell Marine Personnel (I.O.M.) Limited	Euromanx House, Freeport, Ballasalla, IM9 2AP	100
Shell Ship Management Limited	Euromanx House, Freeport, Ballasalla, IM9 2AP	100
ITALY		
Alle S.R.L.	Via Vittor Pisani 16, Milano, 20124	100
Aquila S.p.A.	Via Vittor Pisani 16, Milano, 20124	100
BG Italia Power S.p.A.	Via Tortona 25, Milano, 20144	100
Brindisi LNG S.p.A.	Via Tortona 25, Milano, 20144	100
Infineum Italia S.R.L.	Strada di Scorrimento 2, Vado Ligure (SA), 17047	50
Shell Energy Italia S.R.L.	Via Vittor Pisani 16, Milano, 20124	100
Shell International Exploration and Development Italia S.p.A.	Piazza dell'Indipendenza 11/B, Rome, 00185	100
Shell Italia E&P S.p.A.	Piazza dell'Indipendenza 11/B, Rome, 00185	100
Shell Italia Holding S.p.A.	Via Vittor Pisani 16, Milano, 20124	100
Shell Italia Oil Products S.R.L.	Via Vittor Pisani 16, Milano, 20124	100
Societa Italiana per l'Oleodotto Transalpino S.p.A.	Via Muggia #1, San Dorligo della Valle, Trieste, 34147	19
Societa' Oleodotti Meridionali S.p.A.	Via Emilia 1, San Donato Milanese, 20097	30
JAPAN		
Brunei Energy Services Company Ltd.	1-8-2 Marunouchi, Chiyoda-ku, Tokyo, 100-0005	25
Sakhalin LNG Services Company Ltd.	2-3, Kanda, Awaji-cho, Chiyoda-ku, Tokyo, 101-0063	50
Shell Japan Limited	16F Pacific Century Place, 1-11-1, Marunouchi, Chiyoda-ku, Tokyo, 100-6216	100
JERSEY		
Morzine Limited	Ogier House, The Esplanade, St. Helier, JE4 9WG	33
Shell Service Station Properties Limited	Queensway House, Hilgrove Street, St. Helier, JE1 1ES	100
LUXEMBOURG		

Company by country of incorporation	Address of registered office	%
Shell Finance Luxembourg Sarl	7, Rue de l'Industrie, Bertrange, Luxembourg, L-8069	100
Shell Luxembourgeoise Sarl	7, Rue de l'Industrie, Bertrange, Luxembourg, L-8005	100
Shell Treasury Luxembourg Sarl	7, Rue de l'Industrie, Bertrange, Luxembourg, L-8069	100
MACAU		
Shell Macau Petroleum Company Limited	876 Avenida da Amizade, Edificio Marina Gardens, Room 310, 3rd Floor	100
MALAYSIA		
Bonuskad Loyalty Sdn. Bhd. [i]	Level 8, Symphony House, Block D13, Pusat Dagangan Dana 1, Jalan PJU 1A/46, Petaling Jaya/Selangor Darul Ehsan, 47301	33
IOT Management Sdn. Bhd.	Lot 7689 and Lot 7690, Section 64, Kuching Town Land District, Jalan Pending, Kuching, Sarawak, 93450	7
Kebangsaan Petroleum Operating Company Sdn. Bhd. [b]	Suite 13.03, 13 Floor, Menara Tan & Tan, 207 Tun Razak, Kuala Lumpur/Federal Territory, 50400	30
P S Pipeline Sendirian Berhad	Level 30, Tower 1, Petronas Twin Towers, KLCC, Kuala Lumpur/Federal Territory, 50088	50
P S Terminal Sendirian Berhad	Lot 6.05, Level 6, KPMG Tower, 8 First Avenue Bandar Utama, Petaling Jaya/Selangor Darul Ehsan, 47800	35
Pertini Vista Sdn. Bhd.	Lot 6.05, Level 6, KPMG Tower, 8 First Avenue Bandar Utama, Petaling Jaya/Selangor Darul Ehsan, 47800	100
Provista Ventures Sdn. Bhd.	Lot 6.05, Level 6, KPMG Tower, 8 First Avenue Bandar Utama, Petaling Jaya/Selangor Darul Ehsan, 47800	100
Sarawak Shell Berhad	Lot 6.05, Level 6, KPMG Tower, 8 First Avenue Bandar Utama, Petaling Jaya/Selangor Darul Ehsan, 47800	100
Shell Business Service Centre Sdn. Bhd.	Lot 6.05, Level 6, KPMG Tower, 8 First Avenue Bandar Utama, Petaling Jaya/Selangor Darul Ehsan, 47800	100
Shell Global Solutions (Malaysia) Sdn. Bhd.	Lot 6.05, Level 6, KPMG Tower, 8 First Avenue Bandar Utama, Petaling Jaya/Selangor Darul Ehsan, 47800	100
Shell Malaysia Trading Sendirian Berhad	Lot 6.05, Level 6, KPMG Tower, 8 First Avenue Bandar Utama, Petaling Jaya/Selangor Darul Ehsan, 47800	100
Shell MDS (Malaysia) Sendirian Berhad	Lot 6.05, Level 6, KPMG Tower, 8 First Avenue Bandar Utama, Petaling Jaya/Selangor Darul Ehsan, 47800	72
Shell New Ventures Malaysia Sdn. Bhd. [i]	Lot 6.05, Level 6, KPMG Tower, 8 First Avenue Bandar Utama, Petaling Jaya/Selangor Darul Ehsan, 47800	100
Shell People Services Asia Sdn. Bhd.	Lot 6.05, Level 6, KPMG Tower, 8 First Avenue Bandar Utama, Petaling Jaya/Selangor Darul Ehsan, 47800	100
Shell Sabah Selatan Sendirian Berhad	Lot 6.05, Level 6, KPMG Tower, 8 First Avenue Bandar Utama, Petaling Jaya/Selangor Darul Ehsan, 47800	100
Shell Timur Sdn. Bhd.	Lot 6.05, Level 6, KPMG Tower, 8 First Avenue Bandar Utama, Petaling Jaya/Selangor Darul Ehsan, 47800	70
Shell Treasury Malaysia (L) Limited	Kensington Gardens, No. U1317, Lot 7616, Jalan Jumidar Buyong, Labuan F.T., 87000	100
Tanjung Manis Oil Terminal Management Sdn. Bhd.	Lot 7689 and Lot 7690, Section 64, Kuching Town Land District, Jalan Pending, Kuching, Sarawak, 93450	14
MAURITIUS		
BG Mauritius LNG Holdings Ltd	6th Floor, Tower A, 1 Cybercity, Ebene, 72201	100
BG Mumbai Holdings Limited	6th Floor, Tower A, 1 Cybercity, Ebene, 72201	100
Pennzoil Products International Company	33 Edith Cavell Street, Port Louis, 11324	100
MEXICO		
BG Group Mexico Exploration, S.A. de C.V.	Av. Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
BG Group Mexico Services, S.A. de C.V.	Av. Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
Comercial Importadora S. de R.L. de C.V.	Guillermo González Camarena 400, Centro Ciudad Santa Fe Alvaro, Ciudad de México, 01210	50
Concilia Asesores y Servicios S. de R.L. de C.V.	Guillermo González Camarena 400, Centro Ciudad Santa Fe Alvaro, Ciudad de México, 01210	50
Gas Del Litoral, S. de R.L. de C.V.	Av. Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	75
Shell Exploración y Extracción de México, S.A. de C.V.	Av. Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
Shell México Gas Natural, S. de R.L. de C.V.	Av. Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
Shell México, S.A. de C.V.	Av. Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
Shell Servicios México, S.A. de C.V.	Av. Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
Shell Trading México, S. de R.L. de C.V.	Av. Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
NETHERLANDS		
Amsterdam Schiphol Pijpleiding Beheer B.V.	Amsterdamseweg 55, 1182 GP Amstelveen, P.O. Box 75650, Luchthaven Schiphol, 1118 ZS	40
Attiki Gas B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
B.R.E. B.V.	Lelystad, Deventer, 7425 SB	100
B.V. Dordtsche Petroleum Maatschappij	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
B.V. Petroleum Assurantie Maatschappij	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas Atlantic Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas Brazil E&P 12 B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas Brazil Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas Brazilian Investment B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas Global Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas International B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas International Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas Netherlands Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas Sao Paulo Investments B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BJS Oil Operations B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	80
BJSA Exploration and Production B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Blauwwind Management II B.V.	Schaardijk 211, Rotterdam, 3063 NH	20
Caspi Meruerty Operating Company B.V.	Prins Bernhardplein 200, 1097JB Amsterdam, Amsterdam	40
Chosun Shell B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100

Company by country of incorporation	Address of registered office	%
Cicerone Holding B.V.	Herikerbergweg 238, Amsterdam, 1101 CM	51
ELLBA B.V. [b]	Vondelingenweg 601, Vondelingenplaat, Rotterdam, 3196 KK	50
ELLBA C.V. [b] [d]	Vondelingenweg 601, Vondelingenplaat, Rotterdam, 3196 KK	50
Euroshell Cards B.V.	Weena 70, Rotterdam, 3012 CM	100
Gasterra B.V.	P.O. Box 477, Groningen, 9700 AL	25
Guara B.V.	Weena 722, Rotterdam, 3014 DA	30
Iara B.V.	Weena 762, 9e verdieping, kamer A, Rotterdam, 3014 DA	25
Infineum Holdings B.V.	Herikerbergweg 238, Amsterdam, 1101 CM	50
Integral Investments B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Jordan Oil Shale Company B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Karachaganak Petroleum Operating B.V.	Strawinskylaan 1345, Amsterdam, 1077 XX	29
Lapa Oil & Gas B.V.	Weena 762, 9e verdieping, kamer A, Rotterdam, 3014 DA	30
Libra Oil & Gas B.V.	Weena 762, Rotterdam, 3014 DA	20
LNG Shipping Operation Services Netherlands B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Loyalty Management Netherlands B.V.	Polaris Avenue 81, P.O. Box 2047, 2130 GE, Hoofddorp, 2132 JH	40
Maasvlakte Olie Terminal C.V. [d]	Europaweg 975, Maasvlakte, Rotterdam, 3199 LC	16
Multi Tank Card B.V.	Antareslaan 39, P.O. Box 3068, 2130 KB, Hoofddorp, 2132 JE	30
N.V. Rotterdam-Rijn Pijpleiding Maatschappij [b]	Butaanweg 215, Vondelingplaat-Rotterdam, 3196 KC	56
Nederlandse Aardolie Maatschappij B.V.	Schepersmaat 2, Assen, 9405 TA	50
Netherlands Alng Holding Company B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Noordzeewind B.V.	2e Havenstraat 5b, Ijmuiden, 1976 CE	50
Noordzeewind C.V. [d]	2e Havenstraat 5b, Ijmuiden, 1976 CE	50
North Caspian Operating Company N.V. [b]	Strawinskylaan 1725, Amsterdam, 1077 XX	17
Pagell B.V.	Reactorweg 301, unit 1.3, Utrecht, 3542 AD	50
Raffinaderij Shell Mersin N.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
RESCO B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Rub' AlKhali Gas Development B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Salym Petroleum Development N.V. [b]	Carel van Bylandtlaan 30, The Hague, 2596 HR	50
Shell Abu Dhabi B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Additives Holdings (I) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Additives Holdings (II) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Albania Block 4 B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell and Vivo Lubricants B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	50
Shell Asset Management Company B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Bab Gas Development B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Brazil Holding B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Business Development Central Asia B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Caspian B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Caspian Pipeline Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Chemicals Europe B.V.	Weena 70, Rotterdam, 3012 CM	100
Shell Chemicals Ventures B.V. [k]	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell China B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell China Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Deepwater Tanzania B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Development Iran B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Downstream Services International B.V.	Weena 70, Rotterdam, 3012 CM	100
Shell E and P Offshore Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Egypt N.V. [e]	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Energy Europe B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell EP Holdings (EE&ME) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell EP Middle East Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell EP Russia Investments (III) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell EP Russia Investments (V) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell EP Somalia B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell EP Wells Equipment Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (79) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (82) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (84) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (87) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (88) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (89) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (90) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (91) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (II) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LIX) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LVII) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LXI) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LXII) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100

Company by country of incorporation	Address of registered office	%
Shell Exploration and Production (LXIV) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LXV) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LXVI) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LXXI) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LXXV) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (XLI) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Investments B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Mauritania (C10) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Mauritania (C19) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Services (RF) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production South Africa B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Ukraine I B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Ukraine Investments (I) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Ukraine Investments (II) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Ukraine Investments (IV) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration Company (RF) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration Company (West) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration Company B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration Venture Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Finance (Netherlands) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Gas & Power Developments B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Gas (LPG) Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Gas B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Gas Iraq B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Gas Nigeria B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Gas Venezuela B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Generating (Holding) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Global Solutions (Eastern Europe) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Global Solutions International B.V.	Kessler Park 1, Rijswijk, 2288 GS	100
Shell Global Solutions Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Information Technology International B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Integrated Gas Oman B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell International B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell International Exploration and Production B.V.	Carel van Bylandtlaan 16, The Hague, 2596 HR	100
Shell International Finance B.V. [a]	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Internationale Research Maatschappij B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Internet Ventures B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Iraq Petroleum Development B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Iraq Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Kazakhstan B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Kazakhstan Development B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Kuwait Exploration and Production B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell LNG Port Spain B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Lubricants Supply Company B.V.	Weena 70, Rotterdam, 3012 CM	100
Shell Manufacturing Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Mozambique B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell MSPO 2 Holding B.V.	Vondelingenweg 601, Vondelingenplaat, Rotterdam, 3196 KK	100
Shell Namibia Upstream B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Nanhai B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Nederland B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Nederland Chemie B.V. [i]	Chemieweg 25, P.O. Box 6060, Moerdijk, 4780 LN	100
Shell Nederland Raffinaderij B.V.	Vondelingenweg 601, Vondelingenplaat, Rotterdam, 3196 KK	100
Shell Nederland Verkoopmaatschappij B.V.	Weena 70, Rotterdam, 3012 CM	100
Shell New Energies NL B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Offshore (Personnel) Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Offshore North Gabon B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Offshore Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell OKLNG Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Olie - OG Gasudvinding Danmark B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Olie OG Gas Holding B.V. [k]	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Oman Exploration and Production B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Overseas Investments B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Pensioenbureau Nederland B.V.	Postbus 157, The Hague, 2501 CD	100
Shell Petroleum N.V. [a]	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Philippines Exploration B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Project Development (VIII) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100

Company by country of incorporation	Address of registered office	%
Shell RDS Holding B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Sakhalin Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Sakhalin Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Salym Development B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Services Oman B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Shared Services (Asia) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell South Africa Upstream B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell TapUp B.V.	Hofplein 20, Rotterdam, 3032 AC	100
Shell Technology Ventures Fund I B.V.	Strawinskylaan 3127 Be etage, Amsterdam, 1077 ZX	52
Shell Trademark Management B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Trading Rotterdam B.V.	Weena 70, Rotterdam, 3012 CM	100
Shell Trading Russia B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Upstream Albania B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Upstream Development B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Upstream Indonesia Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Upstream Spain B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Upstream Turkey B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Ventures B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Ventures Investments B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Western LNG B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Windenergy Netherlands B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Windenergy NZW I B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Snijders Olie B.V.	Weena 70, Rotterdam, 3012 CM	100
Syria Shell Petroleum Development B.V. [j]	Carel van Bylandtlaan 30, The Hague, 2596 HR	65
Tamba B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	50
Tankstation Exploitatie Maatschappij Holding B.V.	Weena 70, Rotterdam, 3012 CM	100
The New Motion B.V.	Rigakade 20, Amsterdam, 1013 BC	100
Tupi B.V.	Wilhelminatoren, Wilhelminaplein 14, Rotterdam, 3072	25
Waalbrug Exploitatie Maatschappij B.V.	Henri Bersenbruggestraat 9, Deventer, 7425 SB	100
Zeolyst C.V.	Oosterhorn 36, Farnsum, 9936 HD	50
NEW ZEALAND		
Energy Finance NZ limited	Level 10, ASB Tower, 2 Hunter Street, P.O. Box 1873, Wellington, 6011	100
Energy Holdings Offshore Limited	Level 10, ASB Tower, 2 Hunter Street, P.O. Box 1873, Wellington, 6011	100
Shell (Petroleum Mining) Company Limited	Level 10, ASB Tower, 2 Hunter Street, P.O. Box 1873, Wellington, 6011	100
Shell Energy Asia Limited	Level 10, ASB Tower, 2 Hunter Street, P.O. Box 1873, Wellington, 6011	100
Shell Investments NZ Limited	Level 10, ASB Tower, 2 Hunter Street, P.O. Box 1873, Wellington, 6011	100
Southern Petroleum No Liability	Level 10, ASB Tower, 2 Hunter Street, P.O. Box 1873, Wellington, 6011	100
NIGERIA		
All on Partnerships for Energy Access Limited by Guarantee	44 Bourdillon Road, Ikoyi, Lagos	100
BG Exploration and Production Nigeria Limited	Eko Nominees Limited, 252E Muri Okunola Street, Victoria Island, Lagos	100
BG Upstream A Nigeria Limited	Eko Nominees Limited, 252E Muri Okunola Street, Victoria Island, Lagos	100
Delta Business Development Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Nigeria LNG Limited	Corporate Office, Intels Aba Road Estate, Km16 Aba Expressway, Port Harcourt, 500211	26
NLNG Ship Manning Limited	Corporate Office, Intels Aba Road Estate, Km16 Aba Expressway, Port Harcourt, 500211	20
Shell Exploration and Production Africa Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Business Operations Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Closed Pension Fund Administrator Ltd	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Exploration and Production Company Ltd	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Exploration and Production Echo Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Exploration Properties Alpha Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Exploration Properties Beta Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Exploration Properties Charlie Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Gas Ltd (SNG)	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Infrastructure Development Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Offshore Prospecting Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Oil Products Limited (SNOP)	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Ultra Deep Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Upstream Ventures Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Thrift & Loan Fund Trustees Nig Ltd	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	99
The Shell Petroleum Development Company of Nigeria Limited	Shell Industrial Area, Port Harcourt, Rivers State, P.O. Box 263, Port Harcourt	100
NORWAY		
A/S Norske Shell	Tankvegen 1, Tananger, 4056	100
Aviation Fuelling Services Norway AS	Bygg 6, Drammensveien 134, Oslo, 0277	50
Gasnor AS	Helganesvegen 59, Karmoy, 4262 Avaldsnes	100
Ormen Lange Eiendom DA	Nyhamna, Aukra, 6480	18
Shell Marine Products AS	Karenslyst Allé 2, Oslo, 0278	100
Technology Centre Mongstad DA	Mongstad 71A, Mongstad, 5954	8
Vestprosess DA	Forusbeen 50, Stavanger, 4035	8

Company by country of incorporation	Address of registered office	%
OMAN		
Oman LNG LLC	P.O. Box 560, Mina Al Fahal, Muscat, 116	30
Petroleum Development Oman LLC	P.O. Box 81, Mina Al Fahal, Muscat, 113	34
Shell Development Oman LLC	P.O. Box 74, Mina Al Fahal, Muscat, 116	100
Shell Oman Marketing Company SAOG	P.O. Box 38, Mina Al Fahal, Muscat, 116	49
PAKISTAN		
Pak Arab Pipeline Company Limited	House No. 2-B, Nazimuddin Road, F-8/1, Islamabad, 75400	20
Pakistan Energy Gateway Limited	E110, Khayaban E Jinnah, Lahore Cantonement, Punjab, Cantonement, 54810	33
Shell Pakistan Limited	Shell House, 6 Ch. Khaliqzaman Road, Karachi, 75530	76
PERU		
Shell GNL Peru S.A.C.	Calle Dean Valdivia 111, Oficina 802, San Isidro, Lima, Lima 27	100
Shell Operaciones Peru S.A.C.	Calle Dean Valdivia 111, Oficina 802, San Isidro, Lima, Lima 27	100
PHILIPPINES		
Bonifacio Gas Corporation	2nd Floor, Bonifacio Tech. Center, 31st Street cor. 2nd Avenue, Crescent Park West, Bonifacio Global City, Taguig, Metro Manila	24
Kamayan Realty Corporation	NDC Bldg., 116 Tordesillas St., Salcedo Village, Makati City, Metro Manila, 1227	22
Pilipinas Shell Petroleum Corporation	Shellhouse, 156 Valero Street, Salcedo Village, Brgy. Bel-Air, Makati City, Metro Manila, 1227	55
Shell Chemicals Philippines, Inc.	Shellhouse, 156 Valero Street, Salcedo Village, Brgy. Bel-Air, Makati City, Metro Manila, 1227	100
Shell Gas and Energy Philippines Corporation	Shellhouse, 156 Valero Street, Salcedo Village, Brgy. Bel-Air, Makati City, Metro Manila, 1227	100
Shell Gas Trading (Asia Pacific), Inc.	Subic Bay Free Port Zone, Olongapo City, 2200	100
Shell Solar Philippines Corporation	Shellhouse, 156 Valero Street, Salcedo Village, Brgy. Bel-Air, Makati City, Metro Manila, 1227	100
Tabangao Realty, Inc.	Shellhouse, 156 Valero Street, Salcedo Village, Brgy. Bel-Air, Makati City, Metro Manila, 1227	40
POLAND		
First Utility Poland Sp. z o.o.	Al. Pokuju 5, Krakow, 31-548	100
Shell Polska Sp. z o.o.	ul. Bitwy Warszawskiej 1920 r. nr 7A, Warsaw, 02-366	100
PORTUGAL		
Shell Madeira Praia Formosa - Instalações, Comércio e Distribuição de Combustíveis S.A	Av. dos Combatentes da Grande Guerra nº 17, Freguesia de S. Juliao, Setúbal, 2900-329	100
PUERTO RICO		
Station Managers of Puerto Rico, Inc.	P.O. Box 186, Yabucoa, PR 00767-0186	100
QATAR		
Qatar Liquefied Gas Company Limited (4)	P.O. Box 22666, Doha	30
Qatar Shell Research & Technology Centre QSTP-LLC	Qatar Science & Technology Park Tech1, Office 101, P.O. Box 3747, Doha	100
Qatar Shell Service Company W.L.L.	Al Mirqab Tower, West Bay, P.O. Box 3747, Doha	100
RUSSIA		
Khanty-Mansiysk Petroleum Alliance Closed Joint Stock Company	24 A Yakubovicha ul., Saint Petersburg, 190000	50
[b]		
Limited Liability Company "Shell Neft"	24 Bld D Smolnaya street, Moscow, 125445	100
Limited Liability Company "Shell Neftegaz Development (JV)"	Novinsky blvd, 31, Moscow, 123242	100
LLC Shell NefteGaz Development	Novinsky blvd, 31, Moscow, 123242	100
Syriaga Neftegaz Development LLC	Novinsky blvd, 31, Moscow, 123242	100
SAINT KITTS AND NEVIS		
Shell Oil & Gas (Malaysia) LLC	Morning Star Holdings Limited, Main Street, Suite 556, Charlestown, Nevis, West Indies	90
SAINT LUCIA		
BG Atlantic 1 Holdings Limited	Mercury Court, Choc Estate, Castries	100
BG Atlantic 2/3 Holdings Limited	Mercury Court, Choc Estate, Castries	100
BG Atlantic 4 Holdings Limited	Mercury Court, Choc Estate, Castries	100
BG Central Holdings Limited	Mercury Court, Choc Estate, Castries	100
BG West Indies No. 2 Limited	Mercury Court, Choc Estate, Castries	100
SAUDI ARABIA		
Al Jomaih and Shell Lubricating Oil Co.Ltd.	P.O. Box 41467, Riyadh, 11521	50
Peninsular Aviation Services Company Limited	P.O. Box 6369, Jeddah, 21442	25
Saudi Aramco Shell Refinery Company [b]	P.O. Box 10088, Madinat Al-Jubail Al-Sinaiyah, Al Jubail, 31961	50
Shell Global Solutions Saudi Arabia LLC	P.O. Box 16996, Riyadh, 11474	100
SINGAPORE		
BG Asia Pacific Holdings Pte. Limited	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
BG Asia Pacific Services Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
BG Exploration & Production Myanmar Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
BG Insurance Company (Singapore) Pte Ltd	10 Collyer Quay, #10-01 Ocean Financial Centre, Singapore, 049315	100
BG Myanmar Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
BG Oil Marketing Pte Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Connected Freight Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
CRI/Criterion Marketing Asia Pacific Pte Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Ellba Eastern (Pte) Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Fuelng Pte. Ltd	50 Gul Road, Singapore, 629351	50
Infinium Singapore Pte Ltd	31 International Business Park, #04-08, Creative Resource, Singapore, 609921	50
QPI and Shell Petrochemicals (Singapore) Pte Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	51

Company by country of incorporation	Address of registered office	%
Shell Chemicals Seraya Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Eastern Petroleum (Pte) Ltd [i]	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Eastern Trading (Pte) Ltd [i]	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Gas Marketing Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell India Ventures Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Integrated Gas Thailand Pte.Limited	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell International Shipping Services (Pte) Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Myanmar Energy Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Myanmar Petroleum Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Pulau Moa Pte Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Seraya Pioneer (Pte) Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Singapore Trustees (Pte) Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Tankers (Singapore) Private Limited	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Treasury Centre East (Pte) Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Singapore Lube Park Pte. Ltd. [b]	160 Tuas South Avenue 5, Singapore, 637364	44
Sirius Well Manufacturing Services Pte. Ltd. [b]	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	50
SLOVAKIA		
SHELL Slovakia s.r.o.	Einsteinova 23, Bratislava, 851 01	100
SLOVENIA		
Shell Adria d.o.o.	Bravnicarjeva ulica 13, Ljubljana, 1000	100
SOUTH AFRICA		
Bituguard Southern Africa (Pty) Ltd	Twickenham, The Campus, 57 Sloan Street, Epsom Downs, Bryanston, 2021	36
Blendcor (Pty) Ltd. [b]	Honshu Road, Durban, 4001	36
Sekelo Oil Trading (Pty) Limited	Suite OE/1, The Nautica, The Waterclub, Beach Road, Granger Bay, Cape Town, 8001	43
Shell & BP South African Petroleum Refineries (Pty) Limited [b]	Reunion, Durban, 4001	36
Shell Downstream South Africa (Pty) Ltd	Twickenham, The Campus, 57 Sloan Street, Epsom Downs, Bryanston, 2021	72
Shell Global Customer Services Centre Cape Town (Pty) Ltd	10 Rua Vasco de Gama, Foreshore, Cape Town, 8000	100
Shell South Africa Energy (Pty) Ltd	Twickenham, The Campus, 57 Sloan Street, Epsom Downs, Bryanston, 2021	100
Shell South Africa Exploration (Pty) Limited	Twickenham, The Campus, 57 Sloan Street, Epsom Downs, Bryanston, 2021	100
Shell South Africa Holdings (Pty) Ltd	Twickenham, The Campus, 57 Sloan Street, Epsom Downs, Bryanston, 2021	100
STISA (Pty) Limited	Suite OE/2, The Nautica, The Waterclub, Beach Road, Granger Bay, Cape Town, 8001	72
SOUTH KOREA		
Hankook Shell Oil Company	No. 250, Sinsun-ro, Nam-gu, Busan, 48561	54
Hyundai and Shell Base Oil Co., Ltd	640-6, Daejuk-ri, Daesan-eup, Seosan-shi, Chungchongnam-do, 356-713	40
SPAIN		
BG Energy Iberian Holdings, S.L	Paseo de la Castellana, 257-6º, Madrid, 28046	100
Shell & Disa Aviation España, S.L.	Rio Bullaque, 2, Madrid, 28034	50
Shell España, S.A.	Paseo de la Castellana, 257-6º, Madrid, 28046	100
Shell Spain LNG, S.A.U.	Paseo de la Castellana, 257-6º, Madrid, 28046	100
SUDAN		
Shell (Sudan) Petroleum Development Company Limited	Shell House, P.O. Box 320, Khartoum	100
SWEDEN		
A Flygbränslehantering Aktieföretag	P.O. Box 135, Stockholm-Arlanda, 190 46	25
BG International Services AB	Deloitte, P.O. Box 450, Östersund, 831 26	100
Gothenburg Fuelling Company AB	P.O. Box 2154, Gothenburg, 438 14	33
Malmö Fuelling Services AB	Sturup Flygplats, P.O. Box 22, Malmö, 230 32	33
Shell Aviation Sweden AB	Gustavslundsvägen 22, Bromma, 16751	100
Stockholm Fuelling Services AB	P.O. Box 85, Stockholm-Arlanda, 190 45	25
SWITZERLAND		
Bully 1 (Switzerland) GmbH	Dorfstrasse 19a, Baar, 6340	50
Bully 2 (Switzerland) GmbH	Dorfstrasse 19a, Baar, 6340	50
Saraco SA	Route de Pré-Bois 17, Cointrin, 1216	20
Shell (Switzerland) AG	Baarermatte, Baar, 6340	100
Shell Brands International AG	Baarermatte, Baar, 6340	100
Shell Corporate Services Switzerland AG	Baarermatte, Baar, 6340	100
Shell Finance Switzerland AG	Baarermatte, Baar, 6340	100
Shell Holdings Switzerland AG	Baarermatte, Baar, 6340	100
Shell Lubricants Switzerland AG	Steigerhubelstrasse 8, Bern, 3008	100
Shell Trading Switzerland AG	Baarermatte, Baar, 6340	100
Shell Treasury Company Switzerland AG	Baarermatte, Baar, 6340	100
SOGEP Société Genevoise des Pétales SA	Route de Vernier 132, Vernier, 1214	34
Solen Versicherungen AG	Baarermatte, Baar, 6340	100
Stazioni Autostradali Bellinzona SA	Autostrada A2 (direzione Gottardo), Hotel Bellinzona Sud, Monte Carasso, 6513	50
UBAG - Unterflurbetankungsanlage Flughafen Zürich AG	Zwüscheiteich, Rümlang, 8153	20
SYRIA		
Al Badih Petroleum Company	Damascus New Sham Western Dummer, Island No 1 - Property 2299, P.O. Box 7660, Damascus	22
Al Furat Petroleum Company	Damascus New Sham Western Dummer, Island No 1 - Property 2299, P.O. Box 7660, Damascus	20
TAIWAN		

Company by country of incorporation	Address of registered office	%
CPC Shell Lubricants Co. Ltd	No 2, Tso-Nan Road, Nan-Tze District, P.O. Box 25-30, Kaohsiung, 811	51
Shell Taiwan Limited	International Trade Building, Room 2001, 20th Floor, 333, Keelung Road Section 1, Taipei, 110	100
TANZANIA		
Fahari Gas Marketing Company Limited	1st Floor Kilwa House, Plot 369, Toure Drive, Oyster Bay, P.O. Box 105833, Dar es Salaam	53
Mzalendo Gas Processing Company Limited	1st Floor Kilwa House, Plot 369, Toure Drive, Oyster Bay, P.O. Box 105833, Dar es Salaam	53
Ruvuma Pipeline Company Limited	1st Floor Kilwa House, Plot 369, Toure Drive, Oyster Bay, P.O. Box 105833, Dar es Salaam	53
Tanzania LNG Limited	1st Floor Kilwa House, Plot 369, Toure Drive, Oyster Bay, P.O. Box 105833, Dar es Salaam	100
THAILAND		
Pattanaadhorn Company Limited	10 Soonthornkosa Road, Klongtoey, Bangkok, 10110	42
Sahapanichkijphun Company Limited	10 Soonthornkosa Road, Klongtoey, Bangkok, 10110	42
Shell Global Solutions (Thailand) Limited	10 Soonthornkosa Road, Klongtoey, Bangkok, 10110	48
Shell Global Solutions Holdings (Thailand) Limited	10 Soonthornkosa Road, Klongtoey, Bangkok, 10110	49
Thai Energy Company Limited	10 Soonthornkosa Road, Klongtoey, Bangkok, 10110	100
Unitas Company Limited	10 Soonthornkosa Road, Klongtoey, Bangkok, 10110	42
TRINIDAD AND TOBAGO		
BG 2/3 Investments Limited	5 Saint Clair Avenue, Saint Clair, Port of Spain	100
Point Fortin LNG Exports Limited	5 Saint Clair Avenue, Saint Clair, Port of Spain	81
Shell Gas Supply Trinidad Limited	5 Saint Clair Avenue, Saint Clair, Port of Spain	100
Shell LNG T&T Ltd	5 Saint Clair Avenue, Saint Clair, Port of Spain	100
Shell Manatee Limited	5 Saint Clair Avenue, Saint Clair, Port of Spain	100
Shell Trinidad Central Block Limited	5 Saint Clair Avenue, Saint Clair, Port of Spain	100
Shell Trinidad Ltd	Shell Energy House, 5 St. Clair Avenue, Port of Spain	100
Shell Trinidad North Coast Limited	5 Saint Clair Avenue, Saint Clair, Port of Spain	100
The International School of Port of Spain Limited	1 International Drive, Westmoorings	25
TRINLING Limited	5 Saint Clair Avenue, Saint Clair, Port of Spain	100
TUNISIA		
Amilcar Petroleum Operations S.A.	Immeuble Mezghenni, Rue du Lac Windermere BP36, Les Berges du Lac, Tunis, 1053	50
Shell Tunisia LPG S.A.	Immeuble Rue du Lac Windermere, Les Berges du Lac, Tunis, 1053	100
Tunisian Processing S.A.	Immeuble Rue du Lac Windermere, Les Berges du Lac, Tunis, 1053	100
TURKEY		
Ambarlı Depolama Hizmetleri Ltd. Sti.	Yakuplu Mah. Gencosman Cad. No:7, Beylikduzu, Istanbul, 34524	35
Cekisan Depolama Hizmetleri Ltd. Sti.	Yakuplu Mah. Gencosman Cad. No:3, Beylikduzu, Istanbul, 34524	35
Marmara Depoculuk Hizmetleri A.S.	Sultankoy Mahallesi Maltepe Sokak No:66, Marmara Ereglisi, Tekirdag, 59750	32
Samsun Akaryakit VE Depolama A.S.	Dilovasi Organize Sanayi Bolgesi I.Kisim, 1004 Sokak No:10, Dilovasi, Kocaeli	35
Shell & Turcas Petrol A.S.	Gulbahar Mah.Salih Tozan Sok., Karamancilar Is Merkezi B Blok No:18, Esentepe, Sisli, Istanbul, 34394	70
Shell Enerji A.S.	Gulbahar Mah.Salih Tozan Sok., Karamancilar Is Merkezi B Blok No:18, Esentepe, Sisli, Istanbul, 34394	100
Shell Petrol A.S.	Gulbahar Mah.Salih Tozan Sok., Karamancilar Is Merkezi B Blok No:18, Esentepe, Sisli, Istanbul, 34394	70
UK		
Alie Investments Limited	Shell Centre, London, SE1 7NA	100
Angkor Shell Limited	Shell Centre, London, SE1 7NA	100
Applied Blockchain Ltd	Level 39, One Canada Square, London, E14 5AB	27
Autogas Limited	Athena House, Athena Drive, Tachbrook Park, Warwick, CV34 6RL	50
BG Atlantic Finance Limited	Shell Centre, London, SE1 7NA	100
BG Central Holdings Limited	Shell Centre, London, SE1 7NA	100
BG Cyprus Limited	Shell Centre, London, SE1 7NA	100
BG Delta Limited	Shell Centre, London, SE1 7NA	100
BG Employee Shares Trustees Limited	Shell Centre, London, SE1 7NA	100
BG Energy Capital Plc	Shell Centre, London, SE1 7NA	100
BG Energy Holdings Limited	Shell Centre, London, SE1 7NA	100
BG Energy Marketing Limited	Shell Centre, London, SE1 7NA	100
BG Energy Trading Limited	Shell Centre, London, SE1 7NA	100
BG Equatorial Guinea Limited	Shell Centre, London, SE1 7NA	100
BG Exploration and Production Limited	Shell Centre, London, SE1 7NA	100
BG Gas Marketing Limited	Shell Centre, London, SE1 7NA	100
BG Gas Services Limited	Shell Centre, London, SE1 7NA	100
BG Gas Supply (UK) Limited	Shell Centre, London, SE1 7NA	100
BG General Holdings Limited	Shell Centre, London, SE1 7NA	100
BG General Partner Limited	50 Lothian Road, Festival Square, Edinburgh, EH3 9WJ	100
BG Global Employee Resources Limited	Shell Centre, London, SE1 7NA	100
BG Global Energy Limited	Shell Centre, London, SE1 7NA	100
BG Great Britain Limited	Shell Centre, London, SE1 7NA	100
BG Group Company Secretaries Limited	Shell Centre, London, SE1 7NA	100
BG Group Employee Benefit Trust Limited	Shell Centre, London, SE1 7NA	100
BG Group Employee Shares Trustees Limited	Shell Centre, London, SE1 7NA	100
BG Group Limited	Shell Centre, London, SE1 7NA	100
BG Group Pension Trustees Limited	Shell Centre, London, SE1 7NA	100
BG Group Trustees Limited	Shell Centre, London, SE1 7NA	100
BG Intellectual Property Limited	Shell Centre, London, SE1 7NA	100

Company by country of incorporation	Address of registered office	%
BG International Limited	Shell Centre, London, SE1 7NA	100
BG Iran Limited	Shell Centre, London, SE1 7NA	100
BG Karachaganak Limited	Shell Centre, London, SE1 7NA	100
BG Karachaganak Trading Limited	Shell Centre, London, SE1 7NA	100
BG Kenya L10A Limited	Shell Centre, London, SE1 7NA	100
BG Kenya L10B Limited	Shell Centre, London, SE1 7NA	100
BG LNG Investments Limited	Shell Centre, London, SE1 7NA	100
BG Mongolia Holdings Limited	Shell Centre, London, SE1 7NA	100
BG Netherlands	Shell Centre, London, SE1 7NA	100
BG Netherlands Financing Unlimited	Shell Centre, London, SE1 7NA	100
BG Norge Exploration Limited	Shell Centre, London, SE1 7NA	100
BG Norge Limited	Shell Centre, London, SE1 7NA	100
BG North Sea Holdings Limited	Shell Centre, London, SE1 7NA	100
BG OKLING Limited	Shell Centre, London, SE1 7NA	100
BG Overseas Holdings Limited	Shell Centre, London, SE1 7NA	100
BG Overseas Investments Limited	Shell Centre, London, SE1 7NA	100
BG Overseas Limited	Shell Centre, London, SE1 7NA	100
BG Pension Funding Scottish Limited Partnership [I]	50 Lothian Road, Festival Square, Edinburgh, EH3 9WJ	100
BG Rosetta Limited	Shell Centre, London, SE1 7NA	100
BG Singapore Limited	Shell Centre, London, SE1 7NA	100
BG South Asia LNG Limited	Shell Centre, London, SE1 7NA	100
BG South East Asia Limited	Shell Centre, London, SE1 7NA	100
BG Subsea Well Project Limited	Shell Centre, London, SE1 7NA	100
BG Tanzania Holdings Limited	Shell Centre, London, SE1 7NA	100
BG Trinidad LNG Limited	Shell Centre, London, SE1 7NA	100
BG UK Capital II Limited	Shell Centre, London, SE1 7NA	100
BG UK Capital Limited	Shell Centre, London, SE1 7NA	100
BG UK Holdings Limited	Shell Centre, London, SE1 7NA	100
Brazil Shipping I Limited	Shell Centre, London, SE1 7NA	100
Brazil Shipping II Limited	Shell Centre, London, SE1 7NA	100
British Pipeline Agency Limited	5-7 Alexandra Road, Hemel Hempstead, Herts, HP2 5BS	50
CRI Catalyst Company Europe Limited	Shell Centre, London, SE1 7NA	100
CRI/Criterion Catalyst Company Limited	Shell Centre, London, SE1 7NA	100
Dragon LNG Group Limited [b]	Main Road, Waterston, Milford Haven, Pembrokeshire, SA73 1DR	50
DSX Trading Limited	Shell Centre, London, SE1 7NA	100
Eastham Refinery Limited [b]	8 York Road, London, SE1 7NA	50
Enterprise Oil Limited	8 York Road, London, SE1 7NA	100
Enterprise Oil Middle East Limited	8 York Road, London, SE1 7NA	100
Enterprise Oil Norge Limited	8 York Road, London, SE1 7NA	100
Enterprise Oil Operations Limited	8 York Road, London, SE1 7NA	100
Enterprise Oil U.K. Limited	8 York Road, London, SE1 7NA	100
Farepilot Limited	Shell Centre, London, SE1 7NA	87
First Telecommunications Limited	Columbus House, Westwood Business Park, Coventry, CV4 8HS	100
First Utilities Limited	Columbus House, Westwood Business Park, Coventry, CV4 8HS	100
First Utility Limited	Columbus House, Westwood Business Park, Coventry, CV4 8HS	100
Gainrace Limited	8 York Road, London, SE1 7NA	100
Gatwick Airport Storage and Hydrant Company Limited	8 York Road, London, SE1 7NA	13
Glossop Limited	8 York Road, London, SE1 7NA	100
GGOB Limited	8 York Road, London, SE1 7NA	100
Heathrow Airport Fuel Company Limited	Building 1204, Sandringham Road, Heathrow Airport, Hounslow, Middlesex, TW6 3SH	14
Heathrow Hydrant Operating Company Limited	Building 1204, Sandringham Road, Heathrow Airport, Hounslow, Middlesex, TW6 3SH	10
Impello Limited	Columbus House, Westwood Business Park, Coventry, CV4 8HS	100
International Inland Waterways, Limited	8 York Road, London, SE1 7NA	100
Karachaganak Project Development Limited [b]	Shell Centre, London, SE1 7NA	38
Khmer Shell Limited	Shell Centre, London, SE1 7NA	100
Kite Power Systems Limited	146 New London Road, Chelmsford, Essex, CM2 0AW	25
Lensbury Limited	Broom Road, Teddington, Middlesex, TW11 9NU	100
Machine Max Limited	Shell Centre, London, SE1 7NA	56
Manchester Airport Storage and Hydrant Company Limited	50 Broadway, London, SW1H 0BL	25
Maritime Association for Risk Mitigation & Safety Limited	Shell Centre, London, SE1 7NA	100
Methane Services Limited	Shell Centre, London, SE1 7NA	100
Murphy Schiehallion Limited	Shell Centre, London, SE1 7NA	100
Octane Properties Limited	Shell Centre, London, SE1 7NA	100
Private Oil Holdings Oman Limited	8 York Road, London, SE1 7NA	85
Sabah Shell Petroleum Company Limited	Shell Centre, London, SE1 7NA	100
Saxon Oil Limited	8 York Road, London, SE1 7NA	100
Saxon Oil Miller Limited	8 York Road, London, SE1 7NA	100

[I] Established by BG Group plc and the BG Trustee in 2013 as part of funding agreements associated with the BG pension scheme. Under the exemption conferred by Regulation 7 of the Partnerships (Accounts) Regulations 2008, the accounts of this partnership have not been appended to Shell's Consolidated Financial Statements and have not been filed at the Companies House.

Company by country of incorporation	Address of registered office	%
Schooner Trustees Limited	Shell Centre, London, SE1 7NA	100
SELAP Limited	8 York Road, London, SE1 7NA	100
SF Investment Management Limited	Shell Centre, London, SE1 7NA	100
Shell Aircraft Limited	Shell Centre, London, SE1 7NA	100
Shell Arabia Car Service Limited	Shell Centre, London, SE1 7NA	100
Shell Aviation Limited	Shell Centre, London, SE1 7NA	100
Shell Business Development Middle East Limited	Shell Centre, London, SE1 7NA	100
Shell Caribbean Investments Limited	Shell Centre, London, SE1 7NA	100
Shell Chemical Company of Eastern Africa Limited	Shell Centre, London, SE1 7NA	100
Shell Chemicals (Hellas) Limited	Shell Centre, London, SE1 7NA	100
Shell Chemicals Limited	Shell Centre, London, SE1 7NA	100
Shell Chemicals Support Services Asia Limited	Shell Centre, London, SE1 7NA	100
Shell Chemicals U.K. Limited	Shell Centre, London, SE1 7NA	100
Shell China Exploration and Production Company Limited	Shell Centre, London, SE1 7NA	100
Shell Clair UK Limited	Shell Centre, London, SE1 7NA	100
Shell Club Corringham Limited	Shell Centre, London, SE1 7NA	100
Shell Company (Hellas) Limited	Shell Centre, London, SE1 7NA	100
Shell Company (Pacific Islands) Limited	Shell Centre, London, SE1 7NA	100
Shell Corporate Director Limited	Shell Centre, London, SE1 7NA	100
Shell Corporate Secretary Limited	Shell Centre, London, SE1 7NA	100
Shell Direct (U.K.) Limited	Shell Centre, London, SE1 7NA	100
Shell Distributor (Holdings) Limited	Shell Centre, London, SE1 7NA	100
Shell Employee Benefits Trustee Limited	Shell Centre, London, SE1 7NA	100
Shell Energy Europe Limited	Shell Centre, London, SE1 7NA	100
Shell Energy Investments Limited	Shell Centre, London, SE1 7NA	100
Shell Energy Supply UK LTD.	Shell Centre, London, SE1 7NA	100
Shell EP Offshore Ventures Limited	Shell Centre, London, SE1 7NA	100
Shell Exploration and Production Tanzania Limited	Shell Centre, London, SE1 7NA	100
Shell Gas Holdings (Malaysia) Limited	Shell Centre, London, SE1 7NA	100
Shell Hasdrubal Limited	Shell Centre, London, SE1 7NA	100
Shell Holdings (U.K.) Limited	Shell Centre, London, SE1 7NA	100
Shell Information Technology International Limited	8 York Road, London, SE1 7NA	100
Shell International Gas Limited	Shell Centre, London, SE1 7NA	100
Shell International Limited	Shell Centre, London, SE1 7NA	100
Shell International Petroleum Company Limited	Shell Centre, London, SE1 7NA	100
Shell International Trading and Shipping Company Limited	80 Strand, London, WC2R 0ZA	100
Shell Malaysia Limited	Shell Centre, London, SE1 7NA	100
Shell Marine Products Limited	Shell Centre, London, SE1 7NA	100
Shell New Energies UK Limited	Shell Centre, London, SE1 7NA	100
Shell Overseas Holdings Limited	Shell Centre, London, SE1 7NA	100
Shell Overseas Services Limited	Shell Centre, London, SE1 7NA	100
Shell Pension Reserve Company (SIPF) Limited	Shell Centre, London, SE1 7NA	100
Shell Pension Reserve Company (SOCPF) Limited	Shell Centre, London, SE1 7NA	100
Shell Pension Reserve Company (UK) Limited	Shell Centre, London, SE1 7NA	100
Shell Pensions Trust Limited	Shell Centre, London, SE1 7NA	100
Shell Property Company Limited	Shell Centre, London, SE1 7NA	100
Shell QGC Holdings Limited [i]	Shell Centre, London, SE1 7NA	100
Shell QGC Midstream 1 Limited [i]	Shell Centre, London, SE1 7NA	100
Shell QGC Midstream 2 Limited	Shell Centre, London, SE1 7NA	100
Shell QGC Upstream 1 Limited	Shell Centre, London, SE1 7NA	100
Shell QGC Upstream 2 Limited	Shell Centre, London, SE1 7NA	100
Shell Research Limited	Shell Centre, London, SE1 7NA	100
Shell Response Limited	80 Strand, London, WC2R 0ZA	100
Shell Shared Service Centre - Glasgow Limited	Shell Centre, London, SE1 7NA	100
Shell Subsidiary Distributors Pension Trustee Limited	Shell Centre, London, SE1 7NA	100
Shell Supplementary Pension Plan Trustees Limited	Shell Centre, London, SE1 7NA	100
Shell Tankers (U.K.) Limited	3 Savoy Place, London, WC2R 0DX	100
Shell Trading International Limited	Shell Centre, London, SE1 7NA	100
Shell Treasury Centre Limited	Shell Centre, London, SE1 7NA	100
Shell Treasury Dollar Company Limited	Shell Centre, London, SE1 7NA	100
Shell Treasury Euro Company Limited	Shell Centre, London, SE1 7NA	100
Shell Treasury UK Limited	Shell Centre, London, SE1 7NA	100
Shell Trinidad 5(A) Limited	Shell Centre, London, SE1 7NA	100
Shell Trinidad and Tobago Limited	Shell Centre, London, SE1 7NA	100
Shell Trinidad Block E Limited	Shell Centre, London, SE1 7NA	100
Shell Trustee Solutions Limited	1 Altens Farm Road, Nigg, Aberdeen, AB12 3FY	100
Shell Tunisia Upstream Limited	Shell Centre, London, SE1 7NA	100
Shell U.K. Limited	Shell Centre, London, SE1 7NA	100

Company by country of incorporation	Address of registered office	%
Shell U.K. North Atlantic Limited	Shell Centre, London, SE1 7NA	100
Shell U.K. Oil Products Limited	Shell Centre, London, SE1 7NA	100
Shell Upstream Overseas Services (I) Limited	Shell Centre, London, SE1 7NA	100
Shell Ventures New Zealand Limited	Shell Centre, London, SE1 7NA	100
Shell Ventures U.K. Limited	Shell Centre, London, SE1 7NA	100
Shell-Mex and B.P. Limited	Shell Centre, London, SE1 7NA	60
Stansted Fuelling Company Limited	Exxonmobil House, Ermyn Way, Leatherhead, KT22 8UX	14
Steam Company Limited	Pannone Corporate Llp, 378-380 Deansgate, Castlefield, Manchester, M3 4LY	30
STT (Das Beneficiary) Limited [a]	Shell Centre, London, SE1 7NA	100
Synthetic Chemicals (Northern) Limited	8 York Road, London, SE1 7NA	100
Telegraph Service Stations Limited	8 York Road, London, SE1 7NA	100
The Anglo-Saxon Petroleum Company Limited	Shell Centre, London, SE1 7NA	100
The Asiatic Petroleum Company Limited	Shell Centre, London, SE1 7NA	100
The Consolidated Petroleum Company Limited	Shell Centre, London, SE1 7NA	50
The Consolidated Petroleum Supply Company Limited	Shell Centre, London, SE1 7NA	50
The Mexican Eagle Oil Company Limited	8 York Road, London, SE1 7NA	100
The New Motion EVSE Limited	4th Floor, Davidson Building, 5 Southampton Street, London, WC2E 7HA	100
The Shell Company (W.I.) Limited	Shell Centre, London, SE1 7NA	100
The Shell Company of Hong Kong Limited	Shell Centre, London, SE1 7NA	100
The Shell Company of India Limited	Shell Centre, London, SE1 7NA	100
The Shell Company of Nigeria Limited	Shell Centre, London, SE1 7NA	100
The Shell Company of Thailand Limited	Shell Centre, London, SE1 7NA	100
The Shell Company of The Philippines Limited	Shell Centre, London, SE1 7NA	75
The Shell Company of Turkey Limited	Shell Centre, London, SE1 7NA	100
The Shell Company of West Africa Limited	Shell Centre, London, SE1 7NA	100
The Shell Marketing Company of Borneo Limited	Shell Centre, London, SE1 7NA	100
The Shell Petroleum Company Limited	Shell Centre, London, SE1 7NA	100
The Shell Transport and Trading Company Limited	Shell Centre, London, SE1 7NA	100
Thermocomfort Limited	8 York Road, London, SE1 7NA	100
UK Shell Pension Plan Trust Limited	Shell Centre, London, SE1 7NA	100
United Kingdom Oil Pipelines Limited [b]	5-7 Alexandra Road, Hemel Hempstead, Herts, HP2 5BS	48
Walton-Gatwick Pipeline Company Limited [b]	5-7 Alexandra Road, Hemel Hempstead, Herts, HP2 5BS	52
West London Pipeline and Storage Limited [b]	5-7 Alexandra Road, Hemel Hempstead, Herts, HP2 5BS	38
Wonderbill Limited	Shell Centre, London, SE1 7NA	87
Woodlea Limited	Shell Centre, London, SE1 7NA	100
UKRAINE		
Shell Ukraine Exploration and Production I LLC	4 Mykoly Grinchenka street, Kiev, 03038	100
UNITED ARAB EMIRATES		
Abu Dhabi Gas Industries Limited (GASCO)	P.O. Box 665, Abu Dhabi	15
Emdad Aviation Fuel Storage FZCO	Emdad Aviation Fuel Storage FZCO, P.O. Box 261781, Jebel Ali, Dubai	32
Sharjah Fuelling Services Company Ltd.	P.O. Box 4225, Sharjah, 4225	49
URUGUAY		
BG (Uruguay) S.A.	La Cumparsita, 1373 4th Floor, Montevideo, 11200	100
Dinarel S.A.	La Cumparsita, 1373 4th Floor, Montevideo, 11200	50
Gasoducto Cruz del Sur S.A.	La Cumparsita, 1373 4th Floor, Montevideo, 11200	40
USA		
Aera Energy LLC [b]	10000 Ming Avenue, Bakersfield, CA 93311	52
Aera Energy Services Company	10000 Ming Avenue, Bakersfield, CA 93311	50
Airbiquity Inc.	1011 Western Avenue, Suite 600, Seattle, WA 98104	26
Alba Mobility LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Amberjack Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	29
Asset Management and Power Services LLC	2441 High Timbers Drive, Suite 220, The Woodlands, TX 77380	50
Atlantic 1 Holdings LLC [c]	RL & F Service Corp, 920 N King St Floor 2, New Castle, Wilmington, DE 19801	46
Atlantic 2/3 Holdings LLC [c]	RL & F Service Corp, 920 N King St Floor 2, New Castle, Wilmington, DE 19801	58
Atlantic 4 Holdings LLC [c]	RL & F Service Corp, 920 N King St Floor 2, New Castle, Wilmington, DE 19801	51
Atlantic Shores Offshore Wind, LLC [c]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808	50
Au Energy, LLC	41805 Albrae Street, Fremont, CA, 94538	50
Bacanton Power LLC [c]	1499 38th Boulevard N.W., Cairo, GA 31728	35
Bengal Pipeline Company LLC	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808	29
BG Alaska E&P, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG Brasilia, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG Energy Finance, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG Energy Merchants, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG Gulf Coast LNG, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG Lake Charles Operations, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG LNG Services, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG LNG Trading, LLC	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG North America, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100

Company by country of incorporation	Address of registered office	%
BG US Gathering Company, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG US Production Company, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG US Services, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Brazil Crude Services, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Brazos Wind Ventures, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Caesar Oil Pipeline Company, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	15
Colbea Enterprises, LLC	2050 Plainfield Pike, Cranston, RI 02921	50
Colonial Pipeline Company	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808	13
Concha Chemical Pipeline LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Crestwood Permian Basin LLC	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	23
CRI Catalyst Company LP [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
CRI Sales and Services Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
CRI U.S. LP [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
CRI Zeolites Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
CRI/Criterion, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Criterion Catalyst Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Criterion Catalysts & Technologies L.P. [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Deer Park Refining Limited Partnership [b] [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	50
Distributed Generation Solutions LLC	2441 High Timbers Drive, Suite 220, The Woodlands, TX 77380	33
Endymion Oil Pipeline Company, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	5
Enterprise Oil North America Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
EPP LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
Equilon Enterprises LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Explorer Pipeline Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	32
Gaviota Terminal Company [d]	150 N. Dairy Ashford, Houston, TX 77079	20
GI Endurant LLC [b]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	58
GI Energy Storage LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Husk Power Systems, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	34
Infinium USA Inc.	1900 East Linden Avenue, Linden, NJ 07036	50
Infinium USA LP. [h]	Corporation Service Company, 2711 Centerville Road, Suite 400, Wilmington, DE 19808	50
Jiffy Lube International, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Lake Charles Exports, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	80
Laurentide E&P, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
LOCAP LLC	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	19
LOOP LLC	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	46
Maple Power Holdings LLC	Bechtel Enterprises, 12011 Sunset Hills Road, Reston, VA 20190	68
Mars Oil Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	33
Mattox Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	79
Mayflower Wind Energy LLC [b] [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	50
MP2 Energy LLC [d]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
MP2 Energy NE LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
MP2 Energy NY LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
MP2 Energy Retail Holdings LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
MP2 Energy Texas LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
MP2 Generation LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
MP2 Mesquite Creek Wind LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
Mpower2 LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
Nedpower Mount Storm LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	50
Noble Assurance Company	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
Odyssey Pipeline LLC. [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	33
Oryx Caspian Pipeline, L.L.C. [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pacwest Energy, LLC.	3450 E. Commercial Ct., Meridian, ID 83642	50
Pecten Arabian Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pecten Brazil Exploration Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pecten Midstream LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	46
Pecten Orient Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pecten Orient Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pecten Producing Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pecten Trading Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pecten Victoria Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pecten Yemen Masila Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pennzoil-Quaker State Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pennzoil-Quaker State International Corporation	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pennzoil-Quaker State Nominee Company	The Corporation Trust Company of Nevada, 311 South Division Street, Carson City, NV 89703	100
Peru LNG Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	20
Poseidon Oil Pipeline Company, LLC	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	16
Power Limited Partnership [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Proteus Oil Pipeline Company, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	5

Company by country of incorporation	Address of registered office	%
Quaker State Investment Corporation	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
RDK Ventures, LLC	4080 West Jonathan Moore Pike, Columbus, IN 47201	50
Rilette Springs, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
RK Caspian Shipping Company, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
S T Exchange, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Salamander Solutions Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	29
San Pablo Bay Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Sand Dollar Pipeline LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	46
SCOGI GP [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell (US) Gas & Power M&T Holdings, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell California Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Catalysts Ventures Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Chemical Appalachia LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Chemical LP [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Chemicals Arabia LLC. [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Communications, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Deepwater Royalties Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Downstream Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Energy Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Energy Holding GP LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Energy North America (US), L.P. [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Energy Resources Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell EP Holdings Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Expatriate Employment US Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Exploration & Production Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Exploration Company Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Frontier Oil & Gas Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Gas Gathering Corp. #2	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Global Solutions (US) Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell GOM Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Gulf of Mexico Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Information Technology International Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell International Exploration and Production Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Leasing Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Marine Products (US) Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Midstream LP Holdings LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Midstream Operating LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	46
Shell Midstream Partners GP LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Midstream Partners, L.P. [h]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	46
Shell NA Gas & Power Holding Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell NA LNG LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell New Energies US LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell North America Gas & Power Services Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Offshore and Chemical Investments Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Offshore Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Offshore Response Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Oil Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Oil Company Investments Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Oil Products Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Onshore Ventures Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Petroleum Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Pipeline Company LP [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Pipeline GP LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Rail Operations Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Retail and Convenience Operations LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell RSC Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Thailand E&P Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Trademark Management Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Trading (US) Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Trading North America Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Trading Risk Management, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Trading Services Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Transportation Holdings LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Treasury Center (West) Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell US E&P Investments LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell US Gas & Power LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell US Hosting Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Ventures LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100

Company by country of incorporation	Address of registered office	%
Shell WindEnergy Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell WindEnergy Services Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Ship Shoal Pipeline Company [d]	150 N. Dairy Ashford, Houston, TX 77079	43
Silicon Ranch Corporation [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	44
SOI Finance Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
SOPC Holdings East LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
SOPC Holdings West LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
SOPC Southeast Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
SWEPi LP [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Tejas Coral GP, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Tejas Coral Holding, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Tejas Power Generation, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Texas Petroleum Group LLC	11111 Wilcrest Green, Suite 100, Houston, TX 77042	50
Texas-New Mexico Pipe Line Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
The Valley Camp Coal Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Three Wind Holdings, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	50
TMR Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Tri Star Energy LLC	1740 Ed Temple Blvd, Nashville, TN 37208	33
Triton Diagnostics Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Triton Terminaling LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Triton West LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	46
True North Energy LLC	10346 Brecksville Rd, Brecksville, OH 44141	50
URSA Oil Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	45
West Shore Pipe Line Company	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808	19
Zeolyst International	(Mail address) 910 Louisiana Street, 29th Floor, Houston, TX 77002	50
Zydeco Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	50
VENEZUELA		
Shell Venezuela Productos, C.A.	Av. Orinoco, Edificio Centro Empresarial Premium, Piso 2, Oficina 2-B, Urb. Las Mercedes, Caracas, Miranda, 1060	100
Shell Venezuela, S.A.	Av. Orinoco, Edificio Centro Empresarial Premium, Piso 2, Oficinas 2-A y 2-B, Urb. Las Mercedes, Caracas, Miranda, 1060	100
Sucre Gas, S.A.	Av. Leonardo Da Vinci, Edificio PDV Servicios, Caracas, Distrito Capital	30
VIETNAM		
Shell Vietnam Ltd	Go Dau Industrial Zone, Phuoc Thai Commune, Long Thanh District, Dong Nai Province	100
ZIMBABWE		
Central African Petroleum Refineries (Private) Limited	Block 1, Tendeseka Office Park, CNR Samora Machel Avenue, Renfrew Road, Harare	21

Exhibit 12.1

I, Ben van Beurden, certify that:

1. I have reviewed this Annual Report on Form 20-F of Royal Dutch Shell plc (the Company);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;
4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Company and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the Company's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting; and
5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's Board of Directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal control over financial reporting.

/s/ Ben van Beurden

Ben van Beurden

Chief Executive Officer

March 13, 2019

Exhibit 12.2

I, Jessica Uhl, certify that:

1. I have reviewed this Annual Report on Form 20-F of Royal Dutch Shell plc (the Company);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;
4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Company and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the Company's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting; and
5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's Board of Directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal control over financial reporting.

/s/ Jessica Uhl

Jessica Uhl

Chief Financial Officer

March 13, 2019

Exhibit 13.1

In connection with the Annual Report on Form 20-F of Royal Dutch Shell plc, a public limited company organized under the laws of England and Wales (the Company), for the year ended December 31, 2018, as filed with the Securities and Exchange Commission on the date hereof (the Report), each of the undersigned officers of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to such officer's knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of, and for, the periods presented in the Report.

The foregoing certification is provided solely for purposes of complying with the provisions of Section 906 of the Sarbanes-Oxley Act of 2002 and is not intended to be used or relied upon for any other purpose.

/s/ Ben van Beurden

Ben van Beurden

Chief Executive Officer

/s/ Jessica Uhl

Jessica Uhl

Chief Financial Officer

March 13, 2019

Exhibit 99.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statement on Form F-3 (No. 333-222005) and the Registration Statements on Form S-8 (No. 333-126715, 333-141397, 333-171206, 333-192821, 333-200953, 333-215273, 333-222813, and 333-228137) of Royal Dutch Shell plc of our reports dated March 13, 2019, with respect to the Consolidated Financial Statements and the effectiveness of internal control over financial reporting of Royal Dutch Shell plc, included in the Annual Report on Form 20-F for the year ended December 31, 2018.

/s/ Ernst & Young LLP

Ernst & Young LLP

London, United Kingdom

March 13, 2019

Exhibit 99.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statement on Form F-3 (No. 333-222005) and the Registration Statements on Form S-8 (No. 333-126715, 333-141397, 333-171206, 333-192821, 333-200953, 333-215273, 333-222813, and 333-228137) of Royal Dutch Shell plc of our reports dated March 13, 2019, with respect to the Royal Dutch Shell Dividend Access Trust Financial Statements and the effectiveness of internal control over financial reporting of the Royal Dutch Shell Dividend Access Trust, included in the Annual Report on Form 20-F for the year ended December 31, 2018.

/s/ Ernst & Young LLP

Ernst & Young LLP

London, United Kingdom
March 13, 2019

Notes

Notes

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FINANCIAL CALENDAR IN 2019

The Annual General Meeting will be held on May 21, 2019.

	2018 Fourth quarter [A]	2019 First quarter [B]	2019 Second quarter [B]	2019 Third quarter [B]
Results announcements	January 31	May 2	August 1	October 31
Interim dividend timetable				
Announcement date	January 31 [C]	May 2	August 1	October 31
Ex-dividend date [D]	February 14	May 16	August 15	November 14
Record date	February 15	May 17	August 16	November 15
Closing of currency election date [E]	March 1	June 3	September 2	November 29
Pounds sterling and euro equivalents announcement date	March 11	June 11	September 9	December 5
Payment date	March 25	June 24	September 23	December 18

[A] In respect of the financial year ended December 31, 2018.

[B] In respect of the financial year ended December 31, 2019.

[C] The Directors do not propose to recommend any further distribution in respect of 2018.

[D] The New York Stock Exchange (NYSE), with effect from September 5, 2017, reduced the standard settlement cycle in accordance with the SEC amendments to Exchange Act Rule 15c6-1(a). Under these rules, regular settlement will occur on a T+2 basis for trades occurring on or after the SEC's implementation date of September 5, 2017. As a result RDS A ADSs and RDS B ADSs traded on the NYSE markets will now settle in line with RDS A shares and RDS B shares traded on European markets, who moved to a T+2 settlement basis for trades in 2014, resulting in the same ex-dividend date for RDS A shares, RDS B shares, RDS A ADSs and RDS B ADSs. Record dates will not change. The timings of these are detailed above.

[E] A different currency election date may apply to shareholders holding shares in a securities account with a bank or financial institution ultimately through Euroclear Nederland. This may also apply to other shareholders who do not hold their shares either directly on the Register of Members or in the corporate sponsored nominee arrangement. Shareholders can contact their broker, financial intermediary, bank or financial institution for the election deadline that applies.

REGISTERED OFFICE

Royal Dutch Shell plc
Shell Centre
London SE1 7NA
United Kingdom

Registered in England and Wales
Company number 4366849

Registered with the Dutch Trade Register
under number 34179503

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and to change the way you receive your
company documents:
www.shareview.co.uk

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USA

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USA

+1 888 737 2377 (USA only)

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<http://reports.shell.com>

- Comprehensive financial information on our activities throughout 2018
- Detailed operational information including maps
- Report on our progress in contributing to sustainable development



ANNUAL REPORT AND ACCOUNTS
FOR THE YEAR ENDED DECEMBER 31, 2019
ROYAL DUTCH SHELL PLC

ENERGY FOR A BETTER FUTURE

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Cover image: The Pecten is the key symbol of the Shell Brand. It is sometimes referred to as our icon, logo or emblem, and is one of the world's most recognised symbols. It is an asset with enormous value, and a key enabler of successful business through our customers, governments, business partners, contractors and staff. It has been at the core of our branding for over 100 years.

Design and production: **Friend** www.friendstudio.com

Print: **Tuijtel** under ISO 14001



TERMS AND ABBREVIATIONS

Currencies

\$	US dollar
€	euro
£	sterling

Units of measurement

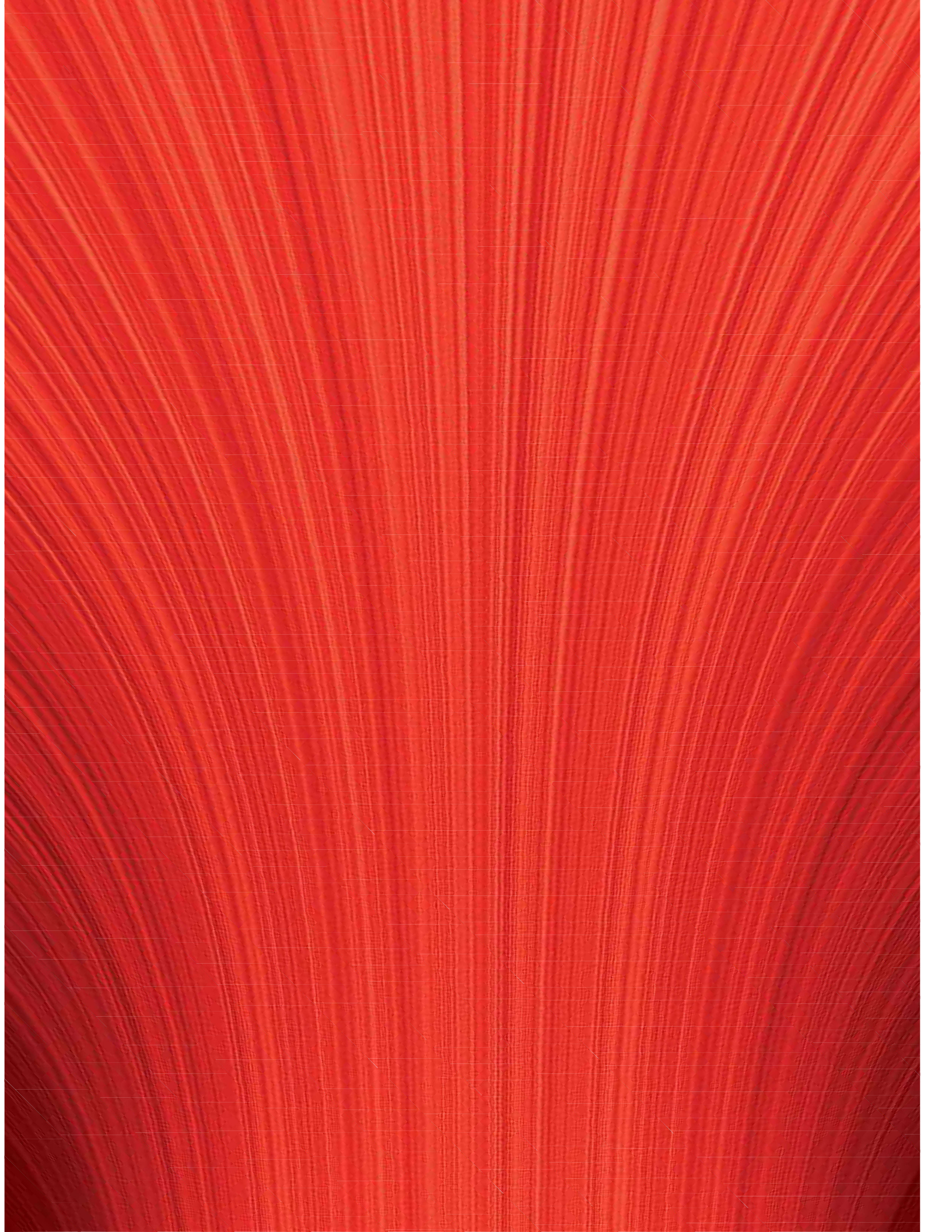
acre	approximately 0.004 square kilometres
b(/d)	barrels (per day)
boe(/d)	barrels of oil equivalent (per day); natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel
kboe(/d)	thousand barrels of oil equivalent (per day); natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel
MMBtu	million British thermal units
megajoule	a unit of energy equal to one million joules
mtpa	million tonnes per annum
per day	volumes are converted into a daily basis using a calendar year
scf(/d)	standard cubic feet (per day)

Products

GTL	gas to liquids
LNG	liquefied natural gas
LPG	liquefied petroleum gas
NGL	natural gas liquids

Miscellaneous

ADS	American Depositary Share
AGM	Annual General Meeting
API	American Petroleum Institute
CCS	carbon capture and storage
CCS earnings	earnings on a current cost of supplies basis
CO ₂	carbon dioxide
EMTN	Euro medium-term note
EPS	earnings per share
FCF	free cash flow
FID	final investment decision
GAAP	generally accepted accounting principles
GHG	greenhouse gas
HSSE	health, safety, security and environment
IAS	International Accounting Standard
IEA	International Energy Agency
IFRS	International Financial Reporting Standard(s)
IOGP	International Association of Oil & Gas Producers
IPIECA	International Petroleum Industry Environmental Conservation Association (global oil and gas industry association for environmental and social issues)
LTIP	Long-term Incentive Plan
OECD	Organisation for Economic Co-operation and Development
OML	oil mining lease
OPEC	Organization of the Petroleum Exporting Countries
OPL	oil prospecting licence
PSC	production-sharing contract
PSP	Performance Share Plan
REMCO	Remuneration Committee
SEC	US Securities and Exchange Commission
TRCF	total recordable case frequency
TSR	total shareholder return
WTI	West Texas Intermediate





“Shell’s business strategy provides the continuity, resilience and growth we will need to deliver change: to play an essential role in the move to a cleaner, lower-carbon world.”

CHAD HOLLIDAY
Chair

“When I look at Shell, I see people with high hopes and social commitment. We wholeheartedly support the goal of the Paris Agreement.”

BEN VAN BEURDEN
Chief Executive Officer

ABOUT THIS REPORT

The Royal Dutch Shell plc Annual Report (this Report) serves as the Annual Report and Accounts in accordance with UK requirements for the year ended December 31, 2019, for Royal Dutch Shell plc (the Company) and its subsidiaries (collectively referred to as Shell). This Report presents the Consolidated Financial Statements of Shell (pages 190-238), the Parent Company Financial Statements of Shell (pages 258-265) and the Financial Statements of the Royal Dutch Shell Dividend Access Trust (pages 269-271). Except for these Financial Statements, the numbers presented throughout this Report may not sum precisely to the totals provided and percentages may not precisely reflect the absolute figures due to rounding.

The financial statements contained in this Report have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the IASB. IFRS as defined above includes interpretations issued by the IFRS Interpretations Committee. Financial reporting terms used in this Report are in accordance with IFRS.

This Report contains certain following forward-looking Non-GAAP measures such as cash capital expenditure and divestments. We are unable to provide a reconciliation of these forward-looking Non-GAAP measures to the most comparable GAAP financial measures because certain information needed to reconcile those Non-GAAP measures to the most comparable GAAP financial measures is dependent on future events some of which are outside the control of the company, such as oil and gas prices, interest rates and exchange rates. Moreover, estimating such GAAP measures with the required precision necessary to provide a meaningful reconciliation is extremely difficult and could not be accomplished without unreasonable effort. Non-GAAP measures in respect of future periods which cannot be reconciled to the most comparable GAAP financial measure are calculated in a manner which is consistent with the accounting policies applied in Royal Dutch Shell plc's financial statements.

The companies in which Royal Dutch Shell plc directly or indirectly own investments are separate legal entities. In addition to the term "Shell", in this Report "Shell Group", "we", "us" and "our" are also used to refer to the Company and its subsidiaries in general or to those who work for them. These terms are also used where no useful purpose is served by identifying the particular entity or entities. "Subsidiaries" and "Shell subsidiaries" refer to those entities over which the Company has control, either directly or indirectly. Entities and unincorporated arrangements over which Shell has joint control are generally referred to as "joint ventures" and "joint operations", respectively. "Joint ventures" and "joint operations" are collectively referred to as "joint arrangements". Entities over which Shell has significant influence but neither control nor joint control are referred to as "associates". The term "Shell interest" is used for convenience to indicate the direct and/or indirect ownership interest held by Shell in an entity or unincorporated joint arrangement, after exclusion of all third party interest. Shell subsidiaries' data include their interests in joint operations.

This Report contains data and analysis from Shell's Sky scenario.

Unlike Shell's previously published Mountains and Oceans exploratory scenarios, the Sky scenario is based on the assumption that society reaches the Paris Agreement's goal of holding the rise in global average temperatures this century to well below two degrees Celsius (2°C) above pre-industrial levels. Unlike Shell's Mountains and Oceans scenarios which unfolded in an open-ended way based upon plausible assumptions and quantifications, the Sky scenario was specifically designed to reach the Paris Agreement's goal in a technically possible manner. These scenarios are a part of an ongoing process used in Shell for over 40 years to challenge executives' perspectives on the future business environment. They are designed to stretch management to consider even events that may only be remotely possible. Scenarios, therefore, are not intended to be predictions of likely future events or outcomes and investors should not rely on them when making an investment decision with regard to Royal Dutch Shell plc securities.

It is important to note that Shell's existing portfolio has been decades in development. While we believe our portfolio is resilient under a wide range of outlooks, including the IEA's 450 scenario (World Energy Outlook 2016), it includes assets across a spectrum of energy intensities including some with above-average intensity. While we seek to enhance our operations' average energy intensity through both the development of new projects and divestments, we have no immediate plans to move to a net-zero emissions portfolio over our investment horizon of 10-20 years. Although we have no immediate plans to move to a net-zero emissions portfolio, in November of 2017, we announced our ambition to reduce our Net Carbon Footprint in step with society's progress towards the Paris Agreement's goal of holding the rise in global average temperatures this century to well below 2°C above pre-industrial levels. Accordingly, assuming society aligns itself with the Paris Agreement's goals, we aim to reduce our Net Carbon Footprint, which includes not only our direct and indirect carbon emissions, associated with producing the energy products which we sell, but also our customers' emissions from their use of the energy products that we sell, by around 20% in 2035 and by around 50% in 2050.

Shell's "Net Carbon Footprint" referred to in this Report includes Shell's carbon emissions from the production of our energy products, our suppliers' carbon emissions in supplying energy for that production, and our customers' carbon emissions associated with their use of the energy products we sell. Shell only controls its own emissions but, to support society in achieving the Paris Agreement goals, we aim to help such suppliers and consumers to likewise lower their emissions. The use of the term Net Carbon Footprint" is for convenience only and not intended to suggest these emissions are those of Shell or its subsidiaries.

Except where indicated, the figures shown in the tables in this Report are in respect of subsidiaries only, without deduction of any non-controlling interest. However, the term "Shell share" is used for convenience to refer to the volumes of hydrocarbons that are produced, processed or sold through subsidiaries, joint ventures and associates. All of a subsidiary's production, processing or sales volumes (including the share of joint operations) are included in the Shell share, even if Shell owns less than 100% of the subsidiary. In the case of joint ventures and associates, however, Shell-share figures are limited only to Shell's entitlement. In all cases, royalty payments in kind are deducted from the Shell share.

Except where indicated, the figures shown in this Report are stated in US dollars. As used herein all references to "dollars" or "\$" are to the US currency.

This Report contains forward-looking statements concerning the financial condition, results of operations and businesses of Shell. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. Forward-looking statements are statements of future expectations that are based on management's current expectations and assumptions and involve known and unknown risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied in these statements. Forward-looking statements include, among other things, statements concerning the potential exposure of Shell to market risks and statements expressing management's expectations, beliefs, estimates, forecasts, projections and assumptions. These forward-looking statements are identified by their use of terms and phrases such as "aim", "ambition", "anticipate", "believe", "could", "estimate", "expect", "goals", "intend", "may", "objectives", "outlook", "plan", "probably", "project", "risks", "schedule", "seek", "should", "target", "will" and similar terms and phrases. There are a number of factors that could affect the future operations of Shell and could cause those results to differ materially from those expressed in the forward-looking statements included in this Report, including (without limitation): (a) price fluctuations in crude oil and natural gas; (b) changes in demand for Shell's products; (c) currency fluctuations; (d) drilling and production results; (e) reserves estimates; (f) loss of market share and industry competition; (g) environmental and physical risks; (h) risks associated with the identification of suitable potential acquisition properties and targets, and successful negotiation and completion of such transactions; (i) the risk of doing business in developing countries and countries subject to international sanctions; (j) legislative, fiscal and regulatory developments including regulatory measures addressing climate change; (k) economic and financial market conditions in various countries and regions; (l) political risks, including the risks of expropriation and renegotiation of the terms of contracts with governmental entities, delays or advancements in the approval of projects and delays in the reimbursement for shared costs; and (m) changes in trading conditions.

Also see "Risk factors" on pages 27-36 for additional risks and further discussion. No assurance is provided that future dividend payments will match or exceed previous dividend payments. All forward-looking statements contained in this Report are expressly qualified in their entirety by the cautionary statements contained or referred to in this section. Readers should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of this Report. Neither the Company nor any of its subsidiaries undertake any obligation to publicly update or revise any forward-looking statement as a result of new information, future events or other information. In light of these risks, results could differ materially from those stated, implied or inferred from the forward-looking statements contained in this Report.

This Report contains references to Shell's website, the Shell Sustainability Report, Tax Contribution Report, Shell Industry Association Report and our report on Payments to Governments. These references are for the readers' convenience only. Shell is not incorporating by reference any information posted on www.shell.com or in the Shell Sustainability Report, Tax Contribution Report, Shell Industry Association Report and our report on Payments to Government.

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DOCUMENTS ON DISPLAY

This Report is also available, free of charge, at www.shell.com/annualreport or at the offices of Shell in The Hague, the Netherlands and London, United Kingdom. Copies of this Report also may be obtained, free of charge, by mail.

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CHAIR'S MESSAGE

MORE AND CLEANER ENERGY



CHAD HOLLIDAY
Chair

As the world changes, it challenges us all to make choices. We can stay the same and risk being left behind. Or we can change, while building on what we know is long-lasting and valuable.

In 2019, people all over the world, many of them very young, demanded change. They demanded urgent action to protect the climate: change to our lifestyles, change to how the world produces and uses energy. As John F. Kennedy said, "Time and the world do not stand still. Change is the law of life." He added a vital point for anyone wanting to thrive in such a world: "Those who look only to the past or the present are certain to miss the future."

In business, the smartest way to change is to build on your strengths, not abandon them. Shell's business strategy provides the continuity, resilience and growth we will need to deliver change: to play an essential role in the move to a cleaner, lower-carbon world. We are working to become one of the world's best investment cases. We must also keep making a positive contribution to people's lives, to maintain what we call our strong societal licence to operate. By getting this right, we will seek to thrive through the transition to a lower-carbon future. We will always abide by our core values – honesty, integrity, and respect for people. Our belief in trust, and the need to nurture it, will also stay as strong as ever.

In 2019, we took significant steps to build trust through greater transparency. We published our Tax Contribution Report, detailing for the first time the corporate income tax we paid in countries and locations where we have a taxable presence. In our Industry Associations Climate Review, we assessed Shell's alignment with 19 industry associations on climate change, deciding to leave one of them as a result. In business, we will only succeed if we stay in step with society and provide products our customers will buy.

In the coming years, as the urgency around climate change grows, our customers will want cleaner energy to power their homes, businesses, and transport. We intend to move with them, investing in power from natural gas and renewable sources such as wind and solar, building charging networks for electric cars, developing lower-carbon biofuels that will not compete with crops for land.

But global demand for energy is still growing, as population increases and more people seek a better quality of life. Among those seeking to improve their living standards are almost a billion who have no electricity supply at all, 2 billion who lack a toilet connected to a proper sewer system, and 785 million – around one-tenth of the world's population – who have no easy access to safe drinking water. There is much more to be done, although we have also seen remarkable progress in improving lives. In 1900, the average newborn baby had a life expectancy of 32 years. Today, worldwide average life expectancy is 73 years. Access to energy played a part in this, for example reinforcing advances in health care by powering life-saving machinery, from refrigerators to store drugs through to incubators for newborn babies.

As the world seeks to make more progress, renewable sources will meet a growing share of rising energy demand, but the need for oil and gas will remain for decades to come. In Shell, as we shape our businesses to deliver more and cleaner energy, we must also continue to invest responsibly in developing conventional oil and gas resources. This generates billions of dollars in revenue, allowing us to reward our investors with dividends. Crucially, it also provides the financial muscle to invest in cleaner forms of energy.

COMMUNITIES BENEFITING FROM OIL AND GAS

Building that financial muscle often requires considerable ingenuity. In the North Sea off Scotland, for instance, we are developing some of the most difficult natural gas fields, such as Fram, operated by Shell and owned as a joint venture with Esso. By developing Fram, we can unlock the full potential of other fields too. Discovered in 1969, Fram was left undeveloped for more than 50 years because there seemed to be no cost-effective way to produce its resources. Until now. To keep costs down, Shell intends to turn a field reaching the last of its gas, Starling, into a staging post. An underwater pipeline laid in 2019 will start taking 41 million standard cubic feet of natural gas a day, plus condensates, from Fram to Starling. From Starling, it can flow through an existing pipeline to our Shearwater platform, before coming ashore at our St Fergus gas plant.

“Those who look only to the past or the present are certain to miss the future.”

– John F. Kennedy



The Shearwater platform in the UK North Sea is now expected to be able to keep supplying energy into the 2030s.



Shell has invested in the Silicon Ranch Corporation, a US solar power generator.

HELPING DESIGN WORLD'S FIRST VESSEL TO TRANSPORT LIQUEFIED HYDROGEN AT

-253°C



The Suiso Frontier is expected to be the first ship to transport liquefied hydrogen across oceans.

This should also help secure Shearwater's future, allowing it to keep supplying the UK with energy into the 2030s. Local communities stand to benefit. Our North Sea oil and gas operations employ 1,000 people directly, but generate economic activity that supports a further 28,000 jobs outside Shell [A].

In Nigeria, gas from our Assa North field, which is expected to start production around 2022, will improve the reliability of the country's electricity supplies. Nearby communities are already benefiting from a Shell programme that has so far helped more than 11,000 local children and adults get free health care.

These are just two examples of how Shell delivers the oil and gas needed to strengthen economies and offer opportunities for local people. But as we focus on delivering today, we must be sure not to miss the future.

TAPPING THE POTENTIAL OF HYDROGEN

Hydrogen, for example, could play a vital role in helping the move towards a lower-carbon world. Hydrogen can be extracted using the electricity generated by wind and solar power. It can then be stored, ready to be converted back to electricity with only one by-product, water. Shell is already working to increase the use of hydrogen, for example with refuelling sites for hydrogen-powered vehicles in Europe and North America. But we would like to open up more possibilities for using hydrogen, across heating, power and transport, helping it to become a significant fuel of the future.

We are contributing to the development of a ship called the Suiso Frontier, which launched in December 2019, in Kobe, Japan. By 2021 it is expected to be the world's first vessel to transport liquefied hydrogen across oceans, at temperatures of minus-253 Celsius.

Shell is working with Kawasaki Heavy Industries and others to design the tank holding the liquefied hydrogen and develop further novel technologies for the ship. Those we have consulted include the USA's National Aeronautics and Space Administration (NASA). They know how to handle liquefied hydrogen. They use it as rocket fuel.

The Suiso Frontier is expected to allow us to develop and demonstrate the technologies needed for a commercial-scale hydrogen supply chain by around 2030. It shows the critical importance of technology – one of Shell's core strengths – in the energy transition. By building on our strengths while embracing change as “the law of life”, we can help address those calls for more urgent action on climate change. With more and cleaner energy, we can make a better future.

CHAD HOLLIDAY
Chair

[A] University of Strathclyde Fraser of Allander Institute and Aberdeen & Grampian Chamber of Commerce.

CHIEF EXECUTIVE OFFICER'S REVIEW

INVESTING FOR THE FUTURE, DELIVERING TODAY

**BEN VAN BEURDEN**

Chief Executive Officer

In a tough year, Shell demonstrated its resilience by delivering credible results on several fronts. We made progress in the face of economic headwinds such as low oil and gas prices, limited global growth, and reduced chemical and refining margins.

Our cash flow from operating activities was strong compared to our industry peers, at \$42.2 billion. We distributed more than \$25 billion to shareholders: \$15.2 billion in dividends, and \$10.2 billion in share buybacks. By the end of January 2020, we had delivered \$14.75 billion of our \$25 billion buyback programme, which began in 2018.

The headwinds did contribute to some negative factors in our financial performance. Gearing increased from 20% to 29%, which is equivalent to 25% on an IAS 17 accounting basis. Income was \$16.4 billion, down from \$23.9 billion in 2018. Earnings on a current cost of supplies (CCS) basis were \$15.8 billion, down from \$24.4 billion in 2018.

Overall, though, Shell's financial foundations remained strong. We continued to show financial discipline by limiting our cash capital expenditure to \$24 billion, at the lower end of the range that we said we would spend. We improved the resilience and quality of our portfolio by making around \$5 billion-worth of divestments.

SAFETY

I am, however, deeply saddened that seven people died while working for Shell in 2019. This is unacceptable. Each death inflicts unimaginable grief on the bereaved family. In Shell, work colleagues mourn. Every person lost is a tragedy. When it comes to safety, we have much more to do. We have responded by introducing a new approach alongside our continuing efforts to review and improve accident-prevention procedures wherever possible.

Our new approach acknowledges that people occasionally make mistakes, and that sometimes the dangerous and unexpected happens even after you follow every safety procedure.

This is not to make excuses. It is to be realistic, and to enable us to do more about it. We can look more closely at how people perform in the moment when things go wrong: when they make mistakes, or processes fail. We can train our people to be even better at dealing with the unexpected. This is demanding, but we want to get to a place where even if there is an incident, everyone emerges unhurt. They go home, alive and well, to their family.

CLIMATE CHANGE

I believe Shell has a constructive approach to the greatest global challenge of our times. In 2019, many protested about climate change, sometimes directly targeting Shell. This may feel uncomfortable, but the spotlight thrown on Shell also gives us an opportunity to explain to a wider audience how we can be an important part of the solution. Perhaps this starts with acknowledging our common humanity. When I look at climate change protesters, I see people who, in the overwhelming majority, act from a wholly justified determination to safeguard our planet. I share many of their frustrations that some things do not seem to be moving fast enough.

I welcome all peaceful efforts to encourage society to shift towards lower-carbon energy, as it must. And when I look at Shell, I see people with equally high hopes and social commitment. We wholeheartedly support the goal of the Paris Agreement to limit the global average temperature rise to well below two degrees Celsius above pre-industrial levels. We also know the energy transition is unfolding, and we must be part of it if we are to survive as a business. As I have often said, those companies that do not stay in step with society will be left behind. Those who are not trusted will be left behind too. Shell must and will be transparent.

In 2019, for example, we published our first Tax Contribution Report, detailing the corporate income tax we paid in countries and locations where we have a taxable presence. We also published our Industry Associations Climate Review, leaving one group because its position on climate change diverged too much from ours.



In 2019, Shell published its first Tax Contribution Report.



Shell UK is working with Forestry and Land Scotland to preserve and extend the ancient forest of Glengarry, in the Scottish Highlands.



Production has started at Shell's Appomattox deep-water asset in the US Gulf of Mexico.

OUR STRATEGY

Shell's strategy sets out our three clear ambitions: to thrive in the energy transition, provide a world-class investment case, and sustain a strong societal licence to operate. In 2019, to help achieve all three ambitions, we refreshed our strategy to focus more strongly on developing our Power business.

If the world is to tackle climate change, it must consume more of its energy in the form of electricity. This is a huge potential growth opportunity for Shell, one we are well positioned to seize. Shell has the brand, the global presence, the retail and marketing expertise that you need when buying and selling electricity and interacting with customers. We are a worldwide supplier of natural gas, a cleaner alternative to coal for electricity generation.

We are actively seeking to increase our investments in renewable power. In 2019, for example, Shell acquired ERM Power, one of Australia's leading commercial and industrial electricity retailers.

We continued to work towards delivering on our Net Carbon Footprint ambition to cut the intensity of the greenhouse gas emissions of the energy products we sell by around 50% by 2050, and as an interim step by 20% by 2035.

As part of this ambition, we launched a worldwide programme that uses trees and other plants to remove carbon dioxide from the atmosphere. We will be protecting, planting or regenerating forests, grasslands and wetlands, in what we call our nature-based solutions programme. Carbon-neutral driving schemes are allied to this. Motorists in the Netherlands and the UK can now offset their fuel emissions by having Shell purchase nature-based carbon credits on their behalf.

While investing for the future, we must also meet the energy demand of today. Our core oil and gas business delivered significant projects in 2019. In March, production started at our Appomattox floating production system in the Gulf of Mexico, which is expected to produce 175,000 barrels of oil equivalent a day at its peak. In June, the first shipment of liquefied natural gas left the Prelude floating liquefied natural gas facility off Australia.

As we look forward to 2020 and beyond, we must be firm in our belief that our business strategy is sound and our financial foundations strong. We believe Shell's underlying resilience will stand us in good stead for the challenges to come.

BEN VAN BEURDEN

Chief Executive Officer

SELECTED FINANCIAL DATA

The selected financial data set out below are derived, in part, from the “Consolidated Financial Statements”. These data should be read in conjunction with the “Consolidated Financial Statements” and related Notes, as well as with this Strategic Report.

Consolidated Statement of Income and of Comprehensive Income data

344,877

Revenue (\$ million)

16,432

Income for the period (\$ million)

590

Income attributable to non-controlling interest (\$ million)

15,842

Income attributable to Royal Dutch Shell plc shareholders (\$ million)

13,773

Comprehensive income attributable to Royal Dutch Shell plc shareholders (\$ million)

\$ million	2019	2018	2017	2016	2015
Revenue	344,877	388,379	305,179	233,591	264,960
Income for the period	16,432	23,906	13,435	4,777	2,200
Income attributable to non-controlling interest	590	554	458	202	261
Income attributable to Royal Dutch Shell plc shareholders	15,842	23,352	12,977	4,575	1,939
Comprehensive income/(loss) attributable to Royal Dutch Shell plc shareholders	13,773	24,475	18,828	(1,374)	(811)

Consolidated Balance Sheet data

404,336

Total assets (\$ million)

96,424

Total debt (\$ million)

657

Share capital (\$ million)

186,476

Equity attributable to Royal Dutch Shell plc shareholders (\$ million)

3,987

Non-controlling interest (\$ million)

\$ million	2019	2018	2017	2016	2015
Total assets	404,336	399,194	407,097	411,275	340,157
Total debt	96,424	76,824	85,665	92,476	58,379
Share capital	657	685	696	683	546
Equity attributable to Royal Dutch Shell plc shareholders	186,476	198,646	194,356	186,646	162,876
Non-controlling interest	3,987	3,888	3,456	1,865	1,245

Consolidated Statement of Cash Flows data

42,178

Cash flow from operating activities (\$ million)

22,971

Capital expenditure (\$ million)

15,779

Cash flow from investing activities (\$ million)

15,198

Cash dividends paid to Royal Dutch Shell plc shareholders (\$ million)

10,188

Repurchases of shares (\$ million)

\$ million	2019	2018	2017	2016	2015
Cash flow from operating activities	42,178	53,085	35,650	20,615	29,810
Capital expenditure	22,971	23,011	20,845	22,116	26,131
Cash flow from investing activities	15,779	13,659	8,029	30,963	22,407
Cash dividends paid to Royal Dutch Shell plc shareholders	15,198	15,675	10,877	9,677	9,370
Repurchases of shares	10,188	3,947	-	-	409

Earnings per share

1.97

Basic earnings per €0.07 ordinary share (\$)

1.95

Diluted earnings per €0.07 ordinary share (\$)

\$	2019	2018	2017	2016	2015
Basic earnings per €0.07 ordinary share	1.97	2.82	1.58	0.58	0.31
Diluted earnings per €0.07 ordinary share	1.95	2.80	1.56	0.58	0.30

Dividend per share

1.88

Dividend per share (\$)

\$	2019	2018	2017	2016	2015
Dividend per share	1.88	1.88	1.88	1.88	1.88

Shares

8,058.3

Basic weighted average number of A and B shares (million)

8,112.5

Diluted weighted average number of A and B shares (million)

Million	2019	2018	2017	2016	2015
Basic weighted average number of A and B shares	8,058.3	8,282.8	8,223.4	7,833.7	6,320.3
Diluted weighted average number of A and B shares	8,112.5	8,348.7	8,299.0	7,891.7	6,393.8

SHELL STORY: WHO WE ARE

Shell is a global group of energy and petrochemical companies with 83,000 employees in more than 70 countries.

We have expertise in the exploration, production, refining and marketing of oil and natural gas, and the manufacturing and marketing of chemicals.

We use advanced technologies and take an innovative approach to help build a sustainable energy future. We also invest in power, including from low-carbon sources such as wind and solar; and new fuels for transport, such as advanced biofuels and hydrogen.

Our Context

The rising standard of living of a growing global population is likely to continue to drive demand for energy, including oil and gas, for years to come. At the same time, technological changes and the need to tackle climate change mean there is a transition under way to a lower-carbon, multi-source energy system with increasing customer choice.


Our stakeholders include:

- Our investor community
- Our customers
- Our employees/pensioners
- Our strategic partners/suppliers
- Communities
- Governments/NGOs/regulators

 See "Section 172(1) statement" on **pages 23-26**, "Environment and society" on **pages 84-90**, "Our people" on **pages 99-101** and "Governance" on **pages 104-171**. For more detailed discussions around our context and stakeholders.

Our Purpose


We power progress together by providing more and cleaner energy solutions.

 See "Strategy and outlook" on **page 19** for more detailed discussion around our purpose.

Our Core Values

Honesty
Integrity
Respect for people

The Shell General Business Principles, Code of Conduct, and Code of Ethics help everyone at Shell act in line with these values and comply with relevant laws and regulations. We also strive to build and maintain a diverse and inclusive culture within our company.

 See "Our people" on **pages 99-101** for more detailed discussion around our core values.

Our strategic ambitions

Thrive in
the energy
transition

to thrive in the energy transition by responding to society's desire for more and cleaner, convenient and competitive energy;

World-class
investment
case

to provide a world-class investment case. This involves growing organic free cash flow and increasing returns, all built upon a strong financial framework and resilient portfolio; and

Strong
licence to
operate

to sustain a strong societal licence to operate and make a positive contribution to society through our activities.



See "Strategy and outlook" on **page 20** for more detailed discussion around our strategic ambitions.

Our strategy by theme

Core Upstream themes



Deep Water



Shales



Conventional
Oil and Gas

Leading Transition themes



Integrated Gas



Oil Products



Chemicals

Emerging Power theme



Power



See "Strategy and outlook" on **page 21** for more detailed discussion around our strategic themes.

Our strategy is to strengthen our position as a leading energy company by providing oil, gas and low-carbon energy as the world's energy system transforms. Safety and social responsibility are fundamental to our business approach.

SHELL STORY: WHAT WE DO

We aim to meet the world's growing need for more and cleaner energy solutions in ways that are economically, environmentally and socially responsible.

Our Inputs [A]

Financial

291,142

Average capital employed
(\$ million)

23,919

Cash capital expenditure (\$ million)

Read more in "Performance indicators" on **pages 42-44** and "Non-GAAP measures reconciliations" on **pages 279-280**.

Operations

90.8%

Refinery and chemical
plant availability

90%

Project delivery on schedule

99%

Project delivery on budget

Read more in "Performance indicators" on **pages 42-44**.

Innovation

962

Investments in research
and development (\$ million)

9,449

Patents [B]

Read more in "Technology and Innovation" on **page 18**.

Human capital

83,000

Employees [B]

373,000

Training days

Read more in "Our people" on **pages 99-101**.

Relationships

Customers
Joint arrangements
Governments relations
Suppliers

>70

Operating countries [B]

Read more in "Section 172(1) statement" on **pages 23-26**, "Environment and society" on **pages 84-90** and "Governance" on **pages 104-171**.

Natural resources

11,096

Proved oil and gas reserves
(million boe) [B]

1,338

Oil and gas production available
for sale (million boe)

192

Fresh water withdrawn
(million cubic metres)

Read more in "Oil and gas information" on **pages 61-69** and "Environment and society" on **pages 84-90**.

Our Business Model

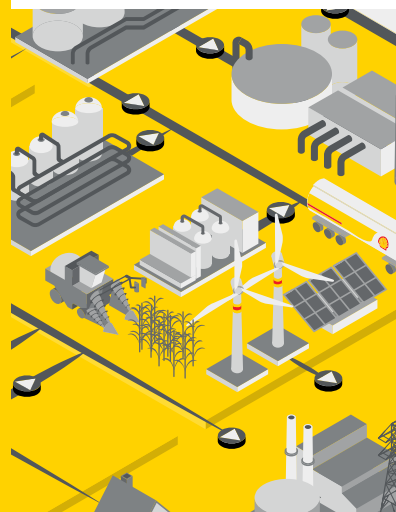
We seek to create shareholder value by:

- exploring for crude oil and natural gas worldwide;
- developing new crude oil and natural gas supplies from major fields and extracting bitumen from oil sands;
- cooling natural gas to produce liquefied natural gas (LNG) and converting gas to liquids (GTL);
- supplying and trading oil, gas and other energy-related products, such as electricity and carbon-emissions rights; and
- having a portfolio of refineries and chemical plants producing a wide range of products including gasoline, diesel, aviation and marine fuel, lubricants and petrochemicals.

The integration of our businesses is one of our competitive advantages, allowing optimisations across our global portfolio.



See **page 16** for more detailed discussion around our Business Model.



[A] In 2019 except stated otherwise. [B] At 31.12.2019.

Our Outcome and Impact [A]

Thriving in the energy transition

Energy transition and climate change

78

Net Carbon Footprint
(grams of CO₂ equivalent
per megajoule)

70

Direct greenhouse gas (GHG)
emissions (million tonnes of
CO₂ equivalent)

Read more in "Climate change and energy transition" on **pages 91-98**.

World-class investment case

Financial performance

6.7%

Return on average capital
employed (ROACE)

25,386

Shareholder distribution
(\$ million)

Read more in "Performance indicators" on **pages 42-44** and
"Non-GAAP measures reconciliations" on **pages 279-280**.

Resilience of business model

26,399

Free cash flow (\$ million)

29.3%

Gearing [B]

Read more in "Performance indicators" on **pages 42-44**
and "Liquidity and capital resources" on **pages 80-83**.

Shell Catalysts & Technologies staff in Port Allen, Louisiana, USA.



Strong licence to operate

Environmental impacts

70

Operational spills
of more than 100kg

0.2

Weight of operational spills
(in '000 tonnes)

Read more in "Environment and society" on **pages 84-90**.

Trust and Transparency

47.5

Brand value (\$ billion) [C]

1,686

Shell Global Helpline
(reports to the helpline)

Publication of the first **Shell Tax Contribution Report**

Read more in "Corporate" on **page 79** and "Our people"
on **pages 99-101**.

Health, Safety and Security

0.9

Total recordable case
frequency (injuries per
million working hours)

130

Operational Tier 1 and 2
process safety events

Read more in "Environment and society" on **pages 84-90**.

Contribution to countries of operation

61.3

Taxes paid and
collected (\$ billion)

44.9

Total spend on goods
and services (\$ billion)

Read more in "Environment and society" on **pages 84-90**.

Our people

26.4%

Women in senior
leadership positions [B]

78

Average employee
engagement score (points)

Read more in "Our people" on **pages 99-101**.

[A] In 2019 except stated otherwise.

[B] At 31.12.2019.

[C] Source: Brand Finance Global 500 2020 Report.

OUR BUSINESS MODEL EXPLAINED

Business activities

Exploration

1. Exploring for oil and gas onshore and offshore

Development and extraction

2. Developing onshore and offshore fields
3. Producing conventional, deep-water and shale oil and gas
4. Capturing carbon dioxide and storing it safely underground
5. Extracting bitumen

Manufacturing and energy production

6. Upgrading bitumen
7. Refining oil into fuels and lubricants
8. Producing gas-to-liquids (GTL) products
9. Producing petrochemicals
10. Producing biofuels
11. Generating renewable power
12. Producing liquefied natural gas (LNG)

Transport and trading

13. Shipping gas to where it is needed
14. Shipping oil to where it is needed
15. Trading oil and gas
16. Supply and distribution of LNG for transport applications
17. Regasifying LNG
18. Trading power

Sales and marketing

19. Supplying domestic electricity
20. Supplying products to businesses, including gas for cooking, heating and electrical power
21. Progressing electric vehicle and hydrogen refuelling infrastructure
22. Providing mobility solutions for customers, including fuels and lubricants
23. Supplying aviation fuel

Technical and business services

24. Researching and developing new technology solutions
25. Managing the delivery of major projects
26. Providing technical and supporting services

Organisation

We describe below how our activities are organised. Integrated Gas, Upstream and Downstream focus on our seven strategic themes (see “Strategy and outlook” on page 21). Our Projects & Technology organisation manages the delivery of Shell’s major projects and drives research and innovation to develop new technology solutions.

Integrated Gas (including New Energies)

This organisation covers two strategic themes: Integrated Gas, which is a Leading Transition theme; and New Energies, which includes the Emerging Power theme.

Integrated Gas manages LNG activities and the conversion of natural gas into GTL fuels and other products. It includes natural gas exploration and extraction, and the operation of upstream and midstream infrastructure necessary to deliver gas to market. It markets and trades natural gas, LNG, electricity and carbon-emission rights and also markets and sells LNG as a fuel for heavy-duty vehicles and marine vessels.

In New Energies, we are exploring emerging opportunities and investing in those where we believe sufficient commercial value is available. We focus on new fuels for transport, such as advanced biofuels, hydrogen and charging for battery-electric vehicles; and power, including from natural gas and low-carbon sources such as wind and solar.

Upstream

Our Upstream organisation covers the core Upstream themes: Conventional Oil and Gas, Deep Water and Shales.

It manages the exploration for and extraction of crude oil, natural gas and natural gas liquids. It also markets and transports oil and gas, and operates infrastructure necessary to deliver them to market.

Painting Shell’s logo, the Pecten.



Downstream

Our Downstream organisation comprises two strategic themes: Oil Products and Chemicals, both of which are Leading Transition themes.

It manages different Oil Products and Chemicals activities as part of an integrated value chain, that trades and refines crude oil, and other feedstocks into a range of products which are moved and marketed around the world for domestic, industrial and transport use. The products we sell include gasoline, diesel, heating oil, aviation fuel, marine fuel, biofuel, lubricants, bitumen and sulphur. We also produce and sell petrochemicals for industrial use worldwide. Our Downstream organisation also manages Oil Sands activities (the extraction of bitumen from mined oil sands and its conversion into synthetic crude oil).

Projects & Technology

Our Projects & Technology organisation manages the delivery of our major projects and drives research and innovation to develop new technology solutions. It provides technical services and technology capability for our Integrated Gas, Upstream and Downstream activities. It is also responsible for providing functional leadership across Shell in the areas of safety and environment, contracting and procurement, wells activities and greenhouse gas management.

Our future hydrocarbon production depends on the delivery of large and integrated projects (see “Risk factors” on pages 27-36). Systematic management of life-cycle technical and non-technical risks is in place for each opportunity, with assurance and control activities embedded throughout the project life cycle. We focus on the cost-effective delivery of projects through commercial agreements, supply-chain management, and construction and engineering productivity through effective planning and simplification of delivery processes. Development of our employees’ project management competencies is underpinned by project principles, standards and processes. A dedicated competence framework, training, standards and processes exist for various technical disciplines. We also provide governance support for our non-Shell-operated ventures or projects.

Segmental Reporting

Our reporting segments are Integrated Gas, Upstream, Downstream and Corporate. Upstream combines the operating segments Upstream (managed by our Upstream organisation) and Oil Sands (managed by our Downstream organisation), which have similar economic characteristics. Integrated Gas, Upstream and Downstream include their respective elements of our Projects & Technology organisation. The Corporate segment comprises our holdings and treasury organisation, self-insurance activities, and headquarters and central functions. See Note 4 to the "Consolidated Financial Statements" on pages 206-208.

With effect from 2020, our reporting segments were amended with the change in the way the CEO reviews and assesses performance of the group and consist of Integrated Gas, Upstream, Oil Products, Chemicals and Corporate.

Revenue by business segment (including inter-segment sales)

	\$ million		
	2019	2018	2017
Integrated Gas			
Third parties	41,322	43,764	32,674
Inter-segment	4,280	5,031	4,096
Total	45,602	48,795	36,770
Upstream			
Third parties	9,965	9,892	7,723
Inter-segment	36,448	37,841	32,469
Total	46,413	47,733	40,192
Downstream			
Third parties	293,545	334,680	264,731
Inter-segment	1,132	917	1,090
Total	294,677	335,597	265,821
Corporate			
Third parties	45	43	51
Total	45	43	51

Revenue by geographical area (excluding inter-segment sales)

	\$ million		
	2019	2018	2017
Europe	98,455	118,960	100,609
Asia, Oceania, Africa	139,916	153,716	114,683
USA	83,212	89,876	66,854
Other Americas	23,294	25,827	23,033
Total	344,877	388,379	305,179

Technology and Innovation

Technology and innovation are essential to our efforts to meet the world's energy needs in a competitive way. If we do not develop the right technology, do not have access to it or do not deploy it effectively, this could have a material adverse effect on the delivery of our strategy and our licence to operate (see "risk factors" on pages 27-36). We continuously look for technologies and innovations of potential relevance to our business. Our Chief Technology Officer oversees the development and deployment of new and differentiating technologies and innovations across Shell, seeking to align business and technology requirements throughout our technology maturation process.

In 2019, research and development expenses were \$962 million, compared with \$986 million in 2018, and \$922 million in 2017. Our main technology centres are in India, the Netherlands and the USA, with other centres in Brazil, China, Germany, Oman, and Qatar. A strong patent portfolio underlies the technology that we employ in our various businesses. In total, we have around 9,449 granted patents and pending patent applications.

STRATEGY AND OUTLOOK

OUR STRATEGY

Shell's purpose is to power progress together by providing more and cleaner energy solutions.

Our strategy is to strengthen our position as a leading energy company by providing oil, gas and low-carbon energy products and services as the world's energy system transforms. Safety and social responsibility are fundamental to our business approach. Shell will only succeed by working collaboratively with customers, governments, business partners, investors and other stakeholders.

Our strategy is founded on our outlook for the energy sector and the chance to grasp the opportunities arising from the substantial changes in the world around us. The rising standard of living of a growing global population is likely to continue to drive demand for energy for years to come. The world will need to find a way to meet this growing demand, while transitioning to a lower-carbon energy system to counter climate change. While liquid and gaseous fuels, including biofuels and hydrogen, will continue to be an important part of the energy mix, over time electricity needs to play a bigger part in the world if it is to meet the goals of the Paris Agreement. Technological advances and the need to tackle climate change mean there is a transition under way to a lower-carbon, multi-source energy system with increasing customer choice. We recognise that the pace and the path forward are uncertain and so require agile decision-making.

FPSO P68, Offshore Brazil. Photo from Petrobras.



"We know the energy transition is unfolding, and we must be part of it if we are to survive as a business. Those companies that do not stay in step with society will be left behind."

BEN VAN BEURDEN
Chief Executive Officer

The field of the future: One of Shell's iShale® well pads is fully solar-powered, and able to run for 14 days with no sun. Permian Basin, USA.

Our strategic ambitions

Against this backdrop, we have the following strategic ambitions to guide us in pursuing our purpose:



**Thrive in
the energy
transition**

to thrive in the energy transition by responding to society's desire for more and cleaner, convenient and competitive energy;



**World-class
investment
case**

to provide a world-class investment case. This involves growing organic free cash flow and increasing returns, all built upon a strong financial framework and resilient portfolio; and



**Strong
licence to
operate**

to sustain a strong societal licence to operate and make a positive contribution to society through our activities.

The execution of our strategy is founded on becoming a more customer-centric and simpler, more streamlined organisation, focused on growing returns and organic free cash flow. By investing in competitive projects, delivering increases in cash flow from operations, and driving down costs, we are continually reshaping our portfolio to become a more resilient and focused company.

Our ability to achieve our strategic ambitions depends on how we respond to competitive forces. We continually assess the external environment – the markets and the underlying economic, political, social and environmental drivers that shape them – to evaluate changes in competitive forces and business models. We use multiple future scenarios to assess the resilience of our strategy. We regularly review the markets we operate in, assessing our competitive position by analysing trends and uncertainties, and the strengths and weaknesses of our traditional and non-traditional competitors.

We maintain business strategies and plans that focus on actions and capabilities to create and sustain competitive advantage. We maintain a risk management framework that regularly assesses our response to, and risk appetite for, identified risk factors.

📄 See “Risk factors” on **pages 27-36**.

Our Executive Directors’ remuneration is linked to the successful delivery of our strategy, based on performance indicators that are aligned with shareholder interests. Long-term incentives form the majority of the Executive Directors’ remuneration for above-target performance. In 2019, the Long-term Incentive Plan (LTIP) included cash generation, capital discipline, value created for shareholders, and a measure focused on Shell’s strategic ambition to thrive in the energy transition.

📄 See the “Directors’ Remuneration Report” on **pages 135-138**.

Our strategic themes

As part of our strategy, we divide our portfolio into strategic themes, each with distinctive capabilities, growth strategies and risk management.

Organising our businesses into seven strategic themes has helped us focus our investment priorities and drive delivery of our long-term ambitions. Due to the evolution of our businesses and the external environment, in 2019 we refreshed the way we group the strategic themes to better communicate our portfolio strategy and long-term outlook:

Core Upstream themes

Core Upstream themes are central to Shell and we will sustain their strong cash generation through the coming decades.



Deep Water

- Leading portfolio, strong growth funnel
- Sustained high-margin production



Shales

- Growing production in high-margin basins
- Competitive delivery



Conventional Oil and Gas

- High-graded portfolio with longevity
- Growth potential in deep resource base

Leading Transition themes

Leading transition themes are businesses where we already have a leading position in the industry and are critical for us to capitalise on the energy transition to a lower-carbon future.



Integrated Gas

- Extend market leadership
- Unique portfolio optimisation capability



Oil Products

- Most successful mobility retailer, #1 in lubricants
- Competitive/high-quality refining backbone



Chemicals

- Strong demand growth despite growing recycling
- Focus on base, derivative and performance chemicals

Emerging Power theme

Emerging Power theme is focused on creating business models to support the evolving customer demands for more electricity through the energy transition to a lower-carbon future. Shell aims to become an integrated power player and grow, over time, a significant new business.



Power

- New sources of value emerging
- Returns drive pace of scaling up

World-class asset
operatorship

+

Trading optimisation
through integration

+

Leverage customer
proximity and intimacy

OUTLOOK FOR 2020 AND BEYOND

We continually seek to improve our operating performance and maximise sustainable organic free cash flow, with an emphasis on health, safety, security, environment and asset performance, as well as our ethics and compliance principles. To do this, we are committed to attracting, developing and retaining a diverse, talented and motivated workforce.

We launched our \$25 billion share buyback programme in 2018, and we have completed about \$15 billion of buybacks as of February 20, 2020. Our intention to complete the \$25 billion share buyback programme remains unchanged, but the pace remains subject to macro conditions and further debt reduction.

Our cash capital expenditure is expected to be at the lower end of the \$24 billion to \$29 billion range in 2020. Following the successful delivery of our \$30 billion divestment programme during 2016-18, divestments are expected to amount to more than \$10 billion over the 2019-2020 period.

We fully support the Paris Agreement's goal to keep the rise in global average temperature this century to well below two degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius. We have set a long-term ambition to reduce the Net Carbon Footprint of our energy products, measured in grams of carbon dioxide equivalent per megajoule consumed, by around 20% by 2035 and by around 50% by 2050, in pace with society. While our ambition is long term, we believe we must act today if we are to help society progress more quickly. In early 2019 we set an unconditional three-year target to reduce our Net Carbon Footprint by 2% to 3% compared to 2016. For the 2020 award, the target range is a 3-4% reduction in our Net Carbon Footprint against the 2016 baseline. It is intended that this target setting will be done annually, with each year's target covering either a three-year or five-year period.

Further details are in the "Climate Change and Energy Transition" on pages 91-98.

Since the start of 2020 there has been a developing outbreak of the COVID-19 (coronavirus). To date, we have not seen a material impact on our operations. As a result of COVID-19, we have seen macro-economic uncertainty with regards to prices and demand for oil, gas and products. Furthermore, recent global developments and uncertainty in oil supply in March have caused further volatility in commodity markets. The scale and duration of these developments remain uncertain but could impact our earnings, cash flow and financial condition.

The statements in this "Strategy and outlook" section, including those related to our growth strategies and our expected or potential future cash flow from operations, organic free cash flow, share buybacks, capital investment, divestments, production and Net Carbon Footprint are based on management's current expectations and certain material assumptions and, accordingly, involve risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied herein.

See "About this Report" on pages 2-3 and "Risk factors" on pages 27-36.



Aerial view of road and Glengarry forest, Scotland, UK.
Forestry and Land Scotland is working with Shell UK to preserve and extend native woodland.

SECTION 172(1) STATEMENT

The revised UK Corporate Governance Code ('2018 Code') was published in July 2018 and applies to accounting periods beginning on or after January 1, 2019. The Companies (Miscellaneous Reporting) Regulations 2018 ('2018 MRR') require Directors to explain how they considered the interests of key stakeholders and the broader matters set out in section 172(1) (A) to (F) of the Companies Act 2006 ('S172') when performing their duty to promote the success of the Company under S172. This includes considering the interest of other stakeholders which will have an impact on the long-term success of the company. The Board welcomes the direction of the UK Financial Reporting Council (the 'FRC'). This S172 statement, which is reported for the first time, explains how Shell Directors:

- have engaged with employees, suppliers, customers and others; and
- have had regard to employee interests, the need to foster the company's business relationships with suppliers, customers and other, and the effect of that regards, including on the principal decisions taken by the company during the financial year.

The S172 statement focuses on matters of strategic importance to Shell, and the level of information disclosed is consistent with the size and the complexity of the business.

GENERAL CONFIRMATION OF DIRECTORS' DUTIES

Shell's Board has a clear framework for determining the matters within its remit and has approved Terms of Reference for the matters delegated to its Committees. Certain financial and strategic thresholds have been determined to identify matters requiring Board consideration and approval. The Manual of Authority sets out the delegation and approval process across the broader business. More information on Shell's Controls and Procedures can be found within the Other regulatory and statutory information page 168.

When making decisions, each Director ensures that he/she acts in the way he/she considers, in good faith, would most likely promote the Company's success for the benefit of its members as a whole, and in doing so have regard (among other matters) to:

S172(1) (A) "THE LIKELY CONSEQUENCES OF ANY DECISION IN THE LONG TERM"

The Directors understand the business and the evolving environment in which we operate, including the challenges of navigating through the energy transition. Based on Shell's purpose to power progress together by providing more and cleaner energy solutions, the strategy set by the Board is intended to strengthen our position as a leading energy company by providing oil, gas and low-carbon energy products and services as the world's energy system transforms while keeping safety and social responsibility fundamental to our business approach. In 2019, to help achieve all three strategic ambitions, the Board refreshed our strategy to further focus on developing Shell's Power business. However, while investing for the future, the Board also recognise we must meet today's energy demand.

As outlined in Our Context in the Shell Story pages 12-18, the rising standard of living of a growing global population is likely to continue to drive demand for energy, including oil and gas, for years to come. At the same time, technological changes and the need to tackle climate change mean there is a transition under way to a lower-carbon, multi-source energy system with increasing customer choice. The three strategic ambitions: thrive in the energy transition, world-class investment case and strong licence to operate pages 19-21 have been set in that context with the objective to increase long-term value for shareholders recognising that the long-term success of our business is dependent on our stakeholders and the external impact of our business activities on society.

The Directors recognise how our operations are viewed by different parts of society and that some decisions they take today may not align with all stakeholder interests. Given the complexity of the energy transition, the Directors have taken the decisions they believe best support Shell's three strategic ambitions.

S172(1) (B) "THE INTERESTS OF THE COMPANY'S EMPLOYEES"

The Directors recognise that Shell employees are fundamental and core to our business and delivery of our strategic ambitions. The success of our business depends on attracting, retaining and motivating employees. From ensuring that we remain a responsible employer, from pay and benefits to our health, safety and workplace environment, the Directors factor the implications of decisions on employees and the wider workforce, where relevant and feasible. The Directors recognise that our pensioners, though no longer employees, also remain important stakeholders.

More information on this can be found within our report on workforce engagement on page 124.

S172(1) (C) "THE NEED TO FOSTER THE COMPANY'S BUSINESS RELATIONSHIPS WITH SUPPLIERS, CUSTOMERS AND OTHERS"

Delivering our strategy requires strong mutually beneficial relationships with suppliers, customers, governments, national oil companies and joint-venture partners. Shell seeks the promotion and application of certain general principles in such relationships. The ability to promote these principles effectively is an important factor in the decision to enter into or remain in such relationships and this alongside other standards are described in The Shell General Business Principles, which are reviewed and approved by the Board periodically. The Board also reviews and approves Shell's approach to suppliers which is set out in the Shell Supplier Principles. The businesses continuously assess the priorities related to customers and those with whom we do business, and the Board engages with the businesses on these topics, for example, within the context of business strategy updates and investment proposals.

Moreover, the Directors receive information updates on a variety of topics that indicate and inform how these stakeholders have been engaged. These range from information provided from the Projects & Technology function (on suppliers and joint-venture partners related to items such as project updates and supplier contract management topics) to information provided by the businesses (on customers and joint-venture partners related to, for example, business strategies, projects and investment or divestment proposals).

S172(1) (D) "THE IMPACT OF THE COMPANY'S OPERATIONS ON THE COMMUNITY AND THE ENVIRONMENT"

This aspect is inherent in our strategic ambitions, most notably on our ambitions to thrive through the energy transition and to sustain a strong societal licence to operate. As such, the Board receives information on these topics to both provide relevant information for specific Board decisions (e.g. those related to specific strategic initiatives such as the Net Carbon Footprint ambition, our nature-based solutions programme and projects, investment or divestment proposals, business strategy reviews and country entry considerations) and to provide ongoing overviews at the Shell group level (e.g., regular Safety & Environment Performance Updates, reports from the Chief Ethics & Compliance Officer and Chief Internal Auditor). In 2019, certain Board Committees and Non-executive Directors conducted site visits of various Shell operations and overseas offices and held external stakeholder engagements, where feasible. More information on this can be found in Understanding and engaging with our stakeholders page 122.

SECTION 172(1) STATEMENT continued

S172(1) (E) “THE DESIRABILITY OF THE COMPANY MAINTAINING A REPUTATION FOR HIGH STANDARDS OF BUSINESS CONDUCT”

Shell aims to meet the world’s growing need for more and cleaner energy solutions in ways which are economically, environmentally and socially responsible. The Board periodically reviews and approves clear frameworks, such as The Shell General Business Principles, Shell’s Code of Conduct, specific Ethics & Compliance manuals, and its Modern Slavery Statements, to ensure that its high standards are maintained both within Shell businesses and the business relationships we maintain. This, complemented by the ways the Board is informed and monitors compliance with relevant governance standards help assure its decisions are taken and that Shell companies act in ways that promote high standards of business conduct.

S172(1) (F) “THE NEED TO ACT FAIRLY AS BETWEEN MEMBERS OF THE COMPANY”

After weighing up all relevant factors, the Directors consider which course of action best enables delivery of our strategy through the long-term, taking into consideration the impact on stakeholders. In doing so, our Directors act fairly as between the Company’s members but are not required to balance the Company’s interest with those of other stakeholders, and this can sometimes mean that certain stakeholder interests may not be fully aligned.

CULTURE

The Board recognises that it has an important role in assessing and monitoring that our desired culture is embedded in the values, attitudes and behaviours we demonstrate, including in our activities and stakeholder relationships. The Board has established honesty, integrity and respect for people as Shell’s core values. The General Business Principles, Code of Conduct, and Code of Ethics help everyone at Shell act in line with these values and comply with relevant laws and regulations. The Shell Commitment and Policy on Health, Safety, Security, Environment & Social Performance applies across Shell and is designed to help protect people and the environment. We relentlessly pursue Goal Zero, our safety goal to achieve no harm and no leaks across all our operations. We also strive to maintain a diverse and inclusive culture.

The Board considers the Shell People Survey to be one of its principal tools to measure employee engagement, motivation, affiliation and commitment to Shell. It provides insights into employee views and has a consistently high response rate. The Board also utilises this engagement to understand how survey outcomes are being leveraged to strengthen Shell culture and values.

STAKEHOLDER ENGAGEMENT (INCLUDING EMPLOYEE ENGAGEMENT)

The Board recognises the important role Shell has to play in society and is deeply committed to public collaboration and stakeholder engagement. This commitment is at the heart of Shell’s strategic ambitions. The Board strongly believes that Shell will only succeed by working with customers, governments, business partners, investors and other stakeholders. Working together is critical, particularly at a time when society, including businesses, governments and consumers, faces issues as complex and challenging as climate change.

We continue to build on our long track record of working with others, such as investors, industry and trade groups, universities, governments, NGOs and in some instances our competitors through our joint-venture operations or industry bodies. We believe that working together and sharing knowledge and experience with others offers us greater insight into our business. We also appreciate our long-term relationships with our investors and acknowledge the positive impact of ongoing engagement and dialogue.

To support strengthening the Board’s knowledge of the significant levels of engagement undertaken by the broader business, guidance on information, proposals or discussion items provided to the Board was updated in 2019 to further promote and focus considerations of the views, interests and concerns of our stakeholders and how these were considered by Management. Board minutes have also reflected key points on stakeholder considerations, where appropriate. Further, the Terms of Reference for our Safety, Environment and Sustainability Committee were updated to include, within the Committee’s remit, the review and consideration of external stakeholder perspectives and how major issues of public concern that could affect the Shell group’s reputation and licence to operate were, or are, being addressed.

The Board also engaged with certain stakeholders directly, to understand their views. More on this engagement is provided in the Understanding and engaging with our stakeholders on page 122.

Information on how the Directors have engaged with employees can be found on page 124 and in the Our people section on pages 99-101. Examples of how Directors have taken the interests of Shell employees into consideration and the consequent outcome on related decisions is incorporated in the table below.

PRINCIPAL DECISIONS

In the table below, we outline some of the principal decisions made by the Board over the year, explain how the Directors have engaged with, or in relation to, the different key stakeholder groups and how stakeholder interests were considered over the course of decision-making.

To remain concise, we have categorised our key stakeholders into six groups. Where appropriate, each group is considered to include both current and potential stakeholders.

- A Investor Community
- B Employees/Workforce/Pensioners
- C Regulators/Governments/NGOs
- D Communities
- E Customers
- F Suppliers/Strategic Partners

Principal decisions

We define principal decisions taken by the Board as those decisions in 2019 that are of a strategic nature and that are significant to any of our key stakeholder groups. As outlined in the FRC Guidance on the Strategic Report, we include decisions related to capital allocation and dividend policy.

How were stakeholders considered

We describe how regard was given to likely long-term consequences of the decision including how stakeholders were considered during the decision-making process.

What was the outcome

We describe which accommodations/ mitigations were made, if any, and how Directors have considered different interests and the factors taken into account.

Approval of Shell's Operating Plan 2020-2022 (OP19)

The approval of OP19 followed an in-depth review by the Board of proposals on capital allocation, capital investment outlook, competitive outlook, operating expenses, return on average capital employed and shareholder distributions. This includes reviews in October 2019 as an advance engagement on OP19 while it was under preparation, and in December 2019 for final approval.

How were stakeholders considered

OP19 discussions included a full review against Shell's three strategic ambitions: thriving in the energy transition, world-class investment case, and strong societal licence to operate. The Directors and Executive Committee balanced the priorities in the operational plan versus the strategy by using feedback received as part of continuous engagement with investors, discussions with equity and debt market analysts and commitments made regarding share buybacks, gearing and organic free cash flow.

The plan was discussed extensively and included commitment to continue investing in the energy transition, which is a reflection of the importance that communities and interest groups were likely to place on key societal contributions/efforts regarding carbon-neutral offerings for mobility customers, growth in Nature-Based Solutions, support for Net Carbon Footprint ambition reductions and published government plans related to the energy transition.

In the assessment, the interests of investors and capital markets received particular focus and featured heavily in many discussions, and potential differing interests of debt and equity investors was observed. This was balanced against the importance of the value placed on Shell by society (including communities, employees, customers, suppliers) for the services provided by the business and the way in which we conduct business.

Information on employees and our organisational structure featured as part of OP19. The plan maintained the approach to salaries, benefits, health, worker welfare, focus on employee experience and training.

Metrics agreed within OP19 underpin the 2020 organisational scorecard, against which all employee bonuses are calculated. Both the Board and the Remuneration Committee discussed these metrics at length to ensure they are suitably stretching and motivating, support the right culture within the business and align to the strategic ambitions.

Investing in new business and acquisitions

Over the course of the year, the Board discussed and approved several new opportunities and projects across the different segments. The Board focused on Power and discussed and approved the continued implementation of the Power Strategy. It made certain recommendations to Management and appraised potential investment opportunities which comprised wholly-owned acquisitions and joint-venture opportunities. The Board receives regular updates and maintains oversight of the operations of the New Energies business even though many of the investments in this area are below the threshold for Board decision.

How were stakeholders considered

The Board obtained a clearer perspective on the pace of local energy transitions, regulation, changing customer needs and technology. This enhanced awareness was used to evaluate the possible impact on stakeholders and risks to its reputation in relation to certain stakeholder groups.

Oil and Gas – During the year Shell has secured new opportunities in a number of regions, some of which were considered and approved by the Board. The Directors carefully reviewed new significant entries and risk and rewards of new projects. During these discussions, the Board was cognisant that some stakeholders may not agree with Shell's strategy to continue to invest in oil and gas during the energy transition.

Purchase of ERM – Although below the normal threshold of investments for Board approval, the discussion was the result of earlier Board requests to enhance its understanding of the New Energies investments, customer demand, the alignment with the Shell strategy and the Board's commitments to its stakeholders including investors. During discussions, particular attention was paid to the alignment of assets owned by ERM with Shell's overall long-term ambitions, and stakeholder views. The discussions and considerations for the purchase of this listed entity covered its business model and people, assets and synergies, fit with the Shell Power strategy and the ability to generate returns while playing a role in the transition to a lower-carbon future. The Board also reflected on the Shell brand and its ability to retain ERM customers under new ownership.

Eneco – The attempted purchase of Eneco is a clear example of the Board's reflections on feedback received from equity and debt market analysts and its statements made regarding the share buybacks, gearing and organic free cash flow. Further, it reflects Shell's desire to increase its operations in this area. Significant engagement was undertaken as part of the bid preparation, which included understanding customer sentiment, government and local municipality opinion and the ability to retain Eneco employees following transfer of ownership in the event of a winning bid. The outcome of this engagement was provided to the Board.

For both proposals, the Board considered the interests of investment partners and potential organisational cultural differences. Customer relationships, local regulatory knowledge and other stakeholder relationships including local community views were also discussed. The Board also discussed how the potential deal(s) could be received by investors and the equity analyst community. The Board was particularly cognisant that investors would want to understand how acquisitions would fit within the existing financial framework and the impact if any on: expected outturns, the share buyback programme, cashflow; and capital investment.

What was the outcome

Following the review of the draft plan, the Board requested further information on specific matters such as capital allocation, new energies and organisational aspects, several of which included certain stakeholder groups. Responses were provided on these items and changes were incorporated into the plan where appropriate.

The early review of the plan identified weaker macroeconomic conditions and challenging outlooks. Although an unwelcome message for stakeholders, this was communicated to the market at the end of the third quarter and reiterated it in the fourth quarter results.

The overall outcome of this decision is an operating plan that the Board believes underpins Shell's strategic ambitions and has taken into account different stakeholder views, realising that not all stakeholder views can nor will completely align with OP19.

While stakeholder opinion may differ on Shell's approach, OP19 is based on the demand for products and services by society. OP19 supports the Company maintaining a reputation for high standards of business conduct, Health, Safety, Security and Environment and maintained the approach to employee remuneration and benefits to pensioners. OP19 seeks to reward our investors with returns and maintaining long-term financial strength to invest in more and cleaner forms of energy and meet the current and future needs of society.

What was the outcome

As a result of discussion and decisions in this area, the Board obtained insights on renewables growth, customers' priorities (around price and interest in clean power), as well as information on anticipated market direction and regulatory frameworks. The Board also committed a large part of its annual strategy event and committed further time later in the years to enhancing its understanding of New Energies and the opportunities in Power through, for instance, site visits with companies, governments, regulators, academics and potential customers. (Read more on page 122)

Oil and Gas – The Board recognises that societal views vary widely in this area. However, it must also bear in mind that global demand for energy is still growing. Although renewable resources will meet a growing share of the rising energy demand, Shell and other experts believe there continues to be a need for oil and gas for many years to come through the energy transition. The Directors also appreciate that it is this business that provides the capital to invest in the energy transition.

Purchase of ERM – Following discussion in the early part of the year, the Board was keen to better understand the New Energies' investments, their alignment with the Power Strategy and the new opportunities being potentially pursued. It now receives summary information of smaller deals and clarifications on the strategic and business alignment of the larger deals. The Directors asked questions and shared their expertise when provided with these updates.

Eneco – The Eneco discussion covered many Board meetings, with questions coming from each discussion and further research and understanding provided back to the Board. As Management and the Board have been clear that they will only pursue ambitions in this area at the right cost, the bid from the Shell consortium was lower than that of its competitors and therefore unsuccessful.

SECTION 172(1) STATEMENT continued

Divestments and exits from markets	What was the outcome
<p>Selected assets were divested in 2019. More information on these can be found further within the Strategic Report. An example divestment is the sale of the Martinez refinery based in California, which was fully completed in February 2020.</p> <p>How were stakeholders considered</p> <p>Given the size of the Martinez asset, the sale was discussed by the Board. The divestment aligned with Shell's strategy to reshape refining efforts towards a smaller, smarter refining portfolio focused on further integration with Shell Trading hubs, Chemicals, and Marketing.</p> <p>The Board considered how the Martinez divestment would be received by local communities and the potential reputational implications. Further, the Board observed that other retained businesses may feel at risk and more widely considered the potential impact on value chain cash generation.</p> <p>The future prospects, environment liabilities and the impact on employees were considered by the Board and included expectations around employee retention by the new buyer. Agreements were put in place regarding certain employee benefits which would be met by Shell for a period of time following the divestment.</p>	<p>Announcements and communications relating to divestments are drafted proactively. The stakeholder engagement plan included local government and communities. The plan focused on supporting community confidence in operations post-divestment.</p> <p>Engagement related to employees was undertaken, and agreement was reached regarding certain Shell-paid benefits.</p> <p>Community concerns regarding Shell's exit were addressed.</p>
Shareholder Distributions	What was the outcome
<p>Every quarter, the Board assessed the continuation of the share buyback programme as well as the ongoing payment and rate of dividend per share payable to shareholders.</p> <p>How were stakeholders considered</p> <p>A number of metrics underpinned each decision, including the BG intention statement regarding the equity issued in connection with the combination with the BG Group.</p> <p>At the time of each decision, the Board received an update on investor views based on equity and debt market opinions, Executive Committee and Investor Relations engagements, Chair engagements and rating agency views. Along with the other investor meetings undertaken by the Board and outlined within the stakeholder engagement section of this report (see page 122), towards the end of the year, the Senior Independent Director undertook a number of engagements to discuss the proposed remuneration policy, this provided investors a further opportunity to share views on other matters.</p> <p>In making decisions, the Board considered investor expectations, the BG intention statement regarding share buybacks, and the flexibility afforded by Operating Plans, which included known and anticipated organic free cash flow and were reflective of the actual and expected business performance at the time of the decisions.</p>	<p>As the macroeconomic environment changed during the year, further considerations were given to differing stakeholder opinion and balanced against prior intention statements. In the later part of the year, as part of the paper requesting approval for the share buyback and dividend payment, the Board received potential market reaction from equity and debt holders on pacing options related to the share buyback in consideration of the prevailing macroeconomic environment, including lower oil and gas prices. At the third quarter results announcement, the Company communicated the potential impact of these conditions on the pace of the share buyback programme and gearing reduction.</p>

RISK FACTORS

The risks discussed below could have a material adverse effect separately, or in combination, on our earnings, cash flows and financial condition. Accordingly, investors should carefully consider these risks.

Further background on each risk is set out in the relevant sections of this Report indicated by way of cross references under each risk factor.

The Board's responsibility for identifying, evaluating and managing our significant risks is discussed in "Other Regulatory and Statutory Information" pages 168-171.

Risk description

How this risk is managed

We are exposed to macroeconomic risks including fluctuating prices of crude oil, natural gas, oil products and chemicals

The prices of crude oil, natural gas, oil products and chemicals are affected by supply and demand, both globally and regionally. Furthermore, macroeconomic risks can affect demand for our products. Government actions may also affect the prices of crude oil, natural gas, oil products and chemicals. This could happen, for example, by promoting the sale of lower-carbon electric vehicles or even through the future prohibition of sales of new diesel or gasoline vehicles, such as the prohibition in the United Kingdom (UK) beginning in 2035. Prices for oil and gas can also move independently of each other. Factors that influence supply and demand include operational issues, natural disasters, weather, pandemics, such as the COVID-19 (coronavirus) outbreak, political instability, conflicts, economic conditions and actions by major oil and gas producing countries. In a low oil and gas price environment, we would generate less revenue from our Upstream and Integrated Gas businesses, and, as a result, parts of those businesses could become less profitable, or could incur losses. Low oil and gas prices have also resulted and could continue to result in the debooking of proved oil or gas reserves, if they become uneconomic in this type of price environment. Prolonged periods of low oil and gas prices, or rising costs, have resulted and could continue to result in projects being delayed or cancelled. Assets have also been impaired in the past, and there could be impairments in the future. Low oil and gas prices could also affect our ability to maintain our long-term capital investment programme and dividend payments. Prolonged periods of low oil and gas prices could adversely affect the financial, fiscal, legal, political and social stability of countries that rely significantly on oil and gas revenue. In a high oil and gas price environment, we could experience sharp increases in costs, and, under some production-sharing contracts, our entitlement to proved reserves would be reduced. Higher prices could also reduce demand for our products, which could result in lower profitability, particularly in our Downstream business. Also, higher prices can result in more capacity being built which results in an oversupply of products that can negatively impact our LNG and Chemicals business. Accordingly, price fluctuations could have a material adverse effect on our earnings, cash flows and financial condition.

See "Market overview" on page 37.

We maintain a diversified portfolio to mitigate the impact of price volatility. We test the resilience of our projects and other opportunities against a range of crude oil, natural gas, oil product and chemical prices and costs. We prepare annual strategic and financial plans that consider and analyse the impact of different pricing scenarios on our businesses and company as a whole. These plans are appraised regularly throughout the year. We also aim to maintain a strong balance sheet to provide resilience against weak market prices.

Our ability to deliver competitive returns and pursue commercial opportunities depends in part on the accuracy of our price assumptions.

We use a range of oil and gas price assumptions, which we review on a periodic basis, to evaluate projects and commercial opportunities. If our assumptions prove to be incorrect, it could have a material adverse effect on our earnings, cash flows and financial condition.

See "Market overview" on page 39.

The range of commodity prices used in our project and portfolio evaluations is subject to a rigorous assessment of short, medium and long-term market drivers.

Our ability to achieve our strategic objectives depends on how we react to competitive forces.

We face competition in each of our businesses. We seek to differentiate our products; however, many of them are competing in commodity-type markets. Accordingly, failure to manage our costs as well as our operational performance could result in a material adverse effect on our earnings, cash flows and financial condition. We also compete with state-owned oil and gas entities with access to vast financial resources. State-owned entities could be motivated by political or other factors in making their business decisions. Accordingly, when bidding on new leases or projects, we could find ourselves at a competitive disadvantage as these state-owned entities may not require a competitive return. If we are unable to obtain competitive returns when bidding on new leases or projects, it could have a material adverse effect on our earnings, cash flows and financial condition.

See "Strategy and outlook" on page 20.

We continually assess the external environment – the markets and the underlying economic, political, social and environmental drivers that shape them – to evaluate changes in competitive forces and business models. We use multiple future scenarios to assess the resilience of our strategy. We maintain business strategies and plans that focus on actions and capabilities to create and sustain competitive advantage.

RISK FACTORS continued

Risk description

We seek to execute divestments in the pursuit of our strategy. We may not be able to successfully divest these assets in line with our strategy.

We may not be able to successfully divest assets at acceptable prices or within the timeline envisaged due to market conditions or credit risk. This would result in increased pressure on our cash position and potential impairments. In some cases, we have also retained certain liabilities following a divestment. Even in cases where we have not expressly retained certain liabilities, we may still be held liable for past acts, failures to act or liabilities that are different from those foreseen. We may also face liabilities if a purchaser fails to honour their commitments. Accordingly, if we are unable to divest assets at acceptable prices or within our envisaged timeframe, this could have a material adverse effect on our earnings, cash flows and financial condition.

See "Strategy and outlook" on page 22.

Our future hydrocarbon production depends on the delivery of large and integrated projects, as well as on our ability to replace proved oil and gas reserves.

We face numerous challenges in developing capital projects, especially those which are large and integrated. Challenges include: uncertain geology; frontier conditions; the existence and availability of necessary technology and engineering resources; the availability of skilled labour; the existence of transportation infrastructure; project delays; the expiration of licences; potential cost overruns; and technical, fiscal, regulatory, political and other conditions. These challenges are particularly relevant in certain developing and emerging-market countries, in frontier areas and in deep-water fields, such as off the coast of Brazil. We may fail to assess or manage these and other risks properly. Such potential obstacles could impair our delivery of these projects, our ability to fulfil the value potential determined at the time of the project investment approval, and/or our ability to fulfil related contractual commitments. These could lead to impairments and could have a material adverse effect on our earnings, cash flows and financial condition.

Future oil and gas production will depend on our access to new proved reserves through exploration, negotiations with governments and other owners of proved reserves and acquisitions, as well as on developing and applying new technologies and recovery processes to existing fields. Failure to replace proved reserves could result in lower future production, potentially having a material adverse effect on our earnings, cash flows and financial condition.

Oil and gas production available for sale

	Million boe [A]		
	2019	2018	2017
Shell subsidiaries	1,182	1,179	1,168
Shell share of joint ventures and associates	156	159	170
Total	1,338	1,338	1,338

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

Proved developed and undeveloped oil and gas reserves [A][B] (at December 31)

	Million boe [C]		
	2019	2018	2017
Shell subsidiaries	9,980	10,294	10,177
Shell share of joint ventures and associates	1,116	1,285	2,056
Total	11,096	11,578	12,233
Attributable to non-controlling interest in Shell subsidiaries	304	331	325

[A] We manage our total proved reserves base without distinguishing between proved reserves from subsidiaries and those from joint ventures and associates.

[B] Includes proved reserves associated with future production that will be consumed in operations.

[C] Natural gas volumes are converted into oil equivalents using a factor of 5,800 scf per barrel.

See "Shell Story" on page 17.

How this risk is managed

We carefully tailor our sales processes against buyers' perceived expectations to deliver the most competitive outcomes. As a general principle, the sales processes are set up so that buyers will acquire the assets including all related liabilities. For some assets, Shell may agree to retain certain liabilities, which are closely monitored and for which appropriate provisions are made.

We continue to explore for, and mature, hydrocarbons across our Deep Water, Conventional Oil and Gas, Shales and Integrated Gas strategic themes. We use our subsurface, project and technical expertise and actively manage non-technical risks across a diversified portfolio of opportunities and projects. This is done with an integrated approach from basin choice through to development, where we employ a number of competitive techniques and benchmark our approach internally and externally.

Risk description

The estimation of proved oil and gas reserves involves subjective judgements based on available information and the application of complex rules; therefore, subsequent downward adjustments are possible.

The estimation of proved oil and gas reserves involves subjective judgements and determinations based on available geological, technical, contractual and economic information. Estimates could change because of new information from production or drilling activities, or changes in economic factors, including changes in the price of oil or gas and changes in the regulatory policies of host governments, or other events. Estimates could also be altered by acquisitions and divestments, new discoveries, and extensions of existing fields and mines, as well as the application of improved recovery techniques. Published proved oil and gas reserves estimates could also be subject to correction due to errors in the application of published rules and changes in guidance. Downward adjustments could indicate lower future production volumes and could also lead to impairment of assets. This could have a material adverse effect on our earnings, cash flows and financial condition.

See “Supplementary information – oil and gas (unaudited)” on page 239.

Rising climate change concerns have led and could lead to additional legal and/or regulatory measures which could result in project delays or cancellations, a decrease in demand for fossil fuels, potential litigation and additional compliance obligations.

In December 2015, 195 nations adopted the Paris Agreement, which we fully support. The Paris Agreement aims to limit increases in global temperatures to well below two degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius. As a result, we expect continued and increased attention to climate change from all sectors of society. This attention has led, and we expect it to continue to lead, to additional regulations designed to reduce greenhouse gas (GHG) emissions.

We expect that a growing share of our GHG emissions will be subject to regulation, resulting in increased compliance costs and operational restrictions. If our GHG emissions rise alongside our ambitions to increase the scale of our business, our regulatory burden will increase proportionally. We also expect that GHG regulation, as well as emission reduction actions by customers, will continue to result in suppression of demand for fossil fuels, either through taxes, fees and/or incentives to promote the sale of lower-carbon electric vehicles or even through the future prohibition of sales of new diesel or gasoline vehicles, such as the prohibition in the United Kingdom (UK) beginning in 2035. This could result in lower revenue and, in the long term, potential impairment of certain assets.

In addition, the physical effects of climate change such as, but not limited to, rise in temperature, sea-level rise and fluctuations in water levels could adversely impact both our operations and supply chains.

In some countries, governments, regulators, organisations and individuals have filed lawsuits seeking to hold fossil fuel companies liable for costs associated with climate change. While we believe these lawsuits to be without merit, losing any of these lawsuits could have a material adverse effect on our earnings, cash flows and financial condition.

Additionally, some groups are pressuring certain investors to divest their investments in fossil fuel companies. If this were to continue, it could have a material adverse effect on the price of our securities and our ability to access capital markets. Additionally, some groups are pressuring commercial and investment banks from financing fossil fuel companies. Furthermore, according to press reports, some financial institutions also appear to be considering limiting their exposure to certain fossil fuel projects. Accordingly, our ability to use financing for future projects may be adversely impacted. This could also adversely impact our potential partners' ability to finance their portion of costs, either through equity or debt.

If we are unable to find economically viable, as well as publicly acceptable, solutions that reduce our GHG emissions and/or GHG intensity for new and existing projects or for the products we sell, we could experience additional costs or financial penalties, delayed or cancelled projects, and/or reduced production and reduced demand for hydrocarbons. This could have a material adverse effect on our earnings, cash flows and financial condition.

If we are unable to keep pace with society's energy transition or we are unable to provide the desired low-GHG-emissions products needed to facilitate society's energy transition, it could have a material adverse effect on our earnings, cash flows and financial condition.

See “Climate change and energy transition” on page 93.

How this risk is managed

A central group of reserves experts undertake the primary assurance of the proved reserves bookings. A multidisciplinary committee reviews and endorses all major proved reserves bookings. All proved reserves bookings are reviewed by Shell's Audit Committee, with final approval residing with Shell's Executive Committee. The Internal Audit function also provides further assurance through audits of the control framework.

The risk is actively monitored and reviewed by the Executive Committee. These regular reviews lead to actions designed to address all the different components of the risk. Overall the mitigation of the risk is addressed through our strategy to thrive in the energy transition. This is made up of three components:

- reducing the GHG emissions intensity of our operations;
- demonstrating resilience by adopting the guidance on disclosure by the Task Force on Climate-related Financial Disclosures; and
- working towards our ambition to reduce the Net Carbon Footprint of the energy products we sell, in step with society's drive to reduce GHG emissions.

Please refer to the risk factor “The nature of our operations exposes us, and the communities in which we work, to a wide range of health, safety, security and environment risks” for further explanation of how the physical effects of climate change on our operations and supply chains are managed.

RISK FACTORS continued

Risk description

Our business exposes us to risks of social instability, criminality, civil unrest, terrorism, piracy, cyber-disruption, acts of war and pandemic diseases, such as the COVID-19 (coronavirus) outbreak, that could have a material adverse effect on our operations.

As seen in recent years, these risks can manifest themselves in the countries in which we operate and elsewhere. These risks affect people and assets. Potential risks include: acts of terrorism; acts of criminality including maritime piracy; cyber-espionage or disruptive cyber-attacks; conflicts including war, civil unrest and environmental and climate activism (including disruptions by non-governmental and political organisations); and pandemic diseases, such as the COVID-19 (coronavirus) outbreak.

The above risks can threaten the safe operation of our facilities and transport of our products, cause disruption of operational activities, environmental harm, loss of life, injuries and impact the well-being of our people.

These risks could have a material adverse effect on our earnings, cash flows and financial condition.

See “Environment and society” on page 84.

We operate in more than 70 countries that have differing degrees of political, legal and fiscal stability. This exposes us to a wide range of political developments that could result in changes to contractual terms, laws and regulations. In addition, we and our joint arrangements and associates face the risk of litigation and disputes worldwide.

Developments in politics, laws and regulations can and do affect our operations. Potential impacts include: forced divestment of assets; expropriation of property; cancellation or forced renegotiation of contract rights; additional taxes including windfall taxes, restrictions on deductions and retroactive tax claims; antitrust claims; changes to trade compliance regulations; price controls; local content requirements; foreign exchange controls; changes to environmental regulations; changes to regulatory interpretations and enforcement; and changes to disclosure requirements. Any of these, individually or in aggregate, could have a material adverse effect on our earnings, cash flows and financial condition.

In addition to the above risks, the UK left the European Union (EU) on January 31, 2020 and enters into a period of transition which ends on December 31, 2020. The UK has stated that it will not extend the period of transition, and has confirmed plans to introduce import controls on EU goods at the border after the period of transition ends. Whatever the outcome of negotiations, we may experience delays in moving our products and employees between the UK and EU. Also, additional tariffs and taxes could impact the demand for some of our products. This potential delay and reduced demand for our products, combined with the potential adverse changes in macroeconomic conditions in both the EU and UK, could have a material adverse effect on our earnings and cash flows.

From time to time, social and political factors play a role in unprecedented and unanticipated judicial outcomes that could adversely affect Shell. Non-compliance with policies and regulations could result in regulatory investigations, litigation and, ultimately, sanctions. Certain governments and regulatory bodies have, in Shell’s opinion, exceeded their constitutional authority by: attempting unilaterally to amend or cancel existing agreements or arrangements; failing to honour existing contractual commitments; and seeking to adjudicate disputes between private litigants. Additionally, certain governments have adopted laws and regulations that could potentially conflict with other countries’ laws and regulations, potentially subjecting us to both criminal and civil sanctions. Such developments and outcomes could have a material adverse effect on our earnings, cash flows and financial condition.

See “Other Regulatory and Statutory Information” on page 134.

How this risk is managed

We seek to obtain the best possible information to enable us to assess threats and risks. We conduct detailed assessments for all our sites and activities, and implement appropriate measures to deter, detect and respond to security risks. Further mitigations include the strengthening of the security of sites, reduction of our exposure as appropriate, journey management, information risk management as well as crisis management and business continuity measures. We conduct training and awareness campaigns for staff and provide travel and health advice and 24/7 assistance while travelling.

We continuously monitor geopolitical developments and societal issues relevant to our interests. Our Legal and Tax functions are organised globally and support the business lines in ensuring compliance with local laws and fiscal regulations. Our Government Relations department engages with governments in countries where we operate to understand and influence local policies and to advocate Shell’s position on topics relevant to our industry. We are prepared to exit a country if we believe we can no longer operate in that country in accordance with our standards and applicable law, and we have done so in the past.

Risk description

The nature of our operations exposes us, and the communities in which we work, to a wide range of health, safety, security and environment risks.

The health, safety, security and environment (HSSE) risks to which we, and the communities in which we work, are potentially exposed cover a wide spectrum, given the geographic range, operational diversity and technical complexity of our operations. These risks include the effects of natural disasters (including weather events), earthquakes, social unrest, personal health and safety lapses, and crime. If a major risk materialises, such as an explosion or hydrocarbon spill, this could result in injuries, loss of life, environmental harm, disruption of business activities, and loss or suspension of our licence to operate or ability to bid on mineral rights. Accordingly, this could have a material adverse effect on our earnings, cash flows and financial condition.

Our operations are subject to extensive HSSE regulatory requirements that often change and are likely to become more stringent over time. Governments could require operators to adjust their future production plans, as has been done in the Netherlands, affecting production and costs. We could incur significant additional costs in the future due to compliance with these requirements or as a result of violations of, or liabilities under, laws and regulations, such as fines, penalties, clean-up costs and third-party claims. Therefore, HSSE risks, should they materialise, could have a material adverse effect on our earnings, cash flows and financial condition.

See “Environment and society” on page 84.

A further erosion of the business and operating environment in Nigeria could have a material adverse effect on us.

In our Nigerian operations, we face various risks and adverse conditions. These include: security issues surrounding the safety of our people, host communities and operations; sabotage and theft; our ability to enforce existing contractual rights; litigation; limited infrastructure; potential legislation that could increase our taxes or costs of operations; the effect of lower oil and gas prices on the government budget; and regional instability created by militant activities. These risks or adverse conditions could have a material adverse effect on our earnings, cash flows and financial condition.

See “Upstream” on page 57.

Production from the Groningen field in the Netherlands causes earthquakes that affect local communities.

Shell and ExxonMobil are 50:50 shareholders in Nederlandse Aardolie Maatschappij B.V. (NAM). An important part of NAM's gas production comes from the onshore Groningen gas field, in which EBN, a Dutch government entity, has a 40% interest and NAM a 60% interest. The gas field is in the process of being closed down due to gas-production-induced earthquakes. Some of these earthquakes have caused damage to houses and other structures in the region, resulting in complaints and lawsuits from the local community. The Government has announced their intent for an accelerated close-down to reduce Groningen production to zero by mid-2022. The exact date is still to be decided. While we are hopeful the closing down of the Groningen gas field will reduce the number and strength of earthquakes in the region, any additional earthquakes and lawsuits could have further adverse impacts on our earnings, cash flows and financial condition.

See “Upstream” on page 54.

How this risk is managed

We have standards and a clear governance structure to help manage potential impacts. They are defined in our Health, Safety, Security, Environment and Social Performance (HSSE & SP) control framework and supporting guidance documents. The process safety and HSSE & SP assurance team provides assurance on the effectiveness of HSSE & SP controls to the Board. We also routinely prepare and practise our emergency response to potential incidents such as a spill or a fire.

We test the economic and operational resilience of our Nigerian projects against a wide range of assumptions and scenarios. We seek to proportionally share risks and funding commitments with joint-venture partners. We monitor the security situation, and liaise with host communities, governmental and non-governmental organisations to help promote peaceful and safe operations.

NAM is working with the Dutch government and other stakeholders to fulfil its obligations to residents of the area, which include compensation for damage caused by the earthquakes. Negotiations with the state are ongoing to determine how the accelerated close-down should be managed. Specific remediations within the agreed scope of responsibilities are planned. NAM's joint-venture partners will review its financial robustness against different scenarios for Groningen's liabilities and costs, with the objective that the venture can self-fund any additional expenses and claims.

Risk description**Our future performance depends on the successful development and deployment of new technologies and new products.**

Technology and innovation are essential to our efforts to meet the world's energy demands in a competitive way. If we do not continue to develop or deploy technology and new products, or fully leverage our data effectively in a timely and cost-effective manner, there could be a material adverse effect on the delivery of our strategy and our licence to operate. We operate in environments where advanced technologies are utilised. In developing new technologies and new products, unknown or unforeseeable technological failures or environmental and health effects could harm our reputation and licence to operate or expose us to litigation or sanctions. The associated costs of new technology are sometimes underestimated, or delays occur. If we are unable to develop the right technology and products in a timely and cost-effective manner, or if we develop technologies and products that adversely impact the environment or health of individuals, there could be a material adverse effect on our earnings, cash flows and financial condition.

See "Shell Story" on **page 18**.

We are exposed to treasury and trading risks, including liquidity risk, interest rate risk, foreign exchange risk and credit risk. We are affected by the global macroeconomic environment as well as financial and commodity market conditions.

Our subsidiaries, joint arrangements and associates are subject to differing economic and financial market conditions around the world. Political or economic instability affects such markets.

We use debt instruments, such as bonds and commercial paper, to raise significant amounts of capital. Should our access to debt markets become more difficult, the potential impact on our liquidity could have a material adverse effect on our operations. Our financing costs could also be affected by interest rate fluctuations or any credit rating deterioration.

We are exposed to changes in currency values and to exchange controls as a result of our substantial international operations. Our reporting currency is the US dollar. However, to a material extent, we hold assets and are exposed to liabilities in other currencies. While we undertake some foreign exchange hedging, we do not do so for all our activities. Furthermore, even where hedging is in place, it may not function as expected.

We are exposed to credit risk; our counterparties could fail or could be unable to meet their payment and/or performance obligations under contractual arrangements. Although we do not have significant direct exposure to sovereign debt, it is possible that our partners and customers may have exposure which could impair their ability to meet their obligations. In addition, our pension plans invest in government bonds, and therefore could be affected by a sovereign debt downgrade or other default.

If any of the risks set out above materialise, they could have a material adverse effect on our earnings, cash flows and financial condition.

See "Liquidity and capital resources" on **page 80** and Note 19 to the "Consolidated Financial Statements" on **pages 227-231**.

How this risk is managed

Shell's Technology organisation and the relevant lines of business work together to determine the content, scope and budget for developing new technology that supports our activities. The new technology is developed to ensure portfolio alignment with Shell's strategic ambitions and deployment commitments. A significant proportion of Shell's technology contributes to Shell's New Energies portfolio and Net Carbon Footprint ambition, and is built around key relationships with leading academic research institutes and universities. We also benefit from working with start-ups. In our Shell GameChanger programme, we help companies to mature early-stage technologies. In our Shell Ventures scheme, we invest in and partner with start-ups and small and medium-sized enterprises that are in the early stages of developing new technologies.

We utilise various financial instruments for managing exposure to foreign exchange and interest rate movements. Our treasury operations are highly centralised and seek to manage credit exposures associated with our substantial cash, foreign exchange and interest rate positions. Our portfolio of cash investments is diversified to avoid concentrating risk in any one instrument, country or counterparty. Other than in exceptional cases, the use of external derivative instruments is confined to specialist central treasury organisations that have appropriate skills, experience, supervision, control and reporting systems. Credit risk policies are in place to ensure that sales of products are made to customers with appropriate creditworthiness, and include detailed credit analysis and monitoring of customers against counterparty credit limits. Where appropriate, netting arrangements, credit insurance, prepayments and collateral are used to manage credit risk. We maintain a committed credit facility. Management believes it has access to sufficient debt funding sources (capital markets) and to undrawn committed borrowing facilities to meet foreseeable requirements.

Risk description

We are exposed to commodity trading risks, including market and operational risks.

Commodity trading is an important component of our Upstream, Integrated Gas and Downstream businesses and is integrated with our supply business. Processing, managing and monitoring a large number of trading transactions across the world, some of which are complex, exposes us to operational and market risks, including commodity price risks. We use derivative instruments such as futures and contracts for differences to hedge market risks. However, we do not hedge all our activities and where hedging is in place, it may not function as expected. The risk of ineffective controls and oversight of trading activities and the risk that traders, individually or as a group, could act intentionally outside of the limits and controls, could have material adverse effect on our earnings, cash flows and financial condition.

See “Liquidity and capital resources” on [page 80](#) and Note 19 to the “Consolidated Financial Statements” on [pages 227-231](#).

We have substantial pension commitments, funding of which is subject to capital market risks and other factors.

Liabilities associated with defined benefit pension plans are significant, as can be cash funding requirement of such plans; both depend on various assumptions. Volatility in capital markets or government policies, and the resulting consequences for investment performance and interest rates, as well as changes in assumptions for mortality, retirement age or pensionable remuneration at retirement, could result in significant changes to the funding level of future liabilities. We operate a number of defined benefit pension plans and, in case of a shortfall, we could be required to make substantial cash contributions (depending on the applicable local regulations) resulting in a material adverse effect on our earnings, cash flows and financial condition.

See “Liquidity and capital resources” on [page 81](#).

We mainly self-insure our risk exposure. We could incur significant losses from different types of risks that are not covered by insurance from third-party insurers.

Our insurance subsidiaries provide hazard insurance coverage to other Shell entities and only reinsure a portion of their risk exposures. Such reinsurance would not provide any material coverage in the event of a large-scale safety and environmental incident. Accordingly, in the event of a material incident, there would not be any material proceeds available from third-party insurance companies to meet our obligations. Therefore, we may incur significant losses from different types of risks that are not covered by insurance from third-party insurers, potentially resulting in a material adverse effect on our earnings, cash flows and financial condition.

See “Corporate” on [page 79](#).

How this risk is managed

In effecting commodity trades and derivative contracts, the Company operates within procedures and policies designed to ensure that risks are managed within authorised limits. For example, the use of external derivative instruments is confined to specialist trading organisations that have appropriate skills, experience, supervision, control and reporting systems. There is regular review of mandated trading limits by senior management, daily monitoring of market risk exposure using value-at-risk (VAR) techniques, daily monitoring of trading positions against limits, and marking-to-fair value of trading exposures with a department independent of traders reviewing the market values applied. Our trading organisation has a compliance manual addressing our operational risks which all staff are required to follow.

A pensions forum, chaired by the Chief Financial Officer oversees Shell's input to pension strategy, policy and operation. The forum is supported by a risk committee in reviewing the results of assurance processes with respect to pension risks. Local trustees manage the funded defined benefit pension plans, with contributions paid based on independent actuarial valuations in accordance with local regulations.

We continuously assess the safety performance of our operations and make risk mitigation recommendations, where relevant, to reduce the risk of an accident to as low as possible. Our insurance subsidiaries are adequately capitalised and transfer risks to third-party insurers where economical, effective and relevant.

RISK FACTORS continued

Risk description

An erosion of our business reputation could have a material adverse effect on our brand, our ability to secure new resources or access capital markets, and on our licence to operate.

Our reputation is an important asset. The Shell General Business Principles (Principles) govern how Shell and its individual companies conduct their affairs, and the Shell Code of Conduct instructs employees and contract staff on how to behave in line with the Principles. Our challenge is to ensure that all employees and contract staff, more than 100,000 in total, comply with the Principles and the Code of Conduct. Real or perceived failures of governance or regulatory compliance or a perceived lack of understanding of how our operations affect surrounding communities could harm our reputation.

Societal expectations of businesses are increasing, with a focus on business ethics, quality of products, contribution to society, minimising environmental impacts, and safety. There is increasing focus on the role of oil and gas in the context of climate change and energy transition.

This could negatively affect our brand, reputation and licence to operate, which could impact our ability to deliver our strategy, consumer demand for our branded and non-branded products, harm our ability to secure new resources and contracts, and limit our ability to access capital markets or attract staff. Many other factors, including the materialisation of the risks discussed in several of the other risk factors, could negatively impact our reputation and could have a material adverse effect on our earnings, cash flows and financial condition.

See “Other Regulatory and Statutory Information” on page 167 and “Our people” on page 100.

Many of our major projects and operations are conducted in joint arrangements or with associates. This could reduce our degree of control, as well as our ability to identify and manage risks.

In cases where we are not the operator, we have limited influence over, and control of, the behaviour, performance and costs of operation of such joint arrangements or associates. Despite not having control, we could still be exposed to the risks associated with these operations, including reputational, litigation (where joint and several liability could apply) and government sanction risks. For example, our partners or members of a joint arrangement or an associate (particularly local partners in developing countries) may not be able to meet their financial or other obligations to the projects, threatening the viability of a given project. Where we are the operator of a joint arrangement, the other partner(s) could still be able to veto or block certain decisions, which could be to our overall detriment. Accordingly, where we have limited influence, we are exposed to operational risks that could have a material adverse effect on our earnings, cash flows and financial condition.

See “Other Regulatory and Statutory Information” on page 169.

We rely heavily on information technology systems in our operations.

The operation of many of our business processes depends on reliable information technology (IT) systems. Our IT systems are increasingly concentrated in terms of geography, number of systems, and dependent on key contractors supporting the delivery of IT services. Shell is the target of attempts to gain unauthorised access to our IT systems and our data through various channels, including more sophisticated and coordinated attempts often referred to as advanced persistent threats. Breaches have occurred, including to our UK LiveWIRE application where approximately 196,000 accounts and personal data were compromised. Where systems, customers' accounts and data have been compromised, we undertake to notify all relevant regulators and impacted customers, in accordance with countries' laws and regulations, including privacy requirements. Timely detection is becoming increasingly complex, but we seek to detect and investigate all such security incidents, aiming to prevent their recurrence. Disruption of critical IT services, or breaches of information security, could harm our reputation and have a material adverse effect on our earnings, cash flows and financial condition.

See “Corporate” on page 79.

How this risk is managed

We continuously assess and monitor the external environment for potential risks to our reputation. We have mitigation plans in place for identified brand and reputation risks at the Group, country and line of business level. Our country chairs are responsible for the implementation of country reputation plans which are updated annually. We continuously develop and defend our brand in line with Shell's purpose and promises, and target our investments to drive brand differentiation, relevance and preference.

Shell appoints a Joint Venture Asset Manager, whose responsibility is to manage performance (create and protect value for Shell) by influencing operators and other partners to adapt their operating practices to appropriately drive value and mitigate identified risks. An annual assurance review takes place on the alignment of standards and processes in joint ventures with the standards applicable to Shell. Any gaps identified are followed up by the Joint Venture Asset Manager.

We continuously measure and improve our cyber-security capabilities. To reduce the likelihood of successful cyberattacks our cyber-security capabilities are embedded into our IT systems. Our IT landscape is protected by various detective and protective technologies. The identification and assessment capabilities are built into our IT support processes and adhere to industry best practices. The security of IT services, operated by external IT companies, is managed through contractual clauses and through formal supplier assurance reports. Shell invests constantly in efforts to embed and improve our controls and monitoring activities. In case of breaches, all entities, including the ones not yet fully integrated into Shell's systems and processes, are required to report and leverage Shell's information security capabilities.

Risk description

Violations of antitrust and competition laws carry fines and expose us and/or our employees to criminal sanctions and civil suits.

Antitrust and competition laws apply to Shell and its joint ventures and associates in the vast majority of countries where we do business. Shell and its joint ventures and associates have been fined for violations of antitrust and competition laws in the past. These include a number of fines by the European Commission Directorate-General for Competition (DG COMP). Due to DG COMP's fining guidelines, any future conviction of Shell or any of its joint ventures or associates for violation of EU competition law could result in significantly larger fines and have a material adverse effect on us. Violation of antitrust laws is a criminal offence in many countries, and individuals can be imprisoned or fined. In certain circumstances, directors may receive director disqualification orders. It is also now common for persons or corporations allegedly injured by antitrust violations to sue for damages. Any violation of these laws can harm our reputation and could have a material adverse effect on our earnings, cash flows and financial condition.

See "Other Regulatory and Statutory Information" on page 167.

Violations of anti-bribery, tax-evasion and anti-money laundering laws carry fines and expose us and/or our employees to criminal sanctions, civil suits and ancillary consequences (such as debarment and the revocation of licences).

Anti-bribery, tax-evasion and anti-money laundering laws apply to Shell, its joint ventures and associates in all countries where we do business. Shell and its joint ventures and associates have in the past settled with the US Securities and Exchange Commission regarding violations of the US Foreign Corrupt Practices Act. Any violation of anti-bribery, tax-evasion or anti-money laundering laws, including those potential violations associated with Shell Nigeria Exploration and Production Company Limited's investment in Nigerian oil block OPL 245 and the 2011 settlement of litigation pertaining to that block, could have a material adverse effect on our earnings, cash flows and financial condition.

See "Our people" on pages 100, "Other Regulatory and Statutory Information" on page 167 and Note 25 to the "Consolidated Financial Statements" on pages 235-237.

Violations of data protection laws carry fines and expose us and/or our employees to criminal sanctions and civil suits.

Data protection laws apply to Shell and its joint ventures and associates in the vast majority of countries where we do business. Most of the countries we operate in have data protection laws and regulations. Additionally, the EU General Data Protection Regulation (GDPR) came into effect in May 2018, which increased penalties up to a maximum of 4% of global annual turnover for breach of the regulation. The GDPR requires mandatory breach notification, the standard for which is also followed outside the EU (particularly in Asia). Non-compliance with data protection laws could expose us to regulatory investigations, which could result in fines and penalties and harm our reputation. In the past we have breached the GDPR and some investigations are still ongoing with European regulators. To date no material fines have been imposed, however, no assurance can be provided that future breaches would have similar outcomes. In addition to imposing fines, regulators may also issue orders to stop processing personal data, which could disrupt operations. We could also be subject to litigation from persons or entities allegedly affected by data protection violations. Violation of data protection laws is a criminal offence in some countries, and individuals can be imprisoned or fined. Any violation of these laws or harm to our reputation could have a material adverse effect on our earnings, cash flows and financial condition.

See "Other Regulatory and Statutory Information" on page 167.

How this risk is managed

We maintain an antitrust programme with adequate resources, a comprehensive governance structure and established reporting lines. Clear guidance is provided to staff, which includes requirements in Shell's Ethics & Compliance manual, an antitrust specific website, training modules where completion is monitored and regular messages from Shell leaders on the importance of managing antitrust risks. Staff must understand and comply with the "Protect Shell Policy", which explains Shell's position on managing competitively sensitive information.

We maintain an anti-bribery and anti-money laundering (ABC/AML) programme with adequate resources, a comprehensive governance structure and established reporting lines in place. Clear guidance is provided to staff, which includes requirements in Shell's Ethics & Compliance manual, an ABC/AML specific website, training modules where completion is monitored and regular messages from Shell leaders on the importance of management of ABC/AML risks. As to OPL 245, the 2011 settlement was a fully legal transaction with Eni and the Federal Government of Nigeria, represented by the most senior officials of the relevant ministries. We maintain our view that there is no basis to convict Shell, or any of our former employees who are also on trial, in Milan.

We maintain a data privacy programme with adequate resources, a comprehensive governance structure and established reporting lines. Clear guidance is provided to staff, which includes requirements in Shell's Ethics & Compliance manual, a data privacy specific website, training modules where completion is monitored and regular messages from Shell leaders on the importance of managing data privacy risks. The requirements for incident management, set forth in our Binding Corporate Rules have been revised to comply with reporting requirements under GDPR, as has our approach to privacy impact assessments. In 2020 we have established a Privacy by Design programme to enhance our controls in this area.

Risk description**Violations of trade compliance laws and regulations, including sanctions, carry fines and expose us and our employees to criminal sanctions and civil suits.**

We use “trade compliance” as an umbrella term for various national and international laws designed to regulate the movement of items across national boundaries and restrict or prohibit trade and other dealings with certain parties. The number and breadth of such laws continue to expand. For example, the EU and the USA continue to impose restrictions and prohibitions on certain transactions involving countries such as Syria, Venezuela, Russia and Cuba. In addition, the USA continues to have comprehensive sanctions in place against Iran, while the EU and other nations continue to maintain targeted sanctions. Additional restrictions and controls directed at defined oil and gas activities in Russia, which were imposed by the EU and the USA in 2014, remain in force. Further restrictions regarding Russia were introduced by the USA in 2017 and expanded in 2018. Both the EU and the USA introduced sectoral sanctions against Venezuela in 2017, which the USA expanded in 2018 and 2019. The US sanctions primarily target the government of Venezuela and the oil industry. Many other nations are also adopting trade-control programmes similar to those administered by the EU and the USA. This expansion of sanctions, including the frequent additions of prohibited parties, combined with the number of markets in which we operate and the large number of transactions we process, make compliance with all sanctions complex and at times challenging. Shell has voluntarily self-disclosed potential violations of sanctions in the past. Any violation of one or more of these regimes could lead to loss of import or export privileges, significant penalties on or prosecution of Shell or its employees and could harm our reputation and have a material adverse effect on our earnings, cash flows and financial condition.

See “Other Regulatory and Statutory Information” on page 167.

How this risk is managed

We continue to develop and maintain a trade compliance programme with adequate resources, a comprehensive governance structure and established reporting lines. Clear guidance is provided to staff, which includes requirements in Shell’s Ethics & Compliance manual, a trade compliance specific website, training modules where completion is monitored and regular messages from Shell leaders on the importance of managing trade compliance risks. The effectiveness of the trade compliance programme is assessed annually (or more frequently if necessary).

Investors should also consider the following, which could limit shareholder remedies.

The Company’s Articles of Association determine the jurisdiction for shareholder disputes. This could limit shareholder remedies.

Our Articles of Association generally require that all disputes between our shareholders in such capacity and the Company or our subsidiaries (or our Directors or former Directors), or between the Company and our Directors or former Directors, be exclusively resolved by arbitration in The Hague, the Netherlands, under the Rules of Arbitration of the International Chamber of Commerce. Our Articles of Association also provide that, if this provision is to be determined invalid or unenforceable for any reason, the dispute could only be brought before the courts of England and Wales. Accordingly, the ability of shareholders to obtain monetary or other relief, including in respect of securities law claims, could be determined in accordance with these provisions.

MARKET OVERVIEW

We maintain a large business portfolio across an integrated value chain and are exposed to crude oil, natural gas, oil product and chemical prices (see “Risk factors” on page 27). This diversified portfolio helps us mitigate the impact of price volatility. Our annual planning cycle and periodic portfolio reviews aim to ensure that our levels of capital investment and operating expenses are appropriate in the context of a volatile price environment. We test the resilience of our projects and other opportunities against a range of crude oil, natural gas, oil product and chemical prices and costs. We also aim to maintain a strong balance sheet to provide resilience against weak market prices.

GLOBAL ECONOMIC GROWTH

Economic activity is one of the key drivers of demand for oil, natural gas and oil products. Widespread economic and geopolitical uncertainty meant the global business environment remained challenging in 2019. According to the World Economic Outlook released by the International Monetary Fund (IMF) in January 2020, global economic growth for 2019 is estimated to have fallen to 2.9% from 3.6% in 2018.

A common feature in the weakening of many countries' GDP was a slowdown in industrial output. According to the IMF, this slowdown was caused by weak business confidence amid growing trade-related tensions between the USA and China. Industrial production also slowed due to changes in technology and emissions standards leading to a fall in car production and many potential vehicle buyers delaying their purchase in favour of a wait-and-see attitude.

The IMF also noted a slowdown in economic growth in China and other large Asian economies, driven by China's regulatory efforts to limit its debt, and exacerbated by increased trade tensions with the USA.

With lingering trade policy and geopolitical uncertainties, the global economic outlook for 2020 remains precarious. A key uncertainty for the global economy will be the impact of the COVID-19 (coronavirus) outbreak in China and elsewhere.

GLOBAL PRICES, DEMAND AND SUPPLY

The following table provides an overview of the main crude oil and natural gas price markers that we are exposed to:

Oil and gas average industry prices [A]

	2019	2018	2017
Brent (\$/b)	64	71	54
West Texas Intermediate (\$/b)	57	65	51
Henry Hub (\$/MMBtu)	2.5	3.1	3.0
UK National Balancing Point (pence/therm)	35	60	45
Japan Customs-cleared Crude (\$/b)	67	73	54

[A] Yearly average prices are based on daily spot prices. The 2019 average price for Japan Customs-cleared Crude excludes December data.

CRUDE OIL

Brent crude oil, an international benchmark, traded between \$53 per barrel (/b) and \$75/b in 2019, ending the year at \$67/b. Brent crude oil prices averaged \$64/b for the year, 10% (or \$7/b) lower than in 2018.

At the beginning of 2019, global oil demand for the year was expected to grow by 1.4 million barrels per day (b/d). However, as the global economic environment weakened throughout 2019, global oil demand growth projections for the full year were adjusted downwards. Year averaged global oil demand grew by 1.0 million b/d, or 1.0%, to 100.3 million b/d, according to the International Energy Agency's (IEA) Oil Market Report published in January 2020. This growth was lower than the historical average of 1.3 million b/d per year since 2000. Oil demand growth was driven by non-OECD economies, where demand grew by 1.1 million b/d, while oil demand contracted by 0.1 million b/d in the OECD. Oil demand growth in 2019 was 0.1 million b/d lower than in 2018, when it rose by 1.1 million b/d.

Oil supply in 2019 is estimated in the Oil Market Report at 100.3 million b/d, unchanged compared to 2018. Because oil supply and oil demand were in balance, we estimate that elevated industry-controlled crude oil and oil products stocks remained unchanged from 2018. This limited price increases. Average commercial inventory levels for OECD countries in November 2019 were estimated at 2,912 million barrels in the Oil Market Report. This was around 52 million barrels higher than in November 2018, and about 211 million barrels more than the average for 2014, when Brent crude oil prices were around \$100/b for most of the year.

Non-OPEC supply growth, mostly in the USA, was balanced by lower OPEC production. The US Energy Information Administration reported another year of supply growth. US production is estimated to have averaged 12.3 million b/d in 2019, 1.5 million b/d higher than in 2018, and 3 million b/d higher than 2017. Supply growth was supported by continued efficiency gains, and occurred despite lower drilling activity reflected by a 23% fall in the onshore oil rig count during the year. Production from other non-OPEC countries increased by 0.5 million b/d in 2019 and averaged 58.1 million b/d.

For most of 2019, OPEC members and co-operating non-OPEC resource holders, most notably Russia, continued to cap their overall production at 2018 levels. In December 2019, they decided to further cap production by 0.5 million b/d becoming effective in 2020. OPEC's production fell from 31.9 million b/d in 2018 to 29.9 million b/d in 2019, in part due to sanctions causing production to fall in Iran and Venezuela. Furthermore, supply from Venezuela was also affected by a deteriorating production environment.

On a yearly average basis, West Texas Intermediate (WTI) crude oil traded at a \$7/b discount to Brent crude oil in 2019, compared with \$6/b in 2018. The discount remained broadly unchanged from 2018, reflecting continued constrained pipeline capacity from the landlocked Cushing storage hub to the US Gulf Coast, against a backdrop of growing supply to the hub. According to the US Energy Information Administration, US crude oil exports increased further to a yearly average of about 3 million b/d in 2019, up by 1 million b/d from 2018, and peaked above 4 million b/d by the end of the year. This helped to limit further widening of the price differential between Brent and WTI.

MARKET OVERVIEW continued

Looking ahead, the IMF's global economic outlook indicates some increase in global economic growth, which should support oil demand growth. According to the IEA, near-term global oil demand growth is projected at around 1.3 million b/d per annum. To keep supply and demand in balance, demand growth and natural production decline from existing operations are to be met by supply growth. If OPEC members and co-operating non-OPEC resource holders continue implementing their current production agreement successfully, then supply growth would have to be delivered by non-OPEC countries, most notably the USA. Markets could tighten and prices could rise if US supply growth slows. The fall in US drilling activity in 2019 could be a first indicator of moderating US supply growth. A lack of industry-wide investment in new supply projects could lead to further market tightening in the next few years, given the long lead time of many of these projects.

On the other hand, we believe the price environment could weaken if the impact of the coronavirus grows or recession fears materialise, and/or OPEC and the non-OPEC resource holders relax their production agreement. The price environment could also weaken if other non-OPEC producers, such as US shale producers, effectively deliver more and cheaper oil to the market.

NATURAL GAS

We estimate global gas demand to have grown by about 2.4% in 2019, in line with the annual growth rate of 2.5% observed since the start of the century. Robust demand growth in power generation and industry was driven by attractive regional spot gas prices that encouraged switching from competing fuels such as coal and oil. In the key regional markets of North America, Europe, and Asia-Pacific, attractive prices have been caused mainly by ample gas supply growth.

In 2019, global liquefied natural gas (LNG) imports grew by 40 million tonnes, or 13% of the total LNG market. LNG supply growth, mainly in Australia, the USA and Russia, outpaced demand growth. In 2019, inventory levels were higher in Asia following mild winter conditions. LNG imports were down in Japan and South Korea due to milder weather and higher nuclear utilisation than in 2018. However, more LNG supply flowed into the European markets.

Natural gas prices can vary from region to region.

In the USA, the natural gas price at the Henry Hub averaged \$2.5 per million British thermal units (MMBtu) in 2019, 19% lower than in 2018. It traded in a range of \$2.0 to 4.1/MMBtu. There was downward pressure on prices due to a strong gas supply growth of about 8 billion cubic feet per day, which averaged 10% higher than in 2018. Gas supply growth was, in part, driven by a growth of associated gas from oil fields, helped by oil prices above \$50/b, and by new gas pipeline capacity. Gas prices found support from demand growth driven by below-normal storage inventory levels; an increase in usage of power for cooling due to warmer than normal weather in the second half of the year; completion of LNG liquefaction projects; increased exports to Mexico by pipeline; and US industrial growth.

In Europe, the average price at the UK National Balancing Point (NBP) was 43% lower in 2019 compared to 2018. At the main continental gas trading hubs – in the Netherlands, Belgium and Germany – prices were also lower, as reflected by weaker Dutch Title Transfer Facility (TTF) prices. European gas prices were lower due to: the rise in LNG volume diverted from the Asia-Pacific region caused by weaker Asia-Pacific demand growth; robust supply of pipeline gas, particularly from Russia; well-filled gas storage inventories; competition with renewables in power generation; and mild weather.

We also produce and sell natural gas in regions where supply, demand and regulatory circumstances differ markedly from those in the USA or Europe. Long-term contracted LNG prices in 2019 in the Asia-Pacific region were broadly comparable to 2018 prices as they are predominantly indexed to oil prices, particularly to the Japan Customs-cleared Crude (JCC) index which has been generally stable year-on-year. Meanwhile, delivered North Asia spot prices, reflected by the Japan Korea Marker, declined by 43% versus 2018 as a result of the oversupply in the global LNG market.

Looking ahead, we expect gas markets in North America, Europe and Asia-Pacific to be well supplied over the next few years, despite our expectation of LNG demand growth in Asia. Price developments are very uncertain and dependent on many factors.

In the USA, Henry Hub gas prices may increase over the next few years due to: increasing demand from LNG exports; exports to Mexico by pipeline; and residential and industrial users. On the other hand, increasing availability of low-cost natural gas and oil, combined with technological improvements, could continue to place pressure on natural gas prices. In Europe, we believe gas prices will be increasingly influenced by the cost of LNG imports from the USA. In the Asia-Pacific region, long-term gas prices are expected to continue to be strongly influenced by oil prices and spot prices increasingly by gas supply and demand fundamentals.

CRUDE OIL AND NATURAL GAS PRICE ASSUMPTIONS

Our ability to deliver competitive returns and pursue commercial opportunities ultimately depends on the accuracy of our price assumptions (see "Risk factors" on page 27). We determine the range of possible future crude oil and natural gas prices to be used in project and portfolio evaluations after a rigorous assessment of short, medium and long-term market drivers. We consider historical analyses, trends and statistical volatility, and market fundamentals such as possible future economic conditions, geopolitics, actions by OPEC and other major resource holders, production costs, and the balance of supply and demand. We use sensitivity analyses to test the impact of low-price drivers like economic weakness, and the effect of high-price drivers, such as strong economic growth and low investment in new production capacity. See also Note 8 to the "Consolidated Financial Statements" on pages 210-213.

REFINING MARGINS

Refining marker average industry gross margins

	2019	2018	\$/b 2017
US West Coast	13.5	11.5	14.0
US Gulf Coast Coking	4.9	7.0	9.9
Rotterdam Complex	2.3	2.5	4.3
Singapore	(0.6)	1.4	3.6

Industry gross refining margins were lower on average in 2019 than in 2018 in three of the four key refining hubs of Europe, Singapore and the US Gulf Coast. Only in the US West Coast did gross margins improve due to, in-part, unplanned outages in the region, which supported product prices. Globally, year-on-year growth in demand for oil products has slowed in line with slowing global economic growth. Refinery capacity additions, especially in the Middle East and Asia, combined with lower demand growth have led to generally lower refinery utilisations, which weakened margins. Refinery activity continued to be low in Latin America amid the ongoing geopolitical uncertainty and poor investment climate.

On January 1, 2020 the new International Maritime Organization low-sulphur shipping fuel specification came into effect. The refining industry started to transition to the new specification in the second half of 2019 by building a significant inventory of low-sulphur fuels. The full effects of the implementation are expected to materialise in 2020.

Refinery margins could weaken in 2020 if the coronavirus materially impacts global demand for oil products.

The outlook for petrochemical margins in 2020 and beyond depends on supply and demand balances and feedstock costs. Demand for petrochemicals is closely linked to economic and trade growth. Product prices reflect prices of raw materials, which are closely linked to crude oil and natural gas prices. The balance of these factors will drive margins.

The statements in this "Market overview" section, including those related to our price forecasts, are forward-looking statements based on management's current expectations and certain material assumptions and, accordingly, involve risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied herein. See "About this Report" on pages 2-3 and "Risk factors" on pages 27-36.

PETROCHEMICAL MARGINS

Cracker industry margins [A]

	2019	2018	\$/tonne 2017
North East/South East Asia naphtha	302	594	688
Western Europe naphtha	531	562	727
US ethane	445	412	471

[A] ICIS data is quoted. Cracker industry margins have been revised from Q1 2018 onwards due to updated cracker margin calculation methodology by ICIS. Further revisions based on available market information to external industry data provider up to the end of the period.

In 2019, Chinese GDP growth slowed and there was continued uncertainty regarding trade and tariffs between the USA and China. Demand growth in several chemicals end-consumption markets slowed and, in the automotive sector, demand even contracted. Cracker industry margins in Asia halved. Cracker margins in Western Europe and the USA were relatively unchanged versus 2018. West European margins were supported by a high level of maintenance outages in the first half of 2019, while in the USA margins were supported by low ethane prices.

SUMMARY OF RESULTS

Key statistics

	\$ million, except where indicated		
	2019	2018	2017
Income for the period	16,432	23,906	13,435
Current cost of supplies adjustment	(605)	458	(964)
Total segment earnings [A][B], of which:	15,827	24,364	12,471
Integrated Gas	8,628	11,444	5,078
Upstream	4,195	6,798	1,551
Downstream	6,277	7,601	8,258
Corporate	(3,273)	(1,479)	(2,416)
Capital expenditure	22,971	23,011	20,845
Cash capital expenditure [B]	23,919	24,078	21,533
Capital investment [B]	28,788	24,878	23,655
Operating expenses [B]	37,893	39,316	38,083
Return on average capital employed [B]	6.7%	9.4%	5.8%
Gearing at December 31 [C]	29.3%	20.3%	25.0%
Oil and gas production (thousand boe/d)	3,665	3,666	3,664
Proved oil and gas reserves at December 31 (million boe)	11,096	11,578	12,233

[A] Segment earnings are presented on a current cost of supplies basis. See Note 4 to the "Consolidated Financial Statements" on pages 206-208.

[B] See "Non-GAAP measures reconciliations" on pages 279-280.

[C] Gearing at end of 2019 on IAS 17 basis was 25%.

EARNINGS 2019-2018

Income for the period was \$16,432 million in 2019, compared with \$23,906 million in 2018. After current cost of supplies adjustment, total segment earnings were \$15,827 million in 2019, compared with \$24,364 million in 2018.

Earnings on a current cost of supplies basis (CCS earnings) exclude the effect of changes in the oil price on inventory carrying amounts, after making allowance for the tax effect. The purchase price of volumes sold in the period is based on the current cost of supplies during the same period, rather than on the historic cost calculated on a first-in, first-out (FIFO) basis. Therefore, when oil prices are decreasing, CCS earnings are likely to be higher than earnings calculated on a FIFO basis and, when prices are increasing, CCS earnings are likely to be lower than earnings calculated on a FIFO basis.

Integrated Gas earnings in 2019 were \$8,628 million, compared with \$11,444 million in 2018. The decrease was mainly driven by lower gains on sale of assets, lower realised oil, LNG and gas prices, higher impairments, higher operating expenses, negative movements in deferred tax positions and lower liquids production volumes. These effects were partly offset by stronger contributions from LNG trading and optimisation, and gains related to the fair value accounting of commodity derivatives. See "Integrated Gas" on pages 45-51.

Upstream earnings in 2019 were \$4,195 million, compared with \$6,798 million in 2018. The decrease was mainly driven by higher impairments, lower realised oil and gas prices, higher depreciation and higher well write-offs. This was partly offset by increased gains on sale of assets and higher volumes. See "Upstream" on pages 52-60.

Downstream earnings in 2019 were \$6,277 million, compared with \$7,601 million in 2018. The decrease was mainly driven by lower realised chemicals, refining and trading margins, legal provisions and lower gains related to fair value accounting of commodity derivatives. This was partly offset by higher marketing margins, benefit from foreign exchange, introduction of IFRS 16 and lower operating costs. See "Downstream" on pages 70-78.

Corporate earnings in 2019 were a loss of \$3,273 million, compared with a loss of \$1,479 million in 2018. The higher loss was mainly driven by the introduction of IFRS 16 and reduced capitalised interest. This was partly offset by reduced tax credits from financing and one-off charges. See "Corporate" on page 79.

EARNINGS 2018-2017

Income for the period was \$23,906 million in 2018, compared with \$13,435 million in 2017. After current cost of supplies adjustment, total segment earnings were \$24,364 million in 2018, compared with \$12,471 million in 2017.

Integrated Gas earnings in 2018 were \$11,444 million, compared with \$5,078 million in 2017. The increase was mainly driven by higher realised oil, gas, and LNG prices, higher gains on divestments, increased contributions from LNG trading, the impact of fair value accounting of commodity derivatives, and higher production. These effects were partly offset by the absence of a gain from the strengthening Australian dollar on a deferred tax position in 2017 and by higher operating expenses. See "Integrated Gas" on pages 45-51.

Upstream earnings in 2018 were \$6,798 million, compared with \$1,551 million in 2017. The increase was mainly driven by higher realised oil and gas prices, lower impairment charges, the absence of a charge as a result of US tax reform legislation in 2017, and lower well write-offs. This was partly offset by the movements in deferred tax positions, lower gains on divestments, lower production, and a charge related to the impact of the weakening Brazilian real on a deferred tax position. See "Upstream" on pages 52-60.

Downstream earnings in 2018 were \$7,601 million, compared with \$8,258 million in 2017. The decrease was mainly driven by higher operating expenses, unfavourable exchange rate effects, and lower realised base chemicals and refining margins. This was partly offset by higher realised marketing margins, lower charges related to provisions, the impact of fair value accounting of commodity derivatives and higher gains on divestments. There was also a charge in 2017 as a result of US tax reform legislation. See "Downstream" on pages 70-78.

Corporate earnings in 2018 were a loss of \$1,479 million, compared with a loss of \$2,416 million in 2017. The lower loss was mainly driven by lower net foreign exchange losses and net interest expense, partially offset by higher costs. There was also a charge in 2017 as a result of US tax reform legislation. See "Corporate" on page 79.

PRODUCTION AVAILABLE FOR SALE

Oil and gas production available for sale in 2019 was 1,338 million barrels of oil equivalent (boe), or 3,665 thousand boe per day (boe/d), compared with 1,338 million boe, or 3,666 thousand boe/d, in 2018. In 2019, lower production was due to the impact of divestments and field decline, partly offset by field ramp-ups in North America, Brazil, Australia and Trinidad and Tobago.

Oil and gas production available for sale [A]

	Thousand boe/d		
	2019	2018	2017
Crude oil and natural gas liquids	1,823	1,749	1,730
Synthetic crude oil	52	53	91
Bitumen	-	-	4
Natural gas [B]	1,790	1,863	1,839
Total	3,665	3,666	3,664
Of which:			
Integrated Gas	922	957	887
Upstream	2,743	2,709	2,777

[A] See "Oil and gas information" on pages 61-69.

[B] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

PROVED RESERVES

The proved oil and gas reserves of Shell subsidiaries and the Shell share of the proved oil and gas reserves of joint ventures and associates are summarised in "Oil and gas information" on pages 61-69 and set out in more detail in "Supplementary information – oil and gas (unaudited)" on pages 239-256.

Before taking production into account, our proved reserves increased by 906 million boe in 2019. This comprised increases of 912 million boe from Shell subsidiaries and decreases of 6 million boe from the Shell share of joint ventures and associates. The increase from Shell subsidiaries included a net increase of 785 million boe from revisions and reclassifications, an increase of 5 million boe from improved recovery, an increase of 276 million from extensions and discoveries and a net decrease of 154 million boe related to purchases and sales of minerals in place. The decrease of 6 million boe from the Shell share of joint ventures and associates comprises a net decrease of 13 million boe from revisions and reclassifications, an increase of 3 million from extensions and discoveries and an increase of 4 million from improved recovery.

In 2019, total oil and gas production was 1,388 million boe, of which 1,338 million boe was available for sale and 50 million boe was consumed in operations. Production available for sale from subsidiaries was 1,182 million boe and 43 million boe was consumed in operations. The Shell share of the production available for sale of joint ventures and associates was 156 million boe and 7 million boe was consumed in operations.

Accordingly, after taking production into account, our proved reserves decreased by 482 million boe in 2019, to 11,096 million boe at December 31, 2019, with a decrease of 314 million boe from subsidiaries and a decrease of 169 million boe from the Shell share of joint ventures and associates.

CASH CAPITAL EXPENDITURE AND OTHER INFORMATION

Cash capital expenditure was \$23.9 billion in 2019, compared with \$24.1 billion in 2018. Capital investment was \$28.8 billion in 2019, compared with \$24.9 billion in 2018.

Operating expenses reduced by \$1.4 billion in 2019, to \$37.9 billion.

Our ROACE decreased to 6.7%, compared with 9.4% in 2018, mainly driven by a lower income in 2019.

Gearing was 29.3% at the end of 2019, compared with 20.3% at the end of 2018, driven by IFRS 16 and a lower cash balance in 2019. Gearing at the end of 2019 on an IAS 17 basis was 25.0%.

SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

See Note 2 to the "Consolidated Financial Statements" on pages 195-204.

LEGAL PROCEEDINGS

See Note 25 to the "Consolidated Financial Statements" on pages 235-237.

PERFORMANCE INDICATORS

These indicators enable management to evaluate Shell's performance against our strategy and operating plans. Those that are used in the determination of the Executive Directors' remuneration are asterisked below and on the following page. See "Directors' Remuneration Report" on pages 135-163.

Financial

Total shareholder return (%)*

0.5 2018: (4.2)

Total shareholder return (TSR) is the difference between the share price at the beginning of the year and the share price at the end of the year (each averaged over 90 days), plus gross dividends delivered during the calendar year (reinvested quarterly), expressed as a percentage of the share price at the beginning of the year (averaged over 90 days). The data used are a weighted average in dollars for A and B shares. The TSRs of major publicly-traded oil and gas companies can be compared directly, thereby providing a way to determine how we are performing relative to our industry peers.

Cash flow from operating activities (\$ million)*

42,178 2018: 53,085

Cash flow from operating activities is the total of all the cash receipts and payments associated with our sales of oil, gas, chemicals and other products. The components that provide a reconciliation from income for the period are listed in the "Consolidated Statement of Cash Flows". This indicator reflects our ability to generate cash to service and reduce our debt and for distributions to shareholders and investments.

See "Liquidity and capital resources" on pages 80-83.

Free cash flow (\$ million)*

26,399 2018: 39,426

Free cash flow is the sum of "Cash flow from operating activities" and "Cash flow from investing activities", which are listed in the "Consolidated Statement of Cash Flows". This indicator is used to evaluate the cash available for financing activities, including dividend payments, after investment in maintaining and growing our business.

See "Non-GAAP measures reconciliations" on pages 279-280.

Organic free cash flow (\$ million)

20,116 2018: 31,183

Organic free cash flow is defined as free cash flow excluding the cash flows from acquisition and divestment activities. It is a measure used by management to evaluate the generation of cash flow without these activities.

See "Non-GAAP measures reconciliations" on pages 279-280.

Return on average capital employed (%)*

6.7 2018: 9.4

ROACE is defined as income for the period, adjusted for after-tax interest expense, as a percentage of the average capital employed during the year. Capital employed is the sum of total equity and total debt. ROACE measures the efficiency of our utilisation of the capital that we employ and is a common measure of business performance.

See "Summary of results" on pages 40-41 and "Non-GAAP measures reconciliations" on pages 279-280.

Earnings on a current cost of supplies basis (\$ million)

15,827 2018: 24,364

Earnings per share on a current cost of supplies basis (\$)

1.88 2018: 2.85

Earnings on a CCS basis is the income for the period, adjusted for the after-tax effect of oil-price changes on inventory. Segment earnings presented on a CCS basis is the earnings measure used by the Chief Executive Officer for the purposes of making decisions about allocating resources and assessing performance.

See "Summary of results" on pages 40-41 and "Non-GAAP measures reconciliations" on pages 279-280.

CCS earnings per share, which is on a diluted basis above, is calculated by dividing the CCS earnings attributable to shareholders (see "Non-GAAP measures reconciliations" on pages 279-280) by the average number of shares outstanding over the year, increased by the average number of dilutive shares related to share-based compensation plans.

Capital investment (\$ million)

28,788 2018: 24,878

Capital investment is the sum of capital expenditure, investments in joint ventures and associates, investments in equity securities, as reported in the "Consolidated Statement of Cash Flows", plus exploration expenses excluding wells written off and leases recognised in the period and other adjustments. Capital investment is a measure used to make decisions about allocating resources and assessing performance.

See "Liquidity and capital resources" on pages 80-83 and "Non-GAAP measures reconciliations" on pages 279-280.

Financial continued

Cash capital expenditure (\$ million)

23,919 2018: 24,078

Cash capital expenditure is the sum of capital expenditure, investments in joint ventures and associates, and investments in equity securities, as reported in the "Consolidated Statement of Cash flows". It is used to monitor investing activities on a cash basis, excluding items such as lease additions that do not necessarily result in cash outflows in the period.

See "Non-GAAP measures reconciliations" on pages 279-280.

Gearing (%)

29.3 2018: 20.3

Gearing is defined as net debt (total debt less cash and cash equivalents) as a percentage of total capital (net debt plus total equity) at December 31. Gearing at the end of 2019 on an IAS 17 basis was 25.0%. The net debt calculation includes the fair value of derivative financial instruments used to hedge foreign exchange, interest rate risks relating to debt and associated collateral balances. The inclusion of these debt-related derivative balances reduces the volatility of net debt caused by fluctuations in foreign exchange and interest rates, and eliminates the potential impact of related collateral payments or receipts. Gearing is a measure of the degree to which our operations are financed by debt.

See "Liquidity and capital resources" on pages 80-83.

Operational

Production available for sale (thousand boe/d)*

3,665 2018: 3,666

Production is the sum of all the average daily volumes of unrefined oil and natural gas produced for sale by Shell subsidiaries and Shell's share of those produced for sale by joint ventures and associates. The unrefined oil comprises crude oil, NGLs, synthetic crude oil and bitumen. The gas volume is converted into equivalent barrels of oil to make the summation possible.

See "Summary of results" on pages 40-41.

LNG liquefaction volumes (million tonnes)*

35.6 2018: 34.3

LNG liquefaction volumes is a measure of the operational performance of our Integrated Gas business and LNG market demand.

See "Integrated Gas" on pages 45-51.

Refinery and chemical plant availability (%)*

90.8 2018: 91.9

Refinery and chemical plant availability is the weighted average of the actual uptime of plants as a percentage of their maximum possible uptime. The weighting is based on the capital employed, adjusted for cash and non-current liabilities. This indicator is a measure of the operational excellence of our Downstream manufacturing facilities.

See "Downstream" on pages 70-78.

Project delivery on schedule (%)*

90 2018: 75

Project delivery on budget (%)*

99 2018: 97

Project delivery reflects our capability to complete major projects on time and within budget on the basis of the targets set in our annual Business Plan. Project delivery on schedule measures the percentage of projects delivered on schedule. Project delivery on budget reflects the aggregate cost against the aggregate budget for those projects.

Proved oil and gas reserves (million boe)

11,096 2018: 11,578

Proved oil and gas reserves are the total estimated quantities of oil and gas from Shell subsidiaries and Shell's share from joint ventures and associates that geoscience and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs, at December 31, under existing economic conditions, operating methods and government regulations. Gas volumes are converted into boe using a factor of 5,800 scf/b. Reserves are crucial to an oil and gas company, as they constitute the source of future production. Reserves estimates are subject to change owing to a wide variety of factors, some of which are unpredictable.

See "Risk factors" on pages 27-36, "Summary of results" on page 40-41, "Oil and gas information" on pages 61-69 and "Supplementary information – oil and gas (unaudited)" on pages 239-256.

Safety and Environment

Total recordable case frequency (injuries per million working hours) *

0.9 2018: 0.9

Total recordable case frequency (TRCF) is the number of employees and contract staff injuries requiring medical treatment or time off for every million hours worked. It is a standard measure of occupational safety.

See "Environment and society" on pages 84-90.

Number of operational Tier 1 and 2 process safety events *

130 2018: 121

A Tier 1 process safety event is an unplanned or uncontrolled release of any material, including non-toxic and non-flammable materials, from a process with the greatest actual consequence resulting in harm to employees, contract staff, or a neighbouring community, damage to equipment, or exceeding a threshold quantity, as defined by the API Recommended Practice 754 and IOGP Standard 456. A Tier 2 process safety event is a release of lesser consequence.

See "Environment and society" on pages 84-90.

Upstream and Integrated Gas GHG intensity (tonnes of CO₂ equivalent/tonne of hydrocarbon production available for sale) *

0.17 2018: 0.16

Upstream/midstream GHG intensity is a measure of GHG emissions (direct and indirect GHG emissions associated with imported energy, excluding emissions from exported energy), expressed in metric tonnes of CO₂ equivalent, emitted into the atmosphere per metric tonne of hydrocarbon production available for sale.

See "Climate change and energy transition" on pages 91-98.

Refining GHG intensity (tonnes of CO₂ equivalent/UEDC™) *

1.06 2018: 1.05

Refining GHG intensity is a measure of GHG emissions (direct and indirect GHG emissions associated with imported energy, excluding emissions from exported energy), expressed in metric tonnes of CO₂ equivalent, emitted into the atmosphere per unit of Utilised Equivalent Distillation Capacity (UEDC™). UEDC™ is a proprietary metric of Solomon Associates. It is a complexity-weighted normalisation parameter that reflects the operating cost intensity of a refinery based on the size and configuration of its particular mix of process and non-process facilities.

See "Climate change and energy transition" on pages 91-98.

Chemicals GHG intensity (tonnes of CO₂ equivalent/tonne petrochemicals produced) *

1.04 2018: 0.96

Chemicals GHG intensity is a measure of GHG emissions (direct and indirect GHG emissions associated with imported energy, excluding emissions from exported energy), expressed in metric tonnes of CO₂ equivalent, emitted into the atmosphere per metric tonne of steam cracker, high-value petrochemicals production.

See "Climate change and energy transition" on pages 91-98.

Number of operational spills of more than 100 kg

70 2018: 93

The operational spills indicator is the number of incidents in respect of activities where we are the operator in which 100 kg or more of oil or oil products were spilled as a result of those activities and reached the environment.

See "Environment and society" on pages 84-90.

Direct GHG emissions (million tonnes of CO₂ equivalent)

70 2018: 71

Direct GHG emissions from facilities operated by Shell, expressed in CO₂ equivalent.

See "Climate change and energy transition" on pages 91-98.

Net Carbon Footprint (grams of CO₂ equivalent per megajoule) *

78 2018: 79

Net Carbon Footprint is a comprehensive measure of the lifecycle carbon intensity of the energy products we sell. It is a weighted average of the lifecycle CO₂ intensities of different energy products, normalised to the same point relative to their final end-use. It includes emissions from the extraction, transportation and processing of crude oil or gas or other feedstocks, transport of products, and our customers' emissions from the use of products we sell. Also included are emissions from elements of this life-cycle not owned by Shell, such as oil and gas processed by Shell but not produced by Shell; or from oil products and electricity marketed by Shell that have not been processed or generated at a Shell facility. Emissions compensated through various measures are also included, such as emissions mitigated by nature-based solutions and carbon capture and storage technology.

See "Climate change and energy transition" on pages 91-98.

INTEGRATED GAS

Key statistics

	\$ million, except where indicated		
	2019	2018	2017
Segment earnings	8,628	11,444	5,078
Including:			
Revenue (including inter-segment sales)	45,602	48,795	36,770
Share of profit of joint ventures and associates	1,791	2,273	1,714
Interest and other income	263	2,230	687
Operating expenses [A]	6,667	6,014	5,471
Exploration	281	208	141
Depreciation, depletion and amortisation	6,238	4,850	4,965
Taxation charge	2,242	2,795	790
Capital expenditure	3,851	3,262	3,515
Cash capital expenditure [A]	4,299	3,819	3,616
Capital investment [A]	6,706	4,259	3,921
Oil and gas production available for sale (thousand boe/d)	922	957	887
LNG liquefaction volumes (million tonnes)	35.6	34.3	33.2

[A] See "Non-GAAP measures reconciliations" on pages 279-280.

OVERVIEW

Our Integrated Gas business manages liquefied natural gas (LNG) activities and the conversion of natural gas into gas-to-liquids (GTL) fuels and other products, as well as our New Energies portfolio. It includes natural gas and liquids exploration and extraction, and the operation of upstream and midstream infrastructure that delivers gas and liquids to market. It markets and trades natural gas, LNG, electricity and carbon-emission rights, and markets and sells LNG as a fuel for heavy-duty vehicles and marine vessels.

BUSINESS CONDITIONS

Global gas demand is estimated to have grown by about 2.4% in 2019 which is in line with the annual growth rate of 2.5% observed since the start of the century.

Global LNG imports grew by 40 million tonnes in 2019. Significant LNG supply growth came mainly from Australia, the USA and Russia. In 2019, inventory levels were higher in Asia following mild winter conditions. LNG imports were down in Japan and South Korea due to milder weather and higher nuclear utilisation than in 2018. However, more LNG supply flowed into the European markets.

Natural gas prices can vary from region to region.

In the USA, the natural gas price at the Henry Hub averaged \$2.5 per million British thermal units (MMBtu) in 2019, 19% lower than in 2018 and traded in a range of \$2.0 to 4.1/MMBtu.

In Europe, natural gas prices were lower than in 2018. The average price at the UK National Balancing Point (NBP) was 35 pence/therm, 43% lower than in 2018. At the main continental gas trading hubs – in the Netherlands, Belgium and Germany – prices were also lower, as reflected by weaker Dutch Title Transfer Facility (TTF) prices.

Long-term contracted LNG prices in the Asia-Pacific region are broadly comparable to 2018 prices as they are predominantly indexed to oil prices, particularly to the Japan Customs-cleared Crude (JCC) index which has been generally stable year-on-year. Meanwhile, North Asia spot prices, reflected by the Japan Korea Marker (JKM) were \$5.55/mmbtu, 43% lower than 2018 as a result of unprecedented additional supply of LNG coming on stream.

See "Market overview" on pages 37-40.

PRODUCTION AVAILABLE FOR SALE

In 2019, production was 336 million barrels of oil equivalent (boe), or 922 thousand boe per day (boe/d), compared with 349 million boe, or 957 thousand boe/d in 2018. Natural gas production increased by 3% compared with 2018, mainly due to field ramp-ups in Australia and Trinidad and Tobago combined with higher availability at Pearl GTL in Qatar in 2019, partially offset by divestments. Liquids production decreased 27%, mainly due to the transfer of the Salym asset in Russia into the Upstream segment.

LNG LIQUEFACTION VOLUMES

LNG liquefaction volumes of 35.6 million tonnes in 2019 were 4% higher than in 2018, driven by additional volumes from increased feedgas availability, mainly from ventures, and new LNG capacity from the Prelude floating LNG facility in Australia and Elba LNG in USA, partly offset by the divestment of Malaysia LNG.

LNG sales volumes of 74.45 million tonnes in 2019 were 5% higher than in 2018, driven by our increased LNG purchases from third parties and by higher LNG liquefaction volumes.

EARNINGS 2019-2018

Segment earnings in 2019 were \$8,628 million, which included a net charge of \$326 million. The net charge mainly reflected impairment charges of \$890 million mostly in Australia, negative movements in deferred tax positions of \$292 million and write-offs of \$131 million in Australia and Trinidad and Tobago, respectively. These were partly offset by a gain of \$787 million related to the fair value accounting of commodity derivatives and a gain of \$203 million on a sale of assets in Australia.

Segment earnings in 2018 were \$11,444 million, which included a net gain of \$2,045 million. The net gain primarily reflected gains of \$1,937 million on sale of assets, mainly related to the divestment of assets in Thailand, New Zealand and India. It also comprised a gain of \$481 million related to the fair value accounting of commodity derivatives and impairment charges of \$371 million related to investments in Trinidad and Tobago and Shell's investment in a joint venture.

INTEGRATED GAS continued

Excluding the net charge described above, segment earnings were \$8,955 million in 2019 compared with \$9,399 million in 2018. Earnings were negatively impacted by lower realised oil, LNG and gas prices, higher operating expenses (of which about 50% relates to New Energies reflecting underlying business growth), and lower liquids production volumes, partly offset by significantly stronger contributions from LNG trading and optimisation.

EARNINGS 2018-2017

Segment earnings in 2018 were \$11,444 million, which included a net gain of \$2,045 million as described above.

Segment earnings in 2017 were \$5,078 million, which included a net charge of \$190 million. The net charge mainly reflected a charge of \$445 million on fair value accounting of commodity derivatives and a charge of \$412 million as a result of US tax reform legislation, partly offset by a gain of \$636 million from the strengthening Australian dollar on a deferred tax position.

Excluding the net gain above, segment earnings were \$9,399 million in 2018 compared with \$5,268 million in 2017. Earnings were positively impacted by increased contributions from trading and higher realised oil, gas and LNG prices (around \$4,200 million), increased LNG volumes from various assets across the portfolio (around \$615 million). Earnings were negatively impacted by higher operating expenses (around \$502 million of which \$246 million relates to growth of New Energies activities) and lower dividends due to divestments (around \$274 million).

In 2018, the impact of exchange rate movements of the Australian dollar on deferred tax balances was significantly reduced, as a result of the change in the fiscal functional currency of a number of Shell entities in Australia to the US dollar with effect from January 1, 2018.

CASH CAPITAL EXPENDITURE AND CAPITAL INVESTMENT

Cash capital expenditure in 2019 was \$4.3 billion, compared with \$3.8 billion in 2018. Capital investment in 2019 was \$6.7 billion, compared with \$4.3 billion in 2018.

PORTFOLIO AND BUSINESS DEVELOPMENT

Key portfolio events in 2019 included the following:

- In December 2018, we formed two joint ventures: with EDF Renewables to build wind farms off the New Jersey coast; and with EDP Renewables (EDPR) to build wind farms off Massachusetts, in the USA. Leases were granted by the authorities for JV with EDF in December 2018 and with EDPR in February 2019. In November, Massachusetts state authorities selected our JV with EDPR (Shell interest 50%) to develop and supply 804 MW of clean, renewable energy from offshore wind to the electricity customers in the state;
- In February, we acquired sonnen, a provider of smart energy storage systems; and
- In November, we acquired ERM Power, one of Australia's leading commercial and industrial electricity retailers.

The following major milestones were reached in 2019:

- In June, the first shipment of LNG sailed from our Prelude Floating Liquefied Natural Gas facility (Shell interest 67.5%);
- In September, the first of 10 Moveable Modular Liquefaction System (MMLS) Units started up at Elba Island in Savannah, Georgia, USA; and
- In November, FID was taken for the Barracuda Project (Shell interest 100%), a subsea tie-back of two gas wells to an existing platform on the East Coast of Trinidad.

We continued to divest selected assets during 2019, including:

- In Timor-Leste (East Timor), we sold our 26.6% interest in the undeveloped Sunrise gas field to the Timor-Leste government; and
- In India, we sold our 10% interest in Mahanagar Gas Limited.

BUSINESS AND PROPERTY

LNG AND GTL

Australia

We have interests in offshore production, LNG liquefaction and exploration licences in the North West Shelf (NWS) and Greater Gorgon areas of the Carnarvon Basin and in the Browse Basin. Woodside is the operator on behalf of the NWS joint venture (Shell interest 16.7%), which produced more than 480 thousand boe/d of gas and condensates in 2019.

We have a 25% interest in the Gorgon LNG joint venture, which is operated by Chevron. The venture started operating in 2016, producing from the offshore Gorgon and Jansz-Io fields via a three-train LNG plant on Barrow Island.

We are also a partner in the Browse joint arrangement (Shell interest 27%) covering the Brecknock, Calliance and Torosa gas fields, which is operated by Woodside.

We are the operator of Prelude FLNG (67.5% Shell interest). During 2019, the facility progressed through the start-up ramp-up phase, with the first condensate offtake in March 2019, followed by the first LNG offtake in June 2019 and the first NGL offtake in July 2019. Our other interests in the basin include a joint arrangement, with Shell as the operator, for the Crux gas and condensate field (Shell interest 82%) and other backfill and contingent resources.

A significant discovery was made at the Bratwurst prospect in Browse basin, Australia near the Prelude FLNG facility which presents an opportunity for a future tie-back to Prelude, currently under evaluation, to maximise the FLNG value.



The Prelude floating liquefied natural gas (FLNG) facility produces natural gas off the coast of Australia.

The sale of Shell's interest in the undeveloped Sunrise gas field in the Timor Sea (Shell interest 26.6%) to the government of Timor-Leste was completed in 2019.

We are a partner in both Shell-operated and other exploration joint arrangements in multiple basins, including Browse, Exmouth Plateau, and Greater Gorgon.

We have a 50% interest in Arrow, a Queensland-based joint venture with CNPC. Arrow owns coal-bed methane assets and a domestic power business.

We have a 50% interest in train one and a 97.5% interest in train two of the Shell-operated Queensland Curtis LNG (QCLNG) venture. The two-train liquefaction plant has an installed capacity of 8.5 mtpa. We also operate the venture's natural gas operations, which include wells, compression stations and processing plants, in Queensland's Surat Basin. We have interests ranging from 44% to 74% in 24 field compression stations and six central processing plants. Our production of natural gas from the onshore Surat Basin supplies the liquefaction plant and the domestic gas market.

A gas sales agreement between Arrow and QCLNG has been signed, under which gas from Arrow's Surat Basin fields would flow to the QCLNG venture, which would then sell gas to local customers and export it through its gas plant on Curtis Island.

Brunei

We have a 25% interest in Brunei LNG Sendirian Berhad.

Canada

In 2018, we took FID on LNG Canada, a liquefied natural gas project in Kitimat, British Columbia, in which we hold a 40% interest. Construction started in October 2018 and first LNG is expected before the middle of this decade.

Egypt

We have interests of 35.5% in train one and 38% in train two of the Egyptian LNG (ELNG) plant. In January 2014, force majeure notices were issued under the LNG agreements as a result of domestic gas diversions severely restricting volumes available to ELNG. These notices remain in place. See "Oil and gas information" on page 61-68.

Gibraltar

We have a 51% interest in the first LNG regasification facility in Gibraltar.

India

We hold a 100% interest in Shell Energy India Pvt Ltd, which operates a regasification terminal, and Hazira Port Pvt Ltd, which manages a cargo port at Hazira, both of which are located in the state of Gujarat on the west coast.



Operator looking at a vessel at the Shell Hazira port and LNG Terminal, India.

Indonesia

We have a 35% interest in the INPEX Masela Ltd joint venture which owns and operates the offshore Masela block. In June 2019, the joint venture received the official approval of Plan of Development (POD) for the Abadi LNG Project from the Indonesian government authorities. The government also granted a 20-year extension to the Masela block PSC in October 2019.

Malaysia

We operate a GTL plant, Shell MDS (Shell interest 72%). Using Shell technology, the plant converts gas into high-quality middle distillates, drilling fluids, waxes and specialty products.

Netherlands

We have access to import and storage capacity at the GATE LNG terminal in the Port of Rotterdam, Netherlands (Shell capacity rights 1.4 million tonnes per annum (mtpa)). We are also using the terminal to supply LNG to our growing truck-refuelling network in the Netherlands.

Nigeria

We have a 25.6% interest in Nigeria LNG Ltd, which operates six LNG trains located on Bonny Island.

Norway

Gasnor AS (Shell interest 100%) provides LNG fuel for ships and industrial customers and has a natural gas pipeline network.

Oman

We have a 30% interest in Oman LNG LLC. We also have an 11% indirect interest in Qalhat LNG.

In February 2019, we signed an Interim Upstream agreement that detailed a funding and a work programme for 2019 for the development of gas resources destined for integrated projects to help meet the Sultanate of Oman's growing need for energy. The other signatories were Petroleum Development Oman (PDO), Oman Oil Company (OOC) and Total. The project covers investments in gas exploration and production. The aim is to integrate the Shell and OOC share of the upstream project with the development of a GTL plant currently under discussion, which would be developed and operated by Shell in partnership with OOC.

Peru

We have a 20% interest in the Peru LNG liquefaction plant.

INTEGRATED GAS continued

Qatar

We operate the Pearl GTL plant (Shell interest 100%) in Qatar under a development and PSC with the government. The fully-integrated facility has capacity for production, processing and transportation of 1.6 billion standard cubic feet per day (scf/d) of gas from Qatar's North Field. It has an installed capacity of about 140 thousand boe/d of high-quality liquid hydrocarbon products and 120 thousand boe/d of natural gas liquids (NGL) and ethane.

We have a 30% interest in Qatargas 4, which comprises integrated facilities to produce about 1.4 billion scf/d of gas from Qatar's North Field, an onshore gas-processing facility and one LNG train with a collective production capacity of 7.8 mtpa of LNG and 70 thousand boe/d of condensate and NGL.



Operators at Pearl GTL plant, Qatar.

Russia

We have a 27.5% interest in Sakhalin-2, the joint venture with Gazprom, an integrated oil and gas project located on Sakhalin island.

Singapore

We have a 50% interest in a joint venture with KS Investments (the investment arm of Keppel Group) that holds a licence to supply LNG fuel for vessels in the Port of Singapore. We have aggregator licences to import LNG into Singapore and market the gas to power plants and other customers.

Tanzania

We have a 60% interest in, and are the operator of, Blocks 1 and 4 offshore southern Tanzania. The blocks cover approximately 4,000 square kilometres of the Mafia Deep Offshore Basin and the northern part of the Rovuma Basin. We continue to develop a potential LNG project with partners in Block 2, in line with the Block 1 and 4 appraisal programme agreed with the Tanzanian government. We are engaging with the government to extend the Block 4 licence. The government has confirmed that the Block 4 licence, which had initially been due to expire on October 31, 2017, remains in full force pending the grant of the licence extension.

Trinidad and Tobago

We have interests in three concessions with producing fields – Central Block, East Coast Marine Area (ECMA) and North Coast Marine Area (NCMA) blocks. We have a 65% interest in Central Block, 100% interest in ECMA and 80.5% interest in NCMA. We also own 90% interest in block 22 and 80% in NCMA 4 which include three undeveloped discoveries. Our interests range from 35% to 100% in exploration activities in blocks 5(c), 5(d), 6(d), and Atlantic Area blocks 3, 5, and 6.

We are the largest shareholder in all four trains at Atlantic LNG.

UK

We have a 50% interest in the Dragon LNG regasification terminal, with long-term arrangements in place governing the use of capacity rights.

USA

We have offtake rights via a lease to 100% of the capacity (2.5 mtpa) of the Kinder Morgan-operated Elba Island liquefaction plant, which consists of 10 MMLS units. The first three of these units started up in 2019. We also lease regasification capacity on Elba Island with contracted capacity of 11.6 mtpa.

We have 13.1 mtpa of contracted capacity in the Lake Charles regasification terminal in Louisiana. We are also evaluating a project to convert the existing regasification facility owned by Energy Transfer into a liquefaction plant in which we would have capacity rights. In March 2019, we signed a project framework agreement with Energy Transfer to advance the proposed Lake Charles LNG export project towards a potential FID. The Lake Charles LNG export project, is planned to have liquefaction capacity of 16.45 million tons per annum and is a 50:50 venture between the two parties.

Trading and Supply

Through our Shell Energy organisation, we market a portion of our share of equity production of LNG and trade LNG volumes around the world through our hubs in the UK, Dubai and Singapore. We also sell trucked LNG in China, Singapore and Europe.

Other gas and power activities

Bolivia

We hold a 37.5% participating interest in the Caipipendi block, where we mainly produce from the Margarita and Huacaya gas-condensate fields. We are also exploring further in the Caipipendi block. We also have a 25% interest in the Petrobras-operated Tarija XX West block where we produce from the Itaú field. We have the rights to explore and further develop the onshore Huacareta block (Shell interest 100% during exploration), and we are currently exploring there. In August 2019, we acquired a 15% participating interest in the Repsol-operated Inguazu exploration Block. In May 2019, we relinquished the La Vertiente Block to the government.

China

We jointly develop and produce from the onshore Changbei tight-gas field under a PSC with China National Petroleum Corporation (CNPC). In 2016, we completed the Changbei I development programme under the PSC and subsequently handed over the production operatorship to CNPC. In December 2017, we took the FID on the Changbei II Phase 1 project. We started drilling activity in early 2019, and remain the operator of Changbei II.



Changbei Natural Gas Processing Facility, China.

India

We had a 30% interest in the producing oil and gas field Panna/Mukta and a 30% interest in the Mid Tapti and South Tapti fields. Both licences expired in December 2019 and operatorship was transferred to Oil & Natural Gas Corporation Limited (ONGC).

In 2019, we divested our 10% interest in Mahanagar Gas Limited, a natural gas distribution company in Mumbai.

Trading and Supply

Trading and Supply also markets and trades natural gas, power and carbon-emission rights in multiple markets in North and South America, Europe, Asia and Australia, of which a portion includes equity volumes from our upstream operations.

We have set up a power marketing and trading business in Japan which began trading in 2019.

In November 2019, we acquired ERM Power, one of Australia's leading commercial and industrial electricity retailers, which builds on Shell Energy Australia's existing gas marketing and trading capability.

Other

We have a 17.9% share in the West African Gas Pipeline Company Limited which owns and operates a 678-kilometre pipeline transporting gas from Nigeria to Ghana, Benin and Togo.

We have a 40% interest in a gas pipeline connecting Uruguay to Argentina.

We have a 35% interest in Cyprus block 12, holding the Aphrodite discovery which is currently under appraisal, a 60% interest in two deep-water blocks in Colombia, interests in offshore blocks in Myanmar and one exploration block licence in Namibia.

We also have interests in Gabon and Morocco.

New Energies

Our New Energies business explores emerging opportunities linked to the energy transition and invests in those where we see sufficient value. We focus on power, from generation to electric-vehicle charging to integration with Trading, as well as on new fuels for transport, including advanced biofuels and hydrogen.

The New Energies portfolio is being built through organic growth and acquisitions. Most of these opportunities are in sectors that are different from Shell's existing oil and gas businesses, but have some similarities and/or adjacencies to our Downstream and gas and power trading businesses. Shell-controlled New Energies companies are subject to the Shell Control Framework. Some are not yet in full compliance with the Shell Control Framework and we are working to bring them into compliance with this framework in a fit-for-purpose manner.



Shell Greenlots' EV charging, Columbus USA.

Power

We began supplying residential customers in the UK for the first time when we acquired First Utility in 2018. We rebranded First Utility to Shell Energy Retail in 2019. In November 2019, Shell Energy Retail completed the acquisition of Hudson Energy Supply UK Limited, which trades as Green Star Energy for consumers and Hudson Energy for businesses. Shell Energy Retail supplies 100% renewable electricity via purchase of certificates, as well as natural gas and smart home technology to more than 900 thousand homes in the UK.

We own a majority interest in GI Energy, a US company that focuses on the integration of distributed energy resources. We refer to distributed energy when customers begin to generate their own power through solar panels or wind turbines, store it and redistribute it back into the grid.

In 2019, we acquired German company sonnen, which provides battery storage systems to homes with solar panels. In 2019, we also acquired energy technology firm Limejump which provides energy storage to smaller renewable energy generators, allowing them to sell clean power in real-time to the National Grid.



Wind turbines at Noordzee Wind Farm, Netherlands.

INTEGRATED GAS continued

In the Netherlands we are part of the Blauwwind consortium (Shell interest 20%) which is developing the Borssele III and IV offshore wind farms that are designed to have a total installed capacity of 731.5 MW, enough to power about 825,000 Dutch homes. We have a 50% interest in the NoordzeeWind joint venture, an offshore wind power project in the Netherlands with total installed capacity of 108 MW.

In the USA, we have developed and become co-owners of four onshore wind projects, from California to Texas. In December 2018, we formed two 50:50 joint ventures: with EDF Renewables to build wind farms off the New Jersey coast; and with EDPR to build wind farms off Massachusetts. In November 2019 Massachusetts state authorities selected our JV with EDPR to develop and supply 804 MW of clean, renewable energy from offshore wind to electricity customers in the state.



Solar panels at Silicon Ranch, West Virginia, USA.

We own a 43.1% interest in Silicon Ranch Corporation, a developer, owner and operator of solar energy assets in the USA.

In 2019, we acquired a 49% interest in Cleantech Solar, which provides solar power to commercial and industrial customers across South-East Asia and India. In 2019, we also acquired a 49% interest in ESCO Pacific, a utility scale solar developer and long-term asset management company in Australia.

In 2019, we completed the acquisition of EOLFI, a French renewable energies developer specialising in floating offshore wind projects.

Through our NewMotion subsidiary, Shell is developing other flexible solutions for EV drivers to charge their vehicles at home or at work. NewMotion operates around 50 thousand private electric charge points for homes and businesses in the Netherlands, Germany, France and the UK.

In 2019, we acquired Greenlots, a California-based company that provides EV charging posts, charging network software and grid services across the USA and has growing business in Canada, Thailand, Malaysia and Singapore.

New fuels for transport

In Bangalore, India, we have built a demonstration plant that is designed to turn waste into petrol or diesel that can power cars.

In Oregon, USA, we are developing a facility to produce renewable natural gas (RNG) from organic waste through a process called anaerobic digestion.

We are part of joint ventures and alliances that have built hydrogen filling stations for passenger cars in the USA (California), Canada, Germany and the UK and announced plans to build several stations in the Netherlands. In California, Shell is also developing filling stations for hydrogen trucks, in co-operation with Toyota, Kenworth and the Port of Los Angeles.

INTEGRATED GAS DATA TABLE

LNG liquefaction volumes

	2019	2018	2017
	Million tonnes		
Australia	12.5	12.1	11.1 [A]
Brunei	1.6	1.6	1.6
Egypt	0.4	0.3	0.2
Malaysia	–	0.6 [B]	1.3 [B]
Nigeria	5.3	5.1	5.2
Norway	0.1	0.1	0.1
Oman	2.6	2.4	2.0
Peru	0.9	0.8	0.9
Qatar	2.5	2.3	2.4
Russia	3.0	3.1	3.1
Trinidad and Tobago	6.7	5.8	5.3
United States	0.1	–	–
Total	35.6	34.3	33.2

[A] Includes LNG liquefaction volumes related to our share in equity securities of Woodside, that were disposed of in 2017.

[B] Includes LNG liquefaction volumes related to our share in equity securities of Malaysia LNG Tiga, that were disposed of in 2018.

LNG AND GTL PLANTS AT DECEMBER 31, 2019**LNG liquefaction plants in operation**

	Asset	Location	Shell interest (%)	100% capacity (mtpa) [A]
Europe				
Norway	Gasnor	Bergen	100.0	0.3
Asia				
Brunei	Brunei LNG	Lumut	25.0	7.6
Oman	Oman LNG	Sur	30.0	7.1
	Qalhat LNG	Sur	11.0 [B]	3.7
Qatar	Qatargas 4	Ras Laffan	30.0	7.8
Russia	Sakhalin LNG	Prigorodnoye	27.5	9.6
Oceania				
Australia	Australia North West Shelf	Karratha	16.7	16.9
	Gorgon LNG	Barrow Island	25.0	15.6
	Prelude	Browse Basin	67.5	3.6
	Queensland Curtis LNG T1	Curtis Island	50.0	4.3
	Queensland Curtis LNG T2	Curtis Island	97.5	4.3
Africa				
Egypt	Egyptian LNG T1	Idku	35.5	3.6
	Egyptian LNG T2	Idku	38.0	3.6
Nigeria	Nigeria LNG	Bonny	25.6	24.1
South America				
Peru	Peru LNG	Pampa Melchorita	20.0	4.5
Trinidad and Tobago	Atlantic LNG T1	Point Fortin	46.0	3.0
	Atlantic LNG T2/T3	Point Fortin	57.5	6.6
	Atlantic LNG T4	Point Fortin	51.1	5.2

[A] As reported by the operator.

[B] Interest, or part of the interest, is held via indirect shareholding.

LNG liquefaction plants under construction

	Asset	Location	Shell interest (%)	100% capacity (mtpa)
North America				
Canada	LNG Canada T1-2	Kitimat	40.0	14.0

GTL plants in operation

	Asset	Location	Shell interest (%)	100% capacity (b/d)
Asia				
Malaysia	Shell MDS	Bintulu	72.0	14,700
Qatar	Pearl	Ras Laffan	100.0	140,000

Key statistics

	\$ million, except where indicated		
	2019	2018	2017
Segment earnings	4,195	6,798	1,551
Including:			
Revenue (including inter-segment sales)	46,413	47,733	40,192
Share of profit of joint ventures and associates	379	285	623
Interest and other income	2,180	600	1,188
Operating expenses [A]	12,043	12,157	12,656
Exploration	2,073	1,132	1,804
Depreciation, depletion and amortisation	17,003	13,006	17,303
Taxation charge/(credit)	5,954	8,791	2,409
Capital expenditure	10,074	12,447	11,389
Cash capital expenditure [A]	10,277	12,582	11,670
Capital investment [A]	11,075	12,785	13,160
Oil and gas production available for sale (thousand boe/d)	2,743	2,709	2,777

[A] See "Non-GAAP measures reconciliations" on pages 279-280.

OVERVIEW

Our Upstream business explores for and extracts crude oil, natural gas and natural gas liquids. It also markets and transports oil and gas, and operates infrastructure necessary to deliver them to market. We are also involved in the extraction of bitumen from mined oil sands and its conversion into synthetic crude oil.

BUSINESS CONDITIONS

Global oil demand grew by 1.0 million barrels per day (b/d), or 1.0%, to 100.3 million b/d in 2019, according to the International Energy Agency's Oil Market Report published in January 2020. Brent crude oil, an international benchmark, traded between \$53 per barrel (/b) and \$75/b in 2019, ending the year at the lower price of \$67/b. It averaged \$64/b for the year, \$7/b lower than in 2018.

On a yearly average basis, West Texas Intermediate crude oil traded at a \$7/b discount to Brent in 2019, compared with \$6/b in 2018. The discount remained broadly unchanged from 2018, reflecting continued constrained pipeline capacity from the landlocked Cushing storage hub to the US Gulf Coast, against a backdrop of growing supply to the hub. US crude oil exports increased further to about 3 million b/d in 2019, up by 1 million b/d from 2018. This helped to limit widening of the price differential between Brent and WTI.

Global gas demand is estimated to have grown by about 2.4% in 2019, which is in line with the annual growth rate of 2.5% observed since the start of the century. Robust demand growth in power generation and industry was driven by attractive regional spot gas prices that incentivised switching away from competing fuels such as coal and oil. In the key regional markets of North America, Europe, and Asia-Pacific, attractive prices have been caused mainly by ample gas supply growth.

In the USA, the natural gas price at the Henry Hub averaged \$2.5 per million British thermal units (MMBtu) in 2019, 19% lower than in 2018, and traded in a range of \$2.0-4.1/MMBtu. There was some downward pressure on prices due to strong gas supply growth of about 8 billion cubic feet per day (cf/d), which averaged 10% higher than 2018. Gas supply growth was, in part, driven by a growth of associated gas from oil fields, helped by oil prices above \$50/b, and by new gas pipeline capacity. Gas prices found support from: demand growth driven by below-normal storage inventory levels; an increase in usage of power for cooling due to warmer than normal weather in the second half of the year; completion of LNG liquefaction projects; increased exports to Mexico by pipeline; and US industrial growth.

In Europe, natural gas prices were lower than in 2018. The average price at the UK National Balancing Point (NBP) was 43% lower in 2019. At the main continental gas trading hubs – in the Netherlands, Belgium and Germany – prices were also lower, as reflected by weaker Dutch Title Transfer Facility (TTF) prices. European gas prices were lower due to: the rise in LNG volume diverted from the Asia-Pacific region caused by weaker Asia-Pacific demand growth; robust supply of pipeline gas, particularly from Russia; well-filled gas storage inventories; competition with renewables in power generation; and mild weather.

See "Market overview" on pages 37-39.

PRODUCTION AVAILABLE FOR SALE

In 2019, production was 1,001 million boe, or 2,743 thousand boe/d, compared with 989 million boe, or 2,709 thousand boe/d in 2018. Liquids production increased by 8% and natural gas production decreased by 9% compared with 2018.

Increases were mainly from new field start-ups and the continuing ramp-up of existing fields (around 190 thousand boe/d), in particular in the Permian Basin in the USA, in the US Gulf of Mexico (Appomattox, Stones and Ursa) and in Brazil (Lula and Berbigao). Further increases from moving Salym from IG to Upstream (around 60 thousand boe/d). Decreases were mainly from divestments (around 90 thousand boe/d), field declines and performance maintenance (around 100 thousand boe/d).

EARNINGS 2019-2018

Segment earnings in 2019 were \$4,195 million, which included a net charge of \$1,930 million related to impairments, primarily in the US Appalachia unconventional gas assets and a drilling rig joint venture, partly offset by a gain of \$1,609 million on sale of assets, mainly in Denmark and the US Gulf of Mexico.

Segment earnings in 2018 were \$6,798 million, which included a net gain of \$23 million. This included a net gain of \$886 million on sale of assets, mainly related to our divestments in Iraq, Malaysia, Oman and Ireland, and a gain of \$149 million related to the fair value accounting of commodity derivatives. These gains were partly offset by a charge of \$561 million related to the impact of the weakening Brazilian real on a deferred tax position, a net impairment charge of \$350 million mainly related to assets in North America and deep-water rig joint ventures, and a charge of \$90 million related to the release of historic currency differences.

Excluding the net charge described above, segment earnings in 2019 were \$4,744 million, compared with \$6,775 million in 2018. Earnings excluding the net charge were adversely impacted by lower realised oil and gas prices, higher depreciation as well as higher well write-offs mainly in Albania and Kazakhstan, partly offset by higher sales volumes associated with the timing of liftings.

EARNINGS 2018-2017

Segment earnings in 2018 were \$6,798 million, which included a net gain of \$23 million as described above.

Segment earnings in 2017 were \$1,551 million, which included a net charge of \$1,540 million. This net charge included impairment charges of \$2,557 million, mainly related to divestments of our oil sands interests in Canada, onshore assets in Gabon and our interest in the Corrib gas project in Ireland. The net charge also involved \$1,089 million related to US tax reform legislation, and redundancy and restructuring charges of \$163 million. These charges were partly offset by gains on divestments of \$1,463 million, mainly related to a package of UK North Sea assets, a credit of \$772 million mainly reflecting the release of tax liabilities, and other items with a net positive impact of \$34 million.

Excluding the net charges described above, segment earnings in 2018 were \$6,775 million compared with \$3,091 million in 2017. Earnings benefited from higher realised oil and gas prices (around \$4,770 million) and lower well write-offs (around \$400 million). These impacts were partly offset by the impact of movements in deferred tax positions (around \$1,520 million) and lower production volumes (around \$510 million).

CASH CAPITAL EXPENDITURE AND CAPITAL INVESTMENT

Cash capital expenditure in 2019 was \$10.3 billion, compared with \$12.6 billion in 2018. Capital investment in 2019 was \$11.1 billion, compared with \$12.8 billion in 2018.

The lower cash capital expenditure and capital investments in 2019 reflected our continuing efforts to improve capital efficiency by pursuing lower cost development solutions, the completion of the Appomattox project, IFRS16 implementation effects and the 2018 impacts of relative higher spend for lease renewals in Nigeria and additional investments in exploration acreage.

PORTFOLIO AND BUSINESS DEVELOPMENT

We took the following key portfolio decisions during 2019:

- In Argentina we won two exploration blocks in the deep-water bid round (Shell interest 60%);
- Also in Argentina, we agreed a 50:50 partnering with Equinor to jointly acquire Schlumberger's 49% interest in the Bandurria Sur block located in the Vaca Muerta basin (Shell interest 24.5%);
- In Brazil, we announced the Final Investment Decision (FID) to contract the Mero 2 floating production, storage and offloading (FPSO) vessel to be deployed at the Mero field offshore Santos Basin in Brazil;
- In Brunei, we acquired the deep-water exploration Block CA-1 (Shell interest 86.95%). The deal is expected to complete in 2020;
- In Egypt, we announced the intention to sell our onshore upstream assets in the country;
- Also in Egypt, we were awarded onshore concessions with 100% Shell interest (West El Fayum, South East Horus, South Abu Sennan) and one producing concession extension (Bed 2-17);
- Also in Egypt, we were awarded two concessions in the Red Sea bid round: Block 4 (Shell interest 70%) and Block 3 as the sole operator. This is awaiting ratification;
- In Kazakhstan, we decided not to progress the Kalamkas-Khazar projects. These projects were not deemed competitive compared to other opportunities in our global portfolio;

- In Malaysia, we took FID on the second phase of the Malikai deep water development (Shell interest 35%);
- In Nigeria, we announced the release of Invitation to Tender (ITT) to contractors for the development of the Bonga South West Aparo (BSWA) oil field;
- In Oman, our partnership with Oman Oil Company Exploration production to explore for oil and gas in Block 42 was ratified (Shell interest 50%);
- Also in Oman, we signed an Exploration & Production Sharing Agreement for Block 55 in the southeast of the Sultanate (Shell interest 100%). This agreement is awaiting ratification via Royal Decree;
- In São Tomé and Príncipe, in the Gulf of Guinea, we acquired interests in Block 6 (Shell interest 20%) and Block 11 (Shell interest 30%) exploration licences;
- In South Africa, we entered the frontier deep-water Cape Basin (Shell interest 40%) and a second block adjacent to our existing acreage in the Namibian Orange Basin (Shell interest 45%);
- In the UK, we announced FID to export gas and oil from the Pierce field, which is located 165 miles east of Aberdeen (Shell interest 92.5%);
- In the US Gulf of Mexico, we announced FID to develop the PowerNap field (Shell interest 100%);
- Also in the US Gulf of Mexico, we acquired 77 blocks across multiple plays in the Gulf of Mexico Lease Sale 252; and
- In the USA, we made a significant discovery at the Blacktip prospect in the deep-water US Gulf of Mexico (Shell interest 52.4%). Blacktip is our second significant discovery in the Perdido Corridor and is part of a continuing exploration strategy to add competitive deep-water options to extend our heartlands.

In the Netherlands, the Dutch government decided to halt Groningen production by 2022, eight years earlier than initially planned.

We achieved the following operational milestones in 2019:

- In deep water off Brazil, we announced first production from two of our FPSOs: P-67, in Lula North (Shell interest 23%, post-unitisation); and P-68, in Berbigão (Shell interest 25%, subject to unitisation);
- In Italy, the Tempa Rossa oil field started up in December 2019 (Shell interest 25%);
- In Malaysia, we completed phase 2 of the Gumusut-Kakap deep-water project, drilling four additional subsea wells (Shell interest 29%);
- In Malaysia offshore Sarawak, we produced first oil and gas from the E6 field in SK308 PSC (Shell interest 50%). We also produced first gas from the Larak field in the SK408 PSC (Shell interest 30%);
- In the US Gulf of Mexico, we announced first production from Appomattox (Shell interest 79%). It is the first commercial discovery brought into production in the deep-water Norphlet formation in the US Gulf of Mexico.

We continued to divest selected assets during 2019, including:

- In Canada, we sold our Foothills sour gas plants and the gas fields which feed them;
- In Denmark, we completed the sale of our 36.8% non-operating interest in our joint venture the Danish Underground Consortium, for \$1.9 billion;
- In Norway, we sold 10% of our 12% interest in Nyhamna gas plant;
- In the US Gulf of Mexico, we sold our 22.45% non-operating interest in the Caesar Tonga asset;
- Also in the USA, we sold our non-Shell operated interest in the Haynesville shale gas formation in Northern Louisiana; and
- Also in the USA, we sold our Norphlet deep-water gathering pipeline system in the US Gulf of Mexico.

BUSINESS AND PROPERTY

Our subsidiaries, joint ventures and associates are involved in all aspects of upstream activities, including matters such as land tenure, entitlement to produced hydrocarbons, production rates, royalties, pricing, environmental protection, social impact, exports, taxes and foreign exchange.

The conditions of the leases, licences and contracts under which oil and gas interests are held vary from country to country. In almost all cases outside North America, the legal agreements are generally granted by, or entered into with, a government, state-owned company, government-run oil and gas company or agency, and the exploration risk usually rests with the independent oil and gas company. In North America, these agreements may also be with private parties that own mineral rights. Of these agreements, the following are most relevant to our interests:

- Licences (or concessions), which entitle the holder to explore for hydrocarbons and exploit any commercial discoveries. Under a licence, the holder bears the risk of exploration, development and production activities, and is responsible for financing these activities. In principle, the licence holder is entitled to the totality of production less any royalties in kind. The government, state-owned company or government-run oil and gas company may sometimes enter into a joint arrangement as a participant, sharing the rights and obligations of the licence but usually without sharing the exploration risk. In a few cases, the state-owned company, government-run oil and gas company or agency has an option to purchase a certain share of production;
- Lease agreements, which are typically used in North America and are usually governed by terms similar to licences. Participants may include governments or private entities. Royalties are either paid in cash or in kind; and
- PSCs entered into with a government, state-owned company or government-run oil and gas company. PSCs generally oblige the independent oil and gas company, as contractor, to provide all the financing and bear the risk of exploration, development and production activities in exchange for a share of the production. Usually, this share consists of a fixed or variable part that is reserved for the recovery of the contractor's cost (cost oil). The remaining production is split with the government, state-owned company or government-run oil and gas company on a fixed or volume/revenue-dependent basis. In some cases, the government, state-owned company or government-run oil and gas company will participate in the rights and obligations of the contractor and will share in the costs of development and production. Such participation can be across the venture or on a field-by-field basis. Additionally, as the price of oil or gas increases above certain predetermined levels, the independent oil and gas company's entitlement share of production normally decreases, and vice versa. Accordingly, its interest in a project may not be the same as its entitlement.

**Europe
Italy**

We have a 39% interest in the Val d'Agri producing concession, operated by ENI.

We also have a 25% interest in the Tempa Rossa producing concession operated by Total.

Netherlands

Shell and ExxonMobil are 50:50 shareholders in Nederlandse Aardolie Maatschappij B.V. (NAM). An important part of NAM's gas production comes from the onshore Groningen gas field, in which NAM holds a 60% interest. The remaining 40% interest is held by EBN, a Dutch government entity.

Production from the Groningen field induces earthquakes that cause damage to houses and other buildings and structures in the region. This has led to complaints and claims for compensation for damage from the local community. NAM is working with the Dutch government and other stakeholders to fulfil its obligations to the residents of the area, which includes compensation for damage caused by above-mentioned earthquakes.

Since 2013, the Dutch Minister of Economic Affairs and Climate (the Minister) has set an annual production level for the Groningen field taking into account all interests, including safety of the residents, security of supply in the domestic gas market as well as supply commitments in EU member states. Production in the gas year 2018-2019 (ending October 1, 2019) was capped at 19.4 billion cubic metres; actual production in this period was 17.5 billion cubic metres.

In June 2018, NAM's shareholders and the Dutch government signed a Heads of Agreement (HoA) to reduce production from Groningen and to ensure the financial robustness of NAM to fulfil its obligations. In the HoA, NAM's shareholders have agreed not to declare dividends for 2018 and 2019. Dividend payments in 2020 and beyond will only be done if a solvency ratio of 25% is reached. In September 2018, detailed agreements were signed to further implement the HoA. As part of these agreements, Shell guarantees NAM's payment obligations vis-à-vis the Dutch government in relation to earthquake-related damages and costs of strengthening houses, up to a maximum of 30%. This maximum equates to Shell's indirect interest in the Groningen production system.

In September 2019, the government issued an update announcing that it was able to reduce Groningen production faster, stopping production in 2022, eight years earlier than initially planned. Negotiations are ongoing between the government and the NAM shareholders to discuss the compensation payable by the government to NAM in order to restore the balance of the package of arrangements laid down in the 2018 HoA.

NAM also has a 60% interest in the Schoonebeek oil field and operates 25 other hydrocarbon production licences onshore and offshore in the North Sea.

Norway

We are a partner in 34 production licences on the Norwegian continental shelf. We are the operator in 14 of these, of which two are producing: the Knarr field (Shell interest 45%), and the Ormen Lange gas field (Shell interest 17.8%). We have interests in the producing fields Troll, Kviteseid, Sindre and Væmon, where we are not the operator.

UK

We operate a significant number of our interests on the UK continental shelf under a 50:50 joint-venture agreement with ExxonMobil. In addition to our oil and gas production from North Sea fields, we have various interests in the Atlantic Margin area where we are not the operator, principally in the West of Shetland area (Clair, Shell interest 28%), and Schiehallion (Shell interest approximately 45%).



Brent decommissioning using Allseas Pioneering Spirit, the world's largest construction vessel.

In June 2019 the "Pioneering Spirit" vessel safely completed the single-lift removal of the 25,000-tonne Brent Bravo topside from the North Sea. Brent Bravo is the second of four platforms, after Brent Delta, to be decommissioned and removed from the Brent oil and gas field. The UK Government initiated consultation with the other signatories of the OSPAR Convention on whether to issue derogations for leaving in-situ the footings of the Brent Alpha steel jacket and each of the gravity-based concrete installations of Brent Bravo, Brent Charlie and Brent Delta.

In October 2019, we announced FID on a project to enable the export of gas and oil from the Pierce field, which lies 165 miles east of Aberdeen. It is a joint venture between Shell (92.52%) and Ithaca (7.48%). The project includes modifying the FPSO vessel, the Haewene Brim, owned and operated by Bluewater. Development is expected to take place between 2020 and 2021 and has Oil and Gas Authority (OGA) approval.

Rest of Europe

We also have interests in Albania, Bulgaria and Germany.

Asia (including the Middle East and Russia)

Brunei

Shell and the Brunei government are 50:50 shareholders in Brunei Shell Petroleum Company Sendirian Berhad (BSP). BSP has long-term oil and gas concession rights onshore and offshore Brunei, and sells most of its gas production to Brunei LNG Sendirian Berhad (see "Integrated Gas" on page 47), with the remainder (12% in 2019) sold in the domestic market.

In addition to our interest in BSP, we have a 35% non-operating interest in the Block B concession, where gas and condensate are produced from the Maharaja Lela field.

We also have non-operating interest in the deep-water exploration Block CA-2 (Shell interest 12.5%), under PSC.

A sale and purchase agreement was signed in October 2019 for the acquisition of Total E&P Deep Offshore Borneo B.V. and all of its interests in the deep-water exploration Block CA-1 (interest 86.95%), under PSC. The deal is expected to complete in 2020.

Over the course of 2019, we have relinquished our interests in the Block A concession (Shell interest 53.9%) following the drilling of the Rapong exploration well. Linked to the relinquishment of Block A, we have also relinquished our interests in the adjacent Block N (Shell interest 50%).

Iraq

We have a 44% interest in the Basrah Gas Company, which gathers, treats and processes associated gas that was previously being flared from the Rumaila, West Qurna 1 and Zubair fields. The processed gas and associated products, such as condensate and LPG, are sold to the domestic market. Any surplus condensate and LPG is exported. In 2019, Basrah Gas Company processed on average around 850 million scf/d of associated gas into dry gas, condensate and LPG.

Kazakhstan

We are the joint operator of the onshore Karachaganak oil and condensate field (Shell interest 29.3%), where we have a licence to the end of 2037.

We have an interest in the North Caspian Sea Production Sharing Agreement (Shell interest 16.8%) which includes the Kashagan field in the Kazakh sector of the Caspian Sea. The North Caspian Operating Company is the operator. This shallow-water field covers an area of around 3,400 square kilometres. Phase 1 development of the field is expected to lead to plateau oil production capacity of about 63 thousand boe/d by 2020 (Shell interest), with the possibility of increases with additional phases of development.

We have a 7.4% interest in Caspian Pipeline Consortium, which owns and operates an oil pipeline running from the Caspian Sea to the Black Sea across parts of Kazakhstan and Russia.



Operators at the Karachaganak field in Kazakhstan.

In 2019 we made the decision not to progress the Kalamkas-Khazar projects. These projects were not competitive enough compared to other opportunities in Shell's global portfolio.

UPSTREAM continued**Malaysia**

We explore for and produce oil and gas offshore Sabah and Sarawak under 16 PSCs, in which our interests range from 20% to 85%.

Offshore Sabah, we operate two producing oil fields. These include the Gumusut-Kakap deep-water field (Shell interest 29%), and the Malikai deep-water field (Shell interest 35%). In August 2019, phase 2 development of the Gumusut-Kakap field successfully achieved first oil and is expected to add 50 thousand boe/d of extra capacity (Shell interest). In December 2019, we also took FID on phase 2 of the Malikai project. The project involves the drilling of two additional oil producing wells and four water injection wells to enhance Malikai's expected recoverable oil volumes. We also have a 21% interest in the Siakap North-Petai deep-water field and a 30% interest in the Kebabangan field, both operated by third parties. Additionally, we have exploration interests in Blocks SB-J, SB-G, SB-N, SB-3G, ND-6 and ND-7 PSCs.

Offshore Sarawak, we are the operator of eight producing gas fields (Shell interest 50%). In June 2019, the Block SK8 PSC expired (Shell equity 37.5%). In 2019, the abandonment of depleted wells for Serai field (Shell interest 37.5%) and Saderi field (Shell interest 37.5%) were completed. In December 2019, we signed a binding Heads of Agreement (HOA) for the extension of the MLNG PSC. Under the terms of the HOA, Shell will continue to be the PSC operator for F6 and F23 hubs and retains the operatorship of E8, F13 East and F13 West fields. Shell will also be the operator for the new exploration acreage and new fields (F22, F27, Selasih), which will now be part of the MLNG Extension PSC. The key terms in the HOA will be further detailed in the definitive agreements expected to be signed in 2020. Nearly all the gas produced offshore Sarawak is supplied to Malaysia LNG and to our gas-to-liquids plant in Bintulu. See "Integrated Gas" on page 47.

In May 2019, first oil and gas were successfully achieved from the E6 field in SK308 PSC (Shell interest 50%) where the field is the first carbonate thin oil-rim and gas development in Malaysia. First gas was also successfully achieved from the Larak field in the SK408 PSC (Shell interest 30%) in December 2019.

We also have interests in the Amended 2011 Baram Delta EOR PSC (Shell interest 40%) and in Block SK-307 PSC (Shell interest 50%), and exploration interests in Blocks SK318, SK320, SK408 and SK319.



Malikai deep-water platform, Malaysia.

Oman

We have a 34% interest in Petroleum Development Oman (PDO); the Omani government has a 60% interest. PDO is the operator of more than 200 oil fields, mainly located in central and southern Oman, over an area of 90,874 square kilometres. The concession expires in 2044.

In October, we signed an Exploration & Production Sharing Agreement for Block 55 in the southeast of the Sultanate. Oman Shell now has a 100% working interest and operatorship of Block 55 with a total area of 7,564 square kilometres. The agreement includes a work programme of regional studies, seismic acquisition and other potential exploration activities. This agreement is awaiting ratification via Royal Decree.

Russia

We have a 50% interest in Salym Petroleum Development N.V., the joint venture with Gazprom Neft, developing the Salym fields in western Siberia, Khanty Mansiysk Autonomous District.

We and Gazprom Neft each have a 50% interest in Khanty-Mansiysk Petroleum Alliance VOF partnership through which Shell is a holder of 50% of shares in JSC Khanty-Mansiysk Petroleum Alliance.

In June 2019, we signed an agreement with Gazprom Neft on the future sales and purchase of the 50% participation interest in LLC Meretoyahaneftgaz. This transaction is expected to be completed in 2020.

With effect from January 1, 2019, Salym and Khanty-Mansiysk Petroleum Alliance VOF partnership is reported in the Upstream segment. Comparative information has not been restated.

As a result of European Union and US sanctions prohibiting certain defined oil and gas activities in Russia, we suspended our support to Salym and Khanty-Mansiysk Petroleum Alliance VOF partnership in relation to shale oil activities since 2014. Also, Salym and Khanty-Mansiysk Petroleum Alliance VOF partnership also suspended any of their shale oil-related activities since 2014 as well.

United Arab Emirates

In Abu Dhabi, we have a 15% interest in the licence of ADNOC Gas Processing, which expires in 2028. ADNOC Gas Processing exports propane, butane and heavier-liquid hydrocarbons, which it extracts from the wet gas associated with the oil produced by ADNOC Onshore.

Rest of Asia

We also have interests in Jordan, Kuwait, the Philippines and Turkey.

Africa**Egypt**

We have a 50% interest in the Badr Petroleum Company (BAPETCO), a self-operated joint venture between Shell and the Egyptian General Petroleum Corporation (EGPC). BAPETCO onshore operations are in the Western Desert where we have an interest in ten oil and gas producing concessions, as well as two exploration concessions (North East Obaiyed, North Matruh). In October 2019, we announced our intention to sell our onshore upstream assets in Egypt. In December 2019, we were awarded onshore concessions with 100% Shell interest (West El Fayum, South East Horus, South Abu Sennan) and one producing concession extension (Bed 2-17).

We have a 25% interest in the Burullus Gas Company (Burullus), a self-operated joint venture between Shell, EGPC and PETRONAS. Burullus operates the West Delta Deep Marine concession (Shell interest 50%), which supplies gas to both the domestic market and the Egyptian LNG plant (see “Integrated Gas” on page 47).

We have a 60% interest in the development rights over the Harmattan Deep discovery and in the Notus discovery offshore the Nile Delta.

We have interests in two gas-producing areas offshore the Nile Delta. We have a 40% interest in the Rashid Petroleum Company, a self-operated joint venture between Shell, EGPC and Edison, which operates the Rosetta concession (Shell interest 80%).

With effect from January 1, 2020, our interest in the offshore Nile Delta will be reported in the Integrated Gas segment. Comparative information will not be restated.

Nigeria

Our share of production, onshore and offshore, in Nigeria was 266 thousand boe/d in 2019, compared with 255 thousand boe/d in 2018. Security issues, sabotage and crude oil theft in the Niger Delta remained significant challenges in 2019.

Onshore

The Shell Petroleum Development Company of Nigeria Limited (SPDC) is the operator of a joint venture (Shell interest 30%) that has 17 Niger Delta onshore oil mining leases (OML).

SPDC commenced litigation against the Federal Government (FGN), in the domestic court to challenge the non-renewal of OML 11. In August 2019, the Court ruled in favour of SPDC affirming that the SPDC JV has fulfilled its obligations under the law for the renewal of OML 11 and ordered the FGN to renew OML 11 for 20 years. In December 2019, the court further refused to grant an application by the FGN to suspend the implementation of the judgement. Though the FGN has appealed the decision of the Court, SPDC continues to operate the block supported by the judgement in its favour which remains in force and unimpaired.

SPDC supplies gas to Nigeria LNG Ltd (see “Integrated Gas” on page 47) mainly through its Gbaran-Ubie and Soku projects.

In 2019, we took the FID on Soku NAG Compressor 2 and Gbaran Single Wells Hookup (Shell interest 30%).

Offshore

Our main offshore deep-water activities are carried out by Shell Nigeria Exploration and Production Company Limited (SNEPCO, Shell interest 100%). SNEPCO has interests in four deep-water blocks, three of which are under PSC terms: Bonga and Erha. SNEPCO operates OMLs 118 (including the Bonga field FPSO, Shell interest 55%) and 135 (Bolia and Doro, Shell interest 55%) and has a 43.8% non-operating interest in OML133 (including the Erha FPSO). Separately, SNEPCO holds a 50% non-operating interest in oil prospecting licence (OPL) 245 (Zabazaba, Etan) under a production sharing agreement (PSA).

Authorities in various countries are investigating our investment in Nigerian oil block OPL 245 and the 2011 settlement of litigation pertaining to that block. See Note 25 to the “Consolidated Financial Statements” on pages 235-237.

SPDC also has three shallow-water licences (OMLs 74, 77 and 79) and a 40% interest in the non-Shell-operated Sunlink joint venture that has one shallow-water licence (OML 144); all four OMLs expire in 2034.

In our Nigerian operations, we face various risks and adverse conditions which could have a significant adverse effect on our operational performance, earnings, cash flows and financial condition (see “Risk factors” on page 32). There are limitations to the extent to which we can mitigate these risks. We carry out regular portfolio assessments to remain a competitive player in Nigeria for the long term. We support the Nigerian government’s efforts to improve the efficiency, functionality and domestic benefits of Nigeria’s oil and gas industry, and we monitor legislative developments. We monitor the security situation and liaise with host communities, governmental and non-governmental organisations to help promote peace and safe operations. We continue to provide transparency in spills management and reporting, along with our deployment of oil-spill response capability and technology. We execute a maintenance strategy to support sustainable equipment reliability and have implemented a multi-year programme to reduce routine flaring of associated gas. See “Climate change and energy transition” on page 91-98.



FPSO Bonga, offshore Nigeria.

Rest of Africa

We also have interests in Algeria, Mauritania, Namibia, São Tomé and Príncipe, South Africa and Tunisia.

North America Canada

We have mineral leases mainly in Alberta and British Columbia. We produce and market natural gas, natural gas liquids, synthetic crude oil and bitumen.

Shales

We have approximately 1.4 million net mineral acres. Our position is primarily in the Duvernay play in Alberta and the Montney play in British Columbia. Activity includes drill-to-fill of our existing infrastructure and an investment focus on our liquid-rich shale acreage. Our Groundbirch asset has the potential to be an integral part of the LNG Canada value chain.

UPSTREAM continued

In 2019, we drilled and brought 30 wells onstream. We have interests in 748 productive wells. In October 2019, we sold our Foothills assets comprising approximately 400 thousand net acres at Waterton, Jumping Pound, West Central and Caroline, with associated gas processing facilities.

After selling our Foothills assets, we operate one natural gas processing facility in Alberta and four natural gas processing facilities in British Columbia.

Bitumen and synthetic crude oil

Synthetic crude oil is produced by mining bitumen-saturated sands, extracting the bitumen from the sands and transporting it to a processing facility where hydrogen is added to produce a wide range of feedstocks for refineries. We have a 50% interest in 1745844 Alberta Ltd. (formerly known as Marathon Oil Canada Corporation), which holds a 20% interest in the Athabasca Oil Sands Project. With effect from January 1, 2020, our interest in the Bitumen and synthetic crude oil will be reported in the Oil Products segment. Comparative information will not be restated.



Transporting Shell Bitumen.

Carbon capture and storage (CCS)

We operate the Quest CCS project (Shell interest 10%), which captured and safely stored more than 1.1 million tonnes of carbon dioxide in 2019.

USA

We produce oil and gas in deep water in the Gulf of Mexico, heavy oil in California and oil and gas from shale in Pennsylvania and Texas. The majority of our oil and gas production interests are acquired under leases granted by the owner of the minerals underlying the relevant acreage, including many leases for federal onshore and offshore tracts. Such leases usually run on an initial fixed term that is automatically extended by the establishment of production for as long as production continues, subject to compliance with the terms of the lease (including, in the case of federal leases, extensive regulations imposed by federal law). Our share of production in the USA was in total 653 thousand boe/d in 2019.

In December 2019, we recognised an impairment, mainly associated with the US Appalachia unconventional gas assets. We will continue to regularly review the economic attractiveness of our Shales investments in light of the macroeconomic environment, which could result in changes to development plans in the future. See Note 8 Property, plant and equipment on page 210-213.

Gulf of Mexico

The Gulf of Mexico is our major production area in the USA and accounts for around 54% of our oil and gas production in the country. We have an interest in approximately 320 federal offshore leases and our share of production averaged 359 thousand boe/d in 2019.

In May 2019, we signed an agreement to sell our 22.45% non-operated interest in the Caesar-Tonga asset in the US Gulf of Mexico to Equinor. The total consideration for this deal was \$965 million in cash. This was completed on July 1, 2019.

In April 2019, we announced a significant discovery at the Blacktip prospect in the deep-water US Gulf of Mexico. Blacktip is a Wilcox discovery in the Perdido thrust belt and was discovered in the Alaminos Canyon Block 380, approximately 30 miles from the Perdido platform and Whale discovery. Evaluation is ongoing and appraisal planning is underway to further delineate the discovery and define development options.

In May 2019, production started at the Shell-operated Appomattox floating production system months ahead of schedule. Appomattox (Shell interest 79%) currently has an expected peak production of 175 thousand boe/d and is the first commercial discovery now brought into production in the deep-water Gulf of Mexico Norphlet formation. In August 2019, we took the FID for the PowerNap deep-water project in the US Gulf of Mexico. PowerNap (Shell interest 100%), discovered in 2014, is a subsea tie-back to the Shell-operated Olympus production hub. The project is expected to start production in late 2021 and expected to produce up to 35 thousand boe/d at peak rates. In August 2019, the Whale project moved into the Define phase. The project is 60% Shell and 40% Chevron, with the exception of the AC815 lease area which is 40% Shell and 60% Chevron.

We are the operator of eight production hubs – Mars A, Mars B, Auger, Perdido, Ursa, Enchilada/Salsa, Appomattox and Stones – as well as the West Delta 143 Processing Facilities (Shell interests ranging from 38% to 100%). We also have non-operating interests in Nakika (Shell interest 50%) and we continue to produce from Coulomb (Shell interest 100%) which ties into the Nakika non-operated platform. Our production in the US Gulf of Mexico assets was adversely impacted by operational constraints.



Perdido offshore deep-water platform in the Gulf of Mexico.

Shales

We have approximately 1.0 million net mineral acres. Our activity is focused in the Permian Basin in West Texas and the Marcellus and Utica plays in Pennsylvania.



Operator climbs drilling rig, Permian Basin, West Texas USA.

In 2019, we drilled and brought 271 wells onstream. We have interests in more than 1,952 productive wells and operate seven central processing facilities. The USA represents 61% of our shales proved reserves and 80% of our shales liquids proved reserves. In the Permian Basin, we increased our production in 2019 by around 40% compared with 2018. In December 2019, the first integrated iShale® facilities came on stream in East Slash Ranch of our Permian asset. Comprising two pads with eight wells in total and a central processing facility, this shale 'field of the future' brings together more than a dozen iShale technologies, including full wireless surveillance and controls, low greenhouse gas emissions technology, multiphase metering, artificial intelligence technologies and solar-powered facilities.

In February 2019, we sold approximately 27 thousand non-core net acres, with 61 wells and associated facilities in the Marshlands area of Pennsylvania.

In February 2019, we also sold 695 non-producing non-core net acres in the Permian Basin.

In December 2019, we sold our non-Shell-operated interest in the Haynesville shale gas formation in Northern Louisiana.

California

We have a 51.8% interest in Aera Energy LLC which operates around 15,000 wells in the San Joaquin Valley in California, mostly producing heavy oil and associated gas.

Alaska

Shell retains two exploration acreage positions in the long-established North Slope area of Alaska. One is a non-operating interest of 50% in 13 federal leases, operated by ENI. An exploratory drilling operation for this joint venture is under way after being permitted by ENI. We continue to evaluate our 18 state leases at nearby Western Harrison Bay, which have geologic affinity with recent discoveries announced by other North Slope operators.

Rest of North America

We also have interests in Mexico.

South america

Argentina

Shales

We have more than 162 thousand net mineral acres in the Vaca Muerta basin, a liquids and gas-rich play located in the Neuquén Province. The operated acreage includes blocks in Cruz de Lorena and Sierras Blancas (Shell interest 90%), Coiron Amargo Sur Oeste (Shell interest 80%), and Bajada de Añelo (Shell interest 50%). We have a 45% non-Shell-operated interest in the Rincon La Ceniza and La Escalonada blocks. In 2019, we drilled and brought 15 wells onstream. We have interests in 47 producing wells. We have a 90% interest in our operated Sierras Blancas/Cruz de Lorena central processing facility.

In December 2019, we agreed a 50:50 partnering with Equinor to jointly acquire Schlumberger's 49% interest in the Bandurria Sur block located in the Vaca Muerta basin (Shell interest 24.5%).

Offshore

In April 2019, we won two frontier exploration blocks in the deep-water bid round offshore of Argentina. For both blocks, Shell is to be operator holding 60% of the participating interest, with Qatar Petroleum holding the remaining 40%.

Brazil

Our share of production in Brazil was in total 383 thousand boe/d in 2019.

We operate the Bijupirá and Salema (Shell interest 80%) and BC-10 fields (Shell interest 50%) in the Campos Basin, offshore Brazil. Our operated portfolio also includes the Gato do Mato field in the Santos Basin and the adjacent Sul de Gato do Mato area (Shell interest 80%), for which development options are being evaluated. Our operated portfolio also includes 10 offshore exploration concessions in the Barreirinhas Basin (Shell interests ranging from 50% to 100%), pre-salt PSCs for Alto Cabo Frio Oeste (Shell interest 55% as operator) and Saturno (Shell interest 45% as operator) in the Santos Basin, C-M-791 exploration block (Shell interest 40%) in the Campos Basin, and one block in the Potiguar Basin (Shell interest 100%). We have entered into an agreement with Ecopetrol for the sale of 30% interest in the Gato do Mato field and Sul de Gato do Mato area, which is still subject to regulatory approvals.



FPSO P68 being towed into position, offshore Brazil.

UPSTREAM continued

In October 2019, during the sixteenth deep-water bid round organised by the Brazilian National Petroleum Agency (ANP), we were granted exploration and production rights as operator with respect to two exploration blocks, C-M-659 and C-M-713, in the Campos Basin (Shell Interest 40%). This is awaiting ratification.

In our non-operated portfolio, we have interests in several fields in the offshore Santos Basin, consisting of 30% interests in BM-S-9, Entorno de Sapinhoá and BM-S-9A blocks Sapinhoá and Lapa fields. In the Santos Basin we also have BMS-11A concession with 25% interest in the Berbigão and Sururu fields, which are accumulations subject to ongoing unitisation agreements and 4% in the Atapu unit, which has already been subject to unitisation in effect from September 2019. The non-operated portfolio in the Santos Basin also includes the BMS-11 concession with the Lula field, which is partly subject to unitisation that has been in effect since April 2019 (Shell interest 23% in the unit). The Iracema area of the Lula field (Shell interest of 25%) is not subject to unitisation. Additionally, we also hold a 20% interest in BM-S-50 offshore exploration block, where the Sagitário prospect was discovered and we hold a 20% interest in the Libra block where the commerciality of the Mero field was declared. FPSO Pioneiro de Libra has been performing extended well tests and operating early production systems since 2017, and exploration is ongoing in the Central and South East areas. The Mero field is also subject to unitisation with adjoining area, for which a unitisation agreement is still subject to government approval. We announced the final investment decision to contract the Mero 2 floating production, storage and offloading (FPSO) vessel to be deployed at the Mero field offshore Santos Basin in Brazil. The FPSO has the capacity to process up to 180 thousand boe/d (Shell interest 20%). We also hold one deep-water exploration block in the Potiguar Basin (Shell interest 40%) and a PSC to explore the Tres Marias block in the Santos Basin (Shell interest 40%).

The activities of operated and non-operated fields are currently supported by 16 producing deep-water FPSOs, of which the fifteenth (P-67) delivered first oil in February 2019 and the sixteenth (P-68) in November 2019. Two additional FPSOs are expected to be brought online over the period 2020-2021 (Atapu I (P-70) and Mero I).

Rest of South America

We also have interests in Colombia and Uruguay.

TRADING AND SUPPLY

We market and trade crude oil from most of our Upstream operations.



Shell markets and trades crude oil.

OIL AND GAS INFORMATION

Proved developed and undeveloped reserves of Shell subsidiaries and Shell share of joint ventures and associates

	Crude oil and natural gas liquids (million barrels)	Natural gas (thousand million scf)	Synthetic crude oil (million barrels)	Bitumen (million barrels)	Total (million boe) [A]
Shell subsidiaries					
Increase/(decrease) in 2019:					
Revisions and reclassifications	444	2,180	(34)	-	785
Improved recovery	4	3	-	-	5
Extensions and discoveries	158	684	-	-	276
Purchases and sales of minerals in place	(91)	(367)	-	-	(154)
Total before taking production into account	515	2,500	(34)	-	912
Production [B]	(627)	(3,355)	(20)	-	(1,226)
Total	(112)	(855)	(54)	-	(314)
At January 1, 2019	4,486	29,847	661	-	10,294
At December 31, 2019	4,374	28,992	607	-	9,980
Shell share of joint ventures and associates					
Increase/(decrease) in 2019:					
Revisions and reclassifications	25	(224)	-	-	(13)
Improved recovery	4	1	-	-	4
Extensions and discoveries	2	5	-	-	3
Purchases and sales of minerals in place	-	-	-	-	-
Total before taking production into account	31	(218)	-	-	(6)
Production [C]	(38)	(721)	-	-	(163)
Total	(7)	(939)	-	-	(169)
At January 1, 2019	290	5,768	-	-	1,285
At December 31, 2019	283	4,829	-	-	1,116
Total					
Increase/(decrease) before taking production into account	546	2,282	(34)	-	906
Production	(665)	(4,076)	(20)	-	(1,388)
Increase/(decrease)	(119)	(1,794)	(54)	-	(482)
At January 1, 2019	4,776	35,615	661	-	11,578
At December 31, 2019	4,657	33,821	607	-	11,096
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31, 2019					
	-	-	304	-	304

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 standard cubic feet (scf) per barrel.

[B] Included 43 million barrels of oil equivalent (boe) consumed in operations (natural gas: 247 thousand million scf; synthetic crude oil: 1 million barrels).

[C] Included 7 million boe consumed in operations (natural gas: 42 thousand million scf).

OIL AND GAS INFORMATION continued

PROVED RESERVES

The proved oil and gas reserves of Shell subsidiaries and the Shell share of the proved oil and gas reserves of joint ventures and associates are set out in more detail in "Supplementary Information – Oil and Gas (unaudited)" on pages 215-226.

Before taking production into account, our proved reserves increased by 906 million boe in 2019. This comprised of increases of 912 million boe from Shell subsidiaries and of decreases of 6 million boe from the Shell share of joint ventures and associates.

After taking production into account, our proved reserves decreased by 482 million boe in 2019 to 11,096 million boe at December 31, 2019.

SHELL SUBSIDIARIES

Before taking production into account, Shell subsidiaries' proved reserves increased by 912 million boe in 2019. This comprised of increases of 515 million barrels of crude oil and natural gas liquids, 431 million boe (2,500 thousand million scf) of natural gas and decrease of 34 million barrels of synthetic crude oil. The 912 million boe increase is the net effect of a net increase of 785 million boe from revisions and reclassifications, an increase of 5 million boe from improved recovery, an increase of 276 million boe from extensions and discoveries, and a net decrease of 154 million boe related to purchases and sales of minerals in place.

After taking into account production of 1,226 million boe (of which 43 million boe were consumed in operations), Shell subsidiaries' proved reserves decreased by 314 million boe in 2019 to 9,980 million boe. In 2019, Shell subsidiaries' proved developed reserves (PD) decreased by 204 million boe to 7,849 million boe, and proved undeveloped reserves (PUD) decreased by 110 million boe to 2,131 million boe.

SHELL SHARE OF JOINT VENTURES AND ASSOCIATES

Before taking production into account, the Shell share of joint ventures and associates' proved reserves decreased by 6 million boe in 2019. This comprised an increase of 31 million barrels of crude oil and natural gas liquids and a decrease of 37 million boe (218 thousand million scf) of natural gas. The 6 million boe decrease comprises a net decrease of 13 million boe from revisions and reclassifications and an increase of 3 million boe from extensions and discoveries and an increase of 4 million boe from improved recovery.

After taking into account production of 163 million boe (of which 7 million boe were consumed in operations), the Shell share of joint ventures and associates' proved reserves decreased by 169 million boe to 1,116 million boe at December 31, 2019.

The Shell share of joint ventures and associates' PD decreased by 178 million boe to 960 million boe, and PUD increased by 9 million boe to 156 million boe.

For further information, see "Supplementary Information – oil and gas (unaudited)" on page 239-249.

PROVED UNDEVELOPED RESERVES

In 2019, Shell subsidiaries and the Shell share of joint ventures and associates' PUD decreased by 98 million boe to 2,287 million boe. There were decreases of 462 million boe due to maturation to PD, mainly 90 million boe in Lula (Brazil), 65 million boe in Appomattox (USA), and 307 million boe spread across other fields. These were offset by increases of 119 million boe due to revisions and net increases of 279 million boe due to extensions and discoveries – mainly in the Permian Basin (69 million boe), Mero (60 million boe) and Groundbirch (52 million boe) – and decreases of 43 million boe due to sales of minerals in place and increases of 9 million boe due to improved recovery spread across other fields.

In addition to the maturation of 462 million boe from PUD to PD, 178 million boe was matured to PD from contingent resources through PUD as a result of project execution during the year.

PUD held for five years or more (PUD5+) at December 31, 2019, amounted to 258 million boe, a decrease of 14 million boe compared with the end of 2018. These PUD5+ remain undeveloped because development either requires the installation of compression equipment and the drilling of additional wells, which will be executed when required to support existing gas delivery commitments (Russia), or will take longer than five years because of the complexity and scale of the project (Australia and the UK).

The decrease in PUD5+ during 2019 was driven mainly by changes in Clair (UK), Champion (Brunei), and Forcados-Yokri (Nigeria).

The fields with the largest PUD5+ at December 31, 2019, were Jansz-Lo and Gorgon (Australia), Lunskeye (Russia) and Clair (UK).

During 2019, we spent \$6.9 billion on development activities related to PUD maturation.

DELIVERY COMMITMENTS

We sell crude oil and natural gas from our producing operations under a variety of contractual obligations. Most contracts generally commit us to sell quantities based on production from specified properties, although some natural gas sales contracts specify delivery of fixed and determinable quantities, as discussed below.

In the past three years, we met our contractual delivery commitments, with the notable exceptions of Egypt, Trinidad and Tobago, and Malaysia. In the period 2020-2022, we are contractually committed to deliver to third parties, joint ventures and associates a total of 7,735 billion scf of natural gas from our subsidiaries, joint ventures and associates. The sales contracts contain a mixture of fixed and variable pricing formulae that are generally referenced to the prevailing market price for crude oil, natural gas or other petroleum products at the time of delivery.

In the period 2020-2022, we expect to meet our delivery commitments for almost all the areas in which they are carried, with an estimated 75.6% coming from PD, 5.4% through the delivery of gas that comes available to us from paying royalties in cash, and 19% from the development of PUD as well as other new projects and purchases.

The key exceptions are:

- BG Egypt Development NOV: The government decision to divert gas from the offshore West Delta Deep Marine fields to domestic use has caused a tangible shortfall of 806 billion scf (87% of the promised gas delivery), expected to continue in the near future leaving LNG gas commitment mostly under force majeure;
- Trinidad and Tobago (East Coast Marine Area and North Coast Marine Area), where PD for all fields fail the economic test at the yearly average price for natural gas. However, we expect to cover 83% of our delivery commitments from existing developed resource volumes and new projects, resulting in an expected true shortfall of some 119 billion scf; and
- In Malaysia, one of the third-party gas supply lines is under repair during 2020. Force majeure has been declared, and no penalties have been incurred.

Summary of proved oil and gas reserves of Shell subsidiaries and Shell share of joint ventures and associates (at December 31, 2019)

Based on average prices for 2019	Crude oil and natural gas liquids (million barrels)	Natural gas (thousand million scf)	Synthetic crude oil (million barrels)	Total (million boe) [A]
Proved developed				
Europe	167	2,615	–	618
Asia	1,643	13,610	–	3,989
Oceania	106	5,805	–	1,107
Africa	314	1,523	–	577
North America				
USA	641	1,615	–	920
Canada	15	781	607	757
South America	675	968	–	841
Total proved developed	3,561	26,917	607	8,809
Proved undeveloped				
Europe	119	976	–	287
Asia	180	1,208	–	388
Oceania	15	2,591	–	462
Africa	80	1,085	–	267
North America				
USA	341	254	–	385
Canada	3	499	–	89
South America	358	291	–	409
Total proved undeveloped	1,096	6,904	–	2,287
Total proved developed and undeveloped				
Europe	286	3,591	–	905
Asia	1,823	14,818	–	4,377
Oceania	121	8,396	–	1,569
Africa	394	2,608	–	844
North America				
USA	982	1,869	–	1,305
Canada	18	1,280	607	846
South America	1,033	1,259	–	1,250
Total	4,657	33,821	607	11,096
Reserves attributable to non-controlling interest in Shell subsidiaries	–	–	304	304

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

OIL AND GAS INFORMATION continued

EXPLORATION

In 2019, we made notable discoveries in the US Gulf of Mexico and Australia. In April 2019, we announced a significant discovery at the Blacktip prospect in the Perdido Corridor within the deep-water US Gulf of Mexico (Shell interest 52.4% as operator). This and other drilling successes in the US Gulf of Mexico highlight the potential of this area. Further exploration is planned in 2020.

We also announced a significant gas discovery at the Bratwurst prospect in the Browse Basin.

We continue to strengthen our portfolio in the US Gulf of Mexico, Brunei, Oman, Brazil and Egypt, while opening up new positions in Argentina, Colombia, São Tomé and Príncipe and South Africa.

In 2018, Shell entered into a partnership with Oman Oil Company Exploration production (Shell interest 50%) to explore for oil and gas in Block 42, a vast under-explored area of 31,068 square kilometres in the Al Sharqiyah Governate, Sultanate of Oman. This was ratified by Royal Decree on January 23, 2019.

In March 2019, the dilution and transfer of operatorship was completed for two exploration blocks in deep-water Colombia, following these blocks' conversion from Technical Evaluation Agreements to Exploration & Production contracts. For both blocks, Noble Energy becomes the operator with 40% working interest, with the remaining 60% held by Shell. The gross area of the COL-3 block is around 4,000 square kilometres, and the gross area of the GUA OFF-3 block is around 4,800 square kilometres.

In US Gulf of Mexico Lease Sale 252 in March 2019 we acquired 77 blocks across multiple plays in the US Gulf of Mexico. This acquisition included significant acquisitions close to the 2019 Blacktip discovery (Shell interest 52.4%), in the underexplored areas of Garden Banks and in Desoto Canyon south east of the Appomattox production facility.

In April 2019, we won two exploration blocks in the deep-water bid round in Argentina. These frontier exploration blocks are at the edge of the continental shelf and have approximate areas of 7,875 square kilometres and 8,340 square kilometres. For both blocks, we are the operator, holding 60% of the participating interest, with Qatar Petroleum holding the remaining 40%.

In South Africa in April 2019, we entered the frontier deep-water Cape Basin (Shell interest 40%) and a second block next to our existing acreage in the Namibian Orange Basin (Shell interest 45%).

In October 2019, during the sixteenth deep-water bid round organised by the Brazilian National Petroleum Agency (ANP), we were granted exploration and production rights with respect to two exploration blocks, C-M-659 and C-M-713, as operator in the Campos Basin (Shell Interest 40%). This is awaiting ratification.

Also in October, we signed an Exploration & Production Sharing Agreement for Block 55 in the southeast of the Sultanate. Oman Shell now has a 100% working interest and operatorship of Block 55 with a total area of 7,564 square kilometres. The agreement includes a work programme of regional studies, seismic acquisition and other potential exploration activities. This agreement is awaiting ratification via Royal Decree.

In November 2019, we completed a farm-in transaction with Kosmos Energy, acquiring participating interests in Block 6 (Shell interest 20%) and Block 11 (Shell interest 30%) exploration licences (together approximately 14,000 square kilometres) offshore of São Tomé and Príncipe, representing a new country entry for Shell. Partners in the blocks are Kosmos Energy (Operator of Block 11), Galp Energia (Operator of Block 6) and ANP-STP, the national oil company.

In December 2019, we were awarded two concessions in the Red Sea bid round. The two blocks cover more than 6,000 square kilometres in an underexplored region of Egypt, south of the Gulf of Suez hydrocarbon province. Block 4 (Shell interest 70%) is in partnership with Mubadala Petroleum and Block 3 as the sole operator, with initial exploration plans being 3D seismic and petroleum system studies. This is awaiting ratification.

In total, the net undeveloped acreage in our exploration portfolio increased by around 9 million acres in 2019. The largest contributions were licence entries in South Africa, Oman, Argentina, Egypt and Colombia, offset by relinquishments and divestments in Australia, Myanmar and Gabon.

For further information, see "Supplementary Information – oil and gas (unaudited)" on page 239-246.

LOCATION OF OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES

Location of oil and gas exploration and production activities [A] (at December 31, 2019)

	Exploration	Development and/or production	Shell operator[B]
Europe			
Albania	•		•
Bulgaria	•		•
Cyprus	•		
Germany	•	•	
Italy	•	•	•
Netherlands	•	•	•
Norway	•	•	•
UK	•	•	•
Asia			
Brunei	•	•	•
China		•	•
Indonesia		•	
Kazakhstan	•	•	
Malaysia	•	•	•
Myanmar	•		
Oman	•	•	•
Philippines	•	•	•
Qatar		•	•
Russia	•	•	
Turkey	•		•
Oceania			
Australia	•	•	•
Africa			
Egypt	•	•	•
Mauritania	•		•
Morocco	•		
Namibia	•		•
Nigeria	•	•	•
São Tomé and Príncipe	•		
South Africa	•		•
Tanzania	•		•
Tunisia		•	•
North America			
Canada	•	•	•
Mexico	•		•
USA	•	•	•
South America			
Argentina	•	•	•
Bolivia	•	•	•
Brazil	•	•	•
Colombia	•		•
Trinidad and Tobago	•	•	•
Uruguay			•

[A] Includes joint ventures and associates. Where a joint venture or an associate has properties outside its base country, those properties are not shown in this table.

[B] In several countries where "Shell operator" is indicated, Shell is the operator of some but not all exploration and/or production ventures.

OIL AND GAS INFORMATION continued

OIL AND GAS PRODUCTION AVAILABLE FOR SALE

Crude oil and natural gas liquids [A]

	2019		2018		2017	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe						
Denmark	7,490	-	13,036	-	15,467	-
Italy	9,747	-	10,921	-	8,733	-
Norway	7,025	-	13,528	-	19,529	-
UK	30,677	-	31,431	-	45,020	-
Other [B]	723	1,135	795	1,417	860	1,272
Total Europe	55,662	1,135	69,711	1,417	89,609	1,272
Asia						
Brunei	196	20,002	283	18,738	1,138	15,831
Kazakhstan	34,269	-	32,432	-	29,491	-
Malaysia	21,993	-	24,650	-	26,574	-
Oman	76,493	-	76,847	-	77,687	-
Russia	22,442	9,413	22,003	10,403	22,049	10,899
Other [B]	28,796	7,709	28,769	7,768	30,180	7,859
Total Asia	184,189	37,124	184,984	36,909	187,119	34,589
Total Oceania [B]	10,058	-	8,883	-	9,098	-
Africa						
Gabon	-	-	-	-	9,750	-
Nigeria	56,589	-	53,102	-	56,337	-
Other [B]	7,802	-	8,265	-	9,003	-
Total Africa	64,391	-	61,367	-	75,090	-
North America						
USA	171,204	-	140,035	-	109,430	-
Canada	11,506	-	13,111	-	10,775	-
Total North America	182,710	-	153,146	-	120,205	-
South America						
Brazil	126,366	-	118,681	-	111,093	-
Other [B]	3,900	-	3,414	-	3,325	-
Total South America	130,266	-	122,095	-	114,418	-
Total	627,276	38,259	600,186	38,326	595,539	35,861

[A] Reflects 100% of production of subsidiaries except in respect of production-sharing contracts (PSCs), where the figures shown represent the entitlement of the subsidiaries concerned under those contracts.

[B] Comprises countries where 2019 production was lower than 10,100 thousand barrels or where specific disclosures are prohibited.

Synthetic crude oil

	Thousand barrels		
	2019	2018	2017
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	19,076	19,514	33,183

Bitumen

	Thousand barrels		
	2019	2018	2017
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	-	-	1,681

Natural gas [A]

	2019		2018		2017	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe						
Denmark	24,433	-	45,027	-	52,105	-
Germany	41,846	-	40,368	-	48,002	-
Ireland	-	-	44,833	-	52,515	-
Netherlands	-	244,286	-	271,303	-	343,126
Norway	182,683	-	239,253	-	243,352	-
UK	62,174	-	82,695	-	174,478	-
Other [B]	15,062	-	16,422	-	13,125	-
Total Europe	326,198	244,286	468,598	271,303	583,577	343,126
Asia						
Brunei	22,185	160,648	21,205	157,476	29,880	158,877
China	44,510	-	42,419	-	43,899	-
Kazakhstan	84,499	-	78,575	-	80,623	-
Malaysia	226,277	-	237,102	-	221,590	-
Philippines	44,374	-	44,017	-	42,958	-
Russia	4,563	134,807	4,044	136,652	4,052	137,890
Thailand	-	-	25,973	-	60,742	-
Other [B]	407,899	118,253	378,785	117,976	288,728	118,352
Total Asia	834,307	413,708	832,120	412,104	772,472	415,119
Oceania						
Australia	686,956	20,840	648,735	18,923	591,860	18,708
New Zealand	-	-	40,153	-	51,943	-
Total Oceania	686,956	20,840	688,888	18,923	643,803	18,708
Africa						
Egypt	92,169	-	148,721	-	122,439	-
Nigeria	234,332	-	232,899	-	236,370	-
Other [B]	30,266	-	30,669	-	36,187	-
Total Africa	356,767	-	412,289	-	394,996	-
North America						
USA	389,130	-	355,075	-	286,529	-
Canada	220,005	-	247,890	-	224,529	-
Total North America	609,135	-	602,965	-	511,058	-
South America						
Bolivia	48,501	-	55,480	-	59,673	-
Brazil	78,526	-	68,865	-	70,100	-
Trinidad and Tobago	159,698	-	104,454	-	73,000	-
Other [B]	8,662	-	8,062	-	8,370	-
Total South America	295,387	-	236,861	-	211,143	-
Total	3,108,750	678,834	3,241,721	702,330	3,117,049	776,953

[A] Reflects 100% of production of subsidiaries except in respect of PSCs, where the figures shown represent the entitlement of the subsidiaries concerned under those contracts.

[B] Comprises countries where 2019 production was lower than 41,795 million scf or where specific disclosures are prohibited.

OIL AND GAS INFORMATION continued

AVERAGE REALISED PRICE BY GEOGRAPHICAL AREA

Crude oil and natural gas liquids

	2019		2018		2017	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe	65.11	58.08	68.23	64.24	50.52	46.88
Asia	58.16	65.25	64.06	70.66	49.08	53.44
Oceania	51.51	-	61.63	-	45.64	-
Africa	65.39	-	71.02	-	53.39	-
North America - USA	54.56	-	61.87	-	47.23	-
North America - Canada	36.61	-	43.72	-	36.00	-
South America	56.68	-	62.67	-	48.10	-
Total	57.56	65.05	63.96	70.43	49.00	53.23

\$/barrel

Synthetic crude oil

	2019	2018	2017
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America - Canada	50.27	48.90	45.90

\$/barrel

Bitumen

	2019	2018	2017
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America - Canada	-	-	34.46

\$/barrel

Natural gas

	2019		2018		2017	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe	5.59	4.95	7.08 [A]	4.06	5.48	4.77
Asia	2.66	6.34	2.99	7.06	2.84	5.45
Oceania	8.22	3.91	8.66 [A]	4.15	6.21	3.11
Africa	2.92	-	3.02	-	2.44	-
North America - USA	2.27	-	3.12	-	3.00	-
North America - Canada	1.37	-	1.35	-	1.85	-
South America	2.33	-	3.50	-	2.93 [A]	-
Total	3.95	5.80	4.63 [A]	5.74	3.90 [A]	5.11

\$/thousand scf

[A] As revised, following a reassessment.

AVERAGE PRODUCTION COST BY GEOGRAPHICAL AREA**Crude oil, natural gas liquids and natural gas [A]**

	2019		2018		2017		\$/boe
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	
Europe	14.14	5.76	15.03	6.37	13.19	5.58	
Asia	6.30	6.17	6.52	6.24	7.71	6.87	
Oceania	9.17	24.49	8.41	32.18	9.24	28.83	
Africa	8.44	-	8.25	-	9.53	-	
North America - USA	11.78	-	12.78	-	16.11	-	
North America - Canada	11.88	-	11.58	-	14.53	-	
South America	6.26	-	8.60	-	8.08	-	
Total	8.95	6.48	9.66	6.81	10.55	6.82	

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

Synthetic crude oil

	2019	2018	2017
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America - Canada	19.29	20.15	23.77

Bitumen

	2019	2018	2017
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America - Canada	-	-	16.19

Key statistics

	\$ million, except where indicated		
	2019	2018	2017
Segment earnings [A]	6,277	7,601	8,258
Including:			
Revenue (including inter-segment sales)	294,677	335,597	265,821
Share of profit of joint ventures and associates [A]	1,725	1,785	1,956
Interest and other income	266	345	154
Operating expenses [B]	18,697	20,743	19,583
Depreciation, depletion and amortisation	5,413	4,064	3,877
Taxation charge [A]	1,241	1,515	1,783
Capital expenditure	8,650	7,083	5,826
Cash capital expenditure [B]	8,926	7,408	6,090
Capital investment [B]	10,542	7,565	6,418
Refinery availability (%) [C]	91	91	91
Chemical plant availability (%) [C]	89	93	92
Refinery processing intake (thousand b/d)	2,564	2,648	2,572
Oil products sales volumes (thousand b/d)	6,561	6,783	6,599
Chemicals sales volumes (thousand tonnes)	15,223	17,644	18,239

[A] See Note 4 to the "Consolidated Financial Statements" on pages 206-208. Segment earnings are presented on a current cost of supplies basis.

[B] See "Non-GAAP measures reconciliations" on pages 279-280.

[C] The basis of calculation differs from that used for the "Refinery and chemical plant availability" measure in "Performance indicators" on page 42, which excludes downtime due to uncontrollable factors and, in 2017, excludes assets which were not part of Shell's operational performance metrics because of portfolio activity (Fredericia and former Motiva sites).

OVERVIEW

Our Downstream business consists of Oil Products and Chemicals activities. They form part of an integrated value chain that trades and refines crude oil and other feedstocks into products that are moved and marketed around the world for domestic, industrial and transport use. The products we sell include gasoline, diesel, heating oil, aviation fuel, marine fuel, biofuel, lubricants, bitumen and sulphur. We also produce and sell petrochemicals for industrial use worldwide.

Our Oil Products activities comprise Refining and Trading, and Marketing. These are referred to as classes of business. Marketing includes Retail, Lubricants, Business-to-Business (B2B), Pipelines and Biofuels. Chemicals has major manufacturing plants, which are located close to refineries, and its own marketing network. In Trading and Supply, we trade crude oil, oil products and petrochemicals to optimise feedstocks for Refining and Chemicals, to supply our Marketing businesses and third parties, and for our own profit.

BUSINESS CONDITIONS

Global oil demand grew by 1.0 million barrels per day (b/d), or 1.0%, to 100.3 million b/d, according to the International Energy Agency's (IEA) Oil Market Report published in January 2020. Oil demand growth in 2019 was 0.1 million b/d lower than in 2018.

Industry gross refining margins were lower on average in 2019 than in 2018 in three of the four key refining hubs in Europe, Singapore and the US Gulf Coast. In the US West Coast gross margins improved, partly due to product prices being supported by unplanned outages in the region. Globally, year-on-year growth in demand for oil products has slowed in line with slowing global economic growth. Refinery capacity additions, especially in the Middle East and Asia, combined with lower demand growth have led to generally lower refinery utilisations, which weakened margins. Refinery activity continued to be low in Latin America amid the ongoing geopolitical uncertainty and poor investment climate. On January 1, 2020, the new International Maritime Organization low-sulphur shipping fuel specification came into effect. The industry has started preparations but the full effect of the implementation is expected later in the year.

Cracker industry margins in Asia halved. Cracker margins in Western Europe and the USA were relatively unchanged versus 2018. West European margins were supported by a high level of maintenance outages in the first half of 2019, while in the USA margins were supported by low ethane prices.

See "Market overview" on page 37.

REFINERY AND CHEMICAL PLANT AVAILABILITY

Refinery availability was 91% in 2019, unchanged from 2018.

Chemicals plant availability was 89% in 2019, compared with 93% in 2018, due to higher planned downtime in Asia and Europe and the impact of strike action in the Netherlands.

OIL PRODUCTS AND CHEMICALS SALES

Oil products sales volumes decreased by 3% in 2019 compared with 2018, reflecting lower trading volumes primarily in Asia and Europe and, to a lesser extent, impact on marketing volumes due to the sale of the Downstream Argentina business to Raizen (volumes reported at 50% Shell share).

Chemicals sales volumes decreased by 14% in 2019 compared with 2018, mainly due to lower downstream demand and higher downtime at some sites.

EARNINGS 2019-2018

Segment earnings in 2019 of \$6,277 million are presented on a current cost of supplies basis (see "Summary of results" on page 40). Segment earnings on a first-in, first-out basis were \$6,883 million, which were \$606 million higher than on a current cost of supplies basis (2018 first-in, first-out segment earnings were \$458 million lower than the current cost of supplies basis). See "Non-GAAP measures reconciliations" on page 279-280.

Segment earnings in 2019 of \$6,277 million were 17% lower than in 2018. Earnings in 2019 included a net charge of \$403 million, compared with a net gain in 2018 of \$34 million, which is described at the end of this section.

Excluding the impact of these items, earnings in 2019 were \$6,680 million, compared with \$7,567 million in 2018. Refining and Trading accounted for 19% of these 2019 earnings, Marketing for 70% and Chemicals for 11%.

The decrease in Downstream earnings, excluding the net charges, of \$887 million (12%) compared with 2018 was driven by lower Refining and Trading margins (around \$400 million) and lower Chemicals margins (around \$1,500 million). This was partly offset by higher Marketing margins (around \$500 million), benefit from foreign exchange (around \$250 million), lower operating costs (around \$130 million) and change in accounting policy IFRS 16 (around \$150 million).

The decrease in earnings of \$887 million analysed by class of business was as follows:

- Refining and Trading earnings were \$279 million lower than in 2018, principally due to lower realised Refining margins due to adverse price variance across all regions driven by lower global demand growth and increase in worldwide refining capacity; and higher maintenance costs. Partly offsetting this were higher earnings from oil products trading and optimisation, mainly fuel oil;
- Marketing earnings were \$727 million higher than in 2018. This was due to stronger unit margins and lower operating expenses in Retail and Lubricants, better revenue from Retail ventures, and lower pension costs. Partly offsetting these were lower earnings from Raízen, the joint venture (Shell interest 50%) in Brazil, due to adverse foreign exchange and lower fuel margins; and
- Chemicals earnings were \$1,334 million lower than in 2018. Results were impacted by lower realised base chemicals and intermediate margins and higher maintenance activities in Asia and Europe, including the impact of strike action in the Netherlands, partly offset by lower operating expenses.

Segment earnings in 2019 included a net charge of \$403 million.

Offsetting items included:

- impairment charges of \$341 million (mainly expenditure at Bukom and other assets);
- costs related to restructuring of \$88 million (various initiatives across Downstream);
- other net charges of \$273 million (mainly legal provision in Chemicals); and
- net charge from fair value accounting of commodity derivatives of \$68 million.

The effects of offsetting items were partially countered by:

- net gains from disposal of assets of \$318 million; and
- gain from one-off tax items of \$49 million (tax rate changes in Alberta, Canada).

Segment earnings in 2018 included a net gain of \$34 million.

Offsetting items included:

- net gains from fair value accounting of commodity derivatives of \$233 million;
- gains from disposal of assets of \$225 million (mainly our Downstream assets in Argentina and other smaller disposals); and
- gains from one-off tax items of \$118 million (mainly corporation tax rate changes in the Netherlands and the USA).

The effect of offsetting items was countered by:

- impairment charge of \$386 million (mainly expenditure at Bukom and on assets at Stanlow);
- costs related to restructuring of \$109 million (various of initiatives across Downstream); and

- other net charges of \$47 million, which included a one-off gain from the Ontario cap-and-trade scheme and onerous contracts related to decommissioning of the Stanlow site.

EARNINGS 2018-2017

Segment earnings which were presented on a current cost of supplies basis were \$458 million higher in 2018 than on a first-in, first-out basis (2017: \$964 million lower).

Segment earnings in 2018 of \$7,601 million were 8% lower than in 2017. Earnings in 2018 included a net gain of \$34 million described above. Earnings in 2017 included a net charge of \$824 million, reflecting impairment charges of \$315 million, redundancy and restructuring charges of \$200 million, charges of \$142 million related to US tax reform legislation and a tax rate change in France, and other net charges of \$231 million (related to onerous contract provision and a legal provision). These were partly offset by divestment gains of \$39 million and net gain of \$25 million from fair value accounting of commodity derivatives.

Excluding the impact of these items, earnings in 2018 were \$7,567 million, compared with \$9,082 million in 2017. Refining and Trading accounted for 20% of these 2018 earnings, Marketing for 53% and Chemicals for 27%.

The decrease in Downstream earnings, excluding the net charges, of \$1,515 million (17%) compared with 2017 was driven by higher operating costs (around \$700 million), adverse foreign exchange effects (around \$530 million), lower base Chemicals margins (around \$370 million), lower refining margins (around \$150 million) and other impacts resulting in a net charge of around \$120 million. This was partly offset by higher marketing margins (around \$360 million). Operating costs were higher due to higher maintenance costs (Chemicals and Refining assets) and higher costs for marketing growth opportunities. Chemicals margins were impacted by higher feedstock costs globally, higher utility costs and new cracker start-ups in the USA, and operational issues in Europe. Marketing margins benefited from favourable market conditions at the end of the year. The other net negative impacts were mainly portfolio effects.

CASH CAPITAL EXPENDITURE AND CAPITAL INVESTMENT

Cash capital expenditure (cash capex) was \$8.9 billion in 2019, compared with \$7.4 billion in 2018. Capital investment was \$10.5 billion in 2019 compared to \$7.6 billion in 2018.

Cash capex in Refining was in line with 2018 at \$2.4 billion. In Chemicals, cash capex increased by \$0.9 billion to \$4.1 billion (increase mainly from investment in our new cracker facilities in Pennsylvania). In Marketing, cash capex increased by \$0.4 billion to \$2.2 billion (increase mainly from investment in a US pipeline project).

Increase in capital investment on account of leases was \$1.4 billion (\$1.6 billion in 2019 compared with \$0.2 billion in 2018) due to accounting policy change (IFRS 16) implemented in 2019.

PORTFOLIO AND BUSINESS DEVELOPMENTS

We continued to high-grade our portfolio in 2019, including:

- In the Kingdom of Saudi Arabia, we completed the sale of our 50% interest in Shell Saudi Arabia (Refining) Limited (SASREF), a joint venture in Jubail Industrial City, to Saudi Arabian Oil Company (Saudi Aramco) for \$631 million.
- In the USA, our subsidiary Equilon Enterprises LLC, doing business as Shell Oil Products US, announced in June 2019 that we have reached an agreement for the sale of Martinez Refinery in California to PBF Holding Company LLC for a \$1.0 billion consideration. The sale was concluded in February 2020 in exchange for \$1.2 billion which includes the refinery and inventory.
- Also in the USA, in March 2020, we announced our intention to sell the Puget Sound refinery in Washington and Mobile site in Alabama.

DOWNSTREAM continued

BUSINESS AND PROPERTY

Refining and trading

Refining

We have interests in 15 refineries worldwide, (after the completion of sale of Martinez refinery in February 2020), with the capacity to process a total of 2.5 million barrels of crude oil per day (Shell share). Our refining capacity is 42% in Europe and Africa, 41% in the Americas and 17% in Asia and Oceania.

In 2019, we concluded the sale of our 50% share of the SASREF joint venture in Jubail Industrial City, the Kingdom of Saudi Arabia, to Saudi Aramco.

Trading and Supply

Through our main trading offices in London, Houston, Singapore, Dubai and Rotterdam, we trade crude oil, natural gas, LNG, electricity, refined products, chemical feedstocks and environmental products. Trading and Supply trades in physical and financial contracts, lease storage and transportation capacities, and manages shipping and wholesale commercial fuel activities globally. This includes supplying feedstocks for our refineries and chemical plants and finished products such as gasoline, diesel and aviation fuel to our Marketing businesses and customers.

Operating in around 30 countries, with more than 125 Shell and joint-venture terminals, we believe our supply and distribution infrastructure is well positioned to make deliveries around the world.

Through its Shipping and Maritime business, Trading and Supply has an interest in around 2,000 Shell-associated vessels and other floating facilities on any given day, and manages one of the world's largest fleets of LNG carriers. Shipping and Maritime enables the Shell Trading and Supply organisation to deliver safely on its contracts. This includes supplying feedstocks for our refineries and chemical plants, and finished products such as gasoline, diesel and aviation fuel to our Marketing businesses and customers.

Shell Wholesale Commercial Fuels provides fuels for transport, industry and heating. Our range of products, from reliable main-grade fuels to premium products, is designed to provide tangible vehicle and business benefits.

Marketing Retail

Shell is the world's largest mobility retailer, by number of sites, with 45,000 service stations operating in close to 80 countries at the end of 2019. We operate different models across these markets, from full ownership of retail sites through to brand licensing agreements.

Every day, more than 30 million customers visit these sites to buy fuel, convenience items, including beverages and fresh food, and services, such as lubricant changes and car washes. We offer our business customers Shell Fleet Solutions, a 'one-stop-shop' for their mobility and energy transition needs, providing items including fuel cards, road services and carbon-neutral offers.

We have more than 100 years' experience in fuel development. Aided by our innovative partnership with Scuderia Ferrari, we have concentrated on developing fuels with special formulations designed to clean engines and improve performance. We sold such fuels under the Shell V-Power brand in 62 countries as at the end of 2019.

In a growing number of markets, we are offering customers lower-emission solutions, including biofuels, electric vehicle fast-charging, hydrogen and various gaseous fuels such as LNG. During 2019, we introduced carbon-neutral driving in the Netherlands and the UK, through which we offset customers' emissions by purchasing carbon credits generated from projects that plant and protect nature like forests, wetlands and other natural ecosystems.



Shell V-Power brand is sold in 62 countries.

Lubricants

Across more than 150 markets, we produce, market and sell technically advanced lubricants for passenger cars, motorcycles, trucks, coaches, and machinery used in manufacturing, mining, power generation, agriculture and construction sectors.

We also manufacture premium lubricants from natural gas using GTL base oils produced at our Pearl GTL plant in Qatar (see "Integrated Gas" on page 48).

We have a global lubricants supply chain with a network of four base oil manufacturing plants, 29 lubricant blending plants, nine grease plants and four GTL base oil storage hubs.

Through our marine activities, we primarily provide lubricants, but also fuels and related technical services, to the shipping and maritime sectors. We supply around 210 grades of lubricants and six types of fuel to vessels worldwide, ranging from large ocean-going tankers to small fishing boats.



Shell lubricant plant, Oman.

Business-to-Business

Our Business-to-Business (B2B) activities encompass the sale of fuels and specialty products and services to a broad range of commercial customers.

Shell Aviation provides fuel and lubricants across more than 60 countries and supplies fuel at about 900 airports.

Shell Bitumen supplies customers across 52 markets and provides enough bitumen to resurface 500 kilometres of road lanes every day. It also invests in technology research and development to create innovative products.

Shell Sulphur Solutions is a business that manages the complete value chain of sulphur, from refining to marketing. The business provides sulphur for use in applications such as fertiliser, mining and chemicals and also develops new technologies for sulphur that benefit sectors such as agriculture.

Pipelines

Shell Pipeline Company LP (Shell interest 100%) owns and operates 10 tank farms across the USA. It transports more than 2 billion barrels of crude oil and refined products a year through about 6,000 kilometres of pipelines in the Gulf of Mexico and five US states. Our various non-Shell-operated ownership interests provide about a further 14,000 pipeline kilometres.

We carry more than 40 types of crude oil and more than 20 grades of gasoline, as well as diesel, aviation fuel, chemicals and ethylene.

Shell Midstream Partners, L.P., a midstream master limited partnership, owns, operates, develops and acquires pipelines and other midstream assets in the USA. Its assets consist of interests in entities that own crude oil and refined products pipelines and terminals that serve as key infrastructure to transport onshore and offshore crude oil production to Gulf Coast and Midwest refining markets. It also delivers refined products from those markets to major demand centres. Its assets also include interests in entities that own natural gas and refinery gas pipelines that transport offshore natural gas to market hubs and deliver refinery gas from refineries and plants to chemical sites along the Gulf Coast. Shell controls the general partner.

See "Governance – Related Party Transactions" on page 167 and Note 29 to the "Consolidated Financial Statements" on page 238.

Biofuels

Raízen, our joint venture in Brazil (Shell interest 50%), produces ethanol from sugar cane, with an annual production capacity of more than 2.5 billion litres; exports sugar, with an annual production of about 3.8 million tonnes; and manages a retail network. In 2015, Raízen opened its first cellulosic ethanol plant at its Costa Pinto mill in Brazil, which produced almost 19.5 million litres in 2019. When fully operational, the mill is expected to produce around 40 million litres a year of advanced biofuels from sugar-cane residues.



Raízen Brazil harvesting crops used for the processing of biofuel.

Chemicals Manufacturing

Our plants produce a range of base chemicals, including ethylene, propylene and aromatics, and intermediate chemicals such as styrene monomer, propylene oxide, solvents, detergent alcohols, ethylene oxide and ethylene glycol. We have the capacity to produce around 6.5 million tonnes of ethylene a year.

Marketing

In 2019, we supplied more than 15 million tonnes of petrochemicals to around 1,000 industrial customers worldwide. Our products are used to make numerous everyday items, from clothing and cars to detergents and bicycle helmets.

DOWNSTREAM BUSINESS ACTIVITIES WITH SUDAN AND SYRIA

Sudan
We ceased all operational activities in Sudan in 2008.

Syria

We ceased supplying polyols, via a Netherlands-based distributor, to private sector customers in Syria in 2018. Polyols are commonly used for the production of foam in mattresses and soft furnishings.

DOWNSTREAM continued**DOWNSTREAM DATA TABLES**

The tables below reflect Shell subsidiaries and instances where Shell owns the crude oil or feedstocks processed by a refinery. In addition, the tables include the Al Jubail refinery on a 50% basis until the date of divestment. Other joint ventures and associates are only included where explicitly stated.

Oil products – cost of crude oil processed or consumed [A]

	\$/barrel		
	2019	2018	2017
Total	54.97	59.94	46.78

[A] Includes Upstream and Integrated Gas margins on crude oil supplied by Shell subsidiaries, joint ventures and associates.

Crude distillation capacity [A]

	Thousand b/calendar day [B]		
	2019	2018	2017
Europe	970	970	970
Asia	704	704	704
Oceania	–	–	–
Africa	83	82	82
Americas	1,075	1,157	1,176
Total	2,832	2,913	2,932

[A] Average operating capacity for the year, excluding mothballed capacity.

[B] Calendar day capacity is the maximum sustainable capacity adjusted for normal unit downtime.

Ethylene capacity [A]

	Thousand tonnes/year		
	2019	2018	2017
Europe	1,701	1,701	1,702
Asia	2,530	2,529	1,904
Oceania	–	–	–
Africa	–	–	–
Americas	2,268	2,268	2,267
Total	6,499	6,498	5,873

[A] Includes the Shell share of capacity entitlement (offtake rights) of joint ventures and associates, which may be different from nominal equity interest. Nominal capacity is quoted at December 31.

Oil products – crude oil processed [A]

	Thousand b/d		
	2019	2018	2017
Europe	829	897	892
Asia	498	545	528
Oceania	–	–	–
Africa	55	66	54
Americas	1,004	1,041	997
Total	2,386	2,549	2,471

[A] Includes natural gas liquids, share of joint ventures and associates and processing for others.

Refinery processing intake [A]

	Thousand b/d		
	2019	2018	2017
Crude oil	2,342	2,434	2,364
Feedstocks	222	214	208
Total	2,564	2,648	2,572
Europe	875	896	892
Asia	517	543	539
Oceania	–	–	–
Africa	55	66	54
Americas	1,117	1,143	1,087
Total	2,564	2,648	2,572

[A] Includes crude oil, natural gas liquids and feedstocks processed in crude distillation units and in secondary conversion units.

Refinery processing outturn [A]

	Thousand b/d		
	2019	2018	2017
Gasolines	952	966	955
Kerosines	417	321	290
Gas/Diesel oils	818	965	925
Fuel oil	223	284	265
Other	282	321	334
Total	2,692	2,858	2,769

[A] Excludes own use and products acquired for blending purposes.

Oil product sales volumes [A][B]

	Thousand b/d		
	2019	2018	2017
Europe			
Gasolines	334	323	317
Kerosines	317	294	272
Gas/Diesel oils	720	745	758
Fuel oil	138	178	170
Other products	278	314	362
Total	1,787	1,854	1,879
Asia			
Gasolines	408	373	399
Kerosines	208	210	216
Gas/Diesel oils	535	543	516
Fuel oil	330	407	349
Other products	518	620	536
Total	2,000	2,153	2,016
Oceania			
Gasolines	-	-	-
Kerosines	-	-	23
Gas/Diesel oils	-	-	-
Fuel oil	-	-	-
Other products	-	-	-
Total	-	-	23
Africa			
Gasolines	46	42	43
Kerosines	13	10	13
Gas/Diesel oils	70	74	78
Fuel oil	2	2	2
Other products	6	6	6
Total	137	134	142
Americas			
Gasolines	1,419	1,446	1,415
Kerosines	239	236	212
Gas/Diesel oils	582	567	545
Fuel oil	120	117	92
Other products	277	276	275
Total	2,637	2,642	2,539
Total product sales [C][D]			
Gasolines	2,207	2,184	2,174
Kerosines	777	750	736
Gas/Diesel oils	1,907	1,929	1,897
Fuel oil	590	704	613
Other products	1,079	1,216	1,179
Total	6,561	6,783	6,599

[A] Excludes deliveries to other companies under reciprocal sale and purchase arrangements, that are in the nature of exchanges. Sales of condensate and natural gas liquids are included.

[B] Includes the Shell share of Raizen's sales volumes.

[C] Certain contracts are held for trading purposes and reported net rather than gross. The effect in 2019 was a reduction in oil product sales of approximately 546,000 b/d (2018: 458,000 b/d; 2017: 596,000 b/d).

[D] Reported volumes in 2019 include the Shell joint ventures sales volumes from key countries.

Chemicals sales volumes [A]

		Thousand tonnes		
	2019	2018	2017	
Europe				
Base chemicals	3,666	4,069	4,059	
Intermediates and others	1,872	1,994	2,056	
Total	5,538	6,063	6,115	
Asia				
Base chemicals	1,057	2,140	2,515	
Intermediates and others	2,848	3,082	3,243	
Total	3,905	5,222	5,758	
Oceania				
Base chemicals	-	-	-	
Intermediates and others	-	-	-	
Total	-	-	-	
Africa				
Base chemicals	-	-	-	
Intermediates and others	-	-	-	
Total	-	-	-	
Americas				
Base chemicals	3,261	3,842	3,839	
Intermediates and others	2,519	2,517	2,527	
Total	5,780	6,359	6,366	
Total product sales				
Base chemicals	7,984	10,051	10,413	
Intermediates and others	7,239	7,593	7,826	
Total	15,223	17,644	18,239	

[A] Excludes feedstock trading and by-products.

MANUFACTURING PLANTS AT DECEMBER 31, 2019

Refineries in operation

				Thousand barrels/calendar day, 100% capacity [B]			
	Location	Asset class	Shell interest (%) [A]	Crude distillation capacity	Thermal cracking/ visbreaking/ coking	Catalytic cracking	Hydro cracking
Europe							
Denmark	Fredericia	●	100	68	39	-	-
Germany	Miro [C]		32	287	36	87	-
	Rheinland	● ●	100	325	44	-	80
	Schwedt [C]		38	214	40	53	-
Netherlands	Pernis	● ●	100	405	23	48	82
Asia							
Philippines	Tabangao		55	95	31	-	-
Singapore	Pulau Bukom	● ●	100	463	72	34	54
Africa							
South Africa	Durban [C]	●	36	165	22	33	-
Americas							
Argentina	Buenos Aires [C]	● ●	50	99	18	20	-
Canada							
Alberta	Scotford	●	100	92	-	-	74
Ontario	Sarnia	●	100	78	4	19	9
USA							
California	Martinez [D]	●	100	144	43	65	37
Louisiana	Convent	●	100	239	-	83	49
	Norco	●	100	229	26	108	39
Texas	Deer Park	● ●	50	312	82	68	53
Washington	Puget Sound	● ●	100	137	22	52	-

[A] Shell interest is rounded to the nearest whole percentage point; Shell share of production capacity may differ.

[B] Calendar day capacity is the maximum sustainable capacity adjusted for normal unit downtime.

[C] Not operated by Shell.

[D] The sale of the Martinez refinery was concluded on February 1, 2020.

- Integrated refinery and chemical complex.
- Refinery complex with cogeneration capacity.
- Refinery complex with chemical unit(s).

DOWNSTREAM continued

Major chemical plants in operation [A]

		Thousand tonnes/year, Shell share capacity [B]				
	Location	Ethylene	Styrene monomer	Ethylene glycol	Higher olefins [C]	Additional products
Europe						
Germany	Rheinland	315	–	–	–	A
Netherlands	Moerdijk	971	815	153	–	A, I
UK	Mossmorran [D]	415	–	–	–	–
Asia						
China	Nanghai [D]	1,100	650	415	–	A, I, P
Singapore	Jurong Island	281	1,069	1,159	–	A, I, P, O
	Pulau Bukom	1,149	–	–	–	A, I
Americas						
Canada	Scotford	–	475	548	–	A, I
USA	Deer Park	836	–	–	–	A, I
	Geismar	–	–	400	1,390	I
	Norco	1,432	–	–	–	A
Total		6,499	3,009	2,675	1,390	

[A] Major chemical plants are large integrated chemical facilities, typically producing a range of chemical products from an array of feedstocks, and are a core part of our global Chemicals business.

[B] Shell share of capacity of subsidiaries, joint arrangements and associates (Shell and non-Shell-operated), excluding capacity of the Infineum additives joint ventures.

[C] Higher olefins are linear alpha and internal olefins (products range from C4 to C2024).

[D] Not operated by Shell.

A Aromatics, lower olefins.

I Intermediates.

P Polyethylene, polypropylene.

O Other.

Other chemical locations [A]

	Location	Products
Europe		
Germany	Karlsruhe	A
	Schwedt	A
Netherlands	Pernis	A, I, O
Americas		
Argentina	Buenos Aires	I
Canada	Sarnia	A, I
USA	Martinez	O
	Mobile	A
	Puget Sound	I

[A] Other chemical locations reflect locations with smaller chemical units, typically serving more local markets.

A Aromatics, lower olefins.

I Intermediates.

O Other.

CORPORATE

Earnings

	\$ million		
	2019	2018	2017
Segment earnings	(3,273)	(1,479)	(2,416)
Comprising:			
Net interest and investment expense [A]	(3,425)	(2,192)	(2,413)
Net foreign exchange losses [B]	(67)	(67)	(292)
Taxation and other [C]	219	780	289

[A] Mainly Shell's interest expense (excluding accretion expense) and interest income, together with the Shell share of joint ventures and associates' net interest expense, and net gains on sales from Shell insurance entities' portfolio of debt securities.

[B] On Shell's financing activities, together with the Shell share of joint ventures and associates' net foreign exchange gains/(losses) on financing activities.

[C] Other earnings mainly comprise headquarters and central functions' costs not recovered from business segments, and net gains on sale of properties.

OVERVIEW

The Corporate segment covers the non-operating activities supporting Shell. It comprises Shell's holdings and treasury organisation, its self-insurance activities and its headquarters and central functions. All finance expense and income as well as related taxes are included in the Corporate segment earnings rather than in the earnings of the business segments.

The holdings and treasury organisation manages many of the Corporate entities and is the point of contact between Shell and external capital markets. It conducts a broad range of transactions, from raising debt instruments to transacting foreign exchange. Treasury centres in London and Singapore support these activities.

Headquarters and central functions provide business support in the areas of communications, finance, health, human resources, information technology, legal services, real estate and security. They also provide support for the shareholder-related activities of the Company. The central functions are supported by business service centres located around the world, which process transactions, manage data and produce statutory returns, among other services. The majority of the headquarters and central-function costs are recovered from the business segments. Those costs that are not recovered are retained in Corporate.

EARNINGS 2019-2017

Segment earnings in 2019 were a loss of \$3,273 million, compared with a loss of \$1,479 million in 2018 and a \$2,416 million loss in 2017.

Net interest and investment expense increased by \$1,233 million compared with 2018. This was primarily due to the introduction of IFRS 16 (Page 195, Note 2) and reduced capitalised interest. In 2018, net interest and investment expense decreased by \$221 million compared with 2017. This was due to a decrease in interest expense due to higher capitalised interest, coupled with higher interest income from increases to both cash levels and higher interest rates.

The Corporate segment includes net foreign exchange gains/(losses) from financing positions. Net foreign exchange gains/(losses) generally relate to the impact of changes in exchange rates on non-functional currency loans and cash balances in operating companies. In 2019 and 2018, unfavourable exchange rate movements resulted in a net foreign exchange loss.

Taxation and other earnings decreased by \$561 million in 2019, compared with 2018, due to reduced tax credits from financing and one-off charges. In 2018, taxation and other earnings increased by \$491 million compared with 2017, due to increased tax credits from foreign exchange losses, which were partially offset by increased corporate expenses and depreciation charges.

SELF-INSURANCE

We mainly self-insure our risk exposure, and capital is set aside to meet self-insurance obligations (see "Risk factors" on page 34). We seek to ensure that the capital held to support the self-insurance obligations is at a level at least equivalent to what would be held in the third-party insurance market. Periodically, surveys of key assets are undertaken that provide risk-engineering knowledge and best practices to Shell subsidiaries with the aim of reducing their exposure to hazard risks. Actions identified during these surveys are monitored to completion.

INFORMATION TECHNOLOGY AND CYBER-SECURITY

Given our digitalisation efforts and increasing reliance on information technology (IT) systems for our operations, we continuously monitor external developments and actively share information on threats and security incidents. Shell employees and contract staff are subject to mandatory courses and regular awareness campaigns aimed at protecting us against cyber threats. We periodically test and adapt cyber-security response processes and seek to enhance our security monitoring capability.

Given our dependence on IT systems for our operations and the increasing role of digital technologies across our business, we are aware that cyber-security attacks could cause significant harm to Shell in the form of loss of productivity, loss of intellectual property, regulatory fines and/or reputational damage. As a result, we continuously measure and, where required, further improve our cyber-security capabilities to reduce the likelihood of successful cyberattacks. Our cyber-security capabilities are embedded into our IT systems and our IT landscape is protected by various detective and protective technologies. The identification and assessment capabilities are built into our support processes and adhere to industry best practices. The security of IT services, operated by external IT companies, is managed through contractual clauses and additionally through formal supplier assurance reports for critical IT services.

Shell is frequently subject to cyberattacks. In 2019, none of these events led to breaches of our business-critical IT landscape and, as such, did not result in any material business impact. When significant incidents occur, they are followed up with a thorough root-cause analysis and, if needed, will result in appropriate follow-up actions.

See "Risk factors" on page 35.

BRAND VALUE

According to the Brand Finance Global 500 2020 – the annual report on the world's most valuable and strongest brands published by leading brand valuation consultancy Brand Finance at the World Economic Forum in Davos this January, Shell's brand value was estimated at \$47.5 billion, up 12% compared to the previous year and 55% versus 2015. The report also shows Shell's brand rating strengthening from AAA- to AAA.

LIQUIDITY AND CAPITAL RESOURCES

We manage our businesses to deliver strong cash flows to fund investment for profitable growth. Our aim is that, across the business cycle, “cash in” (including cash from operations and divestments) at least equals “cash out” (including capital expenditure, interest and dividends), while maintaining a strong balance sheet. In 2020, our priorities for applying our cash are expected to be the servicing and reduction of debt commitments, payment of dividends, followed by a balance of capital investment and share buybacks.



Shell Pecten flag.

FINANCIAL CONDITION AND LIQUIDITY

Despite weaker commodity prices over the course of 2019, the Shell Group generated cash flow from operations of \$42.2 billion and free cash flow of \$26.4 billion, supporting continued progress of the share buyback programme which commenced in 2018. \$10.2 billion share buybacks were completed in 2019. Gearing increased to 29.3% at December 31, 2019, comparable with 25.0% on an IAS 17 basis (2018: 20.3%). Gearing is a key measure of Shell's capital structure and across the business cycle, we aim to return to a gearing level within a range of 15-25%. Note 14 to the “Consolidated Financial Statements” on pages 216-219 provides information on our debt arrangements, including gearing and net debt definitions.

LIQUIDITY

We satisfy our funding and working capital requirements from the cash generated from our operations, the issuance of debt and divestments. In 2019, access to the international debt capital markets remained strong, with our debt principally financed from these markets through central debt programmes consisting of:

- a \$10 billion global commercial paper (CP) programme, with maturities not exceeding 270 days;
- a \$10 billion US CP programme, with maturities not exceeding 397 days;
- an unlimited Euro medium-term note (EMTN) programme (also referred to as the Multi-Currency Debt Securities Programme); and
- an unlimited US universal shelf (US shelf) registration.

All these CP, EMTN and US shelf issuances are issued by Shell International Finance B.V., the issuance company for Shell, with its debt being guaranteed by Royal Dutch Shell plc (the Company).

We also maintain committed credit facilities, which were increased and extended in December 2019 with \$2 billion now expiring in 2020 and \$8 billion in 2024. Each facility includes two one-year extension options at the discretion of each lender. Both remained undrawn at December 31, 2019. These facilities and internally available liquidity provide back-up coverage for our CP programmes. Other than certain borrowing by local subsidiaries, we do not have any other committed credit facilities.

Our total debt increased by \$19.6 billion, of which \$15.7 billion was due to the impact of IFRS16, to \$96.4 billion at December 31, 2019. The total debt excluding leases will mature as follows: 15% in 2020; 8% in 2021; 7% in 2022; 7% in 2023; and 63% in 2024 and beyond. The portion of debt maturing in 2020 is expected to be repaid from a combination of cash balances, cash generated from operations, divestments and the issuance of new debt.

In 2019, we issued \$4 billion of bonds under our US shelf registration and €3 billion under our EMTN programme. Periodically, for working capital purposes, we issued CP. We believe our working capital is sufficient for current requirements.

While our subsidiaries are subject to restrictions, such as foreign withholding taxes on the transfer of funds in the form of cash dividends, loans or advances, such restrictions are not expected to have a material impact on our ability to meet our cash obligations.

MARKET RISK AND CREDIT RISK

We are affected by the global macroeconomic environment as well as financial and commodity market conditions. This exposes us to treasury and trading risks, including liquidity risk, market risk (interest rate risk, foreign exchange risk and commodity price risk) and credit risk. See “Risk factors” on page 18 and Note 19 to the “Consolidated Financial Statements” on pages 227-231. The size and scope of our businesses require a robust financial control framework and effective management of our various risk exposures.

We utilise various financial instruments for managing exposure to commodity price, foreign exchange and interest rate movements. Our treasury and trading operations are highly centralised and seek to manage credit exposures associated with our substantial cash, commodity, foreign exchange and interest rate positions. Our portfolio of cash investments is diversified to avoid concentrating risk in any one instrument, country or counterparty. Other than in exceptional cases, the use of external derivative instruments is confined to specialist trading and central treasury organisations that have appropriate skills, experience, supervision, control and reporting systems. Credit risk policies are in place to ensure that sales of products are made to customers with appropriate creditworthiness, and include detailed credit analysis and monitoring of customers against counterparty credit limits. Where appropriate, netting arrangements, credit insurance, prepayments and collateral are used to manage credit risk. We maintain a committed credit facility. Management believes it has access to sufficient debt funding sources (capital markets) and to undrawn committed borrowing facilities to meet foreseeable requirements.

PENSION COMMITMENTS

We have substantial pension commitments, the funding of which is subject to capital market risks (see "Risk factors" on page 33). We address key pension risks in a number of ways. Principal among these is the Pensions Forum, chaired by the Chief Financial Officer, which oversees Shell's input to pension strategy, policy and operation. A risk committee supports the forum in reviewing the results of assurance processes in respect to pensions risks. In general, local trustees manage the funded defined benefit pension plans, with contributions paid based on independent actuarial valuations in accordance with local regulations. Our total employer contributions to funded and unfunded defined benefit pension plans were \$1.5 billion in 2019 and are estimated to be \$0.7 billion in 2020. See Note 17 to the Consolidated Financial Statements at page 223.

Capitalisation table

	\$ million	
	December 31, 2019	December 31, 2018
Equity attributable to Royal Dutch Shell plc shareholders	186,476	198,646
Current debt	15,064	10,134
Non-current debt	81,360	66,690
Total debt [A]	96,424	76,824
Total capitalisation	282,900	275,470

[A] Of total debt, \$65.7 billion (2018: \$62.7 billion) was unsecured and \$30.7 billion (2018: \$14.1 billion) was secured. See Note 14 to the "Consolidated Financial Statements" on pages 191-194 for further disclosure on debt.

STATEMENT OF CASH FLOWS

Cash flow from operating activities in 2019 was an inflow of \$42.2 billion, compared with \$53.1 billion in 2018, mainly due to lower earnings and an unfavourable working capital impact. The increase in cash flow from operating activities in 2018, compared with \$35.7 billion in 2017, was mainly due to higher earnings and a favourable working capital impact.

Cash flow from investing activities in 2019 was an outflow of \$15.8 billion, compared with an outflow of \$13.7 billion in 2018. The increased cash outflow was mainly due to lower proceeds from the sale of equity securities, partly offset by higher proceeds from sale of assets in 2019. The increased cash outflow in 2018 compared with \$8.0 billion in 2017 was mainly due to lower proceeds from the sale of assets and securities in 2018.

Cash flow from financing activities in 2019 was an outflow of \$35.2 billion, compared with outflows of \$32.5 billion in 2018 and \$27.1 billion in 2017. In 2019, this included payment of dividends to Royal Dutch Shell plc shareholders of \$15.2 billion (2018: \$15.7 billion; 2017: \$10.9 billion), net repayment of debt of \$3.4 billion (2018: \$8.3 billion; 2017: \$11.8 billion), repurchases of shares of \$10.2 billion (2018: \$3.9 billion) and interest paid of \$4.6 billion (2018: \$3.6 billion; 2017: \$3.6 billion).

Cash and cash equivalents were \$18.1 billion at December 31, 2019 (2018: \$26.7 billion; 2017: \$20.3 billion).

CASH FLOW FROM OPERATING ACTIVITIES

The most significant factors affecting our cash flow from operating activities are earnings, which are mainly impacted by: realised prices for crude oil, natural gas and LNG; production levels of crude oil, natural gas and LNG; refining and marketing margins; and movements in working capital.

The impact on earnings from changes in market prices depends on: the extent to which contractual arrangements are tied to market prices; the dynamics of production-sharing contracts; the existence of agreements with governments or state-owned oil and gas companies that have limited sensitivity to crude oil and natural gas prices; tax impacts; and the extent to which changes in commodity prices flow through into operating costs. Changes in benchmark prices of crude oil and natural gas in any particular period therefore provide only a broad indicator of changes in our Integrated Gas and Upstream earnings in that period. In the longer term, replacement of proved oil and gas reserves will affect our ability to maintain or increase production levels, which in turn will affect our earnings and cash flows. Changes in any one of a range of factors, derived from either within the industry or the broader economic environment, can influence refining and marketing margins. The precise impact of any such changes depends on how the oil markets respond to them. The market response is affected by factors such as: whether the change affects all crude oil types or only a specific grade; regional and global crude oil and refined products inventories; and the collective speed of response of refiners and product marketers in adjusting their operations. As a result, margins fluctuate from region to region and from period to period.

CAPITAL INVESTMENT AND CASH CAPITAL EXPENDITURE

The level of capital investment in 2019 and 2018 reflects our discipline, focus and capital efficiency.

Capital investment [A]

	\$ million		
	2019	2018	2017
Integrated Gas	6,706	4,259	3,921
Upstream	11,075	12,785	13,160
Downstream	10,542	7,565	6,418
Corporate	465	269	157
Total capital investment	28,788	24,878	26,655

[A] 2018 and 2017 as revised. See "Non-GAAP measures reconciliations" on pages 279-280.

With effect from January 1, 2019, cash capital expenditure was introduced to monitor investing activities on a cash basis, excluding items such as lease additions which do not necessarily result in cash outflows in the period. The capital discipline demonstrated in 2019 allowed us to maintain our cash capital expenditure in line with the \$24-29 billion range.

Cash capital expenditure

	\$ million		
	2019	2018	2017
Integrated Gas	4,299	3,819	3,616
Upstream	10,277	12,582	11,670
Downstream	8,926	7,408	6,090
Corporate	418	269	157
Total cash capital expenditure	23,919	24,078	21,533

LIQUIDITY AND CAPITAL RESOURCES continued

Cash flow information [A]

	\$ billion		
	2019	2018	2017
Cash flow from operating activities excluding working capital movements			
Integrated Gas	14.8	16.3	8.7
Upstream	20.5	21.9	16.3
Downstream	11.9	10.8	12.6
Corporate	(0.3)	0.7	0.3
Total	47.0	49.7	37.9
(Increase)/decrease in inventories	(2.6)	2.8	(2.1)
(Increase)/decrease in current receivables	(0.9)	2.0	(2.6)
Increase/(decrease) in current payables	(1.2)	(1.3)	2.4
(Increase)/decrease in working capital	(4.8)	3.4	(2.3)
Cash flow from operating activities	42.2	53.1	35.7
Cash flow from investing activities	(15.8)	(13.7)	(8.0)
Cash flow from financing activities	(35.2)	(32.5)	(27.1)
Currency translation differences relating to cash and cash equivalents	0.1	(0.4)	0.6
Increase/(decrease) in cash and cash equivalents	(8.7)	6.4	1.2
Cash and cash equivalents at the beginning of the year	26.7	20.3	19.1
Cash and cash equivalents at the end of the year	18.1	26.7	20.3

[A] See the "Consolidated Statement of Cash Flows" on page 194.

DIVIDENDS

Our policy is to grow the dollar dividend per share through time, in line with our view of our underlying earnings and cash flow. When setting the dividend, the Board of Directors looks at a range of factors, including the macroeconomic environment, the current balance sheet, future investment plans and existing commitments. We returned \$15.2 billion to our shareholders through dividends in 2019.

The fourth quarter 2019 interim dividend of \$0.47 per share will be payable to shareholders on the register at February 14, 2020. See Note 23 to the "Consolidated Financial Statements" on page 235. The Board expects that the first quarter 2020 interim dividend will be \$0.47 per share, equal to the US dollar dividend per share for the same quarter in 2019.

PURCHASES OF SECURITIES

On July 26, 2018, the Company announced the commencement of a share buyback programme of at least \$25 billion, subject to further progress with debt reduction and oil price conditions. This was in accordance with the authority granted by shareholders at the 2018 Annual General Meeting (AGM) for the Company to repurchase up to a maximum of 10% of its issued ordinary shares, excluding treasury shares (834 million ordinary shares). At the 2019 AGM, shareholders granted a renewal of this authority, to repurchase up to a maximum of 815 million ordinary shares, such authority to expire at the earlier of the close of

business on August 21, 2020 and the end of the 2020 AGM. As at December 31, 2019, 445 million A shares with a nominal value of €31 million (\$38 million) and 16 million B shares with a nominal value of €1 million (\$1 million) (5.85% of the Company's total issued share capital at December 31, 2019) had been cumulatively purchased and cancelled since the beginning of this programme, for a total cost of \$14.1 billion including expenses, at an average price of \$30.67 per share. As at December 31, 2019, 647 million ordinary shares could still be repurchased under the current AGM authority. The purpose of the share repurchases in 2018 and 2019, and in the period ended January 24, 2020, was to reduce the issued share capital of the Company. A new resolution will be proposed at the 2020 AGM to renew the authority for the Company to purchase its own share capital, up to specified limits, for a further year. This proposal will be described in more detail in the 2020 Notice of Annual General Meeting.

Shares are also purchased by the employee share ownership trusts and trust-like entities (see the "Directors' Report" on page 104-171) to meet delivery commitments under employee share plans. All share purchases are made in open-market transactions.

The table below provides information on purchases of shares in 2019, and in the period ended January 24, 2020, by the Company and affiliated purchasers. Purchases in euros and sterling are converted into dollars using the exchange rate on each transaction date.

Purchases of equity securities by issuer and affiliated purchasers in 2019 [A]

Purchase period	A shares			B shares			A ADSs [B]	
	Number purchased for employee share plans	Number purchased for cancellation [C]	Weighted average price (\$)[D]	Number purchased for employee share plans	Number purchased for cancellation [C]	Weighted average price (\$)[D]	Number purchased for employee share plans	Weighted average price (\$)[D]
January	–	19,086,716	30.10	–	–	–	1,854,168	59.21
February	–	25,651,490	31.60	–	–	–	–	–
March	–	27,792,913	31.38	–	–	–	83,349	63.45
April	231,910	16,918,437	32.24	95,430	–	31.48	–	–
May	–	29,386,861	31.86	–	–	–	–	–
June	–	20,578,030	31.97	20,830	–	33.49	30,178	65.95
July	141,555	29,200,419	32.31	–	–	–	–	–
August	–	26,663,906	28.47	–	9,701,283	28.02	–	–
September	1,650,000	31,947,755	28.63	709,388	1,787,000	27.70	402,032	58.16
October	4,413,134	26,563,443	29.09	1,933,105	–	29.06	913,430	57.98
November	4,067,133	35,836,732	29.67	1,628,144	–	29.48	1,314,922	59.21
December	1,119,733	30,475,077	29.00	979,363	4,591,341	28.30	200,047	57.83
Total 2019	11,623,465	320,101,779	30.37	5,366,260	16,079,624	28.28	4,798,126	58.95
January	–	23,206,521 [E]	29.63	–	–	–	1,003,452	59.76
Total 2020	–	23,206,521	29.63	–	–	–	1,003,452	59.76

[A] Reported as at settlement date.

[B] American Depositary Shares.

[C] Under the share buyback programme.

[D] Includes stamp duty and brokers' commission.

[E] As at January 24, 2020, the end of the sixth tranche of the share buyback programme.

CONTRACTUAL OBLIGATIONS

The table below summarises our principal contractual obligations at December 31, 2019, by expected settlement period. The amounts presented have not been offset by any committed third-party revenue in relation to these obligations.

Contractual obligations

					\$ billion
	Less than 1 year	Between 1 and 3 years	Between 3 and 5 years	5 years and later	Total
Debt [A]	10.1	9.9	6.5	38.7	65.2
Leases	7.3	9.9	7.6	21.3	46.1
Purchase obligations [B]	24.6	25.1	18.3	48.6	116.6
Other long-term contractual liabilities [C]	–	0.4	–	0.7	1.1
Total	42.0	45.3	32.4	109.3	229.0

[A] See Note 14 to the "Consolidated Financial Statements" on pages 218-219. Debt contractual obligations exclude interest, which is estimated to be \$1.7 billion payable in less than one year, \$3.0 billion between one and three years, \$2.6 billion between three and five years, and \$14.6 billion in five years and later. For this purpose, we assume that interest rates with respect to variable interest rate debt remain constant at the rates in effect at December 31, 2019, and that there is no change in the aggregate principal amount of debt other than repayment at scheduled maturity as reflected in the table. Leases definition follows IFRS 16, which was implemented January 1, 2019. Lease contractual obligations include interest.

[B] Purchase obligations disclosed in the above table exclude commodity purchase obligations that are not fixed or determinable and are principally intended to be resold in a short period of time through sale agreements with third parties. Examples include long-term non-cancellable LNG and natural gas purchase commitments and commitments to purchase refined products or crude oil at market prices. Inclusion of such commitments would not be meaningful in measuring liquidity and cash flow, as the cash outflows generated by these purchases will generally be offset in the same periods by cash received from the related sales transactions.

[C] Includes all obligations included in "Trade and other payables" in "Non-current liabilities" in the "Consolidated Balance Sheet" that are contractually fixed as to timing and amount. In addition to these amounts, Shell has certain obligations that are not contractually fixed as to timing and amount, including contributions to defined benefit pension plans (see Note 17 to the "Consolidated Financial Statements" on pages 223-225) and obligations associated with decommissioning and restoration (see Note 18 to the "Consolidated Financial Statements" on page 226).

GUARANTEES AND OTHER OFF-BALANCE SHEET ARRANGEMENTS

There were no guarantees and other off-balance sheet arrangements at December 31, 2019, or 2018, that were reasonably likely to have a material effect on Shell.

FINANCIAL INFORMATION RELATING TO THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST

The results of operations and financial position of the Royal Dutch Shell Dividend Access Trust (the Trust) are included in the consolidated results of operations and financial position of Shell. Certain condensed financial information in respect of the Trust is given below. See "Royal Dutch Shell Dividend Access Trust Financial Statements" on pages 251-255.

The Shell Transport and Trading Company Limited and BG Group Limited have each issued a dividend access share to Computershare Trustees (Jersey) Limited (the Trustee). For the years 2019, 2018 and 2017, the Trust recorded income before tax of £5,484 million, £5,328 million, and £4,567 million respectively. In each period, this reflected the amount of dividends received on the dividend access shares.

At December 31, 2019, the Trust had total equity of £nil (2018: £nil; 2017: £nil), reflecting cash of £3 million (2018: £3 million; 2017: £2 million) and unclaimed dividends of £3 million (2018: £3 million; 2017: £2 million). The Trust only records a liability for an unclaimed dividend, and a corresponding amount of cash, to the extent that dividend cheque payments have not been presented within 12 months, have expired or have been returned unrepresented.

ENVIRONMENT AND SOCIETY

Our success in business depends on our ability to meet a range of environmental and social challenges. We must operate safely and manage the effect our activities can have on neighbouring communities and wider society. If we fail to do this, we may incur liabilities or sanctions, lose business opportunities, harm our reputation, or our licence to operate may be impacted.

See “Risk factors” on [page 27](#).

Data in this section are reported on a 100% basis in respect of activities where we are the operator. Reporting on this operational control basis differs from that applied for financial reporting purposes in the “Consolidated Financial Statements” on pages 190-238. Detailed data and information on our 2019 environmental and social performance is expected to be published in the Shell Sustainability Report in April 2020.

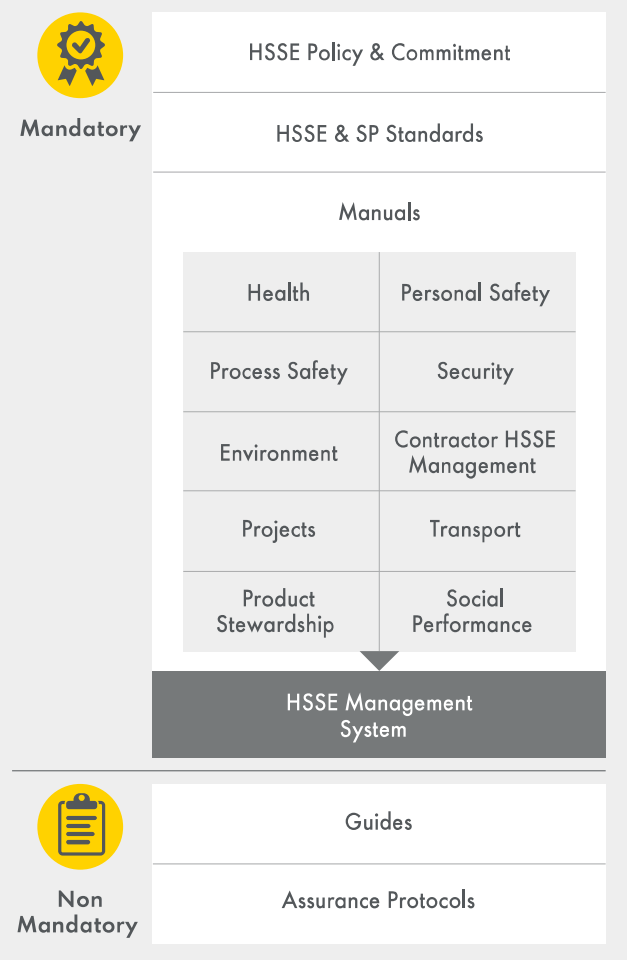
CONTROL FRAMEWORK

The Shell General Business Principles set out our responsibilities to shareholders, customers, employees, business partners and society. They set the standards for the way we conduct business, with integrity, care and respect for people, the protection of the environment and mutually beneficial relationships with communities. All ventures that we operate must conduct their activities in line with our business principles.

We aim to minimise the environmental impact of new projects and existing operations, and we engage with local communities and non-governmental organisations to understand and respond to their concerns. Shell conducts an environmental, social and health impact assessment for every major project. The definition of major projects considers two categories: capacity, including consequences from potential incidents; and cost. This helps us to understand and manage the effects our projects could have on the surrounding environment and local communities. We have standards and a clear governance structure in place to help manage potential impacts. We are committed to the safety of our people and contractors. The standards for Health, Safety, Security, Environment and Social Performance (HSSE & SP) and the scope for application of each of these standards is specified in the Shell HSSE & SP Control Framework (CF). The CF is made up of a series of mandatory manuals, which are in line with the Shell Commitment and Policy on HSSE & SP and the Shell Code of Conduct. They are supported by a number of guidance documents and complemented by assurance protocols. The CF applies to every Shell entity, including all employees and contract staff, and to Shell-operated ventures. The CF defines standards and accountabilities at each level of the organisation and sets out the procedures and processes people are required to follow. We require that all significant HSSE & SP risks associated with our business activities are assessed and managed to as low as reasonably practicable. Our HSSE & SP functions provide expert advice and support for the business. The Process Safety and HSSE & SP Assurance team provides assurance on the effectiveness of HSSE & SP controls to the Board.

We expect joint ventures not operated by Shell to apply standards and principles similar to our own. We support these joint ventures in their implementation of our HSSE & SP Control Framework, or of a similar framework, and offer to review the effectiveness of their implementation. Even if such a review is not carried out, we periodically evaluate HSSE & SP risks faced by the ventures which we do not operate. If one of these joint ventures does not meet our expectations, we work to put remedial action plans in place, in agreement with our partners, to improve performance.

HSSE & SP Control Framework



Shell aims to work with suppliers that behave in a safe, economically, environmentally and socially responsible manner. Our approach to suppliers is set out in our Shell General Business Principles and Shell Supplier Principles. These principles cover expectations in areas such as business integrity, health and safety, environment, and human rights. Working with suppliers in this way is central to maintaining a strong societal support for our operations.

SAFETY

Safety is central to the responsible delivery of energy. We develop and operate our facilities with the aim of preventing any incidents that may harm our employees, contract staff or nearby communities, or cause damage to our assets or adversely impact the environment. We strive to help improve safety performance throughout the energy industry by sharing our safety experience and standards with other operators, contractors and professional organisations, including the International Association of Oil & Gas Producers (IOGP) and the Energy Institute. Shell's Safety, Environment and Sustainability Committee (SESCO) reviews and advises the Board on our safety strategy, policies and performance. Safety performance is included in our annual bonus scorecard for all our employees.

See also “Directors’ Remuneration Report” on [pages 155-163](#).

How we mitigate

We manage safety risks across our businesses through clear standards, controls and compliance systems, combined with a safety-focused culture. We strive to reduce risks and to minimise the potential impact of any incident. Our standards also apply to any joint ventures we operate. We focus on the three areas of safety with the highest risks associated with our activities: personal, process, and transport. We ensure that people responsible for tasks involving a significant safety hazard have the necessary training, skills and competencies. We employ a large number of contractors and we work with them to ensure they understand our safety requirements. Together we build skills and expertise to improve safety performance. We expect everyone working for us to comply with our 12 mandatory Life-Saving Rules. If employees break these rules, they face disciplinary action up to and including termination of employment. If contract staff break the Life-Saving Rules, they can be removed from the worksite.

See also “Control Framework” on page 84.

Personal and process safety

We continue to strengthen the safety culture and leadership among our employees and contract staff, with the focus on caring for people. Our safety goal is to achieve no harm and no leaks across all our operations. We refer to this as our Goal Zero ambition.

We expect everyone working for us to intervene and stop work that may appear to be unsafe. In addition to our ongoing safety awareness programmes, we hold an annual global safety day to give employees and contract staff time to reflect on how to prevent incidents.

Process safety management is about keeping hazardous substances inside pipes, tanks and vessels so they do not cause any harm to people or the environment. It starts at the design and construction stage of our projects and is implemented throughout the life cycle of these facilities to ensure they are safely operated, well-maintained and regularly inspected. Our global standards and operating procedures define the controls and physical barriers we require to prevent incidents. For example, our offshore wells are designed with at least two independent barriers in the direction of flow to mitigate the risk of an uncontrolled release of hydrocarbons. We regularly inspect, test and maintain these barriers to ensure they meet our standards. In the event of a loss of containment such as a spill or a leak, we employ independent recovery measures to prevent the release from becoming catastrophic. This system of barriers and recovery measures is known as a “bow-tie”, a model that visually represents a system where personal and process safety hazards are managed through prevention and response barriers. Since 2016, we have been working on strengthening barriers that involve critical safety tasks carried out by frontline staff. We have embedded a set of process safety fundamentals, which provide clear guidelines for good operating practice to prevent unplanned releases.

Risk management approach



We also routinely prepare and practise our emergency response to potential incidents such as a spill or a fire. This involves working closely with local services and regulatory agencies to jointly test our plans and procedures. These tests continually improve our readiness to respond. If an incident does occur, we have procedures in place to reduce the impact on people and the environment.

Transport safety

Transporting large numbers of people, products and equipment by road, rail, sea and air poses safety risks. We develop best-practice standards within Shell to find ways of reducing transport safety risks, and work with specialist contractors, industry bodies, non-governmental organisations and governments.

Shell employees and contractors drove a combined distance of around 575 million kilometres on business in 2019 in close to 60 countries. We run road safety programmes, such as those that promote safe driving techniques and behaviour. We require everyone driving more than 7,500 kilometres a year on company business on public roads and those who drive in road safety high-risk countries to take a defensive driving course. In addition, we run an annual online defensive driving course for all who drive on public roads on Shell business. Outside our operations, we also work to improve road safety in several communities and countries where we operate. For example, in India, we have rolled out a road safety campaign that provides truck drivers with free eye tests and free prescription glasses.

Safety performance

While we continually work to minimise the likelihood of incidents, some do occur. Regrettably, seven people lost their lives while working for Shell in 2019, compared with two fatalities in 2018.

In 2019, two contractors died in Nigeria when an oil and gas maintenance vessel they were travelling on capsized in bad weather. A Shell employee died after falling from height into water while a vessel was being moored at Shell's Mormon Island facility in the USA. A Shell employee based at Convent Refinery in the USA was fatally injured in a collision on the road when driving from the airport after his return from a business conference. A Shell employee and a contractor died during a routine and mandatory test of the lifeboat launch and retrieval capabilities at the Auger tension-leg platform in the US Gulf of Mexico when the lifeboat disconnected from the lifting apparatus at height. A roll-over incident occurred in Pakistan involving a road tanker which led to one contractor being fatally injured.

Road transportation remains a challenging and complex area for industries worldwide. After a devastating roll-over incident occurred in Pakistan in 2017, involving a road tanker hired by a company that was providing road transport services to Shell Pakistan Limited, Shell Pakistan has been working with road transport companies it hires, regulators and emergency services in Pakistan to improve safety standards.

We require incidents to be investigated to understand the underlying causes, including the technical, behavioural, organisational and human elements. We share learnings and implement mitigations at the site and in the country and business where the incident took place. We seek to translate incident findings into improvements in standards or ways of working that can be applied broadly across similar facilities in Shell.

ENVIRONMENT AND SOCIETY continued

In 2019, Shell's Board and Executive Committee spent considerable time reflecting on the concerning safety performance, measured by the number of fatalities, and what needs to change at Shell to prevent fatalities and all other serious incidents. This included carrying out a full review of Shell's safety approach, which covered the effectiveness of current preventative tools, such as the Life-Saving Rules and Goal Zero ambition.

Since the early 2000s, we made progress in improving the safety of our operations. This was largely due to a stronger safety culture, guided by our Goal Zero ambition to achieve no harm and no leaks, more effective standards, and requirements such as the Life-Saving Rules. Of all the fatalities in recent years, the vast majority have no link to a breach of the Life-Saving Rules. But sadly, we have not been able to eliminate all fatal incidents involving Shell employees and contractors.

We are now building on our current approach to safety with a more consistent focus on the way people, culture, equipment, work systems and processes all interact. Many of our fatalities over the last five years were down to the complex interaction between these elements. We aim to better understand the gap between how we anticipate work will be done safely and how the work is actually carried out. We continue to work to prevent incidents by maintaining safety barriers and providing training, and we acknowledge that people make mistakes and not all incidents may be preventable. Therefore, we will focus more on how people can "fail safely", and on our response in the moment to avoid the risk of a serious injury. This approach is a philosophical change, which we will start to deploy from 2020 onwards for all employees and contractors.

As set out in "Performance indicators" on page 42, our total recordable case frequency (injuries per million working hours) was 0.9 in 2019, compared with 0.9 in 2018, and there were 130 operational Tier 1 and 2 process safety events in 2019, compared with 121 in 2018. Detailed information on our 2019 safety performance is expected to be published in the Shell Sustainability Report in April 2020.

ENVIRONMENT

We are committed to protecting the environment. For us, being responsible means understanding the impact Shell can have on the environment and the communities we share it with – before, during and at the end of our operations. We aim to make a positive contribution to the local environments in which we operate and seek to reduce any potential negative environmental impacts. This is why we set ourselves high internal environmental standards. These match and, in some cases exceed, local regulatory requirements. We aim to continually improve our performance, and to prepare to respond to future challenges and opportunities. We adhere to external standards and guidelines, such as those developed by the World Bank and International Finance Corporation, to inform our approach. For us, protecting the environment also means working to transform our product mix over time, for example, by expanding the choice of lower-carbon products we offer customers. Shell's Safety, Environment and Sustainability Committee (SESCO) reviews and advises the Board on our environment strategy, policies and performance.

How we mitigate

Our global environmental standards cover our environmental performance, including managing emissions of greenhouse gases (GHG), using energy more efficiently, flaring less gas during oil production, preventing spills and leaks of hazardous materials, using less fresh water and conserving biodiversity wherever we operate. When planning new major projects, we carry out detailed environmental, social and health impact assessments.

See also "Control Framework" on page 84.

We apply the mitigation hierarchy in our projects and operations to aim to minimise our impact on the environment as much as possible. When looking at biodiversity, for example, this means that we first aim to avoid impacts on biodiversity and ecosystem services. Where avoidance is not possible, we aim to minimise our impact. Where our operations have affected biodiversity and the communities who rely on biodiversity for their livelihoods, we seek to help restore impacted habitats. We look for opportunities to make a positive contribution to conservation, also known as net-positive impact, where we operate. For example, the Shell-operated QGC gas project in Australia manages the Valkyrie property, an area with a rich ecosystem, as a biodiversity and carbon offset to compensate for clearing vegetation and habitat for the development of gas resources. We believe some areas are too sensitive to enter, so in 2003, we made the commitment that we will not explore for, or develop, oil and gas resources in natural World Heritage Sites.

Another example of how we apply the mitigation hierarchy involves water. Ensuring the availability of fresh water is a growing challenge in some parts of the world. A combination of increasing demand for water resources, growing stakeholder expectations and concerns, and water-related legislation may drive actions that affect our ability to secure access to fresh water and to discharge water from our operations. We manage our water use carefully, and we tailor our use of fresh water to local conditions because water constraints affect people at the local or regional level. In some cases, we use alternatives to fresh water in our operations; these include recycled water, processed sewage water and desalinated water. Our QGC project in Australia produces LNG from natural gas in the water-scarce region of the Surat Basin in Queensland. Water is produced as a natural by-product during the extraction of gas. Two water plants treat most of the produced water so that it is suitable for use by local farmers, industry and town water suppliers. An assessment of risks to water availability is required for each of our facilities and projects and, in areas of water scarcity, we develop water-management action plans that identify ways to use less fresh water, recycle water and closely monitor its use.

In 2019, our intake of fresh water was 192 million cubic metres, compared to 199 in 2018. Around 90% of our fresh water intake was used for manufacturing oil products and chemicals, with the rest mainly used for oil and gas production. Around 40% of freshwater intake was from public utilities, such as municipal water supplies, with the remainder taken from surface water such as rivers and lakes (around 51%) and groundwater (around 9%).

Detailed information on our 2019 environmental performance is expected to be published in the Shell Sustainability Report in April 2020.

See "Climate change and energy transition" on pages 91 for more information on how we manage our GHG emissions.

SPILLS

Large spills of crude oil, oil products and chemicals associated with our operations can adversely impact the environment and wildlife, and result in major clean-up costs as well as fines and other damages. They can also affect our licence to operate and harm our reputation.

How we mitigate

We have requirements and procedures designed to prevent spills. We aim to design, operate and maintain our facilities so that we avoid spills. To further reduce the risk of spills, Shell has routine programmes to maintain and improve the reliability of facilities and pipelines. Our business units are responsible for organising and executing oil-spill responses in line with Shell guidelines and relevant legal and regulatory requirements. All our offshore installations have plans in place to respond to spills. These plans detail response strategies and techniques, available equipment, and trained personnel and contracts. We are able to call upon site-managed resources such as containment booms. We are also able to draw upon the contracted services of oil-spill response organisations, their containment booms, collection vessels, aircraft or other equipment if required for large spills. We conduct regular exercises that seek to ensure these plans remain effective.

We have further developed our ability to respond to spills to water, and we maintain a Global Response Support Network of trained staff to support our worldwide response capability. This is also supported by our global Oil Spill Expertise Centre, which tests local capability and maintains our ability globally to respond to a significant spill into a marine environment.

We are a founding member of the Marine Well Containment Company, a non-profit industry consortium providing a well-containment response system for the Gulf of Mexico. In addition, we are a founding member of the Subsea Well Response Project, an industry cooperative effort to enhance global well-containment capabilities, which has transitioned to Oil Spill Response Limited, an industry consortium.

We also maintain site-specific emergency response plans in the event of an onshore spill. Like the offshore response plans, these are designed to meet Shell guidelines as well as relevant local legal and regulatory requirements. They also provide for the initial assessment of incidents and the mobilisation of resources needed to manage them. In the event of spills on land, businesses are supported by our global Soil & Groundwater Team whose role is to review and implement appropriate remedies such as sustainable remediation. The global Soil & Groundwater Team is engaged throughout the lifecycle of our assets. For example, during acquisition and divestment of assets, they conduct due diligence to identify land contamination liabilities. Through research and development initiatives, the Soil & Groundwater Team collaborates with regulators in developing, modifying, and applying sustainable remediation techniques.

Spills still occur for reasons such as operational failure, accidents or unusual corrosion. In 2019, the number of operational spills of more than 100 kilograms decreased to 70 from 93 in 2018 (see "Performance indicators" on page 44). The weight of operational spills of oil and oil products in 2019 was 0.2 thousand tonnes, a decrease from 0.9 thousand tonnes in 2018. At the time of publication of this report, there was one spill under investigation in Nigeria that may result in adjustments.

Spills in Nigeria

Most oil spills in the Niger Delta region of Nigeria continue to be caused by crude oil theft or sabotage of oil and gas production facilities, and illegal oil refining, including the distribution of illegally refined products. In 2019, about 95% of 164 oil spills of more than 100 kilograms from the Shell Petroleum Development Company of Nigeria Limited (SPDC) joint venture's facilities were due to illegal activities by third parties. In 2019, the volume of crude oil spills caused by sabotage was 2.0 thousand tonnes (157 incidents), compared to 1.6 thousand tonnes (111 incidents) in 2018. However, there are instances where spills occur due to operational reasons. In 2019, SPDC managed to reduce the volume of operational spills of more than 100 kilograms to about 0.03 thousand tonnes of crude oil (seven incidents) compared to about 0.4 thousand tonnes of crude oil (15 incidents) in 2018. This represents a reduction of about 93% in operational spills weight year-on-year.

Irrespective of the cause, SPDC works to clean up and remediate areas impacted by spills originating from its facilities. SPDC succeeded in cutting the average time to complete recovery of free and/or residual oil from about 13 days in 2016 to about seven days in 2019. This entails the average time it takes to safely access an impacted site to commence Joint Investigation Visits (JIV) with diverse stakeholders including NGOs and communities, and clean up oil not mixed with water or soil. Clean-up activities include bio-remediation which stimulates microorganisms that naturally break down and use carbon-rich oil contamination as a source of food and energy, ultimately leading to its removal. Once clean-up and remediation operations are completed, the work is inspected and, if satisfactory, approved and certified by the Nigerian regulators. In case of operational spills, SPDC also pays compensation to people and communities impacted.

To reduce the number of operational spills, SPDC is focused on implementing its ongoing work programme to appraise, maintain and replace key sections of pipelines and flow lines. Over the last eight years, about 1,330 kilometres of pipelines and flow lines have been replaced. This is managed through a pipeline and flow line integrity management system that proactively manages pipeline integrity, puts barriers in place where necessary, and recommends when and where pipeline sections should be replaced to prevent failures. In 2018, this integrity management system was enhanced to manage threats arising from frequent pipeline sabotage or vandalism.

SPDC continues to undertake integrated focused initiatives to prevent and minimise spills caused by theft and sabotage of its facilities in the Niger Delta. In 2019, SPDC continued on-ground surveillance of the SPDC joint venture's areas of operation, including its pipeline network, to mitigate third-party interference and ensure that spills are detected and responded to as quickly as possible. There are also daily overflights of the most vulnerable segments of the pipeline network to identify any new spill incidents or illegal activities. SPDC has also implemented anti-theft protection mechanisms on key infrastructure, such as wellheads and manifolds. The programme to protect well-heads with steel cages continues to help deter theft. By end of 2019, 301 cages had been installed and another 86 units are planned for installation in 2020, including enhanced CCTV for all installed cages. Only three breaches out of about 300 registered attempts were successful.

ENVIRONMENT AND SOCIETY continued

Since 2012, SPDC has worked with the International Union for Conservation of Nature (IUCN) to enhance remediation techniques and to protect biodiversity at sites affected by oil spills in SPDC's areas of operation in the Niger Delta. Based on this collaboration, SPDC has launched further improvement initiatives to help strengthen its remediation and restoration efforts. In 2019, SPDC and IUCN worked together on the Niger Delta Biodiversity Technical Advisory Group which also includes representatives from the Nigerian Conservation Foundation and Wetlands International, to continue to monitor biodiversity recovery of remediated sites.

SPDC also works with a range of stakeholders in the Niger Delta to build greater trust in spill response and clean-up processes. Local communities take part in the remediation work for operational spills.

In certain instances, some non-governmental organisations have also participated in joint investigation visits along with government regulators, SPDC and members of impacted communities, to establish the cause and volume of oil spilled.

SPDC has also implemented several initiatives and programmes to raise awareness of the negative impact of crude oil theft and illegal oil refining. Examples include community-based pipeline surveillance and the promotion of alternative livelihoods through Shell's flagship youth entrepreneurship programme, Shell LiveWIRE.

In 2015, SPDC, on behalf of the SPDC joint venture and the Bodo community, signed a memorandum of understanding (MOU) granting access to SPDC to begin the clean-up of areas affected by two operational spills in 2008. The MOU also provided for the selection of two international contractors to conduct the clean-up and to be overseen by an independent project director. The clean-up project suffered a delay in 2016 and most of 2017 due to access challenges from the community. After engagement with the Bodo community and other stakeholders over two years, beginning in September 2015, and managed by the Bodo Mediation Initiative, the first phase of clean-up and remediation activities started in September 2017. The clean-up consists of three phases: 1) removal of free-phase surface oil, 2) remediation of soil, and 3) planting of mangroves and monitoring. The first phase was completed in August 2018 and the contract procurement process for phase two was finalised in 2019 with four remediation contractors having international technical partners and two consultancy contractors selected. Mobilisation is expected to effectively start in 2020. Prior to engagement on the project, 800 community workers were medically checked, tested for swimming ability, and trained to International Maritime Organization (IMO) Oil Spill Response Levels 1 and 2. Field remediation activities commenced in November 2019. Should activities continue uninterrupted, phase two (soil remediation) is expected to take around 18 months. However, for it to be successful, there must be no re-contamination of cleaned-up sites from illegal third-party activities, such as crude oil theft and illegal refining.

SPDC remains committed to the implementation of the 2011 United Nations Environmental Programme (UNEP) Report on Ogoniland. Over the last eight years, SPDC has taken action on all, and completed most, of the UNEP recommendations addressed specifically to it as operator of the joint venture. The UNEP report recommended the creation of an Ogoni Trust Fund (OTF) with \$1 billion capital, to be co-funded by the Nigerian government, the SPDC joint venture and other operators in the area. The SPDC joint venture remains fully committed to contributing \$900 million as its share over five years to the Fund. SPDC JV partners contributed the first instalment of \$180 million for the clean-up by July 2018 and released the second instalment of \$180 million in 2019. SPDC assigned a senior engineer with project management, contracting, and procurement

experience to support and enhance the capability within the Hydrocarbon Pollution Remediation Project (HYPREP). In November 2018, HYPREP awarded contracts for the first set of remediation projects. In March 2019, 21 contractors started operations on 21 lots which add up to 12 of the 67 polluted sites recorded in the UNEP report. At the same time, medical outreach and livelihood programmes started. The process to select contractors to work on nine additional polluted sites was completed in January 2020. Although remediation works continue to progress, challenges remain. These include re-pollution, lack of contractor funding, land disputes and security issues in Ogoniland. The UNEP continues to monitor the success of the clean-up exercise via its observer status at both the Governing Council and the Ogoni Trust Fund. Its agencies such as UNDP, UNITAR and UNOPS provide services to HYPREP in the area of livelihood programmes, training and project services.

HYDRAULIC FRACTURING

Shale oil and gas resources are a critical part of a modern energy system. These resources are not only abundant and affordable, but offer options to scale up and down investment in the development of these resources. According to US Energy Information Administration (EIA) estimates, there are 7,576.6 trillion cubic feet of unproven technically recoverable wet shale gas resources and 418.9 billion barrels of unproven technically recoverable tight oil resources spread across 46 countries. We believe development of these resources is critical for meeting the energy needs of growing societies around the world.

The oil and gas industry has used hydraulic fracturing to unlock tight/shale oil and gas resources in vertical wells for decades. In the past 20 years, hydraulic fracturing has also been used in horizontal wells to recover natural gas and oil. The technology has opened up vast resources that were previously thought to be unrecoverable. Hydraulic fracturing has been used by the industry in more than 2.5 million oil and gas wells, many of them in the USA. Hydraulic fracturing involves pumping a fluid that is typically 99.9% water and sand, and around 0.1% chemical additives into tight sand or shale rock at high pressure. This creates threadlike fissures – typically the diameter of a human hair – in the rock, creating space through which the hydrocarbons can flow more easily.

At Shell, we believe we can explore, develop and produce tight/shale oil and gas resources safely and responsibly. Our operations are underpinned by our Principles for Producing Tights/Shale Oil and Gas (known as Onshore Operating Principles) that provide a framework for protecting the environment and the communities in which we operate. Our operating principles cover safety, air quality, water protection and usage, land use and engagement with local communities. We review the Onshore Operating Principles annually and update them as new technologies, challenges and regulatory requirements emerge. We also support appropriate and fit-for-purpose regulations.

The availability and quality of water, the local environmental conditions and the regulatory requirements vary from basin to basin. Therefore, we develop a tailor-made water management strategy for each of our shale assets, identifying short and long-term water needs, options for water sourcing, recycling and sharing, options for treatment and disposal, and options for transportation and storage. We aim to minimise the use of water in our shale operations. Depending on local hydro-geologic conditions, we typically use a combination of fresh water, brackish groundwater, produced water and waste water. We actively strive to reduce and ideally eliminate our freshwater intake for our drilling and hydraulic fracturing operations by increasing our recycling capacity and using municipal water.

Potable groundwater aquifers are isolated from the hydrocarbon-producing shale formations by several thousand feet of impermeable rock. However, we often need to drill through potable groundwater aquifers to reach shale formations. Therefore, we design our drilling, hydraulic fracturing and production activities in a way that aims to maintain isolation from potable groundwater aquifers. Before we drill a well, we conduct a hazard assessment to analyse risks to groundwater aquifers and develop control measures to reduce those risks. When we drill, we have at least two physical barriers, consisting of steel casing and cement, between the well bore and potable groundwater aquifers. We continuously monitor wellbore integrity before, during and after hydraulic fracturing and during production activities.

Chemical additives are needed in the hydraulic fracturing fluid to carry sand, reduce friction and prevent the growth of bacteria. Since 2015, we have optimised the composition of our hydraulic fracturing fluids. As a result, we have reduced chemical additive volumes by around 50-60%. Currently, on a volume basis, about 0.1% of our hydraulic-fracturing fluid is chemical additives. We support full disclosure of the chemical additives used in hydraulic-fracturing fluids for Shell-operated wells. Find more information about our water management practices, such as the "Onshore Operating Principles in Action: Water Fact Sheet", on our webpage.

SEISMICITY

As oil and gas fields mature, seismic activity may increase in certain circumstances based on the unique geology of individual fields. For example, production from the onshore Groningen gas field in the Netherlands is in the process of being closed down due to earthquakes induced by the gas production. Some of these earthquakes have caused damage to houses and other structures in the region, resulting in complaints, claims and lawsuits from local house owners and residents. A range of actions have been taken to improve safety, liveability and economic prospects in the region. The gas field is operated by the Nederlandse Aardolie Maatschappij B.V. (NAM, Shell interest 50%). NAM is working with the Dutch government and other stakeholders to fulfil its obligations to residents of the area, which include compensation for damage caused by the earthquakes.

📄 See "Upstream" on page 52.

Overall, we believe there is a relatively low likelihood of hydraulic fracturing or produced water disposal well operations inducing seismicity that is felt on the surface. Shell, however, still takes precautionary measures around induced seismicity, and proactively manages the risk in accordance with, and sometimes beyond, regulatory requirements. We have added induced seismicity to our Onshore Operating Principles and developed internal guidelines that we apply to our shale assets. They outline a risk assessment process and provide a framework for risk management. Subsurface and surface conditions vary from basin to basin, which means that management practices need to reflect the risk profile of each basin and provide customised responses to the risks. We support fit-for-purpose, science-based state and provincial regulations. Find more information about our induced seismicity management practices, such as the "Onshore Operating Principles in Action: Induced Seismicity Fact Sheet", on our webpage.

ENVIRONMENTAL COSTS

We are subject to a variety of environmental laws, regulations and reporting requirements in the countries where we operate. Infringing any of these laws, regulations and requirements could harm our reputation and ability to do business, and result in significant costs, including clean-up costs, fines, sanctions and third-party claims.

Our ongoing operating expenses include the costs of avoiding unauthorised discharges into the air and water, and the safe disposal and handling of waste.

We place a premium on developing effective technologies that are also safe for the environment. However, when operating at the forefront of technology, there is always the possibility that a new technology has environmental impacts that were not assessed, foreseen or determined to be harmful when originally implemented. While we believe we take reasonable precautions to limit these risks, we are subject to additional remedial environmental and litigation costs as a result of our operations' unknown and unforeseen impacts on the environment. Although these costs have so far not been material to us, no assurance can be given that this will always be the case.

SECURITY

Our operations expose us to criminality, civil unrest, activism, terrorism, cyber disruption and acts of war that could have a material adverse effect on our business (see "Risk factors" on pages 27-36). We seek to obtain the best possible information to enable us to assess threats and risks. This includes building strong and open relationships with government security agencies. Mitigation thereafter includes the strengthening of the security of sites, reduction of our exposure as appropriate, journey management, information risk management as well as crisis management and business continuity measures. We conduct training and awareness campaigns for staff, and provide travel advice and 24/7 assistance while travelling. The identities of our employees and contract staff and their access to our sites and activities, both physical and logistical, are consistently verified and controlled. We manage and exercise crisis response and management plans.

CONTRIBUTION TO SOCIETY

In 2019, Shell paid more than \$61.3 billion to governments (2018: \$64.1 billion). We paid \$7.8 billion in income taxes and \$5.9 billion in government royalties, and collected \$47.6 billion in excise duties, sales taxes and similar levies on our fuel and other products on behalf of governments. In 2019, Shell spent \$44.9 billion (2018: \$42.7 billion) on goods and services from 29,361 suppliers globally. Find more information about our approach to tax and transparency in the Tax Contribution Report, and to local content on our webpage.

NEIGHBOURING COMMUNITIES

Engaging with communities is part of our approach to managing human rights and providing access to remedy. Our global requirements for social performance aim to ensure that we operate in a responsible way, by avoiding or minimising the negative social impacts of our operations. They also help us maximise the benefits of our activities, such as employment and contractual opportunities that can support local economies.

These requirements set clear rules and expectations for how we engage with and respect communities that may be impacted by our operations. We require Shell-operated major projects and facilities to have a social performance plan that defines actions for managing potential negative and positive impacts on the communities where they operate. Integral to these plans are the identification of the social environment, the stakeholders who may be vulnerable to the operations, and an appropriate community feedback mechanism for listening and responding to queries, or resolving complaints, in a timely manner. We have specific requirements to avoid, minimise or mitigate potential impacts on indigenous peoples' traditional lifestyles, cultural heritage or involuntary resettlement.

ENVIRONMENT AND SOCIETY continued

We have a network of about 100 community liaison officers (CLO) installed locally to act as a bridge between local communities and our businesses. The CLOs man our community centres on workdays, receiving visitors to listen to questions or complaints. Members of the community can also contact CLOs via dedicated telephone lines. It is their task to take any concerns back to the Shell facility and involve people who are best placed to take action. We are using a tool based on the United Nations Guiding Principles' criteria to measure the effectiveness of our operational community feedback mechanisms.

For example, in Berat, southern Albania, our activities caused traffic to rise, which resulted in dust pollution and caused health concerns for the local community. Shell set up a community centre with a CLO who brought the concerns to the attention of the Shell Upstream Albania leadership team. Three initiatives were implemented: traffic calming measures, dust suppression using environmentally friendly chemicals, and increasing the frequency of watering to mitigate and minimise the impacts of dust. Find more information about our work with communities on our webpage.

HUMAN RIGHTS

Human rights are fundamental to Shell's core values of honesty, integrity and respect for people. Respect for human rights is embedded in our Shell General Business Principles and in our Code of Conduct. Our approach is informed by the Universal Declaration of Human Rights, the core conventions of the International Labour Organization and the United Nations' Guiding Principles on Business and Human Rights. Our joint-venture partners are expected to implement our control framework or an equivalent.

We work closely with other companies and non-governmental organisations to improve the way we apply these principles. Our focus is on four priority areas where respect for human rights is critical to the way we operate: communities, security, labour rights, and supply chain. In each of those areas, we have systems in place to identify potential impacts and to avoid and mitigate them. For example, our HSSE & SP Control Framework contains our mandatory standards and manuals that set out how we identify, assess, and manage our impacts on communities where we operate – including any impact on human rights. We require all our companies and our contractors to respect the human rights of our workforce and our neighbouring communities.

One of the Board committees, the Safety, Environment and Sustainability Committee, has the responsibility to review the standards, policies and conduct of the Company relating to the application of the Shell General Business Principles including sustainable development, and review the effectiveness of the compliance programme, including compliance with the Code of Conduct which includes Shell's responsibility to respect human rights. The overall accountability for sustainability within Shell lies with the Chief Executive Officer and the Executive Committee. A cross-functional Human Rights Working Group advises on and supports the implementation and review of our approach to human rights. The group includes an external advisor. A steering committee composed of senior executives oversees the work of the Human Rights Working Group.

Our approach to due diligence is informed by the UN Guiding Principles on Business and Human Rights. Due diligence in each focus area is typically exercised in areas where there may be a risk of impact to people, and is supported by experts internally. We recognise the role of due diligence in bringing our commitments to life. For example, in our supply chains, we engage contractors and suppliers deemed to be at higher risk for labour rights issues to undertake assessments of their management system prior to the award of a contract. Results of these supplier assessments are evaluated, and where gaps are found, we may work with suppliers and contractors to help them implement corrective action. We may also carry out on-site audits or consider terminating contracts if serious or persistent shortcomings are found. The most common shortcomings found during our supplier assessments typically relate to policy rather than performance gaps in the following areas: freely chosen employment; child labour avoidance; working hours, wages and benefits; dormitory, housing and working conditions; humane treatment, equal opportunities and freedom of association; and supply chain and performance management. In conjunction with the Shell Supplier Principles, Shell companies use a joint industry supplier capability assessment delivered in collaboration with other operators. The sharing mechanism across the participating parties aims to support the improvement of working conditions in our companies' respective supply chains. Find more information about our approach to human rights on our webpage.

CLIMATE CHANGE AND ENERGY TRANSITION

Shell has long recognised that greenhouse gas (GHG) emissions from the use of fossil fuels are contributing to the warming of the climate system. In December 2015, 195 nations adopted the Paris Agreement.

We welcomed the efforts made by governments to reach this global climate agreement, which came into force in November 2016. We fully support the Paris Agreement's goal to keep the rise in global average temperature this century to well below two degrees Celsius (2°C) above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5°C. In pursuit of this goal, we also support the vision of a transition towards a net-zero emissions energy system. Shell agrees with the Intergovernmental Panel on Climate Change (IPCC) 1.5°C special report, which states that in order to limit warming to 1.5°C above pre-industrial levels, the world economy would need to transform in a number of complex and connected ways. Meeting this challenge would require an even more rapid escalation in the scale and pace of change in the coming decades than was foreseen in the Paris Agreement.

Society faces a dual challenge: how to transition to a low-carbon energy future to manage the risks of climate change, while also extending the economic and social benefits of energy to everyone on the planet. This is an ambition that requires, among other things, changes in the way energy is produced, stored, used and made accessible to more people while drastically cutting emissions.

We believe that the need to reduce GHG emissions, will continue to be an important driver in transforming the energy system in this century. This transformation will generate both challenges and opportunities for our existing and future portfolio.

We welcome and support efforts, such as those led by the Task Force on Climate-related Financial Disclosures (TCFD), to increase transparency and to promote investors' understanding of companies' strategies to respond to the risks and opportunities presented by climate change. We believe that companies should be clear about how they plan to be resilient in the energy transition. In 2017, we joined the Oil and Gas Preparer Forum, initiated by the TCFD and convened by the World Business Council for Sustainable Development. The forum's objectives are to review the current state of climate-related financial disclosures, to identify examples of effective disclosure practices and make proposals on how disclosures may evolve over time. These examples were summarised and published in a report, including reflections from investors, in 2018. The Shell Energy Transition Report (SET report), also published in 2018, described the energy transition and considered Shell's resilience against future scenarios. The 2018 SET report followed our discussions with the TCFD about increasing transparency to help investors understand climate-related risks and opportunities. Our approach to the energy transition as described in the 2018 SET report, in combination with the Shell Sustainability Report (expected to be published in April 2020) and the Industry Associations Climate Review, aims to provide additional information to this Report in responding to TCFD recommendations, including discussing the energy transition and Shell's portfolio resilience. In 2019, Shell publicly supported the EU Commission's proposal for the EU to achieve net-zero emissions by 2050, the UK government's target of net-zero emissions by 2050, and the Climate Accord in the Netherlands.

OUR GOVERNANCE AND MANAGEMENT OF CLIMATE CHANGE RISKS AND OPPORTUNITIES

Climate change and risks resulting from GHG emissions have been identified as a significant risk factor for Shell and are managed in accordance with other significant risks through the Board and Executive Committee.

📖 **"Other regulatory and statutory information" on page 169.**

Shell has a climate change risk management structure in place which is supported by standards, policies and controls.

This includes the work of the Board, which discussed a number of matters over the year, including environmental topics and investments in new business areas, for example, in New Energies. In addition, some of the Non-executive Directors received dedicated updates from management and external experts on the various business models, opportunities and risks of having positions along the power value chain, and the opportunities for Shell in the New Energies area. During the annual dedicated strategy meeting, the Board reviewed Shell's Integrated Power strategy from first principles, set against the context of the energy transition and the external environment, and to see how power can create value for Shell.

The Board committees play an important role in assisting the Board with regard to governance and management of climate change risks and opportunities, as described in "Governance" on page 119.

The role of the Safety, Environment and Sustainability Committee (SESCo) (formerly the Corporate and Social Responsibility Committee (CSRC)) is to review and advise the Board on Shell's strategy, policies and performance in the areas of safety, environment, ethics and reputation against the Shell General Business Principles, the Shell Code of Conduct, and the HSSE & SP Control Framework. During 2019, the Committee reviewed its purpose and updated its terms of reference to ensure it focuses on areas of most strategic importance to Shell. This resulted in a name change effective from December 2019. The SESCO's duties comprise, for example, to review progress towards meeting Shell's ambitions regarding climate change, the energy transition and its Net Carbon Footprint. The Committee also has a duty to advise the Remuneration Committee on metrics relating to sustainable development and energy transition. In 2019, the SESCO balanced its time between a number of topics, with discussion in depth including the energy transition and climate change, Shell's Net Carbon Footprint ambition, and the Company's environmental and societal licence to operate. The SESCO conducted one major site visit in Singapore, where the agenda included reviewing Shell's developing New Energies businesses in the country. In 2020, the Committee's focus will be on safety, Shell's policies and commitments related to climate change, environmental performance – for example, in Nigeria and our Canada LNG project – and on specific issues such as plastics, methane, and nature-based solutions. We will continue to advise the Remuneration Committee on metrics concerning sustainability and energy transition.

📖 **Find more information on the SESCO on page 128.**

CLIMATE CHANGE AND ENERGY TRANSITION continued

The Remuneration Committee (REMCO) is responsible for determining the Directors' Remuneration Policy in alignment with our business strategy. In 2019, following recommendations by SESCO, REMCO continued to include GHG intensity metrics in annual bonus performance measures and targets. In December 2018, Shell announced plans to link executive remuneration to short-term targets to reduce the Net Carbon Footprint of the energy products we sell, including our customers' emissions from their use of our energy products. In 2019, following discussions with major shareholders and based on recommendations from SESCO, REMCO decided to add an energy transition condition to the 2019 Long-Term Incentive Plan (LTIP) award. This condition included our first three-year target aligned with the trajectory of our long-term Net Carbon Footprint ambition. It also featured other measures linked to our strategic ambitions, including the growth of Shell's power business, the commercialisation of advanced biofuel technology, and the development of sinks to capture and store carbon. See "Directors' Remuneration Report" on pages 155-163. The Shell employee scorecard structure for determining employees' annual bonus in 2019 was consistent with the Executive Directors' scorecard. The energy transition condition in the 2019 LTIP awards applies to around 150 Senior Executives as well as the Executive Directors. The energy transition condition was included again in the 2020 LTIP awards for Executive Directors and Senior Executives, and will be extended to approximately 16,500 employees across the Group who receive Performance Share Plan awards. For the 2020 award, the target range is a 3-4% reduction in NCF against the 2016 baseline NCF (79 grams of CO₂ equivalent per megajoule). This target range is aligned with the trajectory of our NCF ambition as set out in November 2017. The targets for the other leading energy transition measures are commercially sensitive, and will be disclosed retrospectively. Annual updates on our progress in relation to measures will be provided.

The Audit Committee has key responsibilities in assisting the Board in fulfilling its oversight responsibilities in relation to areas such as the effectiveness of the system of risk management and internal control. Any concerns regarding improvement needed are promptly reported to the Board.

The CEO is the most senior individual with accountability for climate change risk. We have set up several dedicated climate change and GHG-related forums at different levels of the organisation where climate change issues are addressed, monitored and reviewed. Each Shell entity and each Shell-operated venture are responsible for implementing climate change policies and strategies.

The Executive Vice President Safety & Environment, a senior manager who reports directly to the Projects & Technology Director, is accountable for the oversight of GHG issues. This manager's department includes the dedicated Group Carbon team, which is accountable for monitoring and examining the strategic implications of climate change for Shell, and the impact of developments in governmental policy and regulation. The Group Carbon team is responsible for preparing proposed policy positions based on analysis within Shell and external input. The team also provides advice to Shell companies to ensure consistency in the application of our core principles and policy tasks in interactions with policymakers.

Group Carbon also has oversight of Shell's GHG management programme and supports the different lines of business in embedding GHG management strategies. The team includes project managers who advise the projects on the risks and opportunities of GHG-related issues. Risk management at an asset or project level is a structured process of identifying and assessing risks; planning and implementing responses; and monitoring, improving and closing out action items that have an impact on projects' and assets' objectives and performance. Shell policy requires these projects to obtain approval on abatement plans and targets from the Executive Vice President Safety & Environment at defined project phases.

Reporting to the same manager is the HSSE & SP Assurance and Reporting team, which is accountable for the delivery of Shell's non-financial reporting and for auditing the businesses' performance against our HSSE & SP Control Framework requirements, which include climate change risk management.

See "Environment and society" on pages 84-90.

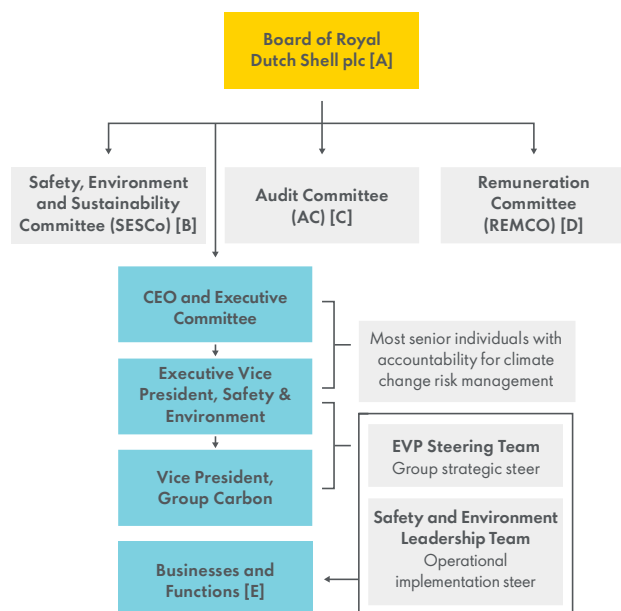
Further support for embedding GHG management is provided by a global risk support team for GHG and energy management. This team is a network of subject-matter experts in GHG topics working globally across our lines of business. Team members are experts in their relevant disciplines, defining improvement areas and sharing good practices and experience.

The above-mentioned teams and experts have provided their input to shape a set of mandatory manuals and complementary guidance documents which are ultimately based on our HSSE & SP Control Framework. These documents provide guidance on how to monitor, communicate and report changes in the risk environment, and how to review the effectiveness of actions taken to manage the identified risks, including ways to:

- ensure consistent assessment of climate risk across Shell;
- clarify expectations for risk management and reporting, including roles and responsibilities;
- strengthen decision-making through better visibility and understanding of the climate risk by line of business; and
- enable integration of Shell's reporting.

For more detail on our definition of risk categories and their relationship to different time horizons, see page 96.

Climate change management organogram



[A] Oversight of climate change risk management.

[B] Non-executive Directors appointed by the Board to review and advise on sustainability policies and practices including climate change.

[C] Non-executive Directors appointed by the Board to oversee the effectiveness of the system of risk management and internal control.

[D] Non-executive Directors appointed by the Board to set the remuneration policy in alignment with strategy.

[E] Responsible for implementing Shell's GHG strategy. They are represented in the Safety and Environment Leadership Team.

This structured approach supports the prioritisation of risks and opportunities. We actively monitor the GHG emissions of all our assets, as well as the lifecycle of our products, to quantify future regulatory costs related to GHG or other climate-related policies. This allows us to effectively prioritise areas of greater concern and assess mitigation options and the most viable responses. Climate-related risks are analysed in context of other identified material risks.

📖 See “Risk factors” on pages 27-36.

We review our portfolio annually to identify emerging risks from changing GHG regulatory regimes and physical conditions. As described in our Shell Energy Transition Report (2018), we tested the resilience of our portfolio against externally published future pathways, including a low-emissions pathway. In 2017, we announced a long-term ambition to reduce the Net Carbon Footprint of the energy products we sell, in step with society's drive to reduce GHG emissions as it moves towards the goal of the Paris Agreement. We aim to reduce the Net Carbon Footprint of the energy products we sell – expressed in grams of CO₂ equivalent per megajoule consumed – by around half by 2050, and as an interim step, by 2035, we aim for a reduction of around 20% compared with our 2016 level, both predicated on societal progress. This was followed by an announcement, in 2018, of our intention to set short-term targets in line with that ambition.

Meeting the Net Carbon Footprint ambition requires evolving our portfolio over the medium to longer term, to reduce the carbon intensity of the products that we sell. We plan for this by developing ideas about how we would like to shape our future portfolio to meet our ambition. These ideas then guide investment decisions. Within the selected portfolio mixes, we develop individual projects and aim to make them as resilient as possible to the future scenarios.

To assess the resilience of new projects, we consider the potential costs associated with operational GHG emissions. In 2018, to help us stay in step with society's progress toward the goals of the Paris Agreement, we switched from using a flat project screening value (PSV) of \$40/tonne of GHG emissions, to country-specific estimates of future carbon costs. By 2050, our carbon cost estimates for all countries increase to \$85/tonne of GHG emissions. These estimates were developed using the current Nationally Determined Contributions (NDCs) submitted by countries as part of the Paris Agreement. They are the first NDCs under the Paris Agreement and are scheduled to be revised every five years. Therefore, as countries update their NDCs, we expect to update our estimates too. Accordingly, we believe they are a more accurate reflection of society's current implementation of the Paris Agreement. The UN believes the current NDCs are consistent with limiting the average global temperature rise to around three degrees Celsius above pre-industrial levels. In coming decades, we expect countries to tighten these NDCs to meet the goals of the Paris Agreement. We further test the robustness of our high-emitting projects by using long-term carbon cost estimates that are consistent with limiting the average global temperature rise to well below two degrees Celsius.

Projects under development that are expected to have a material GHG footprint must meet carbon performance standards or industry benchmarks to allow them to compete and prosper in a more GHG-constrained future. These assessments can lead to projects being stopped, designs being changed, and potential GHG mitigation investments being identified, in preparation for when regulation would make these investments commercially compelling. Our approach continues to evolve with the shifting policy landscape and the differing pace of energy transitions in different regions.

While monitoring emerging climate change plans, we considered the robustness of our activities against a range of scenarios, as referenced in our 2018 SET report. We believe our business strategy is resilient to the implementation of the Paris Agreement, which is now progressing through countries developing their individual NDCs. The emissions from customers using Shell energy products are largely covered by these NDCs. The Paris Agreement acknowledges that emissions will continue and even grow in some parts of the world. It does not stipulate that emissions must fall in all sectors or countries simultaneously, or that all actors within the system will reduce their emissions at the same time or to the same degree. What is important is that overall emissions fall.

OUR PORTFOLIO AND CLIMATE CHANGE

We are seeking cost-effective ways to manage GHG emissions in line with our NCF ambition, and we intend to enable customers to make lower-carbon-intensity choices by bringing lower-carbon-intensity products to the market aligned with demand. We seek to contribute to reducing global GHG emissions in a number of ways:

- supplying more natural gas to replace coal for power generation;
- developing carbon capture and storage (CCS);
- implementing energy-efficiency measures in our operations where reasonably practicable;
- developing new fuels for transport such as advanced biofuels and hydrogen;
- maintaining a focus on using natural gas and renewable electricity to generate power; and
- working with nature-based solutions.

To support this, we continue to advocate the introduction of effective government-led carbon pricing mechanisms.

We are committed to reducing our GHG intensity, but with energy demand increasing and the number of easily accessible oil and gas reservoirs declining, we may develop resources that require more energy and advanced technologies to produce. If our production becomes more energy intensive, this could result in an associated increase in direct GHG emissions from our upstream facilities. We continue to invest in long-range research and carbon-abatement technologies to provide technical solutions to address these challenges.

Some governments have introduced carbon pricing mechanisms, which we believe can be an effective measure to reduce GHG emissions across the economy at lowest overall cost to society. We expect more governments to follow. However, we believe measures taken by governments to control national energy transitions may also have unintended consequences. For example, the prohibition of one technology may encourage other substitute technologies that result in an increase in overall GHG emissions. See “Risk factors” on page 30.

NATURAL GAS

According to the IEA, more than 40% of global CO₂ emissions in 2015 came from electricity and heat generation. For many countries, using gas instead of coal in power generation can make a large contribution, at lower cost, to meeting GHG emission reduction objectives. We expect that, in combination with renewables and the use of CCS, natural gas will be essential in significantly lowering GHG emissions. Natural gas made up more than half of Shell's proved reserves at the end of 2019. As a leader in liquefied natural gas (LNG), and with our conventional gas assets and technologies for recovering gas from tight-rock formations, we can supply natural gas to replace coal for power generation. Natural gas can also act as a partner for intermittent renewable energy, such as solar and wind, to maintain a steady supply of electricity, because gas-fired plants can start and stop relatively quickly.

CLIMATE CHANGE AND ENERGY TRANSITION continued

Methane is a potent greenhouse gas. When released into the atmosphere, it has a much higher global warming impact than CO₂. Natural gas consists mainly of methane. Efforts to address climate change therefore require the industry to reduce both deliberate and unintended methane emissions from the gas value chain, from production to the final consumer.

The IEA estimates that natural gas operations have an average methane leakage rate of 1.7%. At this rate, natural gas emits between 45% and 55% less GHG emissions than coal when burnt at a power plant. Higher levels of methane emissions, however, would reduce this benefit, and we recognise the importance of assessing, and where possible, reducing methane emissions. Methane from the flaring and venting of gas (including equipment venting) in our upstream oil and gas operations was the largest contributor to our reported methane emissions in 2019. We are working to reduce methane emissions from these sources by reducing the overall level of flaring and venting. We also continue to implement leak detection and repair programmes across our sites to identify unintended losses and high-emission equipment, such as high-bleed pneumatic devices, so they can be replaced or repaired. We continue to work on confirming that we have identified all potential methane sources and that we have reported our emissions from these sources in line with regulations and industry standards. In 2017, we joined the Climate and Clean Air Coalition Oil & Gas Methane Partnership. It brings together industry, governments and non-governmental organisations to improve quantification of methane emissions globally and work towards reducing them. Also in 2017, Shell led the development of a set of non-binding Methane Guiding Principles for reducing methane emissions across the natural gas value chain. The principles focus on: continually reducing methane emissions; advancing strong performance across gas value chains; improving accuracy of methane emissions data; advocating sound policies and regulations on methane emissions; and increasing transparency. Shell has been involved in the development of all actions associated with the guiding principles, including the development of a major global outreach programme. The objective is to address a gap in knowledge on managing methane emissions, and thereby provide high-quality educational material and courses on methane science, methane reduction strategies and planning, measurement techniques, technology, policy, and where to get guidance and support. The publicly accessible programme consists of two courses: an executive course targeting senior managers and executives, and masterclasses for managers of frontline staff.

Shell is also a member of the Oil and Gas Climate Initiative (OGCI), a CEO-led effort to lead the industry's response to climate change. One of OGCI's focus areas is methane management. In 2018, OGCI announced a target to reduce the collective average methane intensity of its members' aggregated upstream gas and oil operations by one fifth, to below 0.25% by 2025, with an ambition to achieve 0.2%, corresponding to a reduction of one third.

In 2018, Shell announced a target to maintain its methane emissions intensity below 0.2% by 2025. This target covers all Shell-operated Upstream and Integrated Gas oil and gas facilities. The baseline and target intensities are expressed as percentage figures, representing estimated methane emissions from Shell-operated gas and oil facilities as a percentage of the total amount of gas marketed, or the quantity of marketed oil and condensate where facilities have no marketed gas (e.g. those that re-inject produced gas). Methane emissions include those from unintentional leaks, venting and incomplete combustion, for example in flares and turbines. In 2019, our overall methane intensity was 0.08% for

facilities with marketed gas and 0.01% for facilities without marketed gas. Intensities at facility level ranged from below 0.01% to 1.3%. We believe our methane emissions are calculated using the best methods currently available: a combination of industry standard emission factors (established emission rates per throughput or per piece of equipment), engineering calculations and some actual measurements. There are uncertainties associated with methane emissions quantification. To reduce these uncertainties, our Upstream and Integrated Gas businesses are rolling out methane improvement programmes to further enhance data quality and reporting, continue implementation of leak detection and repair programmes, and make use of methane abatement opportunities. By 2025, all Shell-operated facilities are expected to have implemented more robust quantification methodologies. Externally, we continue to work on new technologies and improved quantification methods through partnerships and several other initiatives.

Detailed information on our approach to managing methane emissions and performance is expected to be published in the Shell Sustainability Report in April 2020.

CARBON CAPTURE, UTILISATION AND STORAGE

CCS or CCUS is a technology used for capturing CO₂ before it is emitted into the atmosphere, then transporting it by pipelines or ships and injecting it into a deep geological formation for permanent storage. In the IPCC Global Warming of 1.5°C special report, the middle-of-the-road scenario (P3) shows cumulative abatement provided by CCS of 687 billion tonnes of CO₂ by 2100. This compares with over 260 million tonnes of man-made CO₂ that has been injected to date (Global Status of CCS 2019 report). By May 2019, our Quest CCS project in Canada (Shell interest 10%), had captured and safely stored more than 4 million tonnes of CO₂ since it began operating in 2015. The Gorgon CCS project in Australia (Shell interest 25%, not operated), which started operating in 2019, is expected to store between 3.4 and 4 million tonnes of CO₂ each year. In Norway, we are involved in the Northern Lights CCS project for capturing and storing industrial CO₂, and in TCM, a CO₂ capture test centre in Mongstad.

As a member of the Oil and Gas Climate Initiative (OGCI), Shell is participating in its Kickstarter initiative to unlock large-scale investment in CCUS. The initiative is designed to help decarbonise multiple industrial hubs around the world, starting with those in the USA, UK, Norway, the Netherlands and China. The aim is to create the necessary conditions for a commercially viable, safe and environmentally responsible CCUS industry. Shell is one of six strategic partners working with OGCI Climate Investments to possibly develop the UK's first commercial clean gas power full-chain CCS project, to be located in Teesside as part of the UK hub.

ENERGY EFFICIENCY

We continue to work on improving energy efficiency at our oil and gas production facilities, refineries and chemical plants. Measures include our GHG and energy management programme that focuses on the efficient operation of existing equipment. This means, for example, using monitoring systems which give us real-time information that we can use to make energy-saving changes and identify opportunities for energy-saving investments in the medium term. Shell's scorecard incorporates GHG metrics that create additional incentives for all our employees to reduce GHG emissions in our portfolio.

See "Directors' Remuneration Report" on [page 155-163](#).

NEW ENERGIES

Our New Energies business explores emerging opportunities linked to the energy transition, and invests in those where we believe sufficient value is available. New Energies expects to invest on average \$1-2 billion a year until 2020 in different services and products from a range of cleaner sources. We focus on new fuels for transport, such as advanced biofuels, hydrogen and charging for battery-electric vehicles; and power, including from low-carbon sources such as wind and solar as well as natural gas. Between 2021 and 2025, our investments in power could grow to \$2-3 billion a year on average, if certain financial conditions are met. Alongside our work in new fuels and power, we are exploring how digital technologies can best support our activities and customers.

See “Integrated Gas” on page 49.

New fuels

We invest in a range of low-carbon technologies and fuels, including biofuels, hydrogen and battery-electric vehicle charging. We believe that hydrogen has the potential to be an important low-carbon transport fuel. We are involved in several initiatives to encourage the adoption of hydrogen-electric energy.

See “Integrated Gas” on page 50.

Biofuels

We believe that biofuels can play a valuable role in reducing CO₂ emissions from the transport sector over the decades ahead.

In 2019, we used around 10.1 billion litres of biofuel in our gasoline and diesel blends worldwide to comply with applicable mandates and targets in the markets where we operate. Through our own long-established sustainability clauses in supply contracts, we request that the biofuels we buy are produced in a way that is environmentally and socially responsible throughout the production chain. Currently, most available biofuels are produced from cereals, vegetable oils and sugar cane. From cultivation to use, some biofuels can emit significantly less CO₂ compared with conventional gasoline. But this depends on several factors, such as how the feedstock is cultivated and the way biofuels are produced. Other challenges include concerns over labour rights, the amount of water used in the production process, and the competing demands for land use between biofuels and food crops.

Over three-quarters of the biofuels we buy are from North American or European feedstock producers. In both regions, regulations for agricultural practices are in place, including considerations for sustainability.

We continue to support the adoption of international sustainability standards, including the Round Table on Responsible Soy (RTRS), the Roundtable for Sustainable Palm Oil (RSPO) and Bonsucro, an organisation for the certification of sugar cane. We also support the Roundtable for Sustainable Biomaterials and the International Sustainability and Carbon Certification (ISCC) scheme for feedstocks. We aim to increase the percentage of certified volumes against these robust multi-stakeholder standards.

Currently, more than 99% of our purchased volumes of biofuels are either covered by our supplier-agreed contract sustainability clauses or certified as sustainable by an independent auditor. We aim to increase the percentage of certified volumes against robust multi-stakeholder standards.

Our Raízen joint venture (Shell interest 50%, not operated) in Brazil has produced low-carbon biofuel from sugar cane since 2011. Through our Raízen joint venture, we produce one of the lowest CO₂ biofuels available today. Raízen produces approximately 2 billion litres of ethanol from sugar cane annually. Brazilian sugar-cane ethanol can reduce CO₂ emissions by around 70% when compared with conventional gasoline, from cultivation of the sugar cane to using the ethanol as fuel.

In 2015, Raízen opened its first advanced biofuels plant at the Costa Pinto mill in Brazil. The technology was first developed from our funding of the Iogen Energy venture, which was subsequently transferred to Raízen. In 2019, the plant produced 19.5 million litres of cellulosic ethanol from sugar-cane residues. It is expected to produce 40 million litres a year once fully operational.

Outside Brazil, we continue to invest in new ways of producing biofuels from sustainable feedstocks, such as biofuels made from waste products or cellulosic biomass. In 2017, we completed construction of a demonstration plant at the Shell Technology Centre Bangalore, India. The plant demonstrates a technology called IH2® that turns waste feedstock into transport fuel. The plant can process around five tonnes per day of feedstock, such as agricultural waste, and aims to demonstrate the technology for possible scaling up and commercialisation.

We continue to look for opportunities to invest in third-party technologies and to collaborate in scaling these up for commercialisation. In February 2019, Shell became an equal equity partner in a commercial-scale waste-to-chemicals project called W2C Rotterdam – in partnership with Air Liquide, Enkern, Nouryon and the Port of Rotterdam. The partners plan to build Europe’s first commercial-scale facility for producing chemicals and biofuels from waste materials which cannot otherwise be recycled. The facility in the Botlek area of the Port of Rotterdam in the Netherlands will use Enkern’s proprietary technology.

Also in 2019, Shell signed an equity investment agreement with PRESPL, an Indian company specialising in biomass aggregation and processing for energy production.

In line with our strategy of developing more sustainable feedstocks for transport, we are also investing in renewable natural gas (RNG) for use in natural-gas-fuelled vehicles, in the USA and Europe. RNG is produced from biogas collected from landfill sites, or via anaerobic digestion of food waste or manure and then processed until it is fully interchangeable with conventional natural gas. The use of RNG in natural-gas vehicles, either in the form of compressed natural gas (CNG) or LNG, offers customers using these vehicles an attractive way of lowering their CO₂ footprint.

In the USA, in May 2018, we acquired the JC Biomethane plant in Junction City, Oregon. We aim to start production after completing an expansion of the facility in 2020. This will increase the facility’s capacity to produce RNG.

CLIMATE CHANGE AND ENERGY TRANSITION continued

Power

Power is the fastest-growing segment of the energy system. We expect that people and companies around the world will use more electricity to power transport and industry, instead of coal and oil, as part of the drive to lower carbon emissions. To help meet this demand, Shell aims to become an integrated power player and grow, over time, a material new business. We are working to deliver more electricity generated by renewable energy, from developing wind and solar projects to selling electricity generated by renewable sources.

See “Integrated Gas” on page 49.

NATURE-BASED SOLUTIONS

We believe that nature will play an important role in the transition to a lower-carbon world. Using nature to capture carbon from the atmosphere presents an immediate opportunity. It can help to bridge the gap until other low-carbon solutions are deployed at scale, or to compensate for emissions which cannot be avoided. Nature-based solutions are expected to be one of Shell’s tools to reduce our Net Carbon Footprint. Nature-based projects typically involve the protection or redevelopment of natural ecosystems such as forests and wetlands, allowing those ecosystems to capture and store more carbon on our behalf. These projects, which also support local communities and conserve biodiversity, generate carbon-emission rights that can then be bought by energy consumers around the world. In 2019, we launched a programme to invest in natural ecosystems as part of our strategy to act on global climate change. For example, in the UK, we are working with Forestry and Land Scotland, a government agency, to generate carbon credits by helping to plant or regenerate around 1 million trees over the next five years. See the Shell Sustainability Report to be published in April 2020 for more information.

OUR STRATEGY ON CLIMATE CHANGE

Our strategy to assess and manage risks and opportunities resulting from climate change includes consideration of different time horizons and specific risks:

- commercial risk: the potential for structural shifts in demand profiles for industry products;
- regulatory risk: the potential for strengthening of existing and introduction of new regulations;
- physical risk: the potential impact on our facilities and the communities in which we operate due to changing physical conditions; and
- societal risk: the potential for a deteriorating relationship with the public, other companies, and governments in countries where Shell operates.

This is how we describe the different time horizons and the relevance for the identification of risks and business planning:

- Short term (up to three years): detailed financial projections are developed and used to manage performance and expectations on a three-year cycle. This three-year plan is shared with the Board;
- Medium term (three years up to around 10 years): the majority of production and earnings expected to be generated in this period come from our existing assets; and
- Long term (beyond around 10 years): for this period, it is expected for the current Shell portfolio to go through changes and evolution with the energy transition. Decision-making and risk identification on the thematic structure of the future portfolio are guided by the pace of progress of society and in step with society as it moves towards the goals of the Paris Agreement.

Shell has a rigorous approach to understanding, managing and mitigating climate risks to its facilities. Shell also requires each business and function to monitor, communicate and report changes in the risk environment and the effectiveness of actions taken to manage identified risks on an ongoing basis. This is outlined in a toolkit for risk management including our Risk Management Manual and complementary guidance documents covering specific aspects such as climate risk. The potential, timing, and severity of the impact of the risks highlighted above are largely dependent on the geographical location and the asset type.

Each Shell business unit needs to consider the adequate management of climate-related risks in their portfolios. To ensure informed judgements are made, businesses’ senior managers present their current assessments of how likely climate risks are to happen, what their potential impact would be, and what is being done to mitigate the risk. Each risk is then categorised as either adequately managed or needing improved mitigation and this aims to guide their ongoing operations and maintenance schedules and response planning. In some instances, Shell may also deploy a risk assessment approach which includes the work of a team of experts to analyse, for example, the physical impact of weather and climatic-related issues and the associated adaptation aspects.

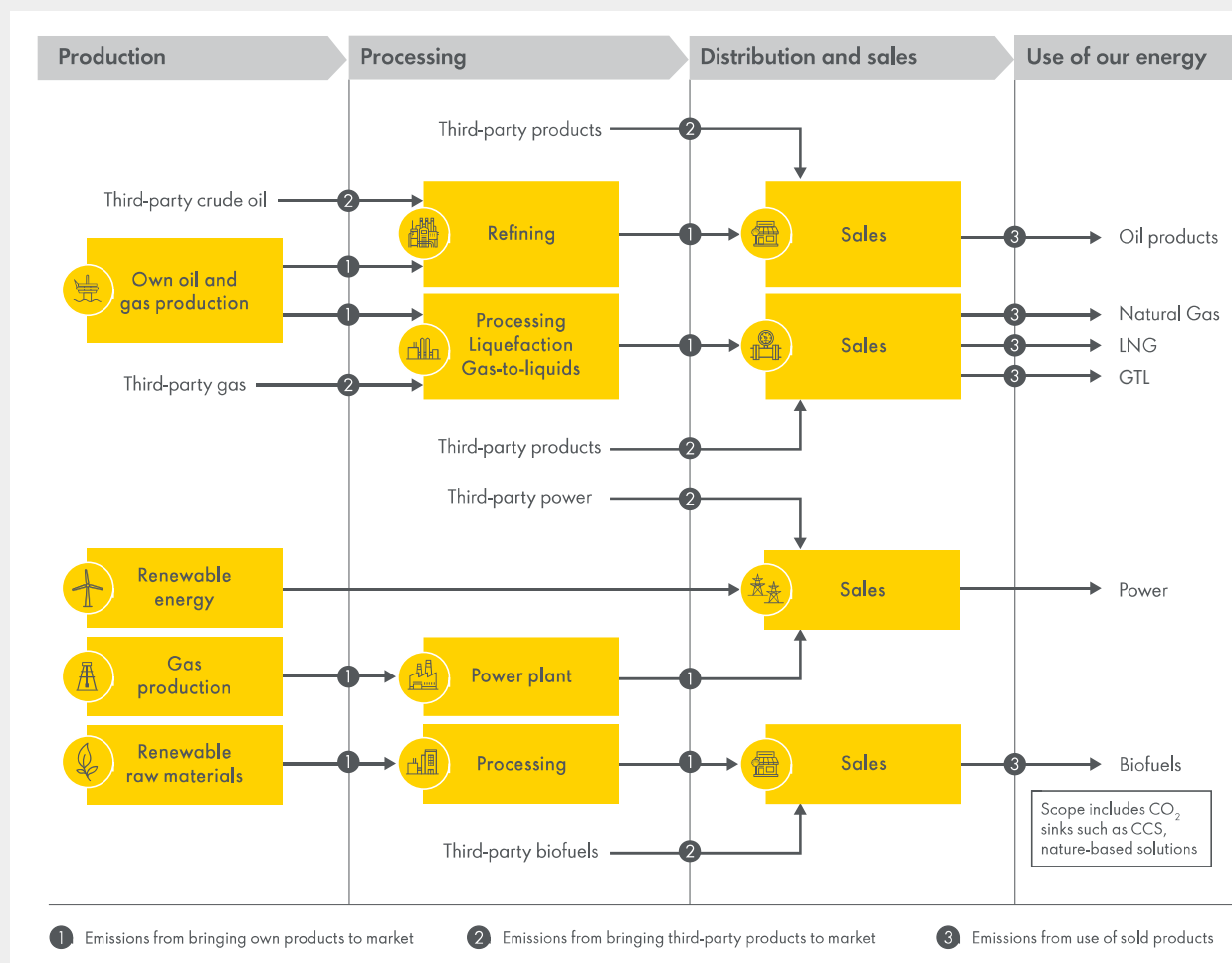
We aim to reduce the GHG intensity of our portfolio and we continue to work on improving the energy efficiency of our existing operations. As discussed above, and as a better way to inform and drive our investment choices and adapt our business over time, in 2017, we announced our Net Carbon Footprint ambition. Our approach to calculating the Net Carbon Footprint covers emissions directly from Shell operations (including from the extraction, transportation and processing of raw materials, and transportation of products), those generated by third parties who supply energy to us for production, and our customers’ emissions from their use of our energy products. Also included are emissions from elements of this life cycle not owned by Shell, such as oil and gas processed by Shell but not produced by Shell, or from oil products and electricity marketed by Shell that have not been processed or generated at a Shell facility. The calculation also includes biofuels, as well as emissions that we offset by using CCS or natural carbon sinks, such as forests and wetlands. Chemicals and lubricants products, which are not used to produce energy, are excluded from the scope of this ambition.

When selecting our Net Carbon Footprint ambition, we have deliberately chosen a wide and meaningful frame against which to manage our performance. The emissions from our operations are important but those of our customers from their use of the energy products are much larger in proportion. More information on our Net Carbon Footprint ambition is available on our webpage.

The diagram below illustrates the scope of the Net Carbon Footprint calculation:

Scope of our Net Carbon Footprint

Emissions from energy products included within the Net Carbon Footprint framework.



To meet the decarbonisation goals of the Paris Agreement, society needs an increasing supply of energy products that produce lower or zero GHG emissions over their full life cycle, to use those products more efficiently and to store emissions that cannot be avoided in sinks. Within this framework, our strategy is to keep increasing the share of such low-carbon energy products in our portfolio, while also developing carbon sinks. By broadening our focus to the full life-cycle emissions from the energy products that we sell to our customers, instead of solely on our operational emissions, we believe we will be better aligned with societal need and growing customer demand for more energy with lower life-cycle GHG emissions. Therefore, our strategy is to reduce our Net Carbon Footprint, mainly by increasing the proportion of lower-carbon products such as natural gas, biofuels, electricity and hydrogen in the mix of products we sell.

We will publish annual updates on our progress towards lowering the Net Carbon Footprint of our energy products. See the Shell Sustainability Report to be published in April 2020 for more information.

Our long-term ambition is to reduce the Net Carbon Footprint of our energy products to be in line with that of society as a whole by 2050. This is a stretching aspiration that aims to ensure that Shell continues to develop a resilient and relevant portfolio over the coming decades. While this is a long-term aspiration that will need periodic recalibration in line with the pace of change in broader society and the wider energy system, it is intended to help ensure that we remain relevant and are competitively positioned in the energy transition. This means supplying energy products and services that our customers need, now and in the future, and developing a resilient portfolio in line with our purpose of providing more and cleaner energy to society.

In the period to 2035, we believe that all forms of GHG reduction measures must be accelerated and increased in scale by society. Major improvements in energy efficiency and new sources of energy, such as renewables, combined with the use of cleaner fossil fuels, such as replacing coal with natural gas, are needed to meet the growing global population's energy needs while reducing GHG emissions. In addition,

CLIMATE CHANGE AND ENERGY TRANSITION continued

the world will need significant growth in CCS and sustained improvements in efficiency. Massive reforestation is also needed to limit temperature rises to 1.5°C. The management of GHG emissions is increasingly important to our shareholders as concerns over climate change lead to tighter environmental regulations. Policies and regulations designed to limit the increase in global temperatures to well below 2°C could have a material adverse effect on Shell – through higher operating costs and reduced demand for some of our products. We actively monitor and assess these potential developments and believe we are best able to manage them when local policies provide a stable and predictable regulatory foundation for our future investments. At this stage, industry is still facing significant uncertainty about how local regulatory policies and consumer behaviour will shape the evolution of the energy system and which technologies and business models will thrive.

In December 2018, we announced our intention to set short-term Net Carbon Footprint targets. In early 2020, it was decided to set a Net Carbon Footprint target for 2022 of 3-4% lower than our 2016 Net Carbon Footprint of 79 grams of CO₂ equivalent per megajoule. We have received third-party limited assurance on our Net Carbon Footprint for the years 2016 to 2019. For 2019, our Net Carbon Footprint was 78 grams of CO₂ equivalent per megajoule. The reduction in our Net Carbon Footprint was due to an increase in sales of electricity in markets with declining grid carbon intensity, and growth in customer demand for carbon-neutral product offerings.

OUR PERFORMANCE

Data in this section are reported on a 100% basis in respect of activities where we are the operator. Reporting on this operational control basis differs from that applied for financial reporting purposes in the “Consolidated Financial Statements” on pages 191-239. Detailed data and information on our 2019 environmental and social performance is expected to be published in the Shell Sustainability Report in April 2020.

Our direct GHG emissions decreased from 71 million tonnes of CO₂ equivalent in 2018 to 70 million tonnes of CO₂ equivalent in 2019. The main contributors to this decrease were divestments (for example in Argentina, Canada, Norway, Iraq, Malaysia and the UK). The level of flaring in our Upstream and Integrated Gas businesses combined increased by around 15%, compared to 2018, primarily as a result of the start-up of our Prelude floating liquefied natural gas installation in Australia and higher levels of flaring in Nigeria, partially offset by our Majnoon divestment in Iraq (mid-2018).

In 2015, we signed up to the World Bank’s Zero Routine Flaring by 2030 initiative. This is an important initiative to ensure that all stakeholders, including governments and companies, work together to address routine flaring. Flaring, or burning off, of gas in our Upstream and Integrated Gas businesses contributed around 8% of our overall direct GHG emissions in 2019. Around 25% of this flaring took place at facilities where there was no infrastructure to capture the gas produced with oil, known as associated gas.

Around 35% of flaring in our Upstream and Integrated Gas facilities in 2019 took place in assets operated by The Shell Petroleum Development Company of Nigeria Limited (SPDC). Flaring from SPDC-operated facilities fell by around 20% between 2015 and 2019. Flaring intensity levels in SPDC in 2019 increased by around 10% compared to 2018. SPDC continues to make progress in close collaboration with its joint-venture partners and the Federal Government of Nigeria towards the objective of ending the continuous flaring of associated gas. Two new gas-gathering projects (Adibawa and Otumara) came on stream at the end of 2017, followed by two more (the Forcados Yokri Integrated Project and Southern Swamp Associated Gas Gathering Solutions) in 2019.

GHG emissions data are provided below in accordance with UK regulations. GHG emissions comprise CO₂, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulphur hexafluoride and nitrogen trifluoride. The data are calculated using locally regulated methods where they exist. Where there is no locally regulated method, the data are calculated using the 2009 API Compendium, which is the recognised industry standard under the GHG Protocol Corporate Accounting and Reporting Standard. There are inherent limitations to the accuracy of such data. Oil and gas industry guidelines (IPIECA/API/IOGP) indicate that a number of sources of uncertainty can contribute to the overall uncertainty of a corporate emissions inventory.

Greenhouse gas emissions

	2019	2018
Emissions (million tonnes of CO ₂ equivalent)		
Direct [A]	70	71
Energy indirect [B]	10	11
Intensity ratio (tonne/tonne)		
All facilities [C]	0.24	0.24

[A] Emissions from the combustion of fuel and the operation of facilities, calculated using global warming potentials from the IPCC’s Fourth Assessment Report.

[B] Emissions from the purchase of electricity, heat, steam and cooling for our own use, calculated using a market-based method as defined by the GHG Protocol Corporate Accounting and Reporting Standard.

[C] In tonnes of total direct and energy indirect GHG emissions per tonne of crude oil and feedstocks processed and petrochemicals produced in Downstream manufacturing, oil and gas available for sale, LNG and GTL production in Integrated Gas and Upstream. Additional information by segment will be published on our webpage.

Detailed information on our 2019 GHG emissions is expected to be published in the Shell Sustainability Report in April 2020 and on our webpage.

The statements in this “Climate change and energy transition” section, including those related to Net Carbon Footprint, are forward-looking statements based on management’s current expectations and certain material assumptions and, accordingly, involve risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied herein.

See “About this Report” on pages 2-3 and “Risk factors” on pages 27-36.

OUR PEOPLE

Performing competitively in the evolving energy landscape requires competent and empowered people working safely together across Shell.

Employees



83,000

employees and a further 4,000 in certain New Energies and Downstream companies at December 31, 2019

Region



>70

countries in which we operate

Training



373,000

formal training days for employees and joint-venture partners

Female employees



31%

female employees

Directors



42%

women on the Board of Directors

Senior leaders



26%

women in senior leadership positions

Experienced hires



2,800

experienced people joined Shell (32% female)

Operations centre hires



3,600

recruited for Shell Business Operations centres (51% female)

Graduate hires



500

graduate hires (48% female)

All metrics except for the Employees metric exclude the 4,000 employees in certain New Energies and Downstream companies.

We recruit, train and recompense people according to a strategy that aims to organise our businesses effectively. Our people are essential to the successful delivery of the Shell strategy and to sustaining business performance over the long term. We accelerate development of our people; grow and strengthen our leadership capabilities; and enhance employee performance through strong engagement.

EMPLOYEE OVERVIEW

The employee numbers presented here are the full-time equivalent number of people employed by Shell on a full- or part-time basis, working in Shell subsidiaries, Shell-operated joint operations, seconded to non-Shell-operated joint operations, or joint ventures and associates.

At December 31, 2019, there were 83,000 employees in Shell and an additional 4,000 in certain New Energies and Downstream companies, compared with 81,000 at December 31, 2018, and 83,000 at December 31, 2017. The net increase in 2019 was driven by accelerated growth of the Information Technology hub in Bangalore, increased project activity in Projects & Technology, growth in Lubricants Asia, and growth in Customer Operations in Downstream Global Commercial. These changes were partly offset by reductions in Upstream and Integrated Gas which were driven by portfolio activities and our continued effort to improve operational efficiency and to reduce costs.

Further statements about employees in this section and data presented in the tables excludes the 4,000 employees in certain New Energies and Downstream companies. Note 26 to the "Consolidated Financial Statements" on page 237 provides the average number of employees by business segment.

Actual number of employees by geographical area

	Thousand		
	2019	2018 [A]	2017 [A]
Europe	24	24	24
Asia	30	28	28
Oceania	2	2	2
Africa	4	4	5
North America	21	21	21
South America	2	2	3
Total	83	81	83

[A] As revised, numbers have been changed from average number to actual number to align with current year definition. These numbers exclude the 4,000 employees in certain New Energies and Downstream companies.

In 2019, a total of 373,000 formal training days were provided for employees and joint-venture partners, compared with 315,000 in 2018. We continue to invest in people and capabilities, and in our continued focus on safety and personal development.

EMPLOYEE COMMUNICATION AND INVOLVEMENT

We strive to maintain a healthy employee and industrial relations environment in which dialogue between management and our employees – both directly and, where appropriate, through employee representative bodies – is embedded in our work practices. On a regular basis, management engages with our employees through a range of formal and informal channels, including all-staff messages from the Chief Executive Officer, webcasts, townhalls, team meetings, face-to-face gatherings, breakfast briefings, interviews with senior management and online publications via our intranet. For further information on stakeholder engagement, see the "Governance" section on page 113.

OUR PEOPLE continued

We promote safe reporting of views about our processes and practices. In addition to local channels, the Shell Global Helpline enables our people and third parties to report potential breaches of the Shell General Business Principles and Shell Code of Conduct, confidentially and anonymously, in a variety of languages. In 2018, there were 1,584 reported cases via the Shell Global Helpline: 1,232 allegations and 352 inquiries. In 2019, there were 1,686 reported cases via the Shell Global Helpline: 1,278 allegations and 408 inquiries. Shell Internal Audit (SIA) is the custodian of the Shell Global Helpline process in Shell, which is managed by an independent third party. SIA is accountable for ensuring that the Shell Global Helpline functions as intended and that all allegations of Code of Conduct breaches (including bribery and corruption) are investigated and followed up appropriately. The Board has formally delegated the responsibility for reviewing the functioning of the Shell Global Helpline, and the reports arising from its operation, to the Audit Committee. The Audit Committee is also authorised to establish and monitor the implementation of procedures for the receipt, retention, proportionate and independent investigation and follow-up action of reported matters.

Strong employee engagement is especially important in maintaining strong business delivery in times of change. The Shell People Survey is one of the principal tools used to measure employee engagement, motivation, affiliation and commitment to Shell. It provides insights into employees' views and has had a consistently high response rate. In 2019, the response rate was 85.5%, which was an increase of 3.5 percentage points compared to 2018. The average employee engagement score was 78 points out of 100, an increase of one point compared to 2018, and places us among the leading results across a range of industries.

DIVERSITY AND INCLUSION

Our diversity and inclusion approach focuses on hiring, developing and retaining the best people.

Embedding the principles of diversity and inclusion in the way we do business gives us a better understanding of the needs of our people, partners, suppliers and customers. We believe that a diverse workforce, and an inclusive and caring environment that respects and nurtures diverse people, is a way to improve our safety and business performance.

We continue our relentless focus on attracting, developing and promoting more women, and we are supporting initiatives that encourage girls to study science, technology, engineering and mathematics. We also do this by creating a culture of respect and inclusion.

We provide equal opportunity in recruitment, career development, promotion, training and rewards for all our people. In 2019, Shell joined the disability campaign The Valuable 500 to eliminate the exclusion of disabled people worldwide. Since 2018, we have completed the implementation of workplace accessibility service to 83 locations globally. The service is designed to ensure that all employees have access to reasonable physical workplace or other adjustments so that they can work effectively and productively.

We also run an initiative called I'm Not OK to promote open and honest conversations about mental health. In 2019, we focused on stigma by launching an online portal for employees worldwide to share their stories about the support that helped them most when they struggled. In doing so, they addressed the issue of stigma by demonstrating that mental ill-health can happen to anyone irrespective of job, nationality, age, gender or culture.

Our focus on workplace inclusion also continues in other areas. At Shell, we support and enable remarkable people from every background, and strive to be a pioneer of lesbian, gay, bisexual and transgender (LGBT) inclusion in the workplace. In 2019, we were again recognised in the top

tier as a Workplace Pride Advocate in the Workplace Pride global LGBTI inclusive workplace benchmark and earned a 100% score in the Human Rights Campaign Foundation's Corporate Equality Index.

In 2019 the Hampton Alexander Review ranked Shell second out of the Financial Times Stock Exchange (FTSE) 350 Oil & Gas Industry index companies and 14th out of the FTSE 100 rankings of Women on Boards and in Leadership. We actively monitor representation of women and local nationals in senior leadership positions and have talent-development processes to support us in mitigating any biases and delivering a more diverse representation.

In 2019, 48% of our graduate recruits were female. At the end of 2019, the proportion of women in senior leadership positions was 26.4%, an increase of 2.4 percentage points compared to end of 2018. "Senior leadership positions" is a Shell measure based on salary group levels (circa 1,400 staff) and is distinct from the term "senior manager" in the statutory disclosures set out below.

Gender diversity data (at December 31, 2019)

	Number	
	Men	Women
Directors of the Company	7 58%	5 42%
Senior managers [A]	632 72%	250 28%
Employees (thousand)	57 69%	26 31%

[A] Senior manager is defined in section 414C(9) of the Companies Act 2006 and, accordingly, the number disclosed comprises the Executive Committee members who were not Directors of the Company, as well as other directors of Shell subsidiaries.

The local national coverage is the number of senior local nationals (both those working in their respective base country and those expatriated) as a percentage of the number of senior leadership positions in their base country.

Local national coverage (at December 31)

	Number of selected key business countries		
	2019	2018	2017
Greater than 80%	12	10	10
Less than 80%	8	10	10
Total	20	20	20

[A] These numbers exclude the 4,000 employees in certain New Energies and Downstream companies.

CODE OF CONDUCT

In line with the UN Global Compact Principle 10 (Businesses should work against corruption in all its forms, including extortion and bribery), we maintain a global anti-bribery and corruption/anti-money laundering (ABC/AML) programme designed to prevent or detect, and remediate and learn from, potential violations. The programme is underpinned by our commitment to prohibit bribery, money laundering and tax evasion, and to conduct business in line with our Shell General Business Principles and Code of Conduct.

We do not tolerate the direct or indirect offer, payment, solicitation or acceptance of bribes in any form. Facilitation payments are also bribes and are prohibited. The Shell Code of Conduct includes specific guidance for Shell staff (which comprises employees and contract staff) on requirements to avoid or declare actual, potential or perceived conflicts of interest, and on offering or accepting gifts and hospitality.

Communications from leaders emphasise both the importance of these commitments and compliance with requirements. These are reinforced with both global and targeted communications to ensure that Shell staff

are frequently reminded of their obligations. Supporting the Code of Conduct, we have mandatory risk-based procedures and controls that address a range of compliance risks and ensure we focus resources, reporting and attention appropriately. By making a commitment to our core values – honesty, integrity and respect – and following the Code of Conduct, we protect Shell's reputation.

In 2019, we continued mandatory ethical leadership workshops for senior executives across our global operations, to reinforce and explore the level of commitment to ethics and compliance expected of leaders at this level. The workshops focus on values, behaviours, business pressures and leadership practices. The workshops are part of our wider work to cultivate a strong corporate culture where impeccable ethics are a matter of personal pride for every employee, rather than only a compliance issue.

As part of our commitment to ethics and compliance, we ensure that our policies, standards and procedures are communicated to Shell employees and contract staff and, where necessary and appropriate, to agents and business partners. Particular areas of focus with third parties include our due diligence procedures, and clearly articulated requirements (for example, through the use of standard contract clauses). In addition, we publish our Ethics and Compliance Manual on shell.com to demonstrate our commitment in this area.

The Shell Ethics and Compliance Office assists the businesses and functions with the ABC/AML and other programme implementation, and monitors and reports on progress. Legal counsel provides legal advice globally and supports the programme's implementation. The Shell Ethics and Compliance Office regularly reviews and revises all ethics and compliance programmes to ensure they remain up to date with applicable laws, regulations and best practices. This includes incorporating results from relevant internal audits, reviews and investigations as well as periodically commissioning external reviews.

We have a duty to investigate all good faith allegations of breaches of the Code of Conduct, however they are raised. We are committed to ensuring all such incidents are investigated by specialists in accordance with our Investigation Principles. Violation of the Code of Conduct or its policies can result in disciplinary action, up to and including contract termination or dismissal. In some cases, we may report a violation to the relevant authorities, which could lead to legal action, fines or imprisonment.

Internal investigations confirmed 263 substantiated breaches of the Code of Conduct in 2019. As a result, we dismissed or terminated the contracts of a total of 93 employees and contract staff.

EMPLOYEE SHARE PLANS

We have a number of share plans designed to align employees' interests with our performance through share ownership. For information on the share-based compensation plans for Executive Directors, see the "Directors' Remuneration Report" on pages 135-154.

PERFORMANCE SHARE PLAN, LONG-TERM INCENTIVE PLAN AND EXCHANGED AWARDS UNDER THE BG LONG-TERM INCENTIVE PLAN

Under the PSP, 50% of the award is linked to certain indicators described in "Performance indicators" on pages 144, averaged over the performance period. From 2017 to 2019, 12.5% of the award is linked to free cash flow (FCF) and the remaining 37.5% is linked to a comparative performance condition which involves a comparison with four of our main competitors over the performance period, based on three performance measures. Under the LTIP, awards made in 2017 and 2018, 25% of the award is linked to the FCF measure and the remaining 75% is linked to the comparative performance conditions mentioned above. From 2019 onwards, 22.5% of the award is linked to the FCF measure and 10% is

linked to an energy transition measure. The remaining 67.5% is linked to the comparative performance condition mentioned above.

Separately, following the BG acquisition, certain employee share awards made in 2015 under BG's Long-Term Incentive Plan were automatically exchanged for equivalent awards over shares in the Company. The outstanding awards take the form of either conditional awards or nil-cost options.

Under all plans, all shares that vest are increased by an amount equal to the notional dividends accrued on those shares during the period from the award date to the vesting date. In certain circumstances, awards may be adjusted before delivery or reclaimed after delivery. None of the awards result in beneficial ownership until the shares vest.

See Note 21 to the "Consolidated Financial Statements" on page 232.

RESTRICTED SHARE PLAN

Under the Restricted Share Plan, awards are made on a highly selective basis to senior staff. Shares are awarded subject to a three-year retention period. All shares that vest are increased by an amount equal to the notional dividends accrued on those shares during the period from the award date to the vesting date. In certain circumstances, awards may be adjusted before delivery or reclaimed after delivery.

GLOBAL EMPLOYEE SHARE PURCHASE PLAN

Eligible employees in participating countries may participate in the Global Employee Share Purchase Plan. This plan enables them to make contributions from net pay towards the purchase of the Company's shares at a 15% discount to the market price, either at the start or at the end of an annual cycle, whichever date offers the lower market price.

UK SHELL ALL EMPLOYEE SHARE OWNERSHIP PLAN

Eligible employees of participating Shell companies in the UK may participate in the Shell All Employee Share Ownership Plan, under which monthly contributions from gross pay are made towards the purchase of the Company's shares. For every six shares purchased by the employee, one matching share is provided at no cost to the employee.

UK SHARESAVE SCHEME

Eligible employees of participating Shell companies in the UK have been able to participate in the UK Sharesave Scheme. Options have been granted over the Company's shares at market value on the invitation date. These options are normally exercisable after completion of a three-year or five-year contractual savings period. From 2017 no further grants were made under this plan.

Separately, following the acquisition of BG, certain participants in the BG Sharesave Scheme chose to roll over their outstanding BG share options into options over the Company's shares. The BG option price (at a discount of 20% to market value) was converted into an equivalent Company option price at a ratio agreed with Her Majesty's Revenue and Customs. These options are normally exercisable after completion of a three-year contractual savings period.

Strategic Report signed on behalf of the Board

/s/ Linda M. Coulter

LINDA M. COULTER

Company Secretary
March 11, 2020

GOVERNANCE

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THE BOARD OF ROYAL DUTCH SHELL PLC



CHARLES O. HOLLIDAY Chair

Tenure

Chair – 4 years and 9 months (appointed Chair May 19, 2015). On Board – 9 years and 6 months (appointed September 1, 2010) (see page 113 for further information)

Board Committee membership

Chair of the Nomination and Succession Committee

Outside interests/commitments

Presiding Director of HCA Holdings, Inc. Director of Deere & Company. Member of the Critical Resource's Senior Advisory Panel. Member of the Royal Academy of Engineering (UK).

Age

72

Nationality

US citizen

Career

Charles (Chad) Holliday was appointed Chair of the Board of Royal Dutch Shell plc with effect from May 19, 2015.

He was Chief Executive Officer of DuPont from 1998 to 2009, and Chairman from 1999 to 2009. He joined DuPont in 1970 after receiving a BS in industrial engineering from the University of Tennessee and held various manufacturing and business assignments, including a six-year Tokyo-based posting as President of DuPont Asia/Pacific.

He has previously served as Chairman of the Bank of America Corporation, The Business Council, Catalyst, the National Academy of Engineering, the Society of Chemical Industry (American Section) and the World Business Council for Sustainable Development. He is a founding member of the International Business Council.

Relevant skills and experience

Chad has a distinguished track record as an international businessman. He was originally appointed to the Board as a Non-executive Director in September 2010 and, prior to his May 2015 appointment as Chair of the Board, served as Chair of the Safety, Environment and Sustainability Committee and Member of the Remuneration Committee.

He has a deep understanding of international strategic, commercial and environmental issues, and gained extensive experience in the areas of safety and risk management during his time with DuPont. In his role as Chair, Chad is committed to developing and maintaining a strong dialogue with investors and other key stakeholders and ensures that their views are considered during Board discussions and decision-making. He has also demonstrated a strong commitment to ensuring that the highest standards of corporate governance, safety, ethics and compliance are maintained. Chad is a particularly avid advocate of greater diversity, which is reflected in the Board's current diversity mix and increased diversity goals across the Shell Group.

Chad's performance was evaluated by the other Directors, led by Gerard Kleisterlee, Deputy Chair and Senior Independent Director, in 2019. More information on the external board evaluation process can be found on page 114.



GERARD KLEISTERLEE Deputy Chair and Senior Independent Director

Tenure

9 years and 4 months (appointed November 1 2010). On January 29, 2020, the Board announced that Gerard Kleisterlee would not be seeking re-election at the 2020 Annual General Meeting.

Board Committee membership

Chair of the Remuneration Committee and member of the Nomination and Succession Committee

Outside interests/commitments

Chairman of Vodafone Group plc and Chairman of the Supervisory Board of ASML Holding N.V.

Age

73

Nationality

Dutch

Career

Gerard was President/Chief Executive Officer and Chairman of the Board of Management of Koninklijke Philips N.V. from 2001 to 2011. Having joined Philips in 1974, he held several positions before being appointed as Chief Executive Officer of Philips' Components division in 1999 and Executive Vice President of Philips in 2000.

He was a member of the Board of Directors of Dell Inc. from 2010 to 2013 and a member of the Supervisory Board of Daimler AG from 2009 to 2014. From 2014 to 2016, he was a Non-executive Director of IBEX Global Solutions plc.

Relevant skills and experience

Gerard is a Dutch businessman with a distinguished career with one of the largest electronics companies in the world. Through a variety of senior roles, he was responsible for operations in places such as China, Europe, Hong Kong, Taiwan. Gerard is also currently Chair of Vodafone, one of the UK's largest global companies, which provides services to more than 500 million customers.

Gerard's business experience provides him with a broad and deep understanding of the geopolitical, strategic and commercial challenges faced by an evolving business. His experience – gained at Philips, Dell and Vodafone, businesses that have seen significant changes in technology and consumer behaviour – has been a great asset to the Board as Shell transitions to a lower-carbon energy system.

Gerard is a skilled leader, making him ideally suited to his position as our Senior Independent Director, Deputy Chair and Chair of our Remuneration Committee. He raises the bar on the level of Board debate, with his insightful, concise and direct questions.



BEN VAN BEURDEN
Chief Executive Officer

Tenure

6 years and 2 months (appointed January 1, 2014)

Board Committee membership

N/A

Outside interests/commitments

No external appointments

Age

61

Nationality

Dutch

Career

Ben was Downstream Director from January to September 2013. Before that, he was Executive Vice President Chemicals from 2006 to 2012. In this period, he also served on the boards of a number of leading industry associations, including the International Council of Chemicals Associations and the European Chemical Industry Council. Prior to this, he held a number of operational and commercial roles in both Upstream and Downstream, including Vice President Manufacturing Excellence. He joined Shell in 1983, after graduating with a master's degree in chemical engineering from Delft University of Technology, the Netherlands.

Relevant skills and experience

Ben has more than 35 years of Shell experience and has built a deep industry understanding and proven management experience across the technical and commercial roles which he has undertaken over his career.

Since 2016, Ben has led Shell to deliver strong financial results, total shareholder returns and earnings per share. He also led Shell through ending the scrip dividend and the start of a \$25 billion share buyback programme. Under his leadership Shell New Energies has been established and Shell has announced industry-leading initiatives in response to the global challenge of the energy transition to a lower-carbon future, including the introduction of Shell's Net Carbon Footprint ambition. Shell is now at the forefront of a cross-industry push to reduce the greenhouse gas impact of natural gas with the Methane Guiding Principles.

Ben led the Company through the acquisition and integration of BG Group, executed an impressive reshaping of our portfolio and completed a divestment programme of \$30 billion of non-core assets, making the Shell Group simpler.



JESSICA UHL
Chief Financial Officer

Tenure

3 years (appointed March 9, 2017)

Board Committee membership

N/A

Outside interests/commitments

No external appointments

Age

52

Nationality

US citizen

Career

Jessica was Executive Vice President Finance for the Integrated Gas business from January 2016 to March 2017. Previously, she was Executive Vice President Finance for Upstream Americas from 2014 to 2015, Vice President Finance for Upstream Americas Unconventionals from 2013 to 2014, Vice President Controller for Upstream and Projects & Technology from 2010 to 2012, Vice President Finance for the global Lubricants business from 2009 to 2010, and Head of External Reporting from 2007 to 2009. She joined Shell in 2004 in finance and business development, supporting the Renewables business.

Prior to joining Shell, Jessica worked for Enron in the USA and Panama from 1997 to 2003 and for Citibank in San Francisco, USA, from 1990 to 1996. She obtained a BA from UC Berkeley in 1989 and an MBA at INSEAD in 1997.

Relevant skills and experience

Jessica is a highly regarded executive with a track record of delivering key business objectives, from cost leadership in complex operations to mergers and acquisitions delivery. Jessica's extensive experience combines an external perspective with more than 15 years of Shell experience: she has held finance leadership roles in Europe and the USA, in Shell's Upstream, Integrated Gas and Downstream businesses, as well as in Projects & Technology and Corporate.

Jessica's tenure as CFO has also been impressive. She was appointed not long after the BG acquisition, when Shell's debt, gearing and development costs were high and when the oil price was still recovering from the lower levels in 2016.

In these challenging conditions, but with great enthusiasm, clarity and discipline, Jessica has overseen Shell's delivery of industry leading cash flow from operating activities (for the 14th consecutive quarter at the end of 2019) and shareholder distributions (\$25 billion in 2019). Jessica has also been a leading force for transparency in the energy industry, including on taxes and climate change. Under her tenure, Shell has continued to expand and enhance disclosures related to climate change in line with the Task Force on Climate-Related Financial Disclosures principles. Most recently, under her guidance, Shell published the Tax Contribution Report, which includes country-by-country report data, a standard set by the Organisation for Economic Co-operation and Development (OECD).

THE BOARD OF ROYAL DUTCH SHELL PLC continued



NEIL CARSON OBE Independent Non-executive Director

Tenure

9 months (appointed June 1, 2019)

Board Committee membership

Member of the Safety, Environment and Sustainability Committee and member of the Remuneration Committee [A]

Outside interests/commitments

Non-executive Chairman of Oxford Instruments plc and TT Electronics plc [B]

Age

62

Nationality

British

Career

Neil is a former FTSE 100 chief executive. After completing an engineering degree, Neil joined Johnston Matthey in 1980 where he held several senior management positions in both the UK and the US, before being appointed Chief Executive Officer in 2004. Since retiring from Johnston Matthey in 2014, Neil has focused his time on his non-executive roles.

Relevant skills and experience

Neil is highly experienced, has a broad industrial outlook and a highly commercial approach with a practical perspective on businesses. He brings a track record of strong operational exposure, familiarity with capital-intensive business and a first-class international perspective on driving value in complex environments. Neil was awarded an OBE for services to the chemical industry in 2016. Neil has leveraged upon his current and past experience in non-executive positions and, despite being new to the Shell Board, he has already made significant contributions to Board discussions. He has also provided valuable insight based on his former executive position and operational experience.

[A] On January 29, 2020, the Board appointed Neil Carson as Chair of the Remuneration Committee with effect from May 20, 2020. Neil has been a member of this Committee since June 1, 2019 and has previously served on a Remuneration Committee before joining the Shell Board.

[B] On December 9, 2019 TTE plc announced Neil's intention to step down as Non-executive Director and Chair of TTE plc, once his successor has been found.



ANN GODBEHERE Independent Non-executive Director

Tenure

1 year and 9 months (appointed May 23, 2018)

Board Committee membership

Chair of the Audit Committee

Outside interests/commitments

Fellow of the Institute of Chartered Professional Accountants and a Fellow of the Certified General Accountants Association of Canada.

Age

64

Nationality

Canadian and British

Career

Ann started her career with Sun Life of Canada in 1976 in Montreal, Canada, and joined M&G Group in 1981, where she served as Senior Vice President and Controller for both life and health, and property and casualty businesses throughout North America. She joined Swiss Re in 1996, after it acquired the M&G Group, and served as Chief Financial Officer from 2003 to 2007. From 2008 to 2009, she was interim Chief Financial Officer and an Executive Director of Northern Rock bank in the initial period following its nationalisation.

Ann has also held several non-executive director positions at Prudential plc, British American Tobacco plc, UBS AG, and UBS Group AG. Most recently, and until May 2019, Ann served as a Non-executive Director of Rio Tinto plc and Rio Tinto Limited. She was also Senior Independent Director of Rio Tinto plc.

Relevant skills and experience

Ann is a former CFO, a Fellow at the Institute of Chartered Professional Accountants, and has more than 25 years of experience in the financial services sector. She has worked her entire career in international business and has lived in or served on boards in nine countries. Ann makes significant contributions and adds exceptional value by bringing both her extensive experience and a new perspective to Board discussions.

Ann's long international business career brings with it an invaluable global perspective and understanding, which is reflected in the insights and constructive challenges she brings to the boardroom. Ann was appointed Chair of the Audit Committee on July 1, 2019, and has made significant contributions in this role. Her highly relevant skills, particularly in investment appraisal and financial risk management, have been a welcome addition to our Board and Audit Committee.



EULEEN GOH
Independent Non-executive Director

Tenure

5 years and 6 months (appointed September 1, 2014)

Board Committee membership

Member of the Nomination and Succession Committee [A]

Outside interests/commitments

Chairman of SATS Ltd. Non-executive Director of DBS Bank Ltd and DBS Group Holdings Ltd. Trustee of the Singapore Institute of International Affairs Endowment Fund. Chairman of the Governing Council of the Singapore Institute of Management and Non-executive Director of Singapore Health Services Pte Ltd, both of which are not-for-profit organisations.

Age

64

Nationality

Singaporean

Career

Euleen is an Associate of the Institute of Chartered Accountants in England and Wales, a Fellow of the Singapore Institute of Chartered Accountants and has professional qualifications in banking and taxation. She has held various senior management positions within Standard Chartered Bank and was Chief Executive Officer of Standard Chartered Bank, Singapore, from 2001 until 2006. She is also a Fellow of the Singapore Institute of Directors.

She has also held non-executive appointments on various boards including Aviva plc, MediaCorp Pte Ltd, Singapore Airlines Ltd, Singapore Exchange Ltd, Standard Chartered Bank Malaysia Berhad, Standard Chartered Bank Thai plc, Capitaland Ltd and Temasek Trustees Pte Ltd. She was previously Non-executive Chairman of the Singapore International Foundation, and Chairman of International Enterprise Singapore and the Accounting Standards Council, Singapore.

Relevant skills and experience

Euleen's current roles as Chair of the Board of Directors of various international companies provide significant experience in the area of strategy development and international businesses. She is a champion of diversity and constructively challenges the Board and management to continue to progress in this area.

Based in Singapore and as Chair of the Risk Committee of the largest bank in south-east Asia, Euleen is close to key emerging/growth markets for our business. Euleen's risk management expertise has elevated the Board's deep deliberations around risk governance. Her extensive travel around the world, through her various executive and non-executive roles, has equipped her with broad geopolitical insight and significant knowledge of operating in the Asian region.

Euleen uses her financial acumen to pose probing and insightful questions, both in and beyond the boardroom. This contributes to well-rounded and incisive Board discussions.

[A] On January 29, 2020, the Board appointed Euleen Goh as Deputy Chair and Senior Independent Director with effect from May 20, 2020.



CATHERINE J. HUGHES
Independent Non-executive Director

Tenure

2 years and 9 months (appointed June 1, 2017)

Board Committee membership

Member of the Safety, Environment and Sustainability Committee and member of the Remuneration Committee

Outside interests/commitments

Non-executive Director of SNC-Lavalin Group Inc.

Age

57

Nationality

Canadian and French

Career

Catherine was Executive Vice President International at Nexen Inc., from January 2012 until her retirement in April 2013, where she was responsible for all oil and gas activities including exploration, production, development and project activities outside Canada. She joined Nexen in 2009 as Vice President Operational Services, Technology and Human Resources.

Prior to joining Nexen Inc., she was Vice President Oil Sands at Husky Oil from 2007 to 2009 and Vice President Exploration & Production Services, from 2005 to 2007. She started her career with Schlumberger in 1986 and held key positions in various countries, including France, Italy, Nigeria, the UK and the USA, and was President of Schlumberger Canada Ltd for five years. She was a Non-executive Director of Statoil from 2013 to 2015.

Relevant skills and experience

Catherine contributes her industry knowledge and ease of engagement with other Directors and managers in the boardroom. With her 30 years of oil and gas sector experience, she brings a geopolitical outlook and deep understanding of the industry. An engineer by training, she has also spent a significant part of her career working in senior human resources roles. The Board highly regards her perspectives on our industry and our most important asset, our people.

Catherine has a strong track record of executing operational discipline with a focus on performance metrics and a continual drive for excellence. Her knowledge of the technology underpinning oil and gas operations, logistics, procurement and supply chains benefits the Board greatly as it considers various projects and investment or divestment proposals.

She also uses her industry knowledge – combined with her commitment to the highest standards of corporate governance and safety, ethics and compliance – in her membership of our Safety, Environment and Sustainability Committee, while using her human resources experience in her membership of the Remuneration Committee.

THE BOARD OF ROYAL DUTCH SHELL PLC continued



ROBERTO SETUBAL Independent Non-executive Director

Tenure

2 years and 5 months (appointed October 1, 2017)
On March 11, 2020, the Board announced that Roberto Setubal would not be seeking re-election at the 2020 Annual General Meeting.

Board Committee membership

Member of the Audit Committee

Outside interests/commitments

Member of the board of the International Monetary Conference (IMC), the Economic and Social Development Council of the Presidency of Brazil, and the International Business Council of the World Economic Forum. He is also President of the Fundação Itaú Social and a member of the Executive Committee of the Instituto Itaú Cultural.

Age

65

Nationality

Brazilian

Career

Roberto was Chief Executive Officer and Vice Chairman of the Board of Directors of Itaú Unibanco Holding S.A. in Sao Paulo, Brazil, until April 2017. At that time, he retired as Chief Executive Officer and currently serves as Co-Chairman of the Board of Directors. Following a brief period with Citibank in New York, he joined Banco Itaú in 1984 where he held a variety of senior roles in investment banking, consumer credit operations and retail banking before being appointed Chief Executive Officer in 1994. After the merger of Banco Itaú and Unibanco, he was appointed to the position of President and Chief Executive Officer of Itaú Unibanco Holding S.A. Previously, he was a Non-executive Director of Petrobras S.A., President of the IMC and Vice-Chairman of the Institute of International Finance.

Relevant skills and experience

Roberto brings significant experience in capital markets and financial services to the Board and has a deep understanding of international strategic management, commercial operations and risk management. He was instrumental in designing and then executing a strategy that led to Itaú becoming the largest bank in Brazil.

His deep financial knowledge enables him to make robust, demanding and constructive challenges to our investment considerations and helps to ensure that projects are aligned with our strategic intent.

Despite spending most of his life in Brazil, Roberto has a strong understanding of global business. Naturally, he also brings an invaluable perspective and insight into operating in his native country, a key growth market for Shell. His contributions also demonstrate his strong advocacy for the highest standards of corporate governance, ethics and compliance. This, combined with his experience of operating in challenging markets, helps to deepen the Board's analyses of difficult matters with multi-faceted risks.



SIR NIGEL SHEINWALD GCMG Independent Non-executive Director

Tenure

7 years and 8 months (appointed July 1, 2012)

Board Committee membership

Chair of the Safety, Environment and Sustainability Committee and member of the Remuneration Committee

Outside interests/commitments

Non-executive Director of Invesco Ltd and Raytheon UK. Senior Adviser to Tanium Inc. and to the Universal Music Group. Visiting Professor and Council Member of King's College, London.

Age

66

Nationality

British

Career

Sir Nigel was a senior British diplomat who served as British Ambassador to the USA from 2007 to 2012, before retiring from the Diplomatic Service. Prior to this, he served as Foreign Policy and Defence Adviser to the Prime Minister and as British Ambassador and Permanent Representative to the European Union in Brussels. He joined the Diplomatic Service in 1976 and served in Brussels, Moscow, Washington and in a wide range of policy roles in London. Since 2012, he has taken on a number of international business roles, and has supported organisations involved in higher education and international affairs.

Relevant skills and experience

Sir Nigel's distinguished track record including three of the most senior international roles in British public service has given him broad geopolitical and public policy experience, as well as knowledge of regulatory issues, communications and stakeholder management. He has a global and strategic outlook which enables him to identify emerging issues that could present geopolitical or reputational challenges.

Sir Nigel brings a unique government policy perspective to our strategic discussions particularly on topics such as the energy transition, that are strongly influenced by the views of governments and a complex range of interested parties. His many contributions to the Board on this and other strategic and operational topics often reflect the interconnections between geopolitics, business and external stakeholder engagement.

He is used to operating in challenging environments and is committed to active external engagement. This, and his understanding of public policy and regulatory issues through his career in government service and membership of think tank and university boards, makes him well suited to the role of Chair of our Safety, Environment and Sustainability Committee.



LINDA G. STUNTZ
Independent Non-executive Director

Tenure

8 years and 9 months (appointed June 1, 2011)
On January 29, 2020, the Board announced that Linda G. Stuntz would not be seeking re-election at the 2020 Annual General Meeting.

Board Committee membership

Member of the Safety, Environment and Sustainability Committee and member of the Nomination and Succession Committee

Outside interests/commitments

Director of Edison International.

Age

65

Nationality

US citizen

Career

Linda retired from her position as founding partner of the law firm of Stuntz, Davis & Staffier, P.C. in January 2019. She was a member of the US Secretary of Energy Advisory Board from 2015 to 2017. She chaired the Electricity Advisory Council of the US Department of Energy from 2008 to 2009. Linda was a member of the board of Directors of Schlumberger Ltd from 1993 to 2010 and of Raytheon Company from 2004 to 2015.

From 1989 to 1993, she held senior policy positions at the US Department of Energy, including Deputy Secretary.

Relevant skills and experience

Linda's Harvard legal training and deep practical legal experience bring unique and valuable expertise in energy-industry and environmental law, as well as extensive public policy experience, to our Board. This is conveyed through her in-depth knowledge of the gas and power industries and her work on issues related to climate change and energy-related measures to minimise greenhouse gas emissions.

As a board director of publicly traded companies for more than 25 years, Linda has provided strategic and legal advice to many energy companies and has substantial experience in overseeing and working with businesses with operations around the world. She has a broad understanding of technology and its development/commercialisation within our industry, from her work with the US government and on the Schlumberger board. She has significant knowledge and understanding of cyber risks as a result of her Raytheon and Edison International board service.

Linda's unique background, coupled with her exceptional ability to frame clear questions that tackle the key points of complex issues, helps deepen the Board's constructive challenges and considerations of critical industry-related matters, particularly those related to the energy transition.



GERRIT ZALM
Independent Non-executive Director

Tenure

7 years and 2 months (appointed January 1, 2013)

Board Committee membership

Member of the Audit Committee and member of the Remuneration Committee

Outside interests/commitments

Director of Moody's Corporation inc and Danske Bank A/S

Age

67

Nationality

Dutch

Career

Gerrit was an adviser to PricewaterhouseCoopers during 2007, Chairman of the Trustees of the International Accounting Standards Board from 2007 to 2010, and an adviser to Permira from 2007 to 2008. He was Chief Economist of DSB Bank from July 2007 to January 2008, Chief Financial Officer from January 2008 to December 2008, and Chairman of the Managing Board of ABN AMRO Bank N.V. from 2010 to 2016. He was Minister of Finance of the Netherlands, twice, from 1994 to 2002 and from 2003 to 2007. In between, he was Chairman of the parliamentary party of the VVD.

Prior to 1994, he was head of the Netherlands Bureau for Economic Policy Analysis, a professor at Vrije Universiteit Amsterdam, and held various positions at the Ministry of Finance and the Ministry of Economic Affairs. He studied general economics at the Vrije Universiteit Amsterdam, from where he also received an honorary doctorate in economics.

Relevant skills and experience

An economist by background, Gerrit's distinguished 12-year service as the Minister of Finance to the Netherlands, coupled with his experience gained from his time with ABN AMRO Bank, brings a deep and valuable understanding of Dutch politics and financial markets to the Board. His international financial management expertise and strategic development experience also benefits the Audit Committee.

A highly regarded and seasoned leader in both the public and private spheres, his significant experience in analysing financial commitments from a wider public stakeholder and a global business standpoint serves the Board well, particularly when considering investment proposals. Gerrit consistently and concisely articulates the logic and reasoning behind his views, benefiting the Board and management. His questions often trigger other analytical questions from fellow Directors, which serves to deepen and widen Board discussions.

THE BOARD OF ROYAL DUTCH SHELL PLC continued



LINDA M. COULTER
Company Secretary

Tenure

3 years and 2 months (appointed January 1, 2017)

Age

52

Nationality

US citizen

Career

Linda was General Counsel of the Upstream Americas business and Head of Legal US, based in the USA, from 2014 to 2016. Previously, she was Group Chief Ethics & Compliance Officer based in the Netherlands from 2011 to 2014. Since joining Shell in 1995, she has also held a variety of legal positions in the Shell Oil Company in the USA, including Chemicals Legal Managing Counsel and other senior roles in employment, litigation, and commercial practice.

Relevant skills and experience

Linda is our Company Secretary and plays an important role as Shell's General Counsel Corporate, overseeing corporate legal teams in Belgium, Canada, the Netherlands, Switzerland, the UK and the USA.

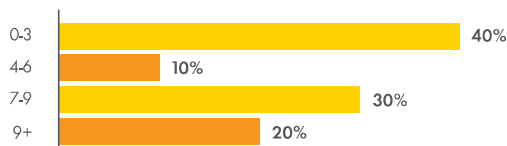
The various legal roles Linda has undertaken at our headquarters, and in supporting both the Upstream and Downstream businesses, have provided her with a strong understanding of our global operations and people. Her experience of engaging with the Board in previous roles, coupled with her broad understanding and engagement across Shell's businesses and functions, helps to ensure that the right matters come to the Board at the right time.

BOARD DIVERSITY

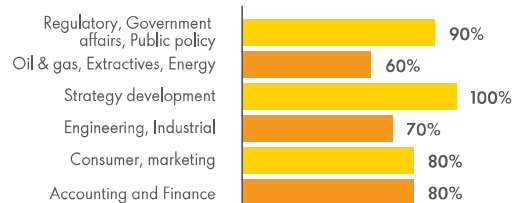
Gender diversity



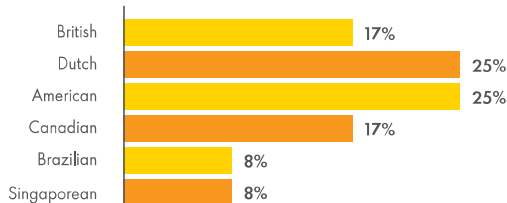
Non-executive Director tenure (years)



Non-executive Director sector experience



Director nationality



ATTENDANCE

Board meeting attendance for 2019 is provided below in the table [A]. The Board held eight scheduled meetings in 2019.

[A] For attendance at Committee meetings during the year, please refer to individual Committee Reports.

[B] Ben van Beurden was not able to attend one Board meeting due to illness. He reviewed the key agenda topics and had a discussion with the Chair prior to the Board meeting. He also conveyed his opinions and comments on the matters to be considered via the Chairman of the Board.

[C] Neil Carson joined the Board in June 2019. Ahead of his appointment, he attended the Board meeting in May 2019. This is not reflected in the table as his appointment was not effective until June 1, 2019. Neil was unable to attend the Board meeting in October due to an immovable commitment which was scheduled prior to his appointment to the Shell Board.

Board Member	Meetings attended
Ben van Beurden[B]	7/8
Neil Carson[C]	3/4
Ann Godbehere	8/8
Eileen Goh	8/8
Charles O. Holliday	8/8
Catherine J. Hughes	8/8
Gerard Kleisterlee	8/8
Roberto Setubal	8/8
Sir Nigel Sheinwald	8/8
Linda G. Stuntz	8/8
Jessica Uhl	8/8
Gerrit Zalm	8/8

DIRECTOR INDEPENDENCE

All the Non-executive Directors are considered by the Board to be independent in character and judgement. The Chair is not subject to the Code's independence test other than on appointment.

SENIOR MANAGEMENT

The Senior Management of the Company comprises the Executive Directors, Ben van Beurden and Jessica Uhl, and those listed below. All are members of the Executive Committee (see “Governance Framework” on page 117).



HARRY BREKELMANS Projects & Technology Director

Tenure

5 years and 5 months (appointed October 2014)

Age

54

Nationality

Dutch

Career

Harry was previously Executive Vice President for Upstream International Operated based in the Netherlands. He joined Shell in 1990 and has held various management positions in Exploration and Production, Internal Audit, and Group Strategy and Planning. From 2011 to 2013, he was Country Chair Russia and Executive Vice President for Russia and the Caspian region.



DONNY CHING Legal Director

Tenure

6 years and 1 month (appointed February 2014)

Age

55

Nationality

Malaysian

Career

Donny was previously General Counsel for Projects & Technology based in the Netherlands. He joined Shell in 1988 based in Australia and then moved to Hong Kong and later to London. In 2008, he was appointed Head of Legal at Shell Singapore, having served as Associate General Counsel for Gas & Power in Asia-Pacific.



RONAN CASSIDY Chief Human Resources & Corporate Officer

Tenure

4 years and 2 months (appointed January 2016)

Age

53

Nationality

British

Career

Ronan was previously Executive Vice President Human Resources, Upstream International. He joined Shell in 1988 and has held various human resources positions in Upstream and Downstream.



WAE SAWAN Upstream Director

Tenure

8 months (appointed July 2019)

Age

45

Nationality

Lebanese and Canadian

Career

On July 1, 2019, Wael succeeded Andy Brown as Upstream Director and was appointed to the Executive Committee.

Wael was previously the Executive Vice President, Deep Water and a member of the Upstream Leadership Team. He joined Shell in 1997 and has worked in a variety of roles in each of Shell's core business units: Upstream, Integrated Gas and Downstream.

SENIOR MANAGEMENT continued



HUIBERT VIGEVENO

Downstream Director

Tenure

2 months (appointed January 2020)

Age

50

Nationality

Dutch

Career

On January 1, 2020, Huibert succeeded John Abbott as Downstream Director and was appointed to the Executive Committee.

Huibert was previously Executive Vice President Global Commercial. He joined Shell in 1995 and led many Downstream businesses across Shell in Europe, Africa, North and South America, and Asia. This included acting as Executive Chairman of Shell in China, and in 2016 leading the integration of BG Group.



MAARTEN WETSELAAR

Integrated Gas and New Energies Director

Tenure

4 years and 2 months (appointed January 2016)

Age

51

Nationality

Dutch

Career

Maarten was previously Executive Vice President of Integrated Gas based in Singapore. He joined Shell in 1995 and has held various financial, commercial and general management roles in Downstream, Trading and Upstream.

2019 LEAVERS

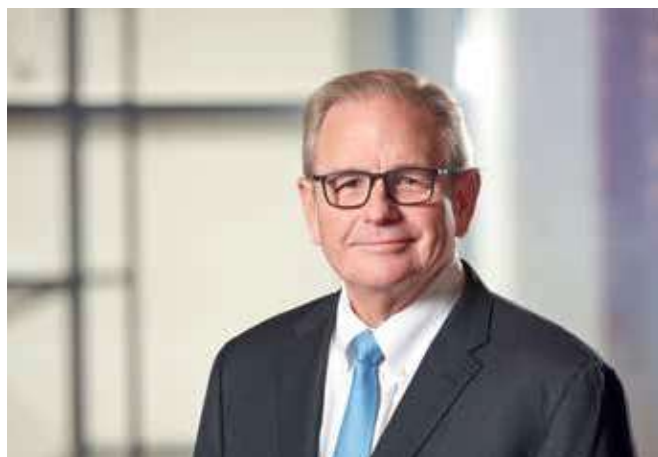
JOHN ABBOTT

Downstream Director until December 2019 (appointed October 2013)

ANDREW BROWN

Upstream Director until June 2019 (appointed January 2016)

INTRODUCTION FROM THE CHAIR



CHAD HOLLIDAY
Chair

As communicated at the start of this Annual Report, and reflected in the reported results, 2019 was not an easy year for the sector in which we operate. The year provided a tough macroenvironment, lower Liquified Natural Gas (LNG) and gas prices, as well as weaker realised refining and chemicals margins. As we look forward, we see continued risk from the difficult-to-predict outcomes of the trade conflicts in some regions, uncertainties within Europe over post-Brexit arrangements, the slowdown and vulnerability of some markets and regional geopolitical tensions. However, we also see robust economic growth in some regions and stronger than expected cyclical recoveries.

Society is also changing, which we welcome, accelerating its perspective on what companies should be doing, increasing the pressure and encouraging us to rise to the challenges ahead as the world moves to an environment supported by lower-carbon energy products. Shell agrees with the importance attached by its stakeholders to the issue of climate change and Shell's future success depends on effectively navigating the risks, opportunities and uncertainties presented by the energy transition. All businesses, governments, and even individuals must work together and have a role to play in shifting demand away from carbon-intensive resources. However, oil and gas will not only be needed by some parts of society for many decades to come, they are key cash generators that support our investment through the energy transition and underpin delivering our ambitions aligned to the goals of the Paris Agreement while providing a world-class investment case to Shell's investors.

BOARD LEADERSHIP AND SHELL'S PURPOSE

The UK Corporate Governance Code (the "Code") provides that the Board should promote the long-term sustainable success of Shell, generating value for shareholders and contributing to wider society. The Board believes that Shell's efforts give it an effective framework to play its part in the energy transition as a growing, successful, commercial organisation. In the Board's view, this framework will allow Shell to provide the energy solutions that consumers will want and buy through this period of uncertain change. The Board also thinks that Shell will be able to reduce the carbon intensity of the energy products it supplies.

The Code asks us to report on our business purpose, which is provided at the start of this Report. However, we have carried the concept of purpose through other reporting areas to provide a further understanding of our operations and the benefits of particular activities.

The key themes of the Code are used in this Report to form the framework for articulating our narrative and we have sought to provide a genuine understanding of how governance supports and protects the business and our stakeholders.

The impact of the Code on Shell's existing governance processes and reporting practices, as well as certain implementation recommendations, were reviewed and considered by the Nomination and Succession Committee, at the end of 2018 and over the course of 2019. Its findings were then discussed and agreed with the Board. Overall, it was considered that while Shell was already applying the principles and the spirit of the Code, the Board recognises that enhanced reporting in this area could help make this clearer for stakeholders. The Board's approach to certain provisions (as explained in further detail below) is considered appropriate, when taking into account circumstances based on a range of factors that are particular to Shell, including its global nature, size, complexity and history. To provide greater insight into our current governance practices, we have highlighted some provisions on page 115, and signposted where more information can be found in the report and, where possible, explain how we see our practices evolving over time.

The importance of stakeholder engagement has received greater external focus in recent years. Given the nature of our business, engagement is considered key to our operations and has been a key focus for some time. How and why we engage with our stakeholders is also provided on page 122. The Board's discharge of its duty in relation to key stakeholder interests, including those of our workforce, and an explanation of how it considered these when making principal decisions is set out on page 124 in the Strategic Report. Additionally, on page 120 we provide information on our Board activities and highlight which stakeholder we considered. We have also enhanced our reporting on our workforce engagement methods. We believe that constructive relationships built on mutual respect and transparency helps Shell attract and retain employees while supporting greater productivity and operational efficiency. Ensuring that the employee voice is heard in the boardroom in practical ways is key to understanding the broader impact of business decisions including with respect to company culture.

The Board clearly recognises the importance of culture and its link to delivering Shell's purpose and strategy. Given our culture's importance it requires long-term commitment. The Board believes that our people and safety culture is strong, something we take pride in. Moreover, our culture reflects the values of the business – honesty, integrity and respect for people – which underpin all the work we do and is embedded within our Strategy and Purpose.

DIVISION OF RESPONSIBILITIES

How the Board and its Committees support the business operations is provided on page 117 with more detail within the Terms of Reference for each Committee, which are provided on our website. Each year the Board Committees' Terms of Reference are reviewed and updated, as required. This year we have also changed the name of our Corporate Social Responsibility Committee to the Safety, Environment and Sustainability Committee (SESCO), reflecting the Committee's focus on safety and environmental matters, including climate change and sustainability. The updates have been made in consideration of external developments.

The importance of independent judgement on the Board is a fundamental governance principle and one supported by the Board. The Code provides circumstances that it considers are likely to impair, or could appear to impair, a Non-executive Director's independence, and tenure is one of these. At the time of the 2020 Annual General Meeting (AGM), Gerard Kleisterlee, Senior Independent Director, will reach a tenure of nine years since his appointment to the Board by shareholders. However,

INTRODUCTION FROM THE CHAIR continued

as he was appointed to the Board by the Directors some seven months ahead of his first election by shareholders, his independence for the period of October 2019, to the 2020 AGM requires deeper evaluation under a new Code provision. Within our statement of compliance with the Code on page 115 we provide the questions the Board considered when testing Gerard's independence.

COMPOSITION, SUCCESSION AND EVALUATION

The Director biographies in this Report provide insight into our Directors' careers, skills and experience. Further, our Board diversity reporting extends past gender and nationality, and outlines the varying sector experience across the Board.

At the 2019 AGM, Neil Carson was elected to the Board by shareholders. An overview of his induction programme is provided on page 120. At the end of the 2020 AGM, both Gerard Kleisterlee, Senior Independent Director, and Linda Stuntz, Independent Non-executive Director will retire from the Board after nine years of service. They both leave strong leadership track records, and the Board is deeply grateful for their many years of dedicated commitment to the business. As we announced on January 29, 2020, Euleen Goh will become Deputy Chair and Senior Independent Director when Gerard retires and Neil Carson will become Chair of our Remuneration Committee.

The Board completed its annual performance evaluation in December 2019, which was facilitated externally. The process again proved to be a valuable exercise, generating reflective discussions and planned actions. The process was led by me and undertaken by Independent Board Evaluation. On page 120 we have sought to provide insight into the process, the outcome and some of the areas we plan to enhance.

One of the Code provisions introduces a recommended nine-year limit to the tenure of the Board Chair. As this is a provision directly relating to me, our Senior Independent Director, Gerard Kleisterlee, provides an explanation on page 115 of how the Board considered this provision and when the Board proposes that my tenure concludes.

AUDIT, RISK MANAGEMENT AND INTERNAL CONTROL

The Audit Committee assists the Board in maintaining a sound system of risk management and internal control and oversight over Shell's financial reporting. A variety of standing matters and more specific topics are discussed by the Audit Committee throughout the year. As part of the year-end reporting process, the Audit Committee advises the Board on the adequacy of the system of risk management and internal control in place, the appropriateness of the viability statement and going concern basis of accounting. The Audit Committee also advises on whether this Report, taken as a whole, is fair, balanced and understandable and provides the information necessary for stakeholders to assess Shell's position and performance, business model and strategy. More information on the Audit Committee's activities, highlights and priorities can be found in its report on page 132.

REMUNERATION

In 2020, shareholders will vote on our revised Directors' Remuneration Policy. Under the new Policy, we have focused on simplifying remuneration structures to improve clarity and transparency while maintaining the existing connection with our business strategy. In keeping with recent governance developments and societal views, we are placing increasing emphasis on the discretionary management of pay to ensure reward outcomes are appropriate. We will also be asking shareholders to vote on the energy transition metric which links reward with our ambitions to reduce our Net Carbon Footprint. Further information can be found on page 163.

Finally, we hope that this new format of document provides a clearer format for our reporting and enhances the understanding of our governance processes for our stakeholders. I would also again like to thank my fellow Directors, my colleagues and our workforce around the world for their continued and considerable efforts to the success of the Company.

CHAD HOLLIDAY

Chair
March 11, 2020

CHANGES TO OUR REPORTING

To assist with providing stakeholders greater insight into Board operations and the governance activities that support the business, we have chosen to split the UK-governed Annual Report from the US-governed Form 20-F. The key strategic messages continue to be provided within both documents. We are now at the start of a journey with the Annual Report and are seeking to adopt a practical approach that is more responsive to the requests of our readers. To avoid duplication, and excessive cross referencing, **the Directors' Report now spans the governance section of this report from page 104 to page 171.** It provides the necessary governance assurances and confirmations, and focuses on the factors that we believe will be of most interest to readers and important to the long-term prospects of Shell.

As society changes we are committed to changing the business to support it and, with this, become more transparent in our operations and the information that we share, especially when working to earn and maintain trust. Building on our disclosures from 2019, such as our Industry Associations Report, the enhancement of our quarterly financial disclosures and our Tax Contribution Report (available on the Shell website). We have also sought to share more information in this Report on Shell's ways of working and how the Board operates.

STATEMENT OF COMPLIANCE WITH THE UK CORPORATE GOVERNANCE CODE

The Board confirms that, throughout the year, the Company has applied the Principles, both in spirit and in form, and complied with the provisions set out in the UK Corporate Governance Code issued by the Financial Reporting Council (FRC) in July 2018 ("the Code"). A copy of the Code can be found on the FRC's website: www.frc.org.uk.

Shell's governance arrangements have been considered alongside the Code. The information set out in the Directors' Report, including the Board Committee Reports on (pages 126-127, 128, 129-134 and 135-138) is intended to provide an explanation of how the Principles of the Code were applied practically throughout the year. We have also chosen to provide information below where we believe stakeholders may benefit from a more specific explanation on particular Code provisions.

Chair Tenure (Provision 19)

Note: The text relating to Chair tenure is provided by Gerard Kleisterlee, Senior Independent Director.

Charles O. Holliday (Chad) was appointed as Chair in 2015 after four and a half years on the Board as a Non-executive Director. In September 2019, he reached a tenure of nine years.

The provisions of the Code address Chair tenure and provide a limit of nine years from the date of first appointment to the Board. However, the Code pragmatically acknowledges that this period can be extended for a limited time to facilitate orderly, effective succession planning and the development of a diverse board. In the 2018 Annual Report and Form 20-F we highlighted that Chad's tenure had been discussed in numerous shareholder engagements and it was disclosed that shareholders were supportive of the extension of his tenure to the 2021 AGM. This meets the Code's limited exception, particularly as the Chair was an existing Non-executive Director on appointment. The Board also takes comfort from the support for Chad's re-election at the 2019 AGM (96% votes in favour) and ongoing support from shareholders.

The Board continues to believe that retaining Chad on the Board and in the position of Chair until the 2021 AGM is right for the business. The Board is confident that this facilitates more effective phasing of his succession. As stated last year, and agreed by shareholders, an earlier departure would be disruptive and could leave a significant deficiency in Shell's corporate knowledge when taking into account the forthcoming departures of other long-serving Directors: both myself and Linda Stuntz.

The Board believes that Chad remains an effective Chair, which was strongly recognised in the independent evaluation of the Board. Although the Board will continue to assess his objectivity, the Board is assured that

Chad will continue to exercise objective judgment, despite his tenure surpassing nine years. The Board finds that the continuity of his corporate knowledge and experience is essential to complement and support the new skills and experience of Director appointments of the last few years, as well as those that we will need to make in the coming year.

Chad's innate understanding and knowledge of the Shell Group, coupled with the strong Shell relationships he has established, are appreciated and highly valued by the Board. His skills enable him to effectively challenge management and coach other, particularly new, Non-executive Directors on the intricacies and nuances of the business, thereby better equipping them to effectively challenge management and enhance overall governance. The Board has also achieved increased diversity under Chad's leadership as Chair. Chad's leadership of the Board through to 2021 is critical to the Board's effective succession planning through the short term.

Director Independence (Provision 10)

As referenced in the Chair's statement, Gerard Kleisterlee has served on the Board for more than nine years, having joined in November 2010. The Board acknowledges the potential impairment of his independence owing to his length of tenure, as outlined in a Code provision. In the Board's view, there has been no notable negative change in Gerard's performance as a Director and in his various Board roles in recent years. The Board continues to regard him as an independent Non-executive Director and undertook a rigorous evaluation to reach this conclusion. Gerard did not participate in his own assessment.

The result of this assessment was positive and given that Gerard's independence is only questioned by one of the seven parameters outlined in the Code, the Board has determined that he remains independent. The Directors have also observed that Gerard continues to be independent of mind and will. He regularly leverages his deep understanding and knowledge of the Shell Group and insightful perspectives based on his corporate memory, coupled with his external background and knowledge to enrich Board discussions while also providing objective judgement and effective challenge to management and the wider Board. Gerard's fellow Directors have also noted, during the evaluation, that he uses his skills and experience to assist the Chair in driving productive discussions and offers considered advice based on objective judgement. The continuity of his Board tenure, corporate knowledge and experience has complemented and supported the skills and experience of relatively newer Director appointments over the years, including those of the Chief Executive and Chief Financial Officers.

ASSESSING DIRECTOR INDEPENDENCE

The following questions were used to assess Gerard's independence:

- Was the Director's re-election supported at the last AGM? Did the level of support, or communication from investors ahead of the AGM indicate concern about the Director's independence?
- Have the conferred interests of other Directors or management unduly influenced behaviour or approach to decision-making?
- How has any potential influence – as a result of familiarity amongst Directors and between Directors and management who have served together for more than the nine years – been avoided?
- How proactive is the Director? Have they stood themselves apart from, or avoided, any potential influence when making decisions?
- Where good working relationships with fellow Directors and management have been developed, are these strictly professional and limited to work-related matters only? Are there any known situations where they have attended the same events in a non-Shell-related capacity and in what context?
- Has the Director previously been involved in the industry in which the Company operates? Is there a network of contacts that could reduce the ability to be objective or contaminate their views?
- Are the views and opinions of Directors and management challenged appropriately and at what frequency?
- Have there been circumstances when the Board is reaching consensus, but the Director has not been afraid to speak up or offer an alternative view?
- Are boardroom behaviours indicative of a strong culture of collaboration, but with robust debate, and in a way that means no one Director dominates discussions?
- How is the Board satisfied that there is no reliance on one or certain viewpoints and that there is inclusive, diverse-thinking boardroom culture?
- How has performance as a Director and, where relevant, performance in a particular role or duty changed over recent years, and since reaching more than nine years of service?

STATEMENT OF COMPLIANCE WITH THE UK CORPORATE GOVERNANCE CODE continued

Workforce engagement (Provision 5)

Our people are essential to the successful delivery of the Shell strategy, and the Board recognises the importance of understanding their views through engagement. However, the size and diversity of our employee base as well as that of our wider workforce complicates the feasibility of implementing any of the three specific workforce engagement methods recommended in the Code. Given the required coverage needed for a global organisation such as ours, the Board believes that its current approach to workforce engagement continues to be pragmatic and effective.

However, the Board has also decided that in 2020 it will increase its direct engagements when the Board, Committees and individual Directors visit our sites across the world and its indirect engagements through enhanced stakeholder engagement information in relevant management reports. The Board also agreed to keep under review the effectiveness of the engagements. More information on the current approach and a description of the channels used by the Board, its Committees, and the Executive Committee are outlined in “Workforce engagement” on pages 124-125.

Appointment of independent Non-executive Director as Senior Independent Director (Provision 12)

Information on the independence of the appointed Senior Independent Director, at the date of publication, is explained under the “Director Independence” heading on the previous page. As provided earlier in this report, Eileen Goh will succeed Gerard in this role following the 2020 AGM, subject to her reappointment by shareholders. Details on succession planning and the work of the Nomination and Succession Committee is contained on pages 126-127.

Composition of the Remuneration Committee (Provision 32, independence)

The Remuneration Committee has five Non-executive Directors making up its membership, four of which are deemed to be independent under the parameters of the Code, and the fifth (Gerard Kleisterlee) is considered to be independent by the Shell Board for the reasons provided in its explanation. Remuneration Committee members have served this Committee for periods ranging from over two years to just over five years, the exception being Neil Carson, who joined the Board and Remuneration Committee on June 1, 2019. As announced on January 29, 2020, Neil Carson will succeed Gerard in the role of Committee Chair following the 2020 AGM, subject to his reappointment by shareholders. Neil has been a member of this Committee since June 1, 2019 and has previously served on a remuneration committee before joining the Shell Board. Having Gerard remain as Committee Chair beyond his nine-year tenure to the natural conclusion of his tenure at the 2020 AGM was a practical step promoting smooth succession. Further details on the composition of the Remuneration Committee are provided on page 139 of the Remuneration Committee Report.

Corporate governance requirements outside the UK

In addition to complying with applicable corporate governance requirements in the UK, the Company complies with the rules of Euronext Amsterdam as well as Dutch securities laws because of its listing on that exchange. The Company likewise adheres to US securities laws and the New York Stock Exchange (NYSE) rules and regulations because its securities are registered in the USA and listed on the NYSE.

BOARD OF DIRECTORS

Chair

- Responsible for ensuring that the Board and its Committees function effectively. One way in which this is achieved is by ensuring Directors receive accurate, timely and clear information; and
- Responsible for making sure that there is an adequate induction and training programme followed by all Directors (see page 127 below), with assistance from the Company Secretary.

Board

- Promotes the long-term sustainable success of the Company, generating value for shareholders and contributing to wider society as detailed throughout our Strategic Report;
- Meets eight times a year and has a formal schedule of matters reserved to it;
- Responsibilities include:
 - Approval of overall strategy and oversight of management;
 - Changes to the corporate and capital structure;
 - Approval of financial reporting and controls (including approval of the Annual Report and Accounts, approval of the Annual Report on Form 20-F, and interim dividends);
 - Oversight of risk management and internal control;
 - Approval of significant contracts;
 - Determining succession planning and new Board appointments;
 - Remuneration for the Chair and Executive Directors; and
 - Corporate governance matters.

Roles and responsibilities

- The roles of the Chair, a non-executive role, and the CEO are separate and clearly defined. The Board has agreed their respective responsibilities and set these out in writing. These are available on request from the Company Secretary.

Board Committees

Audit Committee

- Carries out certain oversight functions on behalf of the Board; and
- Assists the Board in fulfilling its responsibilities in relation to internal control and financial reporting.

More information on the Committee's composition and its role and activities during the year are on pages 130-133.

Safety, Environment and Sustainability Committee [A]

- Carries out certain oversight functions on behalf of the Board; and
- Advises the Board on safety, the environment including climate change, and Shell's overall sustainability performance.

More information on the Committee's composition and its role and activities during the year are on page 128.

Nomination and Succession Committee

- Leads the process for appointments to the Board;
- Recommends Board appointments and re-appointments;
- Reviews and makes recommendations on succession planning; and
- Reviews and makes recommendations on corporate governance guidelines.

More information on the Committee's composition, and its role and activities during the year, including its recommendations made to the Board on the application of the Code, are on pages 126-127.

Remuneration Committee

- Determines and agrees with the Board the remuneration policy for the Chair, Executive Directors and senior management of the Company;
- Within the terms of such agreed policy, determines individual remuneration packages for the Chair, and Executive Directors; and
- Monitors and makes recommendations regarding the structures and levels of remuneration structures and levels for other senior executives, if appropriate.

More information on the Committee's composition, and its role and activities during the year are on page 139.

[A] Formerly known as the Corporate and Social Responsibility Committee.

From time to time the Board may create other special ad-hoc Committees to monitor and/or approve certain matters. One such Committee is the Nigeria Special Litigation Committee, which among other things, monitors the status of the OPL-245 litigation and investigations. Its members consist of Linda Stuntz (Chair), Chad Holliday, Euleen Goh and Ann Godbehere.

GOVERNANCE FRAMEWORK continued

BOARD OF DIRECTORS continued

Deputy Chair/Senior Independent Director

- Sounding board for the Chair;
- Serves as an intermediary for the other Directors and shareholders; and
- Leads the annual appraisal of the Chair's performance.

Non-executive Directors

- Appointed by the Board or by shareholders at general meetings and, in accordance with the Code, seek re-election by shareholders on an annual basis;
- Letters of appointment refer to a specific term of office, the provisions of the Code and the Company's Articles of Association;
- Upon appointment, Non-executive Directors confirm they are able to allocate sufficient time to meet the expectations of the role. Appointments are subject to a minimum of three months' notice of termination, and there is no compensation provision for early termination;
- The Non-executive Directors bring a wide range and balance of skills and international business experience. Through their contribution to the Board and Board Committee meetings, respectively, they are expected to challenge and help develop proposals on strategy and bring independent judgement on issues of performance and risk; and
- Before each Board meeting, the Chair and Non-executive Directors meet without the Executive Directors being present. At these "pre-meetings", the Non-executive Directors discuss, among other matters, the performance of individual Executive Directors. A number of Non-executive Directors also meet major shareholders over the course of the year.

EXECUTIVE MANAGEMENT

Chief Executive Officer

- Has overall responsibility for the implementation, by the Executive Committee, of the overall strategy approved by the Board, the operational management of the Company and the business enterprise connected with it; and
- Supported in this by the Executive Committee that he chairs.

Executive Committee

- Operates under the direction of the Chief Executive Officer (CEO) in support of his responsibility for the overall management of Shell's business. The CEO has final authority in all matters of management that are not within the duties and authorities of the Board or of the shareholders' general meeting; and
- Executive Committee members are listed in the senior management biographies on page 111.

GOVERNANCE DOCUMENTS

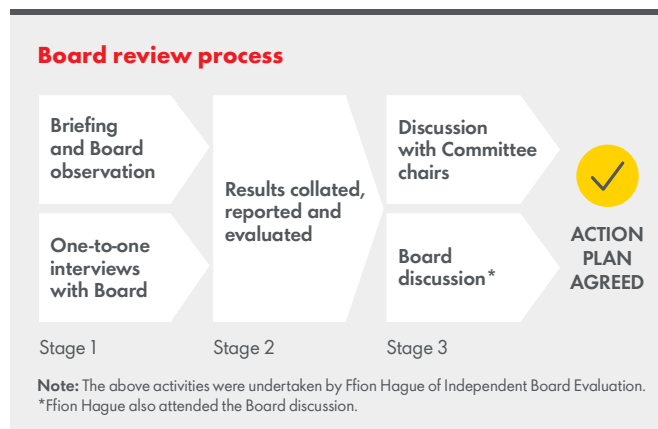
- Articles of Association
- Matters Reserved for the Board
- Board Committee Terms of Reference
- Modern Slavery Statement
- Shell General Business Principles
- Shell Code of Conduct
- Code of Ethics for Executive Directors and Senior Financial Officers

Are available on the website
www.shell.com/investor

BOARD EVALUATION AND ACTIVITIES

The evaluation of the Board was conducted according to the guidance in the Code and was facilitated by Ffion Hague at Independent Board Evaluation. [A]

[A] Ffion Hague and Independent Board Evaluation have no connection or relationship to the Company or to any Director.



Discussion and observation (Stage 1)

A comprehensive brief was given to the assessment team by the Chair in September 2019. The evaluation team also observed Board and Committee meetings in October 2019. Copies of all pre-read materials were provided to the evaluation team, for briefing purposes, ahead of the meeting.

In October and November 2019, detailed interviews were conducted with every Director. All participants were interviewed by Ffion according to a set agenda tailored for the Board. Ffion was supported by her colleague for each interview. In addition, Ffion interviewed each Executive Committee member and the Company Secretary.

Analysis (Stage 2)

A report was compiled by the evaluation team based on the information and views supplied by the Board and other interviewees. All views or comments quoted in the report were made by participants during interviews. All recommendations were based on best practice as described in the Code and other current corporate governance guidelines.

Conclusions (Stage 3)

Draft conclusions were discussed with the Chair and subsequently discussed with the whole Board at a meeting in December 2019 with Ffion present. The conclusions of that discussion were recorded in the minutes of the meeting. Following the Board meeting, Ffion gave feedback to Committee Chairs on the performance of each Committee and discussed the report on the Chair's performance with Gerard Kleisterlee, the Senior

Independent Director. In addition, the Chair received a report on individual Directors and provided individual feedback to every Director on their contributions. In January 2020, Gerard led a separate discussion in relation to the performance of the Chair (in the absence of the Chair).

Insight

The feedback from Board Directors was positive throughout, with particular praise for the culture of the Board and the leadership provided by both the Chair and the Chief Executive Officer. Although areas of Board work were identified for improvement, the Evaluation Report clarified that such improvements were to fine-tune versus radically overhaul the Board's performance.

Feedback themes included noting the strength of the relationship between the Board and management team, the Board process and the Board's confidence in the Management.

Accountability – Board Directors are aware of their accountability to a range of stakeholders including shareholders, employees, communities and society at large; and conscious of the societal scrutiny to which Shell is subject.

Strategy – The strategy process is highly regarded, and Directors appreciate the efforts made to keep them updated on key items, for example, on the science behind climate change, via deep dives into various new energies, and through the Board's engagement with external experts. While the Board appropriately challenges management on strategic issues, Directors agree that strategy is a key focus for the business and the Directors feel well informed and engaged on strategic issues. Going forward, the Board noted the need to further consider the prioritisation of the approved strategic ambitions and to ensure that Board time spent on strategic and operational matters was appropriately balanced.

Governance – Directors note that Shell's identification and follow-up of governance and compliance concerns, including with regard to substance and processes, are dealt with well and thoroughly.

Succession – Succession planning and talent management were identified by Directors as a clear area of strength. Directors particularly noted the attention to talent development within the business, evident in the quality of emerging talent for various roles.

Culture – Board culture was another area of strength highlighted by Directors, crediting the Chair for setting a strong lead in this respect. The Board's values are felt to blend well with the Company's own values and Directors actively enjoy their engagement with their fellow Directors and the business.

BOARD EVALUATION AND ACTIVITIES continued

Planned enhancements include

Board Papers – Board papers contain high-quality, data-rich analysis but could benefit from being shortened and less technical. We will therefore continue to enhance the information provided to the Board to ensure the right information is provided in a digestible format while outlining the necessary facts of a given proposal.

Ongoing training – Induction sessions that combine new and existing Directors proved valuable. The same applied for visits to key sites, which also led to increased quality acquaintance time among Directors, time-efficiency for the management team and further opportunities for Non-executive Director workforce engagement.

We will look to build on our current processes with the development of a calendar of Board travel, that all Directors can opt into, aligned to the Board calendar of forthcoming topics. In addition, details of other induction sessions, Committee trips and Chair visits will be shared with Directors enabling them to also attend as appropriate.

Chair

Ongoing performance evaluation – Directors strongly commend the Chair's diligence, openness, Board preparation, knowledge of the business and positive relationship with the Chief Executive Officer. They also highlight his skill in strengthening individual Director performance through coaching and feedback, which he provides in real-time via his regular contact with all Directors between meetings, rather than awaiting the formal annual process, which many found profiled him as the best Chair of their Non-executive Director careers. On the improvement side, Directors relayed to the Chair the organisational feedback they had received regarding the Chair's suggestions or questions to the business sometimes being misinterpreted as instruction requiring specifically responsive extra work versus simply provoking thought or deepening Board understanding which was recognised as the likely actual intention.

A few Directors also queried whether deliberations on certain Board decisions could have been brought forward where feasible. The Chair fully accepted the feedback and agreed to reflect and act upon it.

BOARD ACTIVITIES

A rolling Board agenda is reviewed at Board meetings, providing effective forward management of meetings and focused discussions. The agenda for each Board meeting includes a number of regular and important items, including reports from the Chief Executive Officer, the Chief Financial Officer, other Executive Committee members and from each Board Committees. Further updates are provided from the various business functions and other key functions, including Investor Relations; Health and Safety, Security and Environment; HR; and Legal, as well as the Company Secretary. The Board also considers and approves the quarterly, half-year and full-year financial results and dividend announcements and, at most meetings, considers investment, divestment and/or financing proposals.

To enable purposeful debates and/or focus on particular aspects of agenda topics, including the impact on key stakeholders, Directors have an opportunity to specify information they require to be provided in advance of Board meetings.

As in previous years, certain Board Committees and Non-executive Directors conducted site visits of various Shell operations and overseas offices. These visits were designed to provide Directors with first-hand insights into certain key portfolio positions. Directors also held various workforce engagements in these locations, as well as external stakeholder engagements, where feasible.

Some of the activities and areas of Board focus from the year, and where not described in further detail elsewhere in this Report, are summarised in the table below.

Topic	Discussion/Activity/Updates included	Examples of Outcome/Progress	Stakeholders considered
Strategy and management			
Management Day	<ul style="list-style-type: none"> Reviewed and discuss the communications for the 2019 Management Day; Reviewed and discussed Messaging to clarify Shell's Net Carbon Footprint ambition; and Considered trading, capital efficiency and supply chain management. 	<ul style="list-style-type: none"> Considered feedback from the investor community regarding progress towards a world-class investment case; and Feedback from investors on sustainability of medium-term growth potential. 	A E F
External business environment	<ul style="list-style-type: none"> Frequent updates on activity occurring within industries and political environments in which Shell operates. 	<ul style="list-style-type: none"> Considered potential risks and mitigation, where possible. 	A B D E

A Investor Community B Employees/Workforce/Pensioners C Regulators/Governments/NGOs D Communities E Customers F Suppliers/Strategic Partners

Topic	Discussion/Activity/Updates included	Examples of Outcome/Progress	Stakeholders considered
Risk management and internal controls			
Safety and Environment	<ul style="list-style-type: none"> In addition to regular updates from Management on health, safety, security and the environment, each Board meeting begins with a reflection or anecdote from a Director or Executive Committee member on the topic of values and/or safety. 	<ul style="list-style-type: none"> In Board meetings, Directors use learnings gained outside Shell to provide perspective and diversity of thought to Board discussions. At times, the Executive Directors have also provided practical commentary and examples of how safety has permeated Shell culture. 	B D
Risk management and internal control	<ul style="list-style-type: none"> Review Risk Report, covering external trends, proposed changes to the Group's strategic and operational risks and deeper analysis of the Conduct Risk Register. 	<ul style="list-style-type: none"> Proposed changes. 	B C D
Board membership and other appointments			
Board membership, other appointments	<ul style="list-style-type: none"> Directors' tenure, external commitments, conflicts of interests and succession planning. 	<ul style="list-style-type: none"> Policy for approving external commitments. Non-executive Director appointments and changes to Committee membership. 	A E F
Talent overview and senior succession review	<ul style="list-style-type: none"> RDS Senior Succession and Resourcing Review covering Executive Director and Executive Committee (EC) succession, EC direct reports and the senior executive group. 	<ul style="list-style-type: none"> Enhanced insight of Shell talent and future leaders; and Assurance of robust succession and contingency plans. 	D
Remuneration Committee updates			
Remuneration and reward matters	<ul style="list-style-type: none"> Reporting and society opinions on executive pay, implementation of UK Shareholder Rights Directive, AGM reflections, Remuneration Policy. 	<ul style="list-style-type: none"> The Remuneration Committee accelerated a planned 2020 policy change which would withdraw element of CEO and CFO bonuses, making these effective from 2019, following consideration of the views of proxy voting firms and other key stakeholders. 	A B E
Corporate governance matters			
Distributions to shareholders	<ul style="list-style-type: none"> Reviewed dividend payment process in conjunction with strategic ambition of world-class investment case; and Discussed the dividend payments that had remained unclaimed by shareholders for a period of more than twelve years. 	<ul style="list-style-type: none"> Streamlining the dividend payment process by introducing a US dollar option and moving to fully electronic settlement in US dollars, euros and sterling; and Agreed that the payments discussed should be forfeited (as per the Articles), and donated to The Shell Foundation. 	A B E
Governance	<ul style="list-style-type: none"> Ethics and compliance, including how to continue to build a strong corporate culture; Senior management succession and corporate governance developments; Modern Slavery Statement and assurance; The Code, changes to process and reporting; Other regulatory and legislative requirements; and Review and assessment of Shell's governance practices against the new Code. 	<ul style="list-style-type: none"> HR strategy on senior succession and regulatory/legislative disclosures approved; and New requirements outlined in the Code were discussed and agreed. 	B C D

A Investor Community B Employees/Workforce/Pensioners C Regulators/Governments/NGOs D Communities E Customers F Suppliers/Strategic Partners

UNDERSTANDING AND ENGAGING WITH OUR STAKEHOLDERS

Shell's commitment to public collaboration and stakeholder engagement is inherent in our three strategic ambitions, most notably in our ambitions to thrive through the energy transition and sustain a strong societal licence to operate. Understanding the views and interests of our key stakeholders is important to the Board, and the Directors have taken steps to consider stakeholders' views in Board discussions and decision-making, as described on page 121. In addition to direct Board engagement, significant levels of engagement are undertaken by the broader business ahead of many of Shell projects or activities. This engagement is often governed by formulated policies, control frameworks, regulation, legislation and may differ by region.

We have categorised our key stakeholders into six groups. Where appropriate, each group is considered to include both current and potential stakeholders. Shell stakeholders include: Investor Community, Employees/Workforce/Pensioners, Regulators/Governments/NGOs, Communities, Customers and Suppliers/Strategic Partners.

Site visits

The Chair, certain Board Committees and Non-executive Directors conduct site visits of various Shell operations and overseas offices. These visits are designed to provide Directors with first-hand insights into portfolio positions. Directors also held various workforce engagements in these locations, as well as external stakeholder engagements.

New Energies, the Energy Transition and the Shell Power Strategy

During 2019, the Board visited the USA (Colorado and California) and SESCO visited operations in Singapore to gain a better understanding of Shell businesses in these countries and elements of the energy transition. The visits included engagements with different internal and external stakeholders and interest groups which provided the Directors with multiple perspectives and considerations on the energy transition including the impact on communities, companies and Shell itself.

Shareholders

The Board recognises the importance of two-way communication with the Company's shareholders. The Chair, the Deputy Chair and Senior Independent Director, the Chief Executive Officer, the Chief Financial

Officer and the Executive Vice President Investor Relations each meet regularly with major shareholders and report the views of such shareholders to the Board. Committee Chairs also seek engagement with shareholders on significant matters related to their areas of responsibility. Over the year, the Chair met with 76 major shareholders including at roadshows. The Deputy Chair, Senior Independent Director and Remuneration Chair met with 70 shareholders over the course of the year. A variety of topics were discussed.

Shareholders can also contact the Company directly via a dedicated email address or via dedicated shareholder telephone numbers, provided on the inside back cover of this report. Shell's website also contains information for institutional and retail shareholders alike.

The Company's registrar operates an internet access facility for registered shareholders, providing details of their shareholdings. Facilities are also provided for shareholders to lodge proxy appointments electronically. The Corporate Nominee service, facilitated by Equiniti, provides a facility for investors to hold their shares in the Company in paperless form.

Board Governance Event

In the past, the Board has held a governance event, "Board Engagement Day" that is attended by Directors including the Chair, Senior Independent Director, Audit Committee Chair and SESCO Chair. This is a biennial event providing investors with an overview of the Board's roles, activities and its key focus areas including stakeholder engagement. The last event was in December 2018. The event covered topics relevant to the Code including stakeholder engagement expectations, Chair tenure and diversity and inclusion on the Board and in the senior management talent pipeline. Attendees could also provide feedback to Directors via a question and answer session, and also informally over refreshments after the event. The next event is scheduled for the latter part of 2020.

The table below further demonstrates examples of various ways in which the Board or others (providing feedback to the Board) engaged with stakeholders during 2019. Further insight on our engagement with stakeholders can be found within our Sustainability Report and our report on payments to governments, scheduled for publication in April 2020.

Engagement before event	Event/Activity	Engagement following event
Annual General Meeting in the Netherlands & Annual shareholder presentation in London [A]		
Directors engaged with investors ahead of the event on a number of matters, including those being voted on at the AGM.	As well as the Company giving a balanced report of results and progress at each AGM, all shareholders had an opportunity to ask questions in person. Shareholders also engaged with Directors prior to and after the formal business of the AGM and informally over refreshments. A separate engagement not part of the AGM was provided in the UK. Shareholders (predominantly retail investors) heard about the Company's progress and asked questions in person.	A number of additional engagements including follow-up meetings and answering of queries.
The Responsible Investment Annual Briefing [B]		
Directors engaged with investors ahead of the event on a number of matters, including the agenda, which was based on topics of interest. Additional speakers from outside Shell, NGOs and charities also invited.	The addition of non-Shell speakers added an interesting perspective and dimension to the presentations and discussions which covered our three strategic ambitions in the context of sustainable development. The speakers included representatives from the Human Rights & Business Initiative, the International Union for the Conservation of Nature, and the World Business Council of Sustainable Development. This event also served as an excellent opportunity to hear from investors and other stakeholders on Environmental, Social and Governance issues which is gaining prominence as a topic amongst the stakeholder community.	Following the event, there were a number of additional engagements including follow-up meetings and presentations with stakeholders.
Engagement with three leading climate scientists		
The Board continued to commit time to this topic throughout the year. The Chair engaged with presenters in preparation for the Board engagement.	This engagement increased the Board's and the Executive Committee's understanding of the underlying science of climate change and helped provide a clearer understanding of this key driver of the energy transition. The engagement included presentations from the scientists and the discussions/presentations: <ul style="list-style-type: none"> were valuable to leaders that are not deep into the science but are charged with navigating the energy transition; built further foundations for future updates as the world's understanding of the science advances and suggests the best sources of information; described key scientific discovery that is underway that could impact actions by governments, business and the population overall; and included subjects that often do not make the popular press coverage but could be important to the organisation. 	The Board recognises the significance and importance of this topic to all stakeholders and Shell's business operations, both now and in the future. The Board reflected on and used learnings from the session as background considering short-term and future investment/divestment decisions, financial and operational plans.

Engagement before event	Event/Activity	Engagement following event
MD19 [C]		
The Board reviewed and approved the Management Day 2019 (MD19) material and outlook and provided feedback to the CEO and CFO.	Engaged with investors on the progress of delivery of Shell's 2020 outlook and plans for positioning the Company for the future of energy, into the next year and further. The session also included presentations by business Directors and a high-level "question and answer" session. Investors were also provided with opportunities to pose detailed business-specific questions in "business breakout panels".	Roadshows with Executive Committee Members were held in London and the US.
Remuneration Committee Chair address		
A number of calls with proxy voting agencies and investors to engage on potential Remuneration Policy changes.	The Chair of the Remuneration Committee/Senior Independent Director provided an update on remuneration and the Company's policy via a video published on the Shell website. He had met and engaged with major investors during a roadshow conducted in November 2019, around choices to be made as part of the 2020 Remuneration Policy update including proposed changes, use of discretionary measures and energy transition in remuneration.	Investors were able to liaise with the Board and discuss their views and opinions; these views were shared with the REMCO, Board and the Chief HR & Corporate Officer to further formulate the policy.
Chair Roadshow		
A number of preparation meetings were held to provide insight into key topics of interest to the investor community.	The Chair of the Board provided an update on the governance of Shell and key investors had opportunities to ask questions to the Chair. Key topics included governance, remuneration, energy transition and business outlook.	Investors were able to engage with the Chair and there was also subsequent dialogue with Investor Relations.
Board visits to Colorado and California		
The Board provided guidance to the planning team ahead of the visit to formulate the agenda and ensure that key areas of interest were covered.	In addition to engagements with various different stakeholders and external experts, the Board met with academics, policy and business leader members of the External Advisory Board, which was established to provide the business with external perspectives in Power and Mobility domains. The Board also visited the National Renewable Energy Laboratory to witness the science and engineering of energy efficiency, sustainable transportation and renewable power technologies. Directors also met with employees and local stakeholders including government representatives, partners and start-ups which Shell has invested in.	
Audit Committee visit to the finance operations centre in Chennai and the IT Hub in Bangalore		
Discussions were held with Audit Committee members ahead of the visit to formulate the agenda and ensure that key areas of interest were covered.	Chennai and Bangalore – Engagements covered presentations from a number of individuals from various parts of the business, on matters such as data analytics and engineering, market risk, reporting and analysis and centres of excellence, digitalisation, and the context of the IT hub, local collaboration with Shell retail operations, process automation and how the business contributes to Shell's overall strategy on digitalisation. Further, the Committee received an overview of the Shell India Diversity and Inclusion Network, and spent time with the women's network, senior leaders and local employees.	The Committee gained an understanding of the operations and met with the local teams in both regions, gaining a deeper understanding of the different processes and challenges the business and its workforce faces.
SESCo visit to Singapore		
Discussions were held with the SESCO Committee members ahead of the visit to formulate the agenda and ensure that key areas of interest were covered.	The Committee met and engaged with a range of representatives from the contractor workforce, communities and social investment partners. Other engagements were held with Shell's partners in the energy transition, a women's network, government and the World Business Council for Sustainable Development. The Directors also had lunch with frontline staff and extended leadership team members. Over the course of these various engagements, a range of topics were considered and discussed including process safety and the environment and societal expectations.	This visit provided Directors with many insights, including Shell's broad and growing capability in developing cleaner energy solutions and the energy transition journey in Singapore.
Director Visits included		
Discussions were held with the respective Directors ahead of the visit to formulate the agenda and ensure that key areas of interest were covered.	Shell QGC Midstream operations in Queensland, Australia The visit included a site tour of the Control room, the LNG plant and the maintenance centre, providing opportunity to engage with the workforce in each location. The Director also spent time with the local leadership team, graduates, engineers and others from the broader functions.	The visits provided Directors further opportunity to engage with the workforce, and gain a deeper understanding of the business and its operations.
	Houston The Director attended the Engagement with Emerging Leaders meeting. This is a formal programme established to develop US-based Senior Executive potential talent. The group meets quarterly with the US Country Coordination Team and is led by the US Country Chair. These meetings provide an opportunity for cross-business collaboration and networking. The Director also toured the remote drilling centre and received an update on how technology has been instrumental in delivering continuous improvement, optimisation and standardisation for the drilling of wells. Further, they received an overview of the lubricants business and spent time with global brand managers, marketing and commercial teams.	
	Permian Basin The Directors received updates from senior leaders, a tour of the central processing facility, drilling rig and other operations.	
	Shell Energy During their visit, Directors met with Shell Energy CEO and the Executive Team. In addition, Directors toured the offices meeting several teams, including leaders from customer services, customer experience, continuous improvement, and telecommunications where they were able to learn more about recent changes to a customer-centric operating model and growth plans for broadband operations.	

[A] The London shareholder meeting was attended by the Chair, CEO and CFO.

[B] Attended by the CEO and Chair of the SESCO, along with the Senior Independent Director.

[C] Attended by CEO and CFO.

WORKFORCE ENGAGEMENT

The publication of the new UK Corporate Governance Code (the “Code”), and The Companies (Miscellaneous Reporting) Regulations 2018, now require companies to report on their engagement with their employees and wider workforce. The Code outlines three suggested workforce engagement approaches. Following an analysis of Shell’s application of the Code in late 2018 and over the course of 2019, the Nomination and Succession Committee (NOMCO) and Board reviewed, considered and discussed Shell Group’s and Board’s existing workforce engagement. Although the Board and NOMCO recognised merit in each of the Code’s workforce engagement mechanism proposals, it noted that boards must consider the size and structure of their business, including its international workforce scope, and select an approach within that context that most practically delivers the underlying spirit and ambition of the Code even if it is not one of the three prescribed approaches. The Code is also supportive of alternate methods where an explanation is provided.

The Code states that its use of the term ‘workforce’ is not meant to align with legal definitions of workforce, employee, worker or similar terms. However, for a global organisation bound by the laws of more than 70 countries, blurring clearly prescribed legal definitions that impact complex issues (such as local HSSE requirements, work contract terms, legal accountability, employment rights) or merging two definitions of the same term could have notable impact on the business, its operations and its stakeholder relationships (including with suppliers). Therefore, Shell considers its workforce to be employees of companies in the Shell Group. However, the Board also engages with others outside of this group (for example, on site visits), and some of this engagement is shared on page 122.

Although our reporting and formal engagement focuses predominantly on our employees, all individuals working on Shell sites (including Shell offices) are required to undertake certain Shell training (for example, HSSE and Code of Conduct-related training). Adhering to the Life Saving Rules (HSSE) and the Code of Conduct compliance obligations is included within our contracts with suppliers, and the Shell Global Helpline is available for all workers to report matters of concern.

For many years Shell has recognised the importance of engaging with its workforce. Engagement is especially important in maintaining strong business delivery in volatile times of change. We therefore strive to maintain a dialogue between management and our workforce – both directly and where appropriate, through representative bodies. Management regularly engages with the workforce through a range of formal and informal channels, including via emails from the Chief Executive Officer and other senior executives, webcasts, townhalls, team meetings, face-to-face gatherings, breakfast briefings, interviews with senior management and online publications via our intranet.

The Board considers effective engagement a key element of its understanding of the Company’s ability to create value as it recognises that our people are our greatest asset. Workforce views can help inform the Board on matters such as operational effectiveness, Shell culture, risk identification and strategy development and delivery.

The Board considers the current workforce engagement approach effective. The information provided in the table below exemplifies various methods of Board engagement.

Board’s Direct Engagements with the Workforce

Informal Engagement

Chair lunches are held from time to time with a select cross-section of employees in various regions. The Board has also held an informal drinks/discussion with select cross-section of employees; for example, to meet future leaders and listen to current issues, challenges, concerns and opportunities.

Nomination and Succession Committee members meet with various senior leaders and high-potential individuals throughout the year. **B E**

The Chair has commented that his meetings provide great insight into the Shell culture and our capacity to deliver on our strategy and purpose. He notes that such direct engagement provides snapshots of employee perspectives across the various countries and cultures within which Shell operates. Further, he considers this a helpful method of engaging with high-potential-talent individuals in an informal environment.

Off-Site Visits

People engagements during Board and/or Committee off-sites. **B A S N**

Meeting talent/leadership teams **B E**

Townhall discussions **B E**

Company Chair engaging with various individuals by attending team meetings Country visits (China, India, Japan, Kazakhstan, Kuwait, Malaysia, the Netherlands, Poland, Singapore, UK and USA). **B A S N**

Through these more formal engagements, the Chair and other Non-executive Directors (either individually or with their Committees) are able to deepen their understanding of how the Company’s purpose, strategy and values are embedded in particular sites and countries. The benefits are mutual as the Board obtains direct insight into local business operations and projects as well as local strengths and challenges while our people have an opportunity to better understand the Board and provide direct feedback on topics of importance to them, their business or function and/or their location.

Employee Network and Related Sessions

Conducted by Directors with for example, female Directors engaging with Shell women’s networks. **S**

Shell female employees who have engaged with female Directors informally (via dinners or through women networks) credit those engagements for not only providing them Board exposure but also in affording them the opportunity to communicate about gender-specific topics and to learn from established female leaders. Directors involved in these engagements likewise note the opportunity to enrich their understanding of the female perspective within Shell as well as the depth of Shell talent and effectiveness of Shell’s Diversity and Inclusion initiatives.

Committee Engagement Key: **B** BOARD **A** AUDIT **S** SESCo
N NOMCO **E** EXEC DIRECTORS

Formal reports and information updates to the Board

Shell People Survey (anonymous survey facilitated externally)

Annual Board discussion to keep it fully apprised of employee engagement levels and quality of leadership across Shell's workforce, as well as a broad range of subjects including collaboration, working conditions, the job, people development, reputation, benefits and rewards, diversity and inclusion, operational excellence, and responsible business. **B E**

The Board considers the Shell People Survey one of its principal tools used to measure employee engagement, motivation, affiliation and commitment to Shell. It provides insights into employee views and has a consistently high response rate. In 2019, the response rate was 85.5%, which was an increase of 3.5% compared to 2018. The average employee engagement score was 78 points out of 100, an increase of one point compared to 2018, and among leading results across a range of industries.

The Board also utilises this engagement to, for example, understand how Shell is leveraging the survey outcomes in: i) data analytics, for example, to identify potential correlative relationships between employee engagement and safety or ethics & compliance incidents; and ii) strengthening Company culture and values.

Senior Succession Resourcing Review

The annual Senior Succession and Resourcing Review focused on the strength of senior leadership and plans for its development and succession, while highlighting the breadth, depth and diversity of its pipeline, the developing profile of the leadership cadre, and recruitment and attrition levels. **B N**

The Nomination and Succession Committee noted the disciplined approach to succession planning and execution, the holistic view taken of leadership and the high levels of information and transparency underpinning it. It particularly noted improved focus on performance and on the talent pipeline of high potential individuals beyond just senior management levels. Along with the results of the annual Shell People Survey, it provided a deeper understanding of culture, leadership talent and the strong levels of employee engagement across the business.

Assessment of key trends and material incidents

Presented by Chief Ethics & Compliance Officer. This is based on the established channels for staff and others to file complaints or report on suspected breaches in relation to the Shell General Business Principles (SGBP), the Code of Conduct or any breaches of law or regulations, including accounting control and auditing concerns. **A S E**

The update covers Shell employees and our wider stakeholder base. The Board (including via the Audit Committee and SESCo) obtains insight into incidents and on reporting levels and remediation which provide indicators of conduct risks and, together with the related Board reports noted below, of the strength of embedding and awareness of the Code of Conduct and SGBP obligations and employees' comfort levels in raising incidents.

The Shell Control Framework

Significant HSSE, Ethics and Compliance, and more broadly, business control incidents are brought to the attention of senior management and Board through regular reporting. **A B S E**

The Board discussed how the organisation could learn more from incidents and how the business could drive safety performance to the next level. The Board requested additional information on incidents from both Shell operated and non-operated ventures and a greater visibility of incidents and investigations.

Conduct Risk Dashboard

Provides a consolidated overview of statistics on Code of Conduct violations. Risk indicators in the Dashboard are potentially linked to organisational culture. Examples that the Dashboard measures are: the number of terminations as a result of formally investigated Code of Conduct violations, and the number of overdues on mandatory Ethics & Compliance training. **B E**

A further update on positive culture and identity leadership is scheduled to be provided, along with an update on conduct risk, to the Board and relevant Board Committees in 2020.

Speaking Up in Shell

Data and insights are provided from the Global Helpline, Shell Ethics & Compliance Organisation and the Shell People Survey. The SESCo endorsed the recommendations with focus on how Speaking Up supports a caring organisation and encourages staff to come forward to raise a concern in good faith. **B S E**

The Audit Committee is kept updated when matters highlighted through the Global Helpline are investigated, and on the associated remediations. For more information please see page 133 within the Audit Committee report.

Assurance activities

Assurance activities, including items raised by Businesses and Functions (through the Group Assurance Letters Process) and independent assurance (from Internal Audit, HSSE, Ethics and Compliance, Reserves Assurance and Reporting), provide additional comfort to the Board of the commitment to high standards of risk management and internal control. The assurance activities ensure that work can be done safely, within regulatory frameworks. **B A E**

The information provided within these reports further support the Board's annual review of the effectiveness of the Group's system of risk management and internal control and feed into the Group Scorecard, which staff bonuses are calculated against.

Other

The Board receives updates on other specific topics. For example, to inform the Board's focus on enhancing ethical leadership and assuring ethical decision-making in the organisation it received updates on the roll out of the Ethical Leadership Expectations Programme (ELEP). **B E**

To better understand the success of the ELEP as reported to the Board, the Chair and the SESCo Chair attended a three-hour ELEP session themselves alongside Shell senior executives. The Chair and SESCo Chair shared feedback from the session in the January 2019 Board meeting with each commending the programme for authentically promoting open and meaningful dialogue and shared learnings on the Company's values and leadership behaviours as well as on the practical dilemmas and business pressures confronting Shell leadership within those topics.

Committee Engagement Key: **B** BOARD **A** AUDIT **S** SESCo
N NOMCO **E** EXEC DIRECTORS

NOMINATION AND SUCCESSION COMMITTEE



CHAD HOLLIDAY

Chair of the Nomination and Succession Committee

Highlights of 2019

- Appointment of two new Executive Committee members
- Appointment of new Non-executive Director and continued discussion on Non-executive Director succession

Priorities for 2020

- Appointment and onboarding of new Non-executive Directors
- Continued discussions on Non-executive Director, and Executive Committee, succession

COMMITTEE ATTENDANCE FOR 2019

Committee member	Member since	Maximum possible meetings	Number of meetings attended	% of meetings attended
Chad Holliday (Chair)	May 19, 2015	5	5	100%
Euleen Goh	July 1, 2019	3	3	100%
Gerard Kleisterlee	May 23, 2018	5	5	100%
Linda Stuntz	June 1, 2016	5	5	100%

“We know we play a crucial role today in selecting those who make the future of Shell. The recognition of that responsibility not only humbles us but also drives our passion to entrust that future into the hands and hearts of those that will safeguard and grow it.”

CHAD HOLLIDAY

Chair

PURPOSE

The Nomination and Succession Committee (the “Committee”) leads the process for appointments to the Board and Senior Management [A] positions, ensures plans are in place for orderly, well planned succession, and oversees the development of a diverse succession pipeline of candidates. Further, it reviews the Company’s policy and strategy on diversity and inclusion, and monitors the effectiveness of diversity initiatives. It makes recommendations to the Board on corporate governance guidelines, as referred to in the Chair’s statement.

[A] “Senior management” refers to the Executive Committee and the Company Secretary.

TALENT MANAGEMENT AND SUCCESSION

The Committee manages Board and Senior Management succession against clear and agreed selection principles. For Non-executive Director succession, the Committee adopted in January 2019 a set of revised Principles for the Strategic Composition of the Board. The principles include both quantitative and qualitative principles, considering both: (i) the overall Board composition and diversity of gender, nationality, background experience and skillsets desired that align with the Company’s strategy and purpose; and (ii) the values, attitudes, and behaviours expected. For Senior Management succession, the principles include process-specific principles, including the identification and development of succession candidates and the long-term nature of the succession planning process. Each Committee meeting includes both sets of principles and, utilising those, the Committee executes changes through a well-defined and diligent process with overall Board engagement. The Committee agrees candidate profiles and meets prospective candidates well ahead of any selection decision being necessary. It also engages the Board early in the process to ensure all Directors have an opportunity to meet and assess prospective candidates. Consequently, some of the leaders whom the Committee and Board have engaged with extensively in the past are now members of the Board or the Executive Committee.

The Committee maintains short, medium and long-term succession plans, and thus an overview of potential candidates multiple years ahead. It oversees a continuous and proactive process of planning, review, engagement and assessment, taking into account the strategic priorities and main factors affecting the long-term success and future of the Company and the associated diversity, skillsets and breadth of perspectives needed to help achieve that in the evolving business environment.

The Committee is fully engaged with the broader senior succession and resourcing across Shell, and with the overall end-to-end approach to talent management that is adopted. This ranges from recruitment to leadership identification and from leadership development to leadership appointment, all of which are underpinned by talent priorities and a commitment to advancing Diversity and Inclusion.

Diversity of leadership

Female representation has steadily improved in recent years. Amongst overall recruitment, Shell companies consistently recruit 40% females, and amongst graduates this is approaching 50%. Female representation in the top 1,400 roles (“Senior Leadership” positions) has been raised by 2.4 percentage points during 2019 to 26.4%, and further improvement is actively pursued. Nationality diversity, such as Asian and American talent, continues to advance in a manner reflective of the business outlook. Senior Leadership is a Shell measure and different from that which we are required to report under the Code, being female representation in Senior Management and their direct reports, where the percentage is 28.9%.

The Committee recognises that improving diversity at each level across the Shell Group is crucial, and therefore takes an active role in reviewing diversity objectives and strategies for the group as a whole, and monitoring the impact of diversity and inclusion initiatives.

More information on diversity within Shell is included within the Our People section on page 99.

Committee Activity

In addition to its considerations regarding succession, the Committee made recommendations on corporate governance guidelines, monitored compliance with corporate governance requirements and made recommendations on disclosures connected with corporate governance. The Committee continues to monitor and review this area, as well as consider whether and how current Company governance matters should be strengthened. Further insight on some of the Committee's areas of consideration in 2019 is provided below.

Succession [A]	Topic of discussion/Example of Board activity
Recommendation	<ul style="list-style-type: none"> ■ Appointment of Neil Carson to the Board; and ■ Changes to the composition of the Board committees.
Review and oversight	<ul style="list-style-type: none"> ■ Royal Dutch Shell Senior Succession Resourcing review.
Oversight	<ul style="list-style-type: none"> ■ Appointment of Wael Sawan as Upstream Director (replacing Andrew Brown); and ■ Appointment of Huibert Vigeveno as Downstream Director (replacing John Abbott).
Governance	Topic of discussion/ Example of Board activity
Governing the Board and its committees	<ul style="list-style-type: none"> ■ Reviewed its Principles for the Strategic Composition of the Board; and ■ Updated its Terms of Reference, and reviewed changes proposed to the Terms of Reference for other Committees and the Matters Reserved for the Board.
Regulation, legislation and other governance-related guidance	<ul style="list-style-type: none"> ■ Alignment to the recommendations within the 2018 UK Corporate Governance Code; ■ Key governance matters impacting the Company's external reporting; and ■ Other governance and regulatory changes agreed or proposed and their impact or potential impact on the Company, its processes and its reporting.
RDS matters	<ul style="list-style-type: none"> ■ Considered any potential conflicts of interest and the independence of the Non-executive Directors; ■ Determined who would undertake the 2019 External Board Evaluation; ■ Reviewed the proposed changes to the Company's Articles of Association, subsequently approved by shareholders at the 2019 AGM; and ■ Reviewed changes proposed to the dividend payment process (announced December 2019).

[A] The Committee was assisted during the year by Russell Reynolds Associates ("Russell Reynolds"), an external global search company whose main role was to propose suitable candidates. Russell Reynolds does not have any connection with the Company other than that of search consultants. The Chair does not participate in discussions regarding his own succession. Russell Reynolds is a signatory to The Voluntary Code of Conduct for Executive Search Firms which aims to improve board diversity.

Director Induction and Training

Following Board appointment, Directors receive a comprehensive induction tailored to their individual needs. This includes site visits and meetings with senior management to enable them to build up a detailed understanding of Shell's business and strategy, and the key risks and issues that Shell faces.

As part of the Board evaluation, director induction was a discussion topic. Directors commented positively on the induction programme and reported that it is comprehensive, well-organised and fully in line with their expectations. Directors shared that they have been able not only to benefit from a comprehensive programme of meetings but also to steer the programme towards their own personal interests and information needs.

Some of the areas Neil Carson's induction has covered are provided below:

Company Operations and Strategy, including:

Strategy & Portfolio; Integrated Gas and New Energies; Downstream, including Chemicals, Retail and Global Commercial; Upstream; and Projects and Technology. Time was spent with the EC members managing these operations and senior leaders from the operations. Further, updates were provided with regard to the internal governance process, the Shell Control Framework, the Board's calendar, minutes from earlier meetings, Company performance, operating plans and key business relationships. Neil also met with the Chief Internal Auditor.

The environment in which we operate, including:

Engagements were held with the Chief Ethics and Compliance Officer, Safety and Environment and senior leaders from the Sustainability Strategy team, and the Global Business Environment team, which is best known for developing forward-looking scenarios to support strategic thinking and direction-setting. Time was also spent with senior leaders from Investor Relations and Group Reporting and the Chief Human Resources and Corporate Director, the Legal Director and the Company Secretary.

Feedback on Board induction

"Given the complexity of the business, I believe that Director induction takes at least a year. The sessions with people in the business benefit from being gradually phased and aid the absorption of information. Site visits are incredibly helpful and can be utilised to a greater extent in the early stages of the programme."

NEIL CARSON

Non-executive Director

SAFETY, ENVIRONMENT AND SUSTAINABILITY COMMITTEE



SIR NIGEL SHEINWALD GCMG

Chair of the Safety, Environment and Sustainability Committee

COMMITTEE ATTENDANCE FOR 2019

Committee Member	Member since	Maximum possible meetings	Number of meetings attended	% of meetings attended
Sir Nigel Sheinwald (Chair of the Committee)	July 1, 2012	8	8	100%
Neil Carson [A]	June 1, 2019	4	3	75%
Catherine J. Hughes	November 1, 2017	8	8	100%
Linda Stuntz	May 23, 2018	8	8	100%

[A] Neil Carson was unable to attend the Committee meeting in October 2019 due to an immovable commitment which was scheduled prior to him joining the Shell Board.

HIGHLIGHTS OF 2019

During 2019, we reviewed the purpose of the Committee and transitioned from the Corporate and Social Responsibility Committee to become the Safety, Environment and Sustainability Committee (the "Committee"). This sharpened focus will allow the Committee to play a more influential role in overseeing the practices and performance of the Company with respect to safety, environment including climate change, and broader sustainability issues.

FOCUS FOR 2020

In 2020, the Committee will continue with the sharpened focus areas established last year. The Committee will use site visits to examine Shell's approach and performance across these focus areas. The Committee will also review Shell's response to developments regarding climate change and the energy transition.

PURPOSE

The Committee assists the Board in reviewing the practices and performance of the Shell Group of companies, primarily with respect to Safety, Environment including Climate Change, and Sustainability.

OVERVIEW

The Committee assesses Shell's overall sustainability performance and provides input into Shell's annual reporting and disclosures on sustainability. It also advises the Remuneration Committee on metrics relating to sustainable development and energy transition that apply to the Executive Committee scorecard and incentive programme.

The Committee also endorses Shell's annual HSSE&SP assurance plan and reviews execution of the plan and audit outcomes.

In addition, it reviews and considers external stakeholder perspectives in relation to Shell's business, and reviews how Shell addresses issues of public concern that could affect its reputation and licence to operate. Examples include plastic waste, human rights, and ethical conduct and culture.

In line with the strategic importance of the Committee's agenda, the Chair and the Chief Executive Officer regularly attend the Committee meetings for discussions on specific topics. The Committee appreciated the assistance throughout the year from the Projects & Technology Business Director, Harry Brekelmans, who continues to be a strong champion for sustainability within Shell.

The overall accountability for sustainability within Shell is with the Chief Executive Officer and the Executive Committee. They are assisted by the HSSE&SP executive team.

ACTIVITIES

During 2019 the Committee reviewed its purpose and updated its terms of reference to ensure it focuses on the areas of most strategic importance to Shell.

It met regularly to review and discuss a range of prioritised topics. These included the safe and responsible operation of Shell's facilities, environmental protection and greenhouse gas emissions, major incidents that impact safety and environmental performance, progress towards meeting Shell's Net Carbon Footprint Ambition and short-term targets, and climate change and the energy transition.

The topics discussed in greater depth included personal and process safety, Shell's Net Carbon Footprint Ambition and the energy transition, and Shell's ethics programme. The Committee also reviewed Shell companies' operations and the challenges faced in Nigeria.

SITE VISITS

One major site visit was conducted in 2019, which was to Singapore. Over three days the Committee met with Shell employees, staff, contractors, Government officials, local community leaders, and representatives from local non-governmental organisations to gain a deeper understanding of Shell's business in Singapore. The Committee visited refinery operations at Pulau Bukom and chemicals operations at Jurong Island, and reviewed Shell's developing New Energies businesses in the country.

AUDIT COMMITTEE REPORT



ANN GODBEHERE
Chair of the Audit Committee

Focus areas for 2019

- First-year application of IFRS 16 Leases
- Shell's Trading and Supply Control Framework
- Net Carbon Footprint Assurance and Reporting Framework
- Oil and Gas Reserves Control Framework

Priorities for 2020

- Decommissioning
- Integrated Risk Management
- New Business Models and Ventures
- Pensions

"The primary role of the AC is to assist the Board in fulfilling its oversight responsibilities in areas such as the integrity of financial reporting, the effectiveness of the risk management framework and internal control system as well as consideration of compliance matters."

ANN GODBEHERE

Dear Shareholders,

I am pleased to present our Audit Committee Report for 2019, having assumed chairmanship of the Audit Committee (AC) when Euleen Goh stepped down in June of last year.

The primary role of the AC is to assist the Board in fulfilling its oversight responsibilities in areas such as the integrity of financial reporting, the effectiveness of the risk management framework and internal control system as well as consideration of compliance matters. We are also responsible for assessing the quality of the audit performed by and the independence and objectivity of the external auditor, and making a recommendation to the Board on the appointment or reappointment of the external auditor. Further, we oversee the work and quality of the internal audit function.

I meet regularly with the Chief Financial Officer, EVP Taxation and Controller, Chief Internal Auditor and the external auditor. Further, these same individuals attend every AC meeting as well as any other members of Shell's management, as necessary, to provide in-depth analysis on specific topics or on more detailed technical matters that may arise.

Over the course of a year, the AC has a rolling agenda covering a variety of standing matters such as the control framework for the reporting of Shell's oil and gas reserves; information risk management; tax matters; and briefings from the Chief Internal Auditor on the effectiveness of Shell's risk management and internal control system and on outcomes of significant audits and notable control matters. Specific attention is given to topics that we consider particularly significant, including issues and judgements relating to Shell's Consolidated Financial Statements, as discussed in more detail later in this report. In 2019 in addition to standing matters, the AC addressed a number of areas of special focus including evaluating the first year of application of the new accounting standard IFRS 16 Leases; Shell's Trading and Supply control framework; and the control framework for the reporting of Shell's Net Carbon Footprint ambition. The AC visited Shell's advanced security operations in the Netherlands, the finance operations centre in Chennai and the IT Hub in Bangalore. With these site visits we deepen our understanding of the operations in the respective locations and how they interface with Shell's business functions. The visits also provide the AC with an opportunity to engage with a cross-section of Shell staff in each location.

In closing I would like to take this opportunity to thank Euleen for her excellent chairmanship of the AC since 2016 and for the valuable insights she provided as both a member since September 2014 and as the Chair.

ANN GODBEHERE
Chair of the Audit Committee
March 11, 2020

AUDIT COMMITTEE REPORT continued

COMPOSITION AND MEETINGS OF THE AUDIT COMMITTEE

During 2019, the members and meeting attendance of the AC were as follows:

Committee Member	Member since	Maximum possible meetings	Number of meetings attended	% of meetings attended
Ann Godbehere (Chair)	May 23, 2018	6	6	100%
Euleen Goh [A]	September 1, 2014	3	3	100%
Roberto Setubal	October 1, 2017	6	6	100%
Gerrit Zalm	March 8, 2017	6	6	100%

[A] Euleen Goh stood down as Chair and a member of the AC on June 30, 2019.

All members of the AC are financially literate, independent Non-executive Directors. In respect of the year ended December 31, 2019, for the purposes of the UK Corporate Governance Code, Ann Godbehere qualifies as: a person with “recent and relevant financial experience” and competence in accounting; and, for the purposes of US securities laws, is an “audit committee financial expert”.

The experience of the AC members outlined on page 130 demonstrates that the AC as a whole has competence relevant to the sector in which Shell operates, as well as the necessary commercial, regulatory, financial and audit expertise required to fulfil its responsibilities. The AC members have gained further knowledge and experience of the sector as a result of their Board membership and through various site visits since their respective appointments.

The AC covers a variety of topics in its meetings. These include both standing items that the AC considers as a matter of course, typically in relation to the quarterly financial reporting, control matters, accounting policies and judgements and reporting matters, and a range of topics relevant to Shell’s control framework.

The AC invites the Chief Financial Officer, the Legal Director, the Chief Internal Auditor, the Executive Vice President Taxation and Controller, the Vice President Accounting and Reporting and the external auditor to attend each meeting. The Chief Executive Officer attends each meeting where the quarterly, half-year and year-end results are discussed. The Chair of the Board also regularly attends the meetings. Other members of management attend when requested. The AC regularly holds private sessions separately with the external auditor and the Chief Internal Auditor without members of management, except for the Legal Director, being present.

RESPONSIBILITIES

The roles and responsibilities of the AC as set out in its Terms of Reference are reviewed annually, taking into account relevant regulatory changes and recommended best practice. The key responsibilities of the AC include, but are not limited to:

- Evaluating the effectiveness of the system of risk management and internal control;
- Reviewing the integrity of the financial statements, including annual reports, half-year reports, and quarterly financial statements;
- Reviewing and discussing with management the appropriateness of judgements involving the application of accounting principles and disclosure rules;
- Advising the Board whether the Annual Report is fair, balanced and understandable and provides the information necessary for shareholders to assess Shell’s position and performance, business model and strategy;
- Reviewing the functioning of the Shell Global Helpline and reports arising from its operations;

- Overseeing compliance with applicable legal and regulatory requirements, including monitoring ethics and compliance risks;
- Monitoring the qualifications, expertise, resources and independence of both the internal and external auditor;
- Assessing the internal and external auditor’s performance and effectiveness each year; and
- Recommending to the Board the appointment or reappointment of the external auditor.

The AC keeps the Board informed of its activities and recommendations and the Chair of the AC provides an update to the Board after every AC meeting. The AC promptly reports concerns to the Board if it is not satisfied with or believes that action or improvement is required concerning any aspect of financial reporting, risk management and internal control, compliance or audit-related activities.

A copy of the AC’s Terms of Reference can be found at www.shell.com.

ACTIVITIES

During 2019, the AC received comprehensive reports from management and the external auditor on a variety of topics related to management controls and accounting policies, practices and reporting. The AC also reviewed whistleblowing reports and internal audit reports, and considered management’s responses and conclusions to the various findings in these reports.

In addition to the items discussed under significant issues on page 133, the AC also dedicated time to the following matters during 2019:

- **Trading and Supply’s Control Framework.** Following its 2018 visit to the Trading and Supply office in London and given the growth in this area, the AC continued to focus on key control matters and improvements in processes underway within Trading and Supply. The AC was briefed on various actions which management is undertaking to further strengthen controls, including system controls and new hires in the areas of compliance and risk management;
- **Shell’s Net Carbon Footprint Control Framework.** Following Shell’s announcement to link a Net Carbon Footprint target and other measures to executive remuneration starting in 2019, the AC reviewed the processes and procedures governing the annual preparation and assurance of Shell’s Net Carbon Footprint value. The AC considered the methodology, key aspects of the Net Carbon Footprint model, important control points, assurance mechanisms to validate the integrity of the data and disclosure, and the process for managing and verifying any changes to the model;
- **Tax risks.** In addition to the regular review of Shell’s tax position, the AC discussed with management the key tax risks stemming from the evolving tax landscape, including intensified audit scrutiny and increasing demands for transparency. The AC also discussed measures underway in response to these trends and developments, including for example Shell’s publication of its first Tax Contribution Report in 2019;
- **Information Risk Management.** The Chief Information Officer briefed the AC on the activities undertaken in 2019 with respect to information risk management, information security controls, security improvement initiatives and Shell’s cyber monitoring and defence capabilities and controls. The AC discussed with the Chief Information Officer the evolving digital landscape and the steps management is taking to manage change, including planned activities for 2020; and
- **Oil and Gas Reserves Control Framework.** The AC was briefed on the framework in place to ensure accurate reserve information is reported in an efficient manner. The AC considered the processes and controls in place to assure compliance with reporting requirements and annual updates to maintain a robust framework.

The AC also reviewed: the year-end reported proved oil and gas reserves, including management judgements and adjustments made to reflect changes in geological, technical, contractual and economic information, the Brent crude oil and Henry Hub natural gas long-term price assumptions; estimated refining margins; discount rates used for financial reporting, particularly with respect to impairment testing and decommissioning and other provisions (see Note 2 to the "Consolidated Financial Statements" on pages 195-204 for further information); and the effectiveness of financial controls.

The AC discussed with the Chief Ethics and Compliance Officer his report on compliance matters, including an overview of the effectiveness of the Shell ethics and compliance programme in managing ethics and compliance risk in Shell's business activities, regulatory developments and compliance risks. The AC also discussed investigations of cases involving ethics and compliance concerns. The AC discussed management's findings in such cases to satisfy itself that a rigorous process had been followed, and, where appropriate, learnings had been embedded by management into the systems and controls of the organisation.

The AC was briefed on litigation matters (see "Governance Framework" on page 117 and Note 25 to the "Consolidated Financial Statements" on pages 235-237); new regulatory requirements, including the UK Financial Reporting Council's (FRC's) 2018 UK Corporate Governance Code, and various market studies and proposals into the external audit market. The AC was also briefed on corporate governance developments, including the EU Sustainable Finance initiatives and related legislative proposals.

In March 2019, the AC visited the advanced security operations in the Netherlands and in May 2019, the finance operations centre in Chennai and the IT Hub in Bangalore. These visits provided the opportunity for the AC to gain a deeper understanding of the various activities undertaken in each location including new technologies and digital opportunities, and how they support Shell's business activities. Topics discussed during the site visits included: threat intelligence; incident management; vulnerability management and forensics; use of data analysis; bots; data engineering; market risk analyses; impairment analysis process; digitalisation; new applications/solutions development process; process automation; and Information Technology General Controls. The AC was provided with information on the external environment and the relevant regulations within each location's operations. During the visits to the Chennai and Bangalore sites, the AC was also briefed on Shell's operations in India.

In 2019, the AC updated its Terms of Reference to reflect applicable provisions from the 2018 UK Corporate Governance Code published by the FRC, including the Chair's engagement with the Company's Shareholders on significant matters related to the AC's responsibilities and the AC's oversight of the audit tender process. The Terms of Reference were also updated to reflect the AC's responsibilities regarding Shell's Global Helpline as well as ethics and compliance risks.

As part of a review of Shell's external reporting, the decision was taken to produce a separate Annual Report and Form 20-F beginning with fiscal year 2019. The AC provided its input on the merits of this initiative and considered the control framework which has been put in place to ensure the disclosures in both reports comply with relevant requirements.

The AC discussed the Company's 2019 Annual Report, half-year report and quarterly unaudited interim financial statements with management and the external auditor. The AC advised the Board that in its view the

2019 Annual Report including the financial statements for the year ended December 31, 2019, taken as a whole, is fair, balanced and understandable and provides the information necessary for shareholders to assess Shell's position and performance, business model and strategy (see "Governance" on page 114). To arrive at this conclusion, the AC critically assessed drafts of the 2019 Annual Report including the financial statements and discussed with management the process undertaken to ensure that these requirements were met. This process included: verifying that the contents of the 2019 Annual Report are consistent with the information shared with the Board and management during the year to support their assessment of Shell's position and performance; ensuring that consistent materiality thresholds are applied for favourable and unfavourable items; considering comments from the external auditor; and receiving assurance from the Executive Committee (EC). The AC further reviewed and considered the Directors' half-year and full-year statements with respect to the going concern basis of accounting. As noted in the viability statement, the Board also reviews the strategic plan which takes account of longer-term forecasts and a wide range of outlooks. Factors considered included: the impact of commodity prices; exchange rates; future carbon costs; major agreements such as LNG contract renewals; planned growth programmes; the financial framework; Shell's business portfolio developments; the project funnel to support future growth; and running models of the financial impact of certain of Shell's principal risks materialising using severe but possible scenarios. The AC considered the mitigating measures and sensitivities that management had applied to the modelling of such scenarios when evaluating the viability statement. The AC also considered external commentaries suggesting that viability statements should be extended beyond a period of three years and concluded that the three-year period selected by the Board for the review of Shell's prospects, in line with the operating plan, remained appropriate. The AC supported the inclusion of Shell's viability statement in "Governance" on page 165 and considered such statement in line with best practice guidance issued by the FRC.

The AC considered and approved the internal audit function's annual audit plan, including focus areas for 2019 comprising of management controls of IT systems and infrastructure, information and data, operational assets and businesses, contracting and procurement, resource and project delivery, and ethics and compliance. The AC also considered and approved proposed updates to the Shell Internal Audit Charter which take into account the revised UK Corporate Governance Code and other regulatory changes. The AC assessed the performance of the internal audit function under the new Chief Internal Auditor, who was appointed with effect from September 2018, as effective. The AC also assessed the performance of the Chief Internal Auditor. With respect to the external auditor, the AC considered the annual external audit plan (including assessing whether the planned materiality levels and proposed resources to execute the audit plan were consistent with the audit scope) and approved related remuneration to ensure that the level of fees would allow an effective and high-quality audit to be conducted by the external auditor.

SYSTEM OF RISK MANAGEMENT AND INTERNAL CONTROL

The AC reviewed reports on risks, controls and assurance, including the annual assessment of the system of risk management and internal control, in order to monitor the effectiveness of the procedures for internal control over financial reporting, compliance and operational matters. This included the Company's evaluation of the internal control over financial reporting as required under Section 404 of the Sarbanes-Oxley Act.

AUDIT COMMITTEE REPORT continued

AUDIT COMMITTEE ACTIVITIES DURING 2019

Activities performed	Frequency
Reporting	
Reviewed Shell's accounting policies and practices, including compliance with accounting and reporting standards	Q
Reviewed the appropriateness of material judgements and the interpretation and application of accounting principles	Q
Considered the integrity of the year-end financial statements and recommended to the Board whether the audited financial statements should be included in the Annual and statutory reports	A
Considered the integrity of the half-yearly report and quarterly financial statements	Q
Reviewed management's assessment of going concern and longer-term viability and endorsed the annual viability statement	P
Reviewed Shell's policies with respect to earnings releases; financial performance information and earnings guidance; oil and gas reserves accounting and reporting; and significant financial reporting issues	Q
Reviewed the internal controls in relation to financial reporting	P
Advised the Board of the AC's view on whether taken as a whole, the Annual Report is fair, balanced and understandable and provides the information necessary for shareholders to assess Shell's position and performance, business model and strategy.	A
Assessed management's response to significant audit findings and recommendations	P
Risk Management and Internal Control	
Monitored the effectiveness of the Shell's risk management and internal control system	P
Received briefings on regulatory developments	P
Reviewed management's SOX 404 assessment	A
Discussed the control framework related to Shell's Net Carbon Footprint	P
Considered the control framework related to oil and gas reserves	P
Discussed significant matters arising from the internal audit with the Chief Internal Auditor, management and Ernst & Young LLP (EY)	Q
Evaluated the quality, efficiency and effectiveness of the internal audit function including the competence, qualifications, expertise, compensation and budget	A
Reviewed and approved the internal audit function's remit, charter and audit plan	A
Assessed the performance of the Chief Internal Auditor	A
Reviewed significant legal matters with Shell's Legal Director	Q
Discussed and reviewed Finance Group's succession planning	A
Reviewed the Chief Financial Officer's significant business and investment transactions for potential conflicts or related party transactions	A
Assessed the Chief Financial Officer's performance	A
Reviewed Shell's information risk management	P
Reviewed Shell's tax function, key tax risks and discussed evolving area of tax transparency	P
Received briefings regarding Shell's Trading and Supply control framework	P
Reviewed and discussed Shell Finance's IT strategy	P
External Auditor	
Considered the independence of EY	A
Reviewed and approved the engagement letter for EY's annual audit of the Company's consolidated and parent company financial statements	A
Approved the remuneration for audit and non-audit services, including pre-approval of permissible non-audit services	Q
Considered the annual external audit plan and monitored the execution and results of the audit	P
Monitored the qualifications, expertise, resources and independence and objectivity of EY	A
Reviewed the Company's representation letter prior to signing by management	A
Assessed the performance and effectiveness of EY, the audit process, the quality of the audit, the handling of key judgements by EY, and EY's response to questions from the AC	P
Recommended to the Board for the re-appointment of EY to be put to the Company's shareholders for approval at the Annual General Meeting (AGM)	A
Compliance and Governance	
Monitored the receipt, retention, investigation and follow-up actions of complaints received, including those from the Shell Global Helpline	P
Reviewed with the Chief Ethics and Compliance Officer the implementation and effectiveness of the Ethics and Compliance programme and function	A
Discussed compliance with applicable external legal and regulatory requirements	P
Performed an evaluation of the AC's performance and effectiveness	A
Reviewed and updated the AC's Terms of Reference	P

Committee Activity Key: A Annually Q Quarterly P Periodically

SIGNIFICANT ISSUES

The AC assessed the following significant issues, including those related to Shell's 2019 Consolidated Financial Statements. The AC was satisfied with how each of the issues below was addressed. As part of this assessment, the AC received reports, requested and received clarifications from management, and sought assurance and received input from the internal and external auditors.

Significant issues

Subject	Issue	How the AC addressed the issue
DISPOSALS		
See Notes 5 and 8 to the "Consolidated Financial Statements" on pages 209 and 210-213.	Several significant disposals were completed in 2019. Prior to disposal, judgement is required in determining whether a sale is highly probable. If it is, the asset should be classified as held for sale, which is a trigger for impairment testing. Judgement may also be required when accounting for the disposal, for example in estimating the amount of any liabilities retained by Shell.	The AC considered the application of the held-for-sale classification, as well as the accounting for any ensuing disposals, including the divestment of Upstream assets in Denmark and US Gulf of Mexico, as well as Downstream assets in the US and Saudi Arabia. Particular attention was given to the assessments of any impairment indicators, as well as the accounting for any retained obligations, together with the assumptions used in determining any resulting charges and the tax treatment thereof.
IMPAIRMENTS		
See Notes 2 and 8 to the "Consolidated Financial Statements" on 198-204 and 210-213.	The carrying amount of an asset should be tested for impairment when there is an indication of possible change in carrying value such as a reduction in performance, other than short term, or being classified as held for sale.	The AC challenged whether there were indicators of impairment or reversals of previously recorded impairments and carefully considered the impairment assessments that were performed. In so doing, the AC reviewed the oil and gas price and refining margin outlooks against market developments and benchmarks. The potential impact of certain price sensitivities was also considered, together with the relevant discount rates applied. The AC also reviewed other significant inputs to impairment assessments, including proved oil and gas reserves. The AC also considered the potential impact of climate change and energy transition.
TAXATION		
See Notes 2 and 16 to the "Consolidated Financial Statements" on pages 198-204 and 220-222.	The determination of tax assets and liabilities requires the application of judgement as to the ultimate outcome, which can change over time depending on facts and circumstances. In particular, the recognition of deferred tax assets requires management to make assumptions regarding future profitability and is therefore inherently uncertain.	The AC considered tax exposures, including those associated with 2019 disposals. The AC also evaluated the appropriateness of the recognition of deferred tax assets. The AC deemed the resulting assessments of uncertain tax exposures and the recognition of deferred tax assets to be reasonable.
FIRST-YEAR APPLICATION OF IFRS 16		
See Note 3 to the "Consolidated Financial Statements" on page 204.	With effect from January 1, 2019, IFRS 16 Leases replaced IAS 17 Leases. Under the new standard, all lease contracts, with limited exceptions, are recognised in the financial statements by way of right-of-use assets and corresponding lease liabilities. Shell applied the modified retrospective transition approach without restating comparative information. In March 2019, the IFRS Interpretation Committee (IFRIC) decision on recognition of lease liabilities in unincorporated joint operations was concluded. During Q2 and Q3 2019 potential exposures were assessed to determine where Shell, as operator, has primary responsibility for the lease liability and would therefore be required to recognise these leases.	In 2018, the AC appraised and approved accounting policy changes resulting from the implementation of IFRS 16. In 2019, the AC reviewed management's analysis of the first-year application of IFRS 16, including key judgements, and concurred with their recommendations. The AC also reviewed the impact of the application of IFRS 16 on the relevant Alternative Performance Measures (APM). The AC assessed management's application of the IFRIC's decision regarding the recognition of lease liabilities by a joint operator in relation to its interest in an unincorporated joint operation.
DISCOUNT RATE FOR PROVISIONS		
	A review was carried out to consider the discount rate applied for provisions due to a lower rate for 30-year US Treasury bonds. Based on management's review the discount rate for provisions was lowered from 4% to 3% in 2019. This was applied to provision balances at December 31, 2019.	The AC considered the impact that this change will have in relation to increasing provisions. There was specific discussion on the impact to decommissioning and restoration provisions and corresponding assets.

INTERNAL AUDIT

The internal audit function is an independent and objective assurance function which supports Shell in improving its overall control framework. The internal audit function contributes to the maintenance of a systematic and disciplined approach to evaluate and improve the design and effectiveness of Shell's risk management, control and governance processes. The primary role of the internal audit function, through its assurance and investigation activities, is to safeguard value by protecting Shell's assets, reputation and sustainability in relation to the organisation's defined goals and objectives.

The AC defines the responsibility and scope of the internal audit function and approves its annual plan. The Chief Internal Auditor reports functionally to the Chair of the AC and administratively to the Chief Financial Officer. The Chair of the AC approves, in consultation with the Chief Financial Officer, all decisions regarding the performance evaluation, appointment or removal of the Chief Internal Auditor.

The Chief Internal Auditor periodically assesses whether the purpose, authority, and responsibilities of the internal audit function continue to enable it to accomplish its objectives. The results of this periodic assessment are communicated to the EC and AC. The Chief Internal Auditor maintains an internal quality assurance and improvement programme covering all aspects of the internal audit activities, to evaluate the conformance of these activities with the Chartered Institute of Internal Auditors' standards. The programme also assesses the efficiency and effectiveness of the internal audit activities and identifies opportunities for improvement. The results of this annual assessment are communicated to the EC and AC and include a reconfirmation to the AC of the continued validity of the charter of the internal audit function, or proposals for an update. At least every five years, the effectiveness and quality of the internal audit function are assessed externally and the report shared with the AC. An independent assessment of internal audit was conducted in 2018 and the next such external assessment is planned to take place in 2023.

AUDIT COMMITTEE REPORT continued

EXTERNAL AUDITOR

The AC is responsible for considering whether, in order to ensure continuing auditor quality and/or independence, there should be a rotation of the independent registered public accounting firm, including consideration of the advisability and potential impact of selecting a different independent public accounting firm. The Company's current external auditor, EY, was first appointed at the AGM in May 2016 following the conclusion of a competitive tender process. The Company has complied with The Statutory Audit Services for Large Companies Market Investigation (Mandatory Use of Competitive Tender Processes and Audit Committee Responsibilities) Order 2014 for the 2019 financial year.

At the AGM in May 2019, a resolution to reappoint EY as external auditor until the conclusion of the next AGM was approved by shareholders. There are no current plans to retender the appointment. The current external audit partner is Allister Wilson, who has held this position since EY's initial appointment as external auditor in 2016 and will therefore be rotating off the Shell audit following the 2020 audit engagement. As part of its annual assessment of EY, the AC discussed the upcoming partner rotation and measures EY has taken for an orderly transition.

The AC evaluated the objectivity and independence of EY and the quality and effectiveness of the external audit process. As part of its evaluation, the AC, considered: (i) the results of Shell management's internal survey relating to EY's performance over the financial year 2019; (ii) views and recommendations from management and the Chief Internal Auditor; (iii) EY's audit quality priorities and actions by EY as part of its sustainable audit quality programme; and (iv) the AC's own experiences, including interactions throughout the year with the external auditor. Key criteria of the evaluation included: professionalism in areas including competence, integrity and objectivity; constructive challenge of management and key judgements; efficiency, covering aspects such as service level and innovation in the audit process; thought leadership and value added; and compliance with relevant legislative, regulatory and professional requirements. Taking into account the above, the AC is satisfied that EY has continued to provide a high-quality and effective audit in its fourth year as auditor and maintained its independence and objectivity.

During 2019, there was no review of EY's audits of Shell's Consolidated Financial Statements by the Audit Quality Review (AQR) team of the FRC.

Following due consideration, the AC has recommended to the Board to propose at the 2020 AGM that EY be reappointed as the external auditor of the Company for the year ending December 31, 2020. There are no contractual obligations that restrict the AC's ability to make such a recommendation.

As required under UK and US auditing standards, the AC received a letter from EY confirming its independence.

NON-AUDIT SERVICES

The AC maintains an independence policy in respect of the provision of services by the external auditor. The AC regularly reviews this policy for necessary changes in response to changes in related standards and regulatory requirements. Following the issuance of the Revised Ethical Standards by the FRC in December 2019, the AC updated its independence policy to reflect these new standards.

This policy, designed to safeguard auditor objectivity and independence, includes rules relating to the provision of audit services, audit-related services and other non-audit services, and stipulates which services require specific prior approval by the AC.

The policy also defines prohibited services that are not to be provided by the auditor as these represent a risk to external auditor independence. Prohibited services are any that relate to management decision-taking or

any other service that would compromise auditor independence or the perception thereof. These prohibited services include all services listed as prohibited in the UK and US auditor independence rules.

For certain services that are not prohibited, because of the knowledge and experience of the external auditor and/or for reasons of confidentiality, it can be more efficient or prudent to engage the external auditor rather than another party. This is particularly the case in relation to audit-related assurance services that are closely connected to the audit function where the external auditor has the benefit of knowledge gained from work already performed as part of the audit.

Under the policy, the AC will only approve services to be carried out by the external auditor or its affiliates where such services do not present a conflict of interest risk in fact or in appearance. The AC reviews quarterly reports from management on the audit and non-audit services reported in accordance with the policy or for which specific prior approval from the AC is being sought. To the extent that the fee value of an additional audit service contract does not individually exceed \$50,000 (as from March 15, 2020: \$100,000), then no prior approval of the AC is required. All non-audit services where the fee for an individual contract exceeds \$100,000, including audit-related services, require individual prior approval by the AC. In each case where the audit or non-audit service contract does not exceed the relevant threshold, the matter is subsequently reported at the next quarterly AC meeting.

The scope of the non-audit services contracted with the external auditor in 2019 consisted mainly of interim reviews and other audit-related assurance services. The associated compensation for these audit-related services and other non-audit services amounted to 4% and 1%, respectively, of the external auditor's audit and audit-related remuneration.

FEES

Note 28 to the "Consolidated Financial Statements" on page 238 provides details of the auditor's remuneration.

AC EVALUATION

The AC undertakes an annual evaluation of its performance and effectiveness. Consistent with the Board's annual performance evaluation for 2019, the AC's performance evaluation was facilitated by Independent Board Evaluation, an independent consulting firm. Each AC member was interviewed for their views covering topics relating to: the management of the AC in areas such as the annual cycle of work, agenda for meetings, and time and input in meetings; rating the quality of the information provided to the AC; the effectiveness of the AC's oversight in areas such as the work of internal and external audit, the Group's financial reporting, the system of internal controls and the risk management policies and practices; rating the AC's performance in reviewing and assessing significant accounting and reporting issues; and generally how to improve the AC's performance. When assessing progress against 2018, the AC concluded that 2019 priorities identified in the 2018 evaluation (including a visit to the finance operations in Chennai and discussions related to the first-year application of IFRS 16, regulatory developments, information risk management and the Net Carbon Footprint control framework) had all been undertaken by the AC in 2019. The AC discussed the outcome of this review as part of its annual evaluation. The AC concluded that its performance in 2019 had been effective and that it fulfilled its role in accordance with its Terms of Reference.

In preparing its workplan for 2020 the AC has agreed the following focus areas in addition to the standing items: Trading and Supply, regulatory developments, decommissioning, integrated risk management, new business models and ventures, pensions and visits to Shell's operations in Singapore, Kuala Lumpur, Malaysia, and the finance operations centre in Krakow, Poland.

DIRECTORS' REMUNERATION REPORT



GERARD KLEISTERLEE

Chair of the Remuneration Committee

"Listening to shareholders has been critical for the REMCO in shaping our decisions for 2019 and the proposed 2020 remuneration policy"

2019 outcomes

Annual bonus: below-target award, with downward discretion applied for fatalities.

LTIP: above-target vesting, based on long-term performance.

2020 policy features

Alignment to strategy: formalisation of energy transition LTIP condition.

Quantum: reduce CEO LTIP grant and increased focus on the REMCO's use of discretion to manage Single Figure outcomes.

Simplification: removed individual performance factor and reduced CEO target bonus.

THIS REPORT

This Directors' Remuneration Report for 2019 has been prepared in accordance with relevant UK corporate governance and legal requirements, in particular Schedule 8 of The Large and Medium-sized Companies and Groups (Accounts and Reports) Regulations 2008 (as amended). The Board has approved this report.

This report consists of two further sections:

- the Annual Report on Remuneration (describing 2019 remuneration as well as the planned implementation of the Directors' Remuneration Policy in 2020) which will be subject to an advisory vote at the 2020 AGM; and
- the Directors' Remuneration Policy which will be subject to a binding shareholder vote at the 2020 AGM.

Dear Shareholders,

I am pleased to present the 2019 Directors' Remuneration Report. This includes my last letter as Chair of the Remuneration Committee (REMCO), our Annual Report on Remuneration and the proposed Directors' Remuneration Policy for 2020 onwards.

It has been another busy year for the REMCO and we have appreciated the ongoing support and engagement of our shareholders as we finalised our proposals on a revised policy and navigated the requirements of the new UK Corporate Governance Code.

In preparing the Annual Report on Remuneration for the year ended December 31, 2018, the REMCO paid particular attention to enhancing disclosures and explaining its decision making, and it was pleased with the level of support (89.93%) received in favour.

The outstanding performance, which underpinned the 2018 pay outcomes, the strong link between pay and performance and the REMCO's prudence in managing pay outcomes over the long term was recognised by many shareholders. Notwithstanding this, a number of shareholders raised concerns over the absolute quantum of the CEO's 2018 remuneration. The REMCO has reflected long and hard on this and quantum has been a matter of careful consideration both in our decisions for the 2019 remuneration outcome as well as in our proposals for the 2020 policy update, as I hope you will appreciate.

So let me now turn to 2019 performance and the remuneration outcomes.

2019 PERFORMANCE AND REMUNERATION OUTCOMES

Annual Bonus

During 2019 the ambition to thrive in the energy transition was progressed; the optimisation and marketing capabilities of the Integrated Gas and Downstream businesses helped deliver above-plan earnings, and project delivery was strong, reflecting the focus on capital discipline. However, assessed against the 2019 scorecard targets, a poor outcome on safety, a difficult macroeconomic environment and areas of operational challenge meant overall performance was below target.

It is worth reiterating that the REMCO has long had a policy of not adjusting remuneration measures to take into account changes in oil and gas prices and currency fluctuations. This means Senior Management also experience the ups and downs of the macroeconomic environment impacting our business and shareholders. In our engagements with our largest shareholders, many have appreciated the transparency this brings.

Financial performance

Cashflow from operations was below the minimum threshold set for 2019. This was driven by challenging macroeconomic conditions, with lower than anticipated oil and gas prices and very difficult market conditions for Shell's Refining and Chemicals businesses. This was exacerbated by operational issues in parts of the Upstream and Integrated Gas businesses.

Operational performance

- Production volumes were below target by 2.53%. This was driven by a number of operational issues and delays bringing projects on-stream;
- LNG liquefaction volumes were below target by 2.20%, mainly due to delayed project start-ups and slower ramp-ups;

DIRECTORS' REMUNERATION REPORT continued

- The combined Refinery and Chemicals Availability outcome was above target by 0.44%, with higher downtime from unplanned events being more than compensated by lower downtime from planned events; and
- Combined Project Delivery, which provides an indication of our ability to deliver projects within budget and schedule, was strong, with 90% of projects on-time and with aggregated costs below budget, reflecting the focus on capital discipline and project execution.

Sustainable Development

Shell has made significant progress on safety performance over a long period of time. This is reflected on the scorecard where the targets have been made more challenging over time, and although the total recordable case frequency (TRCF) threshold was not met in 2019, the outcome remains the joint second best on Shell's record, following the record low in 2017. However, the seven fatalities that occurred under Shell's operational control in 2019 are not acceptable and further work on safety is needed.

Performance on the other sustainability metrics was mixed. The process safety measure in 2019 was below target. Greenhouse gas emissions were at target for Upstream and Integrated Gas, and Refining. Chemicals emissions were below target due to a strike at Moerdijk and reliability issues at Deer Park.

Summary of Scorecard Performance

The mathematical outcome of the annual bonus scorecard was 0.48 and the REMCO determined to reduce the outcome to 0.43 for Senior Management. This downward discretion was applied as a result of the increased number of fatalities in 2019. Safety is, and must remain, Shell's number one priority. This reduction is based on the REMCO's judgment and was not a formulaic adjustment.

Reflecting the collective responsibility of senior executives in the safe operation of Shell, internally it was decided to apply the downward discretion to around 150 senior leaders.

This brings the ten-year average scorecard outcome to 1.17. The detailed bonus scorecard breakdown and further commentary on performance are on page 142.

Annual Bonus Outcomes

For 2019, to simplify the annual bonus structure following shareholder feedback, the individual performance multiplier was removed from the bonus calculation formula for the Executive Directors. Annual bonuses are determined based solely on business performance. The CEO's target bonus was also reduced from 150% to 125%.

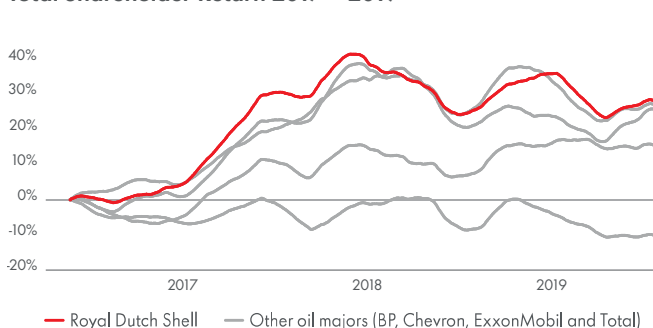
Based on the scorecard outcome of 0.43, the annual bonus outcome for the CEO was €800,000 and for the CFO was €500,000. This represents 41% of target (21% of maximum) and is a 73% reduction from 2018 for the CEO and a 68% reduction for the CFO.

The annual bonus for the Executive Directors is paid 50% in cash and 50% in shares subject to a three-year holding period, which applies beyond an Executive Director's tenure.

Long-term incentive plan (LTIP)

While performance in 2019 assessed against our annual bonus scorecard metrics was below target, on the LTIP we continue to see the impact of the longer-term efforts to transform Shell to deliver increased shareholder value and better performance against the comparator companies.

Total Shareholder Return 2017 – 2019



Shell made \$61 billion of distributions to shareholders over the performance period, including dividend payments and share buybacks. Shell was second on total shareholder return (TSR), by less than 0.4%, during a period which has recently been challenging for the sector. Relative CFO growth was third in the comparator group. Shell generated \$131 billion over the period, ranking first in absolute terms. ROACE of 5.6% was also improved, with growth ranking first in the comparator group, reflecting our work to high-grade and reshape the portfolio [A].

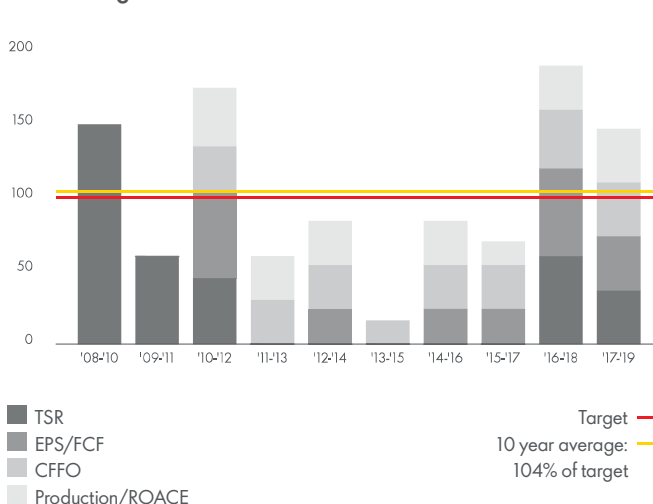
On free cash flow (FCF), Shell exceeded the three-year cumulative target of \$85 billion with total FCF over the period of \$93.4 billion.

These outcomes continue to reflect the success of Shell's strategy since 2016 and the progress made in building a world-class investment case. Over the 2017-2019 performance period, Shell has delivered on commitments to strengthen the financial framework; cancelling the Scrip Dividend Programme and starting the \$25 billion share buyback programme (\$14.75 billion completed as at January 22, 2020).

After taking account of the outcome of the performance metrics, as well as considering the wider performance of Shell over the performance period, the final vesting outcome of the 2017 LTIP award was approved at 147%.

This brings the ten-year average vesting outcome to 104%. This is broadly aligned with our target grant, although there have been a number of high and low-vesting outcomes over the past 10 years. The REMCO believes this illustrates the fundamental effectiveness of the LTIP and the close alignment between pay and performance the current LTIP structure has provided over a long period of time.

LTIP Vesting



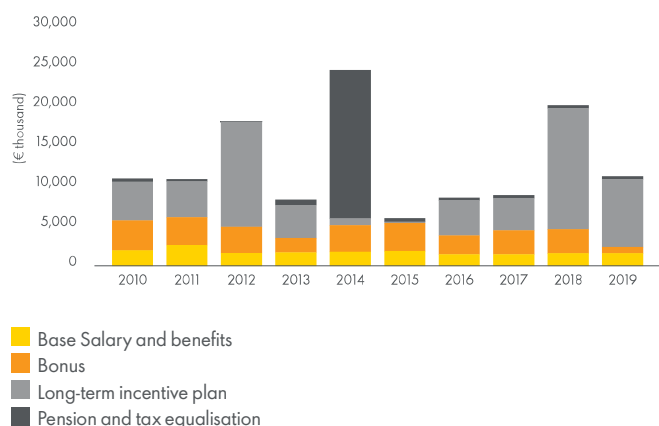
[A] For comparability purposes we calculate ROACE for LTIP purposes on disclosed net income which is not adjusted for the after-tax interest expense, it therefore differs from disclosed ROACE.

CEO Single Figure Outcomes

The REMCO considered the quantum of the Single Figure outcome (€9,963,670 for the CEO) and in finalising their remuneration decisions for 2019, considered a range of factors, further details of which are provided on page 144. These included both Shell's and personal performance in 2019, in the period 2017-2019 and the internal relativity of remuneration compared to the variable pay outcomes for employees.

The REMCO noted that it had already reduced the CEO's target bonus for 2019 from 150% to 125% and the quantum of award was further adjusted downwards on a discretionary basis given the seven fatalities in the year. It recognised the strong competitive results from 2017-2019, but also reflected on the challenging 2019 performance, partly driven by difficult macroeconomic conditions, related to lower cash flow, operational challenges and safety. The REMCO also noted the reductions in annual bonus and LTIP outcomes and that the CEO's overall remuneration was 51% lower than in 2018, and was satisfied that the Single Figure represented an appropriate and competitive level of remuneration within the bounds of the shareholder-approved policy.

CEO's single figure outcomes over last 10 years



PAY IN A WIDER CONTEXT

The REMCO believes that there should be alignment between pay structures for the Executive Directors and employees. This is important, both to reinforce a common commitment to Shell's strategic goals and to give employees the opportunity to share in Shell's success. The majority of Shell's employees share the same scorecard as the Executive Directors. In addition, around 16,500 of Shell's employees are granted performance share awards on terms that are broadly similar to the conditions that also apply to the Executive Directors through the LTIP.

The ratio of the CEO's pay to the median UK worker is 87. The global pay ratio, calculated by comparing the CEO single figure to the average employee headcount cost, is 75. These numbers have significantly decreased from 2018, where the average pay ratio was 143 compared to the UK median ratio and 149 in comparison to the global employee ratio. The principal reasons for the changes are the decrease in the CEO's single figure from 2018, balanced by the reduction in the variable pay outcomes for all employees, and the acquisition of First Utility (now Shell Energy Retail).

The REMCO noted that even with the exceptional CEO pay outcome in 2018 based on strong company performance, our pay ratio was consistent with the pay ratios seen in other major FTSE 30 companies. The REMCO is cautious about drawing any direct conclusions from the comparison of ratios, given the differences in industry and employee profile between companies.

CEO: Pay ratio

2019 CEO single total figure against actual average global employee costs



- 1 Shell minimum pay ratio [A]
- 2 Shell 2018 global pay ratio [B]
- 3 Shell 2019 global pay ratio [C]
- 4 Shell maximum pay ratio [D]

- [A] Based on CEO 'minimum' pay scenario as disclosed on page 160 compared to the average global employee cost in 2019.
- [B] Based on the 2018 CEO single total figure compared to the average global employee cost in 2018.
- [C] Based on the 2019 CEO single total figure compared to the average global employee cost in 2019.
- [D] Based on CEO 'maximum' pay scenario (excluding the 50% share price appreciation) as disclosed on page 160 compared to the average global employee cost in 2019.

Shell's gender pay gap for 2019, published in accordance with the reporting required under the UK Equality Act 2010 (Gender Pay Gap Information) Regulations, increased slightly from 18.6% to 18.7%. This increase is primarily due to the effect of including employees from Shell's acquisition of First Utility in the calculation for the first time. On a like-for-like basis, it would have been 15.1%, an improvement of 3.5 percentage points. Shell's goal is to ensure the equal participation of women and men in all areas of work, at all levels and locations ensuring equal access to the same recognition, reward and career progression opportunities. As 2019 illustrates, these changes will be influenced by changes in our business and may be non-linear. However, the REMCO has confidence in the policies Shell has to increase the representation of women at all levels in the organisation.

2020 REMUNERATION POLICY

I would now like to turn to the remuneration policy that will be voted on at the 2020 AGM.

The REMCO has spent time considering the alignment of remuneration policies to Shell's strategic goals, listening to shareholder views, gathering input on executive pay market developments, and reflecting on wider societal trends in developing the revised policy. I have had the opportunity to meet with many shareholders personally during this process and want to thank them for expressing their point of view. The various perspectives they have provided have helped shape a number of key decisions. Notably, this feedback has been critical in shaping our development of the Energy Transition metric and our intended response to managing the issue of quantum.

In our policy deliberations, we have been guided by three objectives:

Strategy should be set first, and then the remuneration policies designed to support the achievement of those strategic goals. This is our overriding imperative: the decisions we make as the REMCO must be tightly and inextricably linked to Shell's strategy.

DIRECTORS' REMUNERATION REPORT continued

Second, we must maintain a package that is externally competitive and ensures the business can attract and retain the management talent capable of ensuring the ongoing success of Shell and delivering a high level of returns for shareholders while navigating through the complexity of the energy transition.

Finally, there must be internal proportionality. The policies we enact for the Executive Directors should be, as far as possible, consistent and aligned with the approach to managing remuneration across the Shell Group.

The REMCO believes the existing structures remain robust and consistent with these objectives. The annual bonus and the LTIP are closely aligned with Shell's strategy: incentivising outperformance of our closest competitors on a number of key financial metrics; the delivery of the annual operational business plan; and progressing the ambition to thrive in the energy transition. While variable pay outcomes have fluctuated over time, the 10-year average vesting outcomes are close to target, demonstrating the effectiveness of these structures in delivering pay for performance over the long term. In discussions with shareholders there was a clear preference for maintaining a strong and direct link between reward and performance. Structures which potentially reduced this link, such as restricted shares, received limited support from shareholders in consultation.

Quantum

There is good support for target reward levels, but some shareholders raised concerns regarding pay quantum at the extremes of performance and this has been a key issue for the REMCO when considering the 2020 policy. In 2019, we reviewed a range of alternative reward structures that might moderate high pay outcomes while keeping target pay competitive. Following extensive consultation with shareholders, we concluded that changing reward design is not the best way to address quantum if it means making compromises on the alignment between pay and performance in the delivery of strategy. This also allows for alignment between reward structures for Executive Directors and employees. The REMCO also considered whether a cap on remuneration levels was appropriate. The REMCO believes it is important to maintain flexibility in order to respond to changing business requirements and/or governance developments if required. The introduction of an arbitrarily defined cap may adversely affect that flexibility and, given the good alignment between pay and performance, would be an unnecessary policy feature. Also some shareholders are of the view that strong performance should be rewarded with strong variable pay outcomes. Accordingly, we have sought ways to manage quantum outcomes within the existing tried and tested performance framework.

Proposals

Under the proposed policy, we are:

- reducing the CEO's target bonus from 150% to 125% (a change already implemented in 2019);
- reducing the maximum LTIP opportunity from 800% of base salary to 600%. In doing so we will reduce the 2020 target LTIP grant level for the CEO from 340% to 300%; and
- introducing a greater emphasis on discretionary management of remuneration outcomes for the CEO. From now on the REMCO will, based on the formulaic Single Figure outcome, undertake a further and final review of the CEO's and company's overall performance and be prepared to adjust the Single Figure in order to ensure that the highest variable pay outcomes are only achieved for the highest quality of performance across all significant areas of activity. It is not expected that this discretion would be applied upwards, and any discretion would be disclosed and explained to shareholders.

As you know, in a first for our industry and following extensive collaboration with shareholders, we incorporated an energy transition measure to our LTIP from 2019, again adopting early a change originally intended for the 2020 policy. That condition continues to feature in the policy, and it remains the REMCO's intent to increase its weighting over time.

The REMCO reflected carefully on the matter of pensions. It is already a long-standing remuneration policy that pensions for Shell's Executive Directors are aligned with those of employees in their home country and we are proposing to continue this policy.

The CEO participates in the mainstream Shell Netherlands pension arrangements on the same terms as all other members. It is a feature of Netherlands pension schemes that the contribution rate increases with age and this is a requirement of Dutch pension legislation. As the CEO is near the top of the ladder based on age, his contribution rate is 27%. The REMCO is aware that this may appear high by UK standards of pension contribution. However, this is the standard contribution rate applicable to all employees of his age in this plan, and we believe that this is aligned with the spirit of recent developments in corporate governance regarding pension provision. Jessica Uhl also participates in the pension arrangements applicable to employees in her home country (USA). The only difference in her arrangements in comparison to other employees is that her bonus is non-pensionable. This is in accordance with UK corporate governance best practice. Further information on pensions is provided on page 145.

We are proposing a number of other changes to simplify the policy and to ensure it remains aligned with shareholder interests and developing corporate governance best practice. These changes include increasing the CFO's shareholding requirement, introducing a post-employment shareholding requirement and extending our malus and clawback provisions.

A summary of the changes from the existing policy are set out on page 145. Having consulted with shareholders on these changes through the course of the last two years, I am confident of your support.

LOOKING AHEAD

The 2020 AGM will be my last as the REMCO Chairman, as I will be stepping down from the RDS Board following the meeting. It has been a privilege to chair the REMCO over a period which has seen a great deal of change, both for Shell and in the executive remuneration landscape. I believe that the proposed 2020 remuneration policy will provide strong support in achieving Shell's strategic ambitions and I wish my successor, Neil Carson, every success for the future.

GERARD KLEISTERLEE

Chair of the REMCO
March 11, 2020

ANNUAL REPORT ON REMUNERATION

The Annual Report on Remuneration sets out

- The REMCO's responsibilities and activities, **page 139**;
- Remuneration at a glance, **page 140**;
- Directors' remuneration for 2019, **page 141**; and
- the statement of the planned implementation of policy in 2020, **page 152**.

The base currency in this Annual Report on Remuneration is the euro, as this is the currency of the base salary of the Executive Directors. Where amounts are shown in other currencies, an average exchange rate for the relevant year is used, unless a specific date is stated, in which case the average exchange rate for the specific date is used.

REMUNERATION COMMITTEE

Biographies are given on pages 104-110; and REMCO meeting attendance is set out below:

Committee Member	Member since	Maximum possible meetings	Number of meetings attended	% of meetings attended
Mr. Gerard Kleisterlee (Chair)	21 May 2014	5	5	100%
Mr. Neil Carson [A]	01 June 2019	3	2	67%
Mrs. Catherine Hughes	26 July 2017	5	5	100%
Sir Nigel Sheinwald	24 May 2017	5	5	100%
Mr. Gerrit Zalm	21 May 2014	5	5	100%

[A] Neil Carson was unable to attend the meeting in October due to an immovable commitment, which was scheduled prior to his appointment to the Shell Board.

The REMCO's key responsibilities include determining:

	Senior Management		
	Executive Directors	Executive Committee	Company Secretary
Performance Framework	✓	✗	✗
Remuneration policy	✓	✓	✗
Actual remuneration and benefits	✓	✓	✓
Annual Bonus and Long-Term Incentive Measures and Targets	✓	✓	✓

In addition, the REMCO has the responsibility for determining the Chair of the Board's remuneration. The REMCO monitors the level and structure of remuneration for senior executives below Senior Management and makes recommendations if appropriate to ensure consistency and alignment with Shell's remuneration objectives. The REMCO reviews workforce remuneration and related policies and the alignment of incentives and rewards with culture, taking these into account when setting the policy for Executive Director remuneration.

In exercising its responsibilities, the REMCO takes into account a variety of stakeholder considerations.

The REMCO operates within its Terms of Reference, which are reviewed annually. They were last updated on March 13, 2019 and are available at www.shell.com.

Advice from within Shell was provided by:

- Ben van Beurden, CEO;
- Ronan Cassidy, Chief Human Resources and Corporate Officer and Secretary to the REMCO; and
- Stephanie Boyde, Executive Vice President Remuneration and HR Operations.

The Chair of the Board was consulted on remuneration proposals affecting the CEO, and the CEO was consulted on proposals relating to the CFO and Senior Management.

During 2019, the REMCO met five times and its activities included:

- setting annual bonus and long-term incentive plan performance measures and targets, including considering the energy transition in the context of long-term remuneration;
- deciding on 2018 annual bonus outcomes, 2019 base salaries, 2019 target bonuses and 2019 LTIP awards for Senior Management;
- determining vesting of the 2016 LTIP award for Senior Management;
- approving the 2018 Directors' Remuneration Report;
- carefully deliberating on quantum for the CEO;
- preparing for shareholder consultation;
- developing the Directors' Remuneration Policy in preparation for the 2020 AGM vote; and
- monitoring external developments and assessing their impact on Shell's Remuneration Policy.

In 2019, PWC provided an update to advice first provided in 2018 regarding market practice in relation to remuneration developments and Shell's remuneration structures. PWC were appointed by the REMCO to provide this advice on the basis of their credentials for assessing the risk profile of remuneration policies and their knowledge of shareholder expectations and international market practice in the oil industry and long-term businesses. PWC is a member of the Remuneration Consultants Group and operates under the group's Code of Conduct when providing advice. PWC provides other consultancy and accountancy services to Shell. However, the REMCO is satisfied that the advice provided on executive remuneration matters was objective and independent. The total fees paid to PWC in relation to this advice were £10,000 (excluding VAT).

PRINCIPLES

The principles that underpin the REMCO's approach to executive remuneration are set out on page 155.

The REMCO considered the provisions of the new UK Corporate Governance code, and has sought to reflect the principles of clarity, simplicity, risk management, predictability, proportionality and alignment to culture in deciding 2019 pay outcomes and developing 2020 policy.

Shell has a consistent global reward and performance philosophy that sets clear expectations of employees. Through the annual bonus scorecard and the LTIP, remuneration is clearly aligned to Shell's operating plan and strategic ambitions and the same measures apply to Senior Management and to a significantly broader employee base. This provides alignment throughout the organisation to Shell's culture and strategy. The annual operating plan translates into targets on the annual bonus scorecard and a quarterly update on performance against scorecard targets is provided to employees. Similarly the LTIP is largely based on outperforming the competition, and regular updates on Shell's performance against competitors is provided to employees. In reviewing the Directors' Remuneration Policy, the REMCO sought to make changes that help to simplify remuneration structures (for example, removing the individual performance factor for Executive Directors) and giving more transparent outcomes (for example, removing the bonus asymmetry from the CEO's remuneration structure). To assist in the mitigation of reputational risk and ensure proportionality, the powers of the REMCO to apply malus and clawback and make discretionary adjustments to variable pay outcomes have been expanded, with the intention that the REMCO will use discretion to ensure the highest pay outcomes are delivered only for outstanding performance.

ANNUAL REPORT ON REMUNERATION continued

REMUNERATION AT A GLANCE

2019

FIXED PAY AND SHAREHOLDING

Base salary

€1,557,000 €1,015,000

Ben van Beurden (CEO) Jessica Uhl (CFO)

Pension

Executive directors participate in the same home country pension arrangements as other employees

Benefits

Typically include car allowance, transport between home and office, and medical insurance

Shareholding

Target levels, % of base salary at 31 December 2019

700% 400%

CEO CFO

Actual levels, % of base salary at 31 December 2019

1,136% 265%

CEO CFO

ANNUAL BONUS

2019 annual bonus

€800,000 €500,000

CEO (73% reduction from 2018) CFO (68% reduction from 2018)

2019 bonus scorecard outcome

Mathematical outcome

0.48

Given safety outcomes in 2019, including seven fatalities, this was reduced to:

0.43

No individual performance factor used in bonus calculation

Bonus Delivery

50% delivered in cash

50% delivered in shares

Shares are subject to a 3-year holding period which extends beyond an Executive Directors' tenure

LONG TERM INCENTIVE PLAN

2017 – 2019 LTIP vesting outcome

€7,191,223 \$4,357,430

CEO (53% reduction from 2018) CFO (115% increase from 2018)

Vesting outcome

Measures	Outcome	Vesting
TSR	1 2 3 4 5	38%
CFFO	1 2 3 4 5	20%
ROACE growth	1 2 3 4 5	50%
FCF		39%
		147%

(out of a 200% maximum)

Shares are subject to a 3-year holding period which extends beyond an Executive Directors' tenure

2020

FIXED PAY AND SHAREHOLDING

Base salary

€1,588,000 €1,035,000

CEO CFO

↑ 2% ↑ 2%

Pension

No change from 2019

Benefits

No change from 2019

Shareholding

Target levels, % of base salary 2020

700% ↑ 500%

CEO CFO (increased from 400%)

Actual levels, % of base salary 5 March 2020

1,090% 467%

CEO CFO

ANNUAL BONUS

Target % of base salary

Target

125% 120%

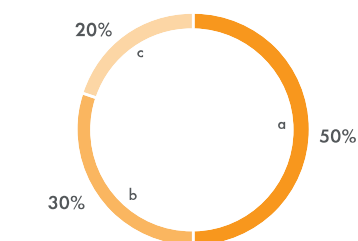
CEO CFO

Maximum

250% 240%

CEO CFO

Scorecard architecture



a Operational Excellence
(Project delivery 12.5%, Production 12.5%, LNG liquefaction volumes 12.5%, OP/CH availability 12.5%)

b Operational Cash flow

c Sustainable Development
(GHG 10%, TRCF 5%, Tier 1 & 2 Process Safety 5%)

LONG TERM INCENTIVE PLAN

Target awards % of base salary

Target

↓ 300% 270%

CEO (reduced from 340% in 2019)

CFO

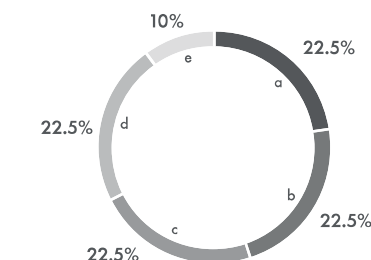
Maximum

↓ 600% 540%

CEO (reduced from 680% in 2019)

CFO

Performance conditions



a TSR

b ROACE

c Cash from operating activities

d FCF

e Energy transition (new from 2019)

DIRECTORS' REMUNERATION FOR 2019

Single total figure of remuneration for Non-executive Directors (audited)

	€ thousand					
	Fees		Taxable benefits[A]		Total	
	2019	2018	2019	2018	2019	2018
Neil Carson [B]	99	N/A	–	N/A	99	N/A
Ann Godbehere [C]	178	97	–	–	178	97
Euleen Goh	201	220	–	–	201	220
Charles O. Holliday [D]	850	850	71	75	921	925
Catherine J. Hughes	200	199	–	7	200	206
Gerard Kleisterlee	242	216	–	7	242	223
Roberto Setubal	190	190	2	–	192	190
Sir Nigel Sheinwald	187	180	–	6	187	186
Linda G. Stuntz	189	197	8	13	197	210
Gerrit Zalm	177	177	–	–	177	177

[A] UK regulations require the inclusion of benefits where these would be taxable in the UK, on the assumption that Directors are tax residents in the UK. On this premise, the taxable benefits include the cost of Non-executive Director's occasional business-required partner travel. Shell also pays for travel between home and the head office in The Hague, where Board and committee meetings are typically held, as well as related hotel and subsistence costs. For consistency, these business expenses are not reported as taxable benefits as for most Non-executive Directors this is international travel and hence would not be taxable in the UK.

[B] Appointed as a Director with effect from June 1, 2019.

[C] Appointed as Director with effect from May 23, 2018.

[D] Including the use of a Shell provided apartment whilst in the Hague (2019: €70,624; 2018: €70,015)

Single total figure of remuneration for Executive Directors (audited)

	€ thousand			
	Ben van Beurden		Jessica Uhl	
	2019	2018	2019	2018
Salaries [A]	1,557	1,527	1,015	995
Taxable benefits [B]	20	32	51	49
Total fixed remuneration	1,577	1,559	1,066	1,044
Annual bonus [C]	800	3,000	500	1,550
LTIP [D]	7,191	15,209	3,903	1,783
Total variable remuneration	7,991	18,209	4,403	3,333
Total direct remuneration	9,568	19,768	5,469	4,376
Pension [E]	395	369	261	196
Tax equalisation [F]	–	–	275	289
Total remuneration including pension and tax equalisation	9,963	20,138	6,005	4,862
in dollars	11,155	23,790	6,724	5,744
in sterling	8,746	17,817	5,271	4,302

[A] As disclosed in the 2018 Directors' Remuneration Report, the REMCO set Ben van Beurden's base salary for 2019 at €1,557,000 (+2.0% compared with 2018) effective from January 1, 2019, and Jessica Uhl's base salary at €1,015,000 (+2.0% compared with 2018) effective from January 1, 2019.

[B] Executive Directors received car allowances, transport between home and office, occasional business-required partner travel, as well as employer contributions to life and medical insurance plans.

[C] The full value of the bonus, comprising both the 50% delivered in cash and 50% bonus delivered in shares. For 2019, the market price of A shares on February 21, 2020 (€22.735), was used to determine the number of shares delivered, resulting in 9,521 A shares for Ben van Beurden and 5,951 A shares for Jessica Uhl. For 2018, 50% of the bonus was delivered in shares and the market price of A shares on February 21, 2019 (€27.745), was used to determine the number of shares delivered, resulting in 28,045 A shares for Ben van Beurden and 14,490 A shares for Jessica Uhl.

[D] Remuneration for performance periods of more than one year, comprising the value of released LTIP awards. The amounts reported for 2019 relate to the 2017 LTIP award, which vested on March 4, 2020, at the market price of €19.986 and \$45.21 for A shares and A ADSs respectively. The value in respect of the LTIP is calculated as the product of: the number of shares of the original award multiplied by the vesting percentage; plus accrued dividend shares; and the market price of A shares or A ADSs at the vesting date. The market price of A ADSs is converted into euros using the exchange rate on the respective date. Ben van Beurden also received a release of 57,980 RDS A shares under the 2017 Deferred Bonus Plan (DBP) on March 4, 2020. The original deferred bonus share awards, which are those represented by the deferred bonus and dividend shares accrued on these shares are not considered as long-term remuneration as they relate to the 2016 short-term annual bonus value. Share price appreciation accounted for -€1,603,428 on the LTIP and -€317,962 on the DBP for Ben van Beurden and -\$521,010 on the LTIP for Jessica Uhl.

[E] For Ben van Beurden, the amount reported for pension consists of a net pay defined contribution amount of €395,060. The amount to be reported for his defined benefit pension accrual is 0 calculated in accordance with UK reporting requirements. For Jessica Uhl, the amount reported for pension consists of a defined contribution amount of €102,709 and a defined benefit pension accrual of €158,012.

[F] Includes tax equalisation of pension contributions to foreign pension plan(s), when they are taxable above a certain pensionable salary threshold or once a double tax treaty exemption ceases, under Dutch law. Tax equalisation is applied for the loss of pension relief for members of a foreign pension plan(s) in their host country.

ANNUAL REPORT ON REMUNERATION continued

Notes to the single total figure of remuneration for executive directors table (audited)

Annual bonus

The Annual bonus operated in line with the policy as disclosed on page 156.

Determination of the 2019 annual bonus

The table below summarises the 2019 annual bonus scorecard measures including their weightings, targets and outcomes. The mathematical scorecard outcome for 2019 was 0.48. Please refer to pages 135-136 for a commentary on the scorecard outcome.

After reviewing the mathematical scorecard outcome, and considering the context of wider company performance for the year, the REMCO exercised discretion to adjust the scorecard result downwards to 0.43. This downwards adjustment was to reflect the seven fatalities under Shell operational control during the year.

Accordingly, the REMCO determined a final bonus outcome of €800,000 for the CEO which is 41% of target and 21% of maximum. This is a 73% reduction from 2018. The REMCO determined a final bonus outcome of €500,000 for the CFO which is 41% of target and 21% of maximum. This is a 68% reduction from 2018.

2019 annual bonus outcome (audited) [A][B]

Measures	Weight (% of scorecard)	Threshold	Target set	Outstanding	Result achieved	Score (0-2)
Cash flow from operating activities (\$ billion)	30%	44	50	56	42	0
Operational excellence	50%					0.72
Production (kboe/d)	12.5%	3,647	3,760	3,873	3,665	0.16
LNG liquefaction volumes (mtpa)	12.5%	35.3	36.4	37.4	35.6	0.23
Refinery and chemical plant availability (%)	12.5%	88.4	90.4	92.4	90.8	1.20
Project delivery on schedule (%)	6.25%	60	80	100	90	1.50
Project delivery on budget (%)	6.25%	105	100	95	99	1.10
Sustainable development	20%					0.59
Total recordable case frequency (injuries/million hours)	5%	0.9	0.7	0.5	0.9	-
Operational Tier 1 and 2 process safety events (number)	5%	145	115	85	130	0.50
Upstream and Integrated Gas GHG intensity (tonnes of CO ₂ equivalent/tonne of hydrocarbon production available for sale)	4%	0.176	0.168	0.160	0.168	1.00
Refining GHG intensity (tonnes CO ₂ equivalent per Solomon's Utilized Equivalent Distillation Capacity (UEDC™))	4%	1.11	1.06	1.01	1.06	1.00
Chemicals GHG intensity (tonnes CO ₂ equivalent/tonne of petrochemicals production)	2%	1.10	1.00	0.90	1.04	0.60
	100%					
Mathematical scorecard outcome						0.48
Adjusted scorecard outcome						0.43

[A] These metrics measure the effectiveness with which we operate our assets and portfolio base, assessed against our operational business plan. Shell's longer-term strategic ambitions are measured in the LTIP metrics.

[B] Scorecard targets are based on Shell's annual operating plan and increase or decrease year-on-year. In 2019, target refinery and chemical plant availability was lower and target GHG emission intensities higher than 2018, due to planned business activities, reflecting scheduled maintenance and expected market conditions, and portfolio developments.

[C] In external disclosure, we may use an alternative performance measure, i.e. CFO excluding Working Capital, to describe the cash flow generation from our operations without the effect of working capital changes.

2019 bonus outcome calculation

Ben van Beurden

Target bonus:

€1,557,000 (base salary)
x 125% = **€1,946,250**



2019 scorecard
result 0.43



€800,000 [A]
(51% of base salary)
↓ 73% reduction from 2018

Jessica Uhl

Target bonus:

€1,015,000 (base salary)
x 120% = **€1,218,000**



2019 scorecard
result 0.43



€500,000 [A]
(49% of base salary)
↓ 68% reduction from 2018

[A] Rounded downwards to the nearest €50,000, and half was delivered in shares subject to a three-year holding period which extends beyond the Executive Director's tenure.

LTIP Vesting

In 2017, Ben van Beurden was granted a conditional LTIP award of 340% (max 680%) of base salary and Jessica Uhl an award of 270% (max 540%) excluding share price movement and dividends.

In making the vesting decision, the REMCO considered Shell's performance over the three-year vesting period. The REMCO noted the strong performance of Shell relative to both the other oil majors and the wider oil and gas sector in generating shareholder returns, in particular the \$61 billion distributed to shareholders in the form of dividends and share buybacks. This strong relative performance led to a very close TSR outcome, with Shell ranking second by a difference of less than 0.4%. Cash performance was also strong with CFFO leading the comparator group on absolute CFFO generated, and FCF was well above the cumulative target set for the three-year performance cycle. ROACE has also improved, reflecting the focus on capital discipline. The REMCO also took account of the fact that Shell's competitors are some of the strongest companies in the industry and achieving relative outperformance is challenging.

The REMCO also took account of share price at grant (€25.47 for the CEO and \$51.74 for the CFO) and at vest when making the vesting decision. As the share price at grant was only 2% higher from the three-month average share price leading up to grant, the REMCO was comfortable that there were no notable windfall gains arising from the LTIP vesting.

Accordingly, the REMCO determined that the LTIP should vest without discretionary adjustment at 147%. This is illustrated opposite.

The CEO's and CFO's vested awards are subject to a further three-year holding period which extends beyond executive director tenure.

2017 LTIP vesting outcome – performance metrics



2017 LTIP vesting outcome

Ben van Beurden

Vesting outcome: [A]

198,900 x 147% =
292,383 RDS A Shares
(€7,446,995)



Change in share price: [B]

292,383 x -€5.484
(-€1,603,428)



Accrued dividends: [C]

67,430 RDS A Shares
(€1,347,656)



Total LTIP Vesting: [C][D]

359,813 RDS A Shares
(€7,191,223)
↓ 53% reduction
from 2018

Jessica Uhl

Vesting outcome: [A]

54,277 x 147% =
79,787 RDS.A Shares
(\$4,128,189)



Change in share price: [B]

79,787 x -\$6.53
(-\$521,010)



Accrued dividends: [C]

16,595 RDS.A ADS
(\$750,251)



Total LTIP Vesting: [C][D]

96,382 RDS.A ADS
(\$4,357,430)
↑ 115% increase
from 2018 [E]

[A] Based on the share price at grant of €25.47 for Ben van Beurden and \$51.74 for Jessica Uhl.

[B] Calculated as the share price at vesting date minus the share price at the date of grant for Ben van Beurden €19.986 - €25.47 = -€5.484 and for Jessica Uhl: \$45.21 - \$51.74 = -\$6.53

[C] Based on the share price at vesting date of €19.986 for Ben van Beurden and \$45.21 for Jessica Uhl.

[D] Vested shares are subject to a two year holding period.

[E] Jessica Uhl's LTIP awards which vested in 2018 was made prior to appointment as CFO and were lower in accordance with our principle of internally proportionate pay that increases with seniority. The awards which vested in respect of 2019 were the first granted following promotion to CFO.

ANNUAL REPORT ON REMUNERATION continued

Overall pay outcome

In determining the final pay outcomes, the REMCO also considered the personal performance of the Executive Directors.

Personal performance 2017 – 2019

Key Goals	Ben van Beurden	Jessica Uhl
Deliver a world-class investment case	<p>Under the CEO's leadership, Shell continues to transform, with a clear purpose and well-defined strategic intents that balance societal progress with performance, to deliver higher returns. Over the 2017 – 2019 performance period, financial performance was strong: CFFO was \$131 billion, FCF was \$93 billion, an all-cash dividend was paid, and the share buyback programme was started (\$14.75 billion completed as at January 22, 2020). The \$30 billion divestment programme was also completed (in 2018) and investments have been made in a disciplined manner.</p> <p>In terms of broader company performance, the REMCO recognised the strategic clarity the CEO has provided around the purpose and direction of Shell. Shell has delivered on its commitments to shareholders to date and remains committed to its intent to achieve 2020 targets. Albeit this timeframe is less certain given prevailing weak macroeconomic conditions and challenging outlook.</p>	<p>The CFO demonstrated strong cost and capital discipline leadership. This was enabled by a consistent focus on the strategic management of Shell's Financial Framework, which has been a key contribution to the health and success of Shell in the period under review. Key milestones included: the cancellation of the scrip dividend and start of the share buyback programme, sustained investment discipline, reduced costs and a strengthened balance sheet with AA equivalent credit metrics. The introduction of publication of a quarterly update enhances disclosures and increases transparency.</p> <p>In terms of broader company performance, the REMCO recognised the strategic insight the CFO has provided in terms of effective capital allocation, portfolio and investment decisions that further Shell's world-class investment case.</p>
Thrive in the energy transition	<p>The CEO continued to lead Shell's NCF ambition through driving internal plans and targets, integrating business and world-class investment decisions with thriving in the energy transition, and by preparing the organisation for changing investor and customer preferences as the transition unfolds.</p> <p>The CEO continues to lead the way in the energy transition debate externally, for example, through the first joint statement with institutional shareholders, encouraging other companies to adopt the NCF methodology, and shaping the debate on energy transition. He has been instrumental in galvanising coalitions to start action on sectoral decarbonisation. His personal role, for example in the Aviation Clean Skies Initiative, is recognised by both customers and external stakeholders. His interventions have helped in shifting the climate agenda towards the practical measures that will be needed for creating sustained demand for lower carbon products. Shell set and disclosed NCF reduction targets. The CEO extended this measure to the remuneration of 16,500 Shell employees through the Performance Share Plan (PSP).</p>	<p>The CFO further matured the internal management systems relating to carbon dioxide (CO₂) in portfolio, planning and resource allocation decisions.</p> <p>The CFO led the publication of the Shell Energy Transition Report, which is aligned with the Task Force on Climate-related Financial Disclosures (TCFD) recommendations and sets out how Shell plans to be resilient to expected changes in the energy system and how its strategy helps it to thrive as the world transitions to lower-carbon energy.</p>
Strengthen licence to operate	<p>In terms of HSSE leadership, performance was mixed, which shows further improvement is required. The 2019 personal injury rate was flat to 2018, following the lowest ever injury rate on record in 2017. The fatalities in Shell-operated ventures in 2019 are unacceptable and provide a stark reminder of the need for an ongoing focus on safety. In 2018, there was a notable improvement in operational process safety, with a reduction in the number of both Tier 1 and Tier 2 events. This, however, deteriorated in 2019.</p> <p>In 2019, Shell published the Industry Associations Climate Review, which assesses alignment with 19 industry associations on climate-related policy and decided not to renew Shell's membership of one association as a result.</p>	<p>The CFO maintained a strong financial disclosure, reporting and control framework.</p> <p>The CFO played a key role in Shell's endorsement of the responsible tax principles set out by the non-profit organisation, The B Team. In 2019, Shell published its inaugural Tax Contribution Report marking an important step towards greater transparency around Shell's approach to paying taxes to governments.</p>

The REMCO considered the quantum of the Single Figure outcomes, and noting that the CEO's overall remuneration was 51% lower than in 2018, was satisfied that they represent a fair level of remuneration, taking into account the strong competitive performance from 2017 to 2019 and the significant bonus reduction in 2019 reflecting the number of fatalities and safety challenges as well as the lower cash flow and operational challenges.

In finalising its remuneration decisions for 2019, the REMCO considered a range of factors, including:

- Shell's performance in 2019 and over the LTIP performance period 2017-2019;
- potential risk adjustment considerations, including safety, ethics and compliance and feedback from the Audit and Safety, Environment and Sustainability Committees;

- the final scorecard outcome including the downwards discretion applied to the final vesting outcome;
- the final LTIP vesting outcome;
- the internal relativity of remuneration compared to the variable pay outcomes for the general workforce based on the group scorecard and Performance Share Plan; and
- the personal performance of the executive directors.

After reflecting on the above factors, the REMCO was satisfied that the remuneration policies had operated as intended.

Pension

Ben van Beurden's pension arrangements comprise a defined benefit plan with a maximum pensionable salary of €96,729; and a net pay defined contribution pension plan with a 2019 employer contribution of 27% of salary in excess of €96,729. He has the option to take cash as an alternative to pension contributions (in either case subject to income tax) and elected to take his benefit in the form of contributions throughout 2019.

The employer contribution levels are in line with those applicable to other Netherlands-based employees. Under the Dutch pension regulations applicable to the pension arrangement in which he participates, the contribution rate increases with age and is shown below.

At December 31, 2019 the average contribution rate for NL employees who participate in the net pay defined contribution pension arrangement on the same terms as Ben van Beurden was 22%. For reference, in the UK, the average employer contribution rate to the Shell UK defined contribution plan is 20%.

Shell Netherlands Pension Stichting Net pay defined contribution ladder

Age	Employer contribution
15 – 19	6.30%
20 – 24	7.54%
25 – 29	8.99%
30 – 34	10.44%
35 – 39	12.31%
40 – 44	14.38%
45 – 49	17.07%
50 – 54	19.77%
55 – 59	23.29%
60 – 64	(2019 rate for Mr van Beurden) 27.02%
65 – 67	30.13%

Jessica Uhl is a member of the Shell US retirement benefit arrangements, which include the Shell Pension Plan (a defined benefit plan), and a defined contribution plan where she receives an employer contribution of 10% of salary. This is the same as the average employer contribution rate for US employees at December 31, 2019, which was also 10%. As for all other pre-2013 members of the Shell Pension Plan, she has an annual choice of two accrual formulas with different forms of benefits, one in the form of a lifetime annuity and the other allowing for a lump-sum payment. She elected to accrue benefits for 2019 under the former. Approximately 10,000 out of 17,000 Shell US employees have the option of choosing between the two formulas. These arrangements are the same for all employees who joined Shell US at the same time as Jessica Uhl. The difference in pension provision for Jessica Uhl, compared to employees who joined pre-2013, is that her bonus is not pensionable as an Executive Director while for other relevant US employees the bonus is pensionable. She also has a deferred Dutch defined benefit pension plan, as a result of a prior Shell assignment on local Dutch terms and conditions.

The REMCO believe these arrangements are aligned with the recent corporate governance developments in the UK which emphasise Executive Directors' pension arrangements being the same for the general employee population.

Scheme interests awarded in 2019

Scheme interests awarded to Executive Directors in 2019 (audited)

Scheme interest type	Type of interest awarded	End of performance period	Target award [A]	Potential amount vesting	
				Minimum performance (% of shares awarded) [B]	Maximum performance (% of shares of the target award) [A]
LTIP	Performance shares	December 31, 2021	Ben van Beurden: 194,625 A shares, equivalent to 3.4 x base salary or €5,293,800. Jessica Uhl: 49,927 A ADS shares, equivalent to 2.7 x base salary or €2,740,500.	0%	Maximum number of shares vesting is 200% of the shares awarded, before dividends.

[A] The award for Ben van Beurden was based on the closing market price on February 1, 2019, for A shares of €27.20. The award for Jessica Uhl was based on the closing market price on February 1, 2019, for A ADSs of \$62.84.

[B] Minimum performance relates to the lowest level of achievement, for which no reward is given.

ANNUAL REPORT ON REMUNERATION continued

The measures and weightings applying to LTIP awards made in 2019 were: energy transition (10%), FCF (22.5%), TSR (22.5%), ROACE growth (22.5%) and cashflow from operating activities growth (22.5%).

Absolute measures

Energy Transition

The energy transition condition is focused on Shell's strategic ambition to thrive in the energy transition and supports delivery of Shell's Net Carbon Footprint (NCF) ambition.

This measure was introduced to the LTIP in 2019 under the existing remuneration policy, in advance of the 2020 policy vote. The condition consists of a mix of leading and lagging measures that set the foundations to contribute to Shell's strategic ambitions in the longer term. These will comprise:

Lagging measure – a measure of our progress in meeting our ambition

- Net Carbon Footprint: a target for reducing the NCF of the energy products Shell sells (a carbon intensity measure that takes into account their full life-cycle emissions, including customers' emissions associated with using them).

Leading measures – the levers we will use to drive future NCF reduction

- The growth of our power business: growth in the use of electricity and continuing decarbonisation of electricity by shifting to renewables and gas-fired power generation is recognised as a key lever in all decarbonisation scenarios. Our ambition to grow the power business is based on selective investments in generation, and in business models based on reselling power generated by others;
- Advanced biofuels technology: biofuels are expected to play a valuable role in the changing energy mix and are likely to be the key decarbonisation levers for sectors that need to continue to use liquid fuels in the foreseeable future, such as some segments of transport and industry. For society and for Shell, commercialisation of advanced biofuel technology is one of the most important steps in energy transition; and

- the development of systems to capture and absorb carbon: carbon capture and storage (CCS) and carbon sinks, such as nature-based solutions are required as part of the global response to climate change.

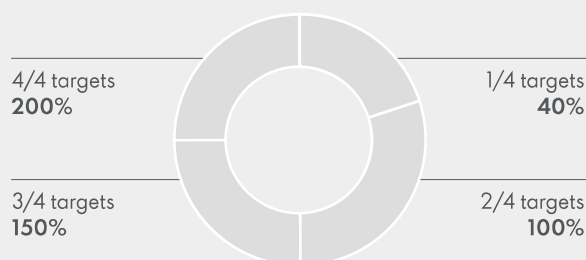
Targets have been set for each element. Progress in the energy transition is not expected to be linear as it will reflect the pace of change of society as a whole and the speed at which Shell progresses its strategic business objectives. Therefore, most of the targets have been set as ranges. Energy transition targets, with the exception of the NCF target, are considered to be commercially sensitive and will therefore be disclosed retrospectively. Annual updates on our progress in relation to the measures will be provided. The first update on progress is provided at page 147.

The vesting outcome for the part of the award weighted to the energy transition condition ranges from 0% to 200% of grant. The REMCO, at its sole discretion, will determine vesting outcomes after taking into account achievement against the target ranges and feedback from the Safety, Environment and Sustainability Committee (SESCO). In doing so, the REMCO will take into account, in relation to each element, progress over the performance period relative to nearer-term aims in pursuit of the long-term ambition announced by Shell to reduce the NCF of energy products sold by around half by 2050, and by around 20% by 2035, in step with society's drive to meet the goals of the Paris Agreement. The starting point for determining the vesting outcome will be scoring how many of the targets have been met for each of the four areas. One out of four will equal 40%, two will equal 100%, three will equal 150% and 200% will be achieved for scoring four out of four. However, it is important to note that performance against these elements will serve simply as a starting point for the REMCO, which will also take into account any other considerations it deems appropriate, including (without limitation) the relative importance of these elements in meeting the long-term ambition announced by Shell. For example, the REMCO may decide to allocate a greater emphasis to overall performance in relation to the NCF than the other three elements. The REMCO believes this approach is

Operation of energy transition measures in the 2019 LTIP

Lagging – NCF reduction target <ul style="list-style-type: none"> ■ Measured against 2016 base year 	2019 – 2021 performance period <ul style="list-style-type: none"> ■ Target range 2-3% reduction 	Thrive in the energy transition
Leading - Drive future NCF reduction <ul style="list-style-type: none"> ■ Growing our power business ■ Advanced biofuels technology ■ Systems to capture and absorb carbon 	<ul style="list-style-type: none"> ■ Target ranges ■ Commercially sensitive ■ Disclosed retrospectively 	

Energy transition vesting (basis for the Remuneration Committee's decision) [A]



- 10% weighting in 2019: expect to increase over time
- Combination of leading and lagging measures
- Targets set as ranges
- Commercially sensitive targets so will be disclosed retrospectively. Annual updates on progress relating to the measures will be provided

[A] The vesting schedule for the energy transition metric will be based on how many of the four targets are met. 1/4 will equal 40% vesting, 2/4 100%, 3/4 150%, 4/4 200%. The Remuneration Committee may take into account other appropriate considerations, after taking advice from the Safety, Environment and Sustainability Committee. For example, increasing the weighting of NCF relative to the other performance conditions in making its vesting discretion. Any use of discretion will be disclosed and explained.

appropriate to reflect the uncertainties around the speed and direction of progress in the energy transition. The application of any discretion will be fully disclosed and explained by the REMCO.

FCF

The FCF performance condition supports our strategic ambition of being a world-class investment case, and the delivery of our cash flow priorities, namely: to service and reduce debt, pay dividends, buy back shares and make future capital investments.

The target for FCF, along with the ranges for threshold and outstanding performance, will be set by reference to Shell's annual operating plans, being the aggregate of our plan FCF targets over the three-year performance period. Given FCF is heavily influenced by the volatility of oil and gas prices, the annual operating plans are updated each year to set an annual target to reflect a changing oil price premise. As a result, FCF targets are set annually for each annual operating plan and will only be disclosed in aggregate retrospectively after the three-year period. While consideration has been given to setting a three-year target at the outset, the REMCO has determined that such an approach would require adjustments for oil and gas price premise and other matters at the end of the period, given the unpredictability and volatility in oil and gas prices. The REMCO has a long-standing 'no adjustments' policy and therefore believes a more appropriate target-setting approach is to set the target based on the aggregation of the annual operating plans.

The amounts payable under this measure will range from 20% of the available maximum, for threshold performance, to full vesting for outstanding performance. A straight-line vesting schedule will apply for performance between threshold and outstanding.

Relative measures

The relative measures support our strategic ambition of being a world-class investment by measuring our performance on a number of key financial metrics against the other oil majors.

For relative measures, we measure and rank growth based on the data points at the end of the performance period compared with those at the beginning of the period, using publicly reported data.

- TSR, calculated in dollars using a 90-day averaging period around the start and end of the performance period;
- ROACE growth. For this purpose, in order to facilitate the comparison, the calculation of ROACE differs from that described in "Performance indicators" on page 42 as there is no adjustment for after-tax interest expense; and
- cash flow from operating activities growth.

Each relative measure can vest independently with the amounts payable ranging from 0% to 200%, in accordance with the following vesting schedule:

- Ranking first equals 200% vesting for the element of the LTIP weighted to that metric;
- Ranking second equals 150% vesting for the element of the LTIP weighted to that metric;
- Ranking third equals 80% vesting for the element of the LTIP weighted to that metric; and
- 0% vesting for the element weighted to that metric for ranking fourth or fifth.

If the TSR ranking is fourth or fifth, the level of the award that can vest on the basis of the other measures will be capped at 50% of the maximum.

Performance update on absolute measures

FCF progress to date on outstanding 2018 LTIP award

At December 31, 2019, FCF performance is above target, with an above-target outcome for 2018 of \$39 billion (target \$29 billion) and below target for 2019 of \$26.4 billion (target \$35 billion). As one year of FCF performance remains, and 75% of the award is subject to relative performance conditions, this does not reflect the potential vesting of the award.

FCF progress to date on outstanding 2019 LTIP award

At December 31, 2019, FCF performance, \$26.4 billion for 2019, is below target (\$35 billion). As two years of FCF performance remain, and 77.5% of the award is subject to relative and the energy transition performance conditions, this does not reflect the potential vesting of the award.

Energy Transition progress to date on outstanding 2019 LTIP award

The target for the 2019 LTIP grant was a 2-3% reduction from 2016 NCF (79 grams of CO₂ equivalent per megajoule). We have received third-party limited assurance on our Net Carbon Footprint for the years 2016 to 2019. For 2019, our Net Carbon Footprint was 78 grams of CO₂ equivalent per megajoule.

The targets for the other energy transition metrics are considered commercially sensitive and will not be disclosed until the end of the performance period. Examples of initiatives to progress our ambitions in the energy transition which the REMCO will take into account in determining the vesting outcome of the 2019 LTIP award, include: the acquisition of ERM Power Ltd (a large Australian business utility), and the WeForest and Forestry and Land Scotland NBS projects.

Statement of Directors' shareholding and share interests (audited)

Shareholding guidelines

The REMCO believes that Executive Directors should align their interests with those of shareholders by holding shares in Royal Dutch Shell plc (the Company). The CEO is expected to build a shareholding with a value of 700% of base salary, and the CFO 400% of base salary (increased to 500% from 2020).

Only unfettered shares count. Unvested shares held under the DBP and any shares delivered but subject to holding requirements, also count towards the guidelines. As at March 5, 2020, Ben van Beurden held shares worth 1,090% of his base salary. At March 5, 2020, Jessica Uhl held 467% of her base salary and has until March 2022 to meet her current shareholding target and January 2024 to meet her revised shareholding target. Non-executive Directors are encouraged to hold shares with a value equivalent to 100% of their fixed annual fee and maintain that holding during their tenure.

For 2020 the shareholding requirement will be extended to apply post-employment such that the Executive Director will be required to maintain their shareholding requirement, or the number of shares actually held if this is less than the shareholding requirement, for a period of two years post-employment.

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Executive Directors' shareholding (audited)

	Shareholding guideline (% of base salary)	Value of shares counting towards guideline (% of base salary at December 31, 2019)[A]
Ben van Beurden	700%	1,136%
Jessica Uhl	400%	265%

[A] Representing the value of share interests and the estimated after-tax value of DBP shares (not subject to performance conditions).

Directors' share interests

The interests (in shares of the Company or calculated equivalents) of the Directors in office during 2019, including any interests of their connected persons, are set out in the table below.

Directors' share interests (audited)

	January 1, 2019		December 31, 2019	
	A shares	B shares	A shares	B shares
Executive directors [A]				
Ben van Beurden	281,524	-	647,426	-
Jessica Uhl	61,097 [B]	-	116,168 [C]	-
Non-executive directors				
Neil Carson	-	-	16,000	-
Ann Godbehere	-	4,700 [D]	-	4,700 [D]
Euleen Goh	-	12,895	-	12,895
Charles O. Holliday	-	50,000 [E]	-	50,000 [E]
Catherine J. Hughes	4,080	46,904	4,080	51,904 [F]
Gerard Kleisterlee	5,254	-	5,254	-
Roberto Setubal	15,400 [G]	-	15,400 [G]	-
Sir Nigel Sheinwald	-	1,124	-	1,124
Linda G. Stuntz	-	12,400 [H]	-	12,400 [H]
Gerrit Zalm	2,026	-	2,026	-

[A] Includes vested LTIP awards subject to holding conditions. Excludes unvested interests in shares awarded under the LTIP and DBP.

[B] Held as 10,941 RDS A shares and 25,078 ADS (RDS.A ADS). Each RDS.A represents two A shares.

[C] Held as 26,590 RDS A shares and 44,789 ADS (RDS.A ADS). Each RDS.A represents two A shares.

[D] Held as 2,350 ADSs (RDS.B ADS). Each RDS.B represents two B shares.

[E] Held as 25,000 ADSs (RDS.B ADS). Each RDS.B represents two B shares.

[F] Held as 46,904 RDS B shares and 2,500 ADS (RDS.B. ADS). Each RDS.B represents two B shares.

[G] Held as 7,700 ADSs (RDS.A ADS). Each RDS.A represents two A shares.

[H] Held as 6,200 ADSs (RDS.B ADS). Each RDS.B represents two B shares.

Following the vesting of the 2017 LTIP and DBP awards, and delivery of the 2019 bonus in shares, Ben van Beurden's share interests increased by 233,519 RDS A shares, and Jessica Uhl's by 5,951 RDS A shares and 58,456 RDS.A ADS.

In addition, Ben van Beurden sold 14,510 RDS A shares on January 31, 2020. He also pledged 105,000 RDSA shares as collateral against a mortgage provided by Van Lanschot N.V. who adjusted their risk premium associated with the mortgage.

The value of shares counting towards the shareholding guideline (as a percentage of base salary) for the CEO and CFO, were 1,090% and 467%, respectively, at March 5, 2020.

At March 5, 2020, the Directors and Senior Management (pages 104-112) of the Company beneficially owned, individually and in aggregate (including shares under option), less than 1% of the total shares of each class of the Company shares. These shareholdings are not considered sufficient to affect the independence of the Directors.

Directors' scheme interests

The table below shows the aggregate position for Directors' interests under share schemes at December 31. These are A shares for Ben van Beurden and A ADSs for Jessica Uhl. During the period from December 31, 2019, to March 5, 2020, scheme interests have changed as a result of the vesting of the 2017 LTIP and DBP awards on March 4, 2020, and the 2020 LTIP awards made on January 31, 2020, as described on pages 143 and 145-147 respectively.

Directors' scheme interests (audited)

	Share plan interests [A]					
	LTIP/PSP subject to performance conditions [B]		DBP not subject to performance conditions [C]		Total	
	2019	2018	2019	2018	2019	2018
Ben van Beurden	660,814	715,591	56,783	159,617	717,597	875,208
Jessica Uhl	173,509	130,180	-	-	173,509	130,180

[A] Includes unvested long-term incentive awards and notional dividend shares accrued at December 31. Interests are shown on the basis of the original awards. The shares subject to performance conditions can vest at between 0% and 200%. Dividend shares accumulate each year on an assumed notional LTIP/DBP award. Such dividend shares are disclosed and recorded on the basis of the number of shares conditionally awarded but, when an award vests, dividend shares will be awarded only in relation to vested shares as if the vested shares were held from the award date. Shares released during the year are included in the "Directors' share interests" table.

[B] Total number of unvested LTIP shares at December 31, including dividend shares accrued on the original LTIP award.

[C] The number of shares deferred from the bonus (original DBP award) and the dividend shares accrued on these at December 31. Delivery of the original DBP award and the related accrued dividend shares is not subject to performance conditions.

Dilution

In any 10-year period, no more than 5% of the issued ordinary share capital of the Company may be issued or issuable under executive (discretionary) share plans adopted by the Company, or 10% when aggregated with awards under any other employee share plan operated by the Company. To date, no shareholder dilution has resulted from these plans, although it is permitted under the rules of the plans subject to these limits.

Payments to past Directors (audited)

Simon Henry left the Company on June 30, 2017. On March 4, 2020, Simon Henry's 2017 DBP award vested and he received a total of 31,140 RDS B shares, with a value at vesting of £539,158. While the original award of 25,339 RDS B shares was reported in the 2017 Directors' Remuneration Report, it is included again here in the interest of transparency. The remaining 5,801 RDS B shares represent accrued dividends paid in accordance with the plan and the value of these at vesting was £100,439.

Payments below €5,000 are not reported as they are considered de minimis.

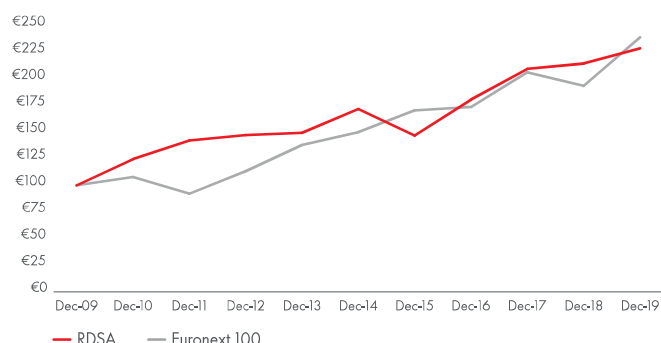
TSR performance and CEO pay

Performance graphs

The graphs compare the TSR performance of Royal Dutch Shell plc over the past ten financial years with that of the companies comprising the Euronext 100 and the FTSE 100 share indices. The Board regards these indices as appropriate broad market equity indices for comparison, as they are the leading market indices in Royal Dutch Shell plc's home markets.

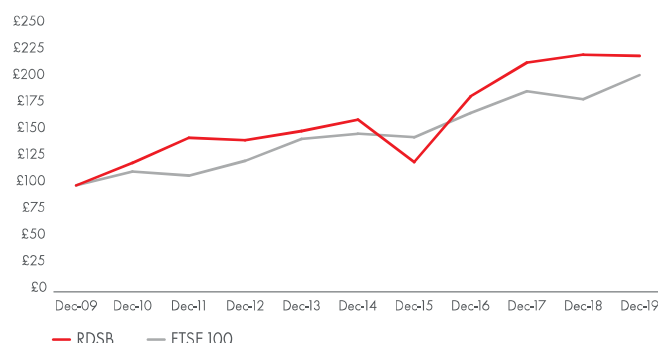
Historical TSR performance (RDSA)

Value of Hypothetical €100 Holding



Historical TSR performance (RDSB)

Value of Hypothetical £100 Holding



CEO pay outcomes

The following table sets out the single total figure of remuneration, and the annual bonus payout and long-term incentive (LTI) vesting rates compared with the respective maximum opportunity, for the CEO for the last ten years.

CEO pay outcomes

Year	CEO	Single total figure of remuneration (€000)	Annual bonus payout against maximum opportunity	LTI vesting rates against maximum opportunity
2019	Ben van Beurden	9,963	21%	74%
2018	Ben van Beurden	20,138	79%	95%
2017	Ben van Beurden	8,909	81%	35%
2016	Ben van Beurden	8,593	66%	42%
2015	Ben van Beurden	5,576	98%	8%
2014	Ben van Beurden [A]	24,198	94%	49%
2013	Peter Voser	8,456	44%	30%
2012	Peter Voser	18,246	83%	88%
2011	Peter Voser	9,941	90%	30%
2010	Peter Voser	10,611	100%	75%

[A] Ben van Beurden's single figure for 2014 was impacted by the increase in pension accrual (€10.695 million) calculated under the UK reporting regulations and tax equalisation (€7.905 million) as a result of his promotion and prior assignment to the UK.

Change in remuneration of Directors and employees from 2018 to 2019

As Royal Dutch Shell plc does not have any direct employees, the table below compares the remuneration of the Directors of Royal Dutch Shell plc with an employee comparator group consisting of local employees in the Netherlands, the UK and the USA. The local employee population of these countries is considered to be a suitable employee comparator group because: these are countries with a significant Shell employee base; a large proportion of senior managers come from these countries; and the REMCO considers remuneration levels in these countries when setting

base salaries for Executive Directors. For the purposes of comparison, the change in employee remuneration is calculated by reference to the change in salary scale, benefits and annual bonus for a notional employee in each of the base countries not by reference to the actual change in pay for a group of employees.

Taxable benefits are those that align with the definition of taxable benefits applying in the respective country. In line with the "Single total figure of remuneration for Executive Directors" table, the annual bonus is included in the year in which it was earned.

Change in remuneration of directors and employees

	RDS employees	UK, US & NL employees	Executive Directors		Non-executive directors								
			CEO	CFO	NS	AG	CH	GK	LS	CJH	RS	GZ	NC
Salaries	N/A	3.3%	2.0%	2.0%	3.9%	82.6%	0.0%	12.2%	-4.1%	0.0%	0.0%	0.0%	-
Taxable benefits[A]	N/A	-8.0%	-36.4%	4.9%	-94.7%	0.0%	-6.3%	-100.0%	-39.0%	-100.0%	100.0%	0.0%	-
Annual bonus	N/A	-62.2%	-73.3%	-67.7%	-	-	-	-	-	-	-	-	-

[A] The reduction in taxable benefits for employees is principally due to the buyout of a medical insurance allowance paid to Netherlands employees who received a one-off payment of €4,935 in 2018, which was not received in 2019. For the CEO, benefits are lower in 2019 due to the medical allowance, which he also received, and lower commuting and business required partner travel costs.

ANNUAL REPORT ON REMUNERATION continued

Relative importance of spend on pay

Distributions to shareholders by way of dividends and share buybacks and remuneration paid to or receivable by employees for the last five years are set out below, together with annual percentage changes.

Relative importance of spend on pay

Year	Dividends and share buybacks [A]		Spend on pay (all employees) [B]	
	\$ billion	Annual change	\$ billion	Annual change
2019	25.4	26%	13.2	-1.3%
2018	20.2	29%	13.4	-6%
2017	15.6	4%	14.3	-9%
2016	15.0	25%	15.7	-8%
2015	12.0	-18%	17.1	5%

[A] Dividends paid, which includes the dividends settled in shares via our Scrip Dividend Programme, and repurchases of shares as reported in the "Consolidated Statement of Changes in Equity".

[B] Employee costs, excluding redundancy costs, as reported in Note 26 to the "Consolidated Financial Statements".

Spend on pay can be compared with the major costs associated with generating income by referring to the "Consolidated Statement of Income". Over the last five years, the average spend on pay was 5% of the major costs of generating income. These costs are considered to be the sum of: purchases; production and manufacturing expenses; selling, distribution and administrative expenses; research and development; exploration; and depreciation, depletion and amortisation.

Total pension entitlements (audited)

During 2019, Ben van Beurden and Jessica Uhl accrued retirement benefits under defined benefit plans. The pension accrued under these plans at December 31, 2019, is set out below. The exchange rates used for conversion into euros and dollars are at December 31, 2019.

Accrued pension (audited)

Thousand	Local	€	\$
Ben van Beurden [A]	€ 1,285	€ 1,285	\$1,441
Jessica Uhl [B]	\$1,247	€ 1,112	\$1,247

[A] The accrued benefits are disclosed on a per annum basis.

[B] Jessica Uhl has an annual choice of two accrual formulas with different forms of benefits, one in the form of a lifetime annuity and the other allows for a lump-sum payment. She elected to accrue benefits up to 2018 under the former and the eventual lump sum benefit is shown. In 2019, she elected to accrue benefits as a lifetime annuity, the value of this accrued benefit at December 31, 2019 was \$3,932 per annum plus a lump sum of \$98,281. She also has a deferred Dutch defined benefit pension plan, as a result of a prior Shell assignment on local Dutch terms and conditions. The age at which Jessica Uhl can receive any pension benefit without an actuarial reduction under this plan is 60. The value of the deferred pension benefit is €3,369 per annum.

The age at which Ben van Beurden can receive any pension benefit without actuarial reduction is 68 and for Jessica Uhl this is age 65. Any pension benefits on early retirement are reduced using actuarial factors to reflect early payment. No payments were made in 2019 regarding early retirement or in lieu of retirement benefits.

Please refer to page 145 for further details. (Pension)

External appointments

The Executive Directors held no external appointments in 2019.

Statement of voting at 2019 AGM

Shell's 2019 AGM was held on May 21, 2019, in the Netherlands. The result of the poll in respect of Directors' remuneration was as follows:

Approval of Directors' Remuneration Report

Votes	Number	Percentage
For	4,357,260,297	89.93%
Against	488,139,305	10.07%
Total cast	4,845,399,602 [A]	100.00%
Withheld [B]	130,596,261	

[A] Representing 59.71% of issued share capital.

[B] A vote "withheld" is not a vote under English law and is not counted in the calculation of the proportion of the votes "for" and "against" a resolution.

The result of the poll in respect of the Directors' Remuneration Policy approved at the 2017 AGM was as follows:

Approval of Directors' Remuneration Policy

Votes	Number	Percentage
For	4,064,279,529	92.34%
Against	337,361,835	7.66%
Total cast	4,401,641,364 [A]	100.00%
Withheld [B]	37,303,341	

[A] Representing 53.53% of issued share capital.

[B] A vote "withheld" is not a vote under English law and is not counted in the calculation of the proportion of the votes "for" and "against" a resolution.

Directors' employment arrangements and letters of appointment

Executive Directors are employed for an indefinite period. Non-executive Directors, including the Chair, have letters of appointment. Details of Executive Directors' employment arrangements can be found in the Directors' Remuneration Policy on page 161.

Further details of Non-executive Directors' terms of appointment can be found in the "Other regulatory and statutory information" on page 170 and the "Governance Framework" report on page 118.

Compensation of directors and senior management

During the year ended December 31, 2019, Shell paid and/or accrued compensation totalling \$38 million (2018: \$43 million) to Directors and Senior Management for services in all capacities while serving as a Director or member of Senior Management, including \$3 million (2018: \$3 million) accrued to provide pension, retirement and similar benefits. The amounts stated are those recognised in Shell's income on an IFRS basis. See Note 27 to the "Consolidated Financial Statements". Personal loans or guarantees were not provided to Directors or Senior Management.

CEO pay ratio

Shell has chosen to use option A to calculate the CEO pay ratio in accordance with guidance from the UK government that this is the preferred approach and provides the statistically most accurate method for identifying the ratios. Under option A, a comparable single figure for all UK employees has been calculated in order to identify the employee whose pay and benefits are at the 25th, 50th and 75th percentiles for comparison with the CEO. Employee pay has been calculated based on the total pay and benefits paid in respect of 2019 for all employees who were employed on 31 December 2019. For part-time workers and joiners in the year, pay and benefits have been annualised based on the proportion of their working time in the UK during the year. This is calculated with an approach consistent with the methodology for determining those employees' 2019 annual bonuses. The REMCO believes that this provides a fair and reasonable calculation of the pay ratios for Shell employees in the UK.

	Option	25th Percentile pay ratio	Median pay ratio	75th pay ratio
2019	A	147:1	87:1	54:1
Total pay and benefits:		£59,419	£100,755	£161,717
Salary:		£40,417	£56,721	£79,991
2018	A	202:1	143:1	92:1

The ratio has changed for 2019 compared to 2018 principally due to the decrease in the Single Figure of remuneration for the CEO. This decrease is due to the lower bonus and LTIP vesting outcomes for 2019 compared to the outcomes in 2018. The pay and benefits for the 25th, 50th and 75th percentile employees have also reduced in relation to 2018. Please refer to page 137 for a discussion of the reasons behind the changes in employee pay and benefits. The REMCO believes these changes are consistent with the Group's approach to managing pay as well as strategic developments in Shell's business portfolio.

Workforce engagement

The REMCO took a wide perspective in making the remuneration decisions for 2019 and determining the 2020 policy. As examples, in 2019 the REMCO noted:

- the alignment between Shell's culture and workforce policies, and incentives and rewards as part of the 2020 remuneration policy review;
- the planned general employee salary increases in the UK, US and NL when determining 2020 base salaries;
- the scorecard and Performance Share Plan (PSP) outcomes for employees in determining the 2019 variable pay outcomes for Executive Directors; and
- the CEO pay ratio, which Shell has been voluntarily disclosing in advance of the regulatory requirement to do so, and gender pay gap reporting.

Executive remuneration structures in Shell are strongly aligned to the broader Shell pay policy:

- in recent years the Group Scorecard architecture has been identical to the Executive Committee and Senior Executive Scorecard in terms of measures, weightings and targets;
- Executive Directors and Executive Committee members participate in the Long-Term Incentive Plan. Around 150 Senior Executives participate in the same plan. The measures and metrics for that plan also apply to 50% of the PSP awarded to around 16,500 employees; and
- all employees in the Group participate in the relevant pension plan for their country based on their date of joining. Shell does not operate separate executive pension arrangements.

This consistency means that less explanation of executive remuneration structures is required than in companies where alignment is not the default.

ANNUAL REPORT ON REMUNERATION continued

STATEMENT OF 2020 PLANNED IMPLEMENTATION OF POLICY

The proposed Directors' Remuneration Policy as outlined on pages 155-163 will, subject to shareholder approval, take effect from May 19, 2020 and will be effective until the 2023 AGM, unless a further policy is proposed by Shell and approved by shareholders in the meantime. This section describes elements that apply for 2020, within the boundaries of the policy.

Executive Directors Salaries

Effective from January 1, 2020, the base salaries were set at €1,588,000 (+2.0%) for Ben van Beurden and at €1,035,000 (+2.0%) for Jessica Uhl, in accordance with the proposed 2020 remuneration policy as set out on page 156. These increases are consistent with planned salary increases in the US, UK and NL for the general employee population which range from 1.7% – 3.4%.

Annual bonus

There are no changes to the scorecard measures and weightings for 2020. Performance measures are comprised of cash flow from operating activities, operational excellence and sustainable development measures. These measures and weightings were reviewed by the REMCO as part of the 2020 policy review, with the REMCO determining that these remain well-aligned with our strategic and operational priorities and consistent with the performance indicators set out on pages 42-44.

The performance measures, weightings and link to strategy for the 2020 performance year are set out below:

2020 annual bonus scorecard measures and weightings

Performance measure	Weighting
Financial	30%
Operational excellence	50%
Sustainable development	20%
	Link to strategy
Financial <ul style="list-style-type: none"> Cashflow from operating activities 	Aligned with our financial priorities, reflecting our ability to generate cash to service and reduce debt, pay the dividend and fund capital investment.
Operational excellence <ul style="list-style-type: none"> Production LNG liquefaction volumes Refinery and chemical plant availability Project delivery 	<p>Representative performance metrics from our main business lines to drive focus on the operational delivery critical to our success and inspire a shared culture and alignment with our purpose, strategy and values.</p> <p>These metrics measure the effectiveness with which we operate our assets and portfolio base. This operational performance underpins the successful delivery of our financial framework and ambitions to progress in the energy transition. Shell's longer-term strategic ambitions are measured in the LTIP metrics.</p>
Sustainable development <ul style="list-style-type: none"> Safety Environmental performance 	We must maintain focus on safety and environmental performance, as this provides assurance to shareholders, employees and society of our commitment to safety and progress in the energy transition.

Annual bonus scorecard targets are not disclosed prospectively because to do so in a meaningful manner would require the disclosure of commercially sensitive information. As in previous years, scorecard targets will be disclosed in the subsequent Directors' Remuneration Report when they are no longer deemed to be commercially sensitive.

Long-term Incentive Plan

On January 31, 2020, a conditional award of performance shares under the LTIP was made to the Executive Directors resulting in 200,589 Royal Dutch Shell plc A shares (A shares) being conditionally awarded to Ben van Beurden and 59,062 Royal Dutch Shell plc A American Depositary Shares (A ADSs) to Jessica Uhl. The award had a face value of 300% (maximum performance outcome 600%) of the base salary for the CEO and 270% (maximum performance outcome 540%) of the base salary for the CFO, excluding potential share price appreciation and dividends. In making these awards, the REMCO considered the Company's share price and determined that there was no significant share price volatility that would require an adjustment to the size of the awards.

The award for the CEO has been reduced from a face value award of 340% (maximum vesting outcome 680%) in prior years. This reduction is part of the REMCO's response to addressing quantum and further details are provided on pages 137-138.

For LTIP awards made in 2020, performance will be assessed over a three-year period based on four financial measures and an energy transition condition.

The target for the FCF metric is the aggregate of our annual operational business plan FCF targets over the three-year performance period. These are considered to be commercially sensitive and will be disclosed retrospectively, with annual updates on progress provided.

The NCF target range for the 2020 – 2022 LTIP grant is set as a 3-4% reduction from the 2016 NCF of 79g CO₂e/MJ. This target is aligned with the trajectory of our NCF ambition set out in November 2017. There is no change to the other energy transition measures other than the advanced biofuel technology measure is extended to include a measure of alternative fuel development. The targets for the other leading energy transition measures are commercially sensitive, and will be disclosed retrospectively.

2020 LTIP measure and vesting schedule

■ Absolute measures □ Relative measures

Energy transition	10%
Free cash flow	22.5%
TSR	22.5%
ROACE growth	22.5%
Cash flow from operating activities growth	22.5%

Link to strategy	Vesting schedule (% of initial LTIP award)
Energy transition Focused on Shell's strategy to thrive in the energy transition and support delivery of our NCF ambition.	Vesting based on how many targets are achieved: 1/4 = 40% 2/4 = 100% 3/4 = 150% 4/4 = 200% REMCO may take into account other appropriate considerations
Free cash flow Recognition of the importance of generating cash after net capital expenditure to service and reduce debt, pay dividends, buy back shares and make future capital investments.	Maximum – 200% Target – 100% Threshold – 40% Below threshold – 0%
TSR Assessment of actual wealth created for shareholders.	1st – 200% 2nd – 150% 3rd – 80% 4th or 5th – nil
ROACE growth Indicator of capital discipline.	
Cash flow from operating activities growth Source of capital expenditure commitments which support sustainable growth based on portfolio and cost management.	
TSR underpin If TSR is in fourth or fifth, vesting on the other measures is capped at 50% of maximum.	
Holding period 3-years post-vesting which remains in force post-tenure.	

Discretion, adjustment (malus) and recovery (clawback)

Variable pay elements are subject to adjustment (malus) and recovery (clawback) provisions, which may apply in case of direct responsibility or supervisory accountability. The REMCO may adjust an award, for example by lapsing part or all of it, reducing the number of shares which would otherwise vest, by imposing additional conditions on it, or imposing a new holding period or applying clawback.

Please refer to the policy section on pages 157 and 159 for a full description of the circumstances under which discretion, malus and clawback might be applied to a variable pay award.

Pension

Ben van Beurden's pension arrangements comprise a defined benefit plan for which the maximum pensionable salary has increased to €98,993 for 2020 and a net pay defined contribution pension plan with an employer contribution of 27% of salary in excess of this amount.

Jessica Uhl's US retirement benefit arrangements include the Shell Pension Plan, a defined benefit plan, and a defined contribution plan with an employer contribution of 10% of salary. She also has a deferred Dutch defined benefit pension plan, as a result of a prior Shell assignment on local Dutch terms and conditions.

Further details of Executive Director pension arrangements can be found on page 145.

ANNUAL REPORT ON REMUNERATION continued

Non-executive Directors' fees

Non-executive Directors' fees 2020

	€	Other fees
Chair of the Board	850,000	Non-executive Directors receive an additional fee of €5,000 for any Board meeting involving intercontinental travel – except for one meeting a year held in a location other than The Hague.
Non-executive Director	135,000	
Senior Independent Director	55,000	
Audit Committee		
Chair [A]	60,000	
Member	25,000	
Safety, Environment and Sustainability Committee [B]		
Chair [A]	35,000	
Member	17,250	
Nomination and Succession Committee		
Chair [A]	25,000	
Member	12,000	
Remuneration Committee		
Chair [A]	40,000	
Member	17,250	

[A] The chair of a committee does not receive an additional fee for membership of that committee.

[B] Formerly the Corporate and Social Responsibility Committee.

The Chair's fee is determined by the REMCO and the annual fee for Charles O. Holliday was set at €850,000 upon appointment in 2015 and will remain unchanged for 2020. The Chair of the Board does not receive any additional fee for chairing the Nomination and Succession Committee or attending any other Board committee meeting.

The Non-executive Directors receive a basic fee. There are additional fees for the Senior Independent Director, a Board committee chair or a Board committee member for each committee. Non-executive Directors receive an additional fee of €5,000 for any Board meeting involving intercontinental travel, except for one meeting a year held in a location other than The Hague. Business expenses (including transport between home and office and occasional business-required spouse travel) and associated tax are paid or reimbursed by Shell. The Chair has use of a Shell-provided apartment while in The Hague.

The Board reviews Non-executive Directors' fees periodically to ensure that they are aligned with those of other major listed companies using the FTSE 30 and the Europe Comparator group as the primary points of reference. The last general review was carried out in 2018 with a review of the Nomination and Succession Committee fees in 2019 and fees will remain unchanged for 2020.

DIRECTORS' REMUNERATION POLICY

The Directors' Remuneration Policy sets out

- Summary of proposed changes to the Directors' Remuneration Policy, **page 155**;
- Executive Directors' Remuneration Policy, **page 156**; and
- Non-executive Directors' Remuneration Policy, **page 162**.

This section describes the Directors' Remuneration Policy (Policy) which, subject to shareholder approval at the 2020 Annual General Meeting (AGM), will come into effect from May 19, 2020, and will be effective until the 2023 AGM, unless a further policy is proposed by Royal Dutch Shell plc (the Company) and approved by shareholders in the meantime.

The principles underpinning the REMCO's approach to executive remuneration are the foundation for everything we do, and are:

- **Alignment with Shell's strategy:** the Executive Directors' compensation package should be strongly linked to the achievement of stretching targets that are seen as indicators of the execution of Shell's strategy;
- **Pay for performance:** the majority of the Executive Directors' compensation (excluding benefits and pensions) should be linked directly to Shell's performance through variable pay instruments;
- **Competitiveness:** remuneration levels should be determined by reference internally against Shell's Senior Management and externally against companies of comparable size, complexity and global scope;
- **Long-term creation of shareholder value:** Executive Directors should align their interests with those of shareholders by holding shares in Shell;
- **Consistency:** the remuneration structure for Executive Directors should generally be consistent with the remuneration structure for Shell's senior management. This consistency builds a culture of alignment with Shell's purpose and a common approach to sharing in Shell's success;
- **Compliance:** decisions should be made in the context of the Shell General Business Principles and Code of Conduct. The REMCO

also seeks to ensure compliance with applicable laws and corporate governance requirements when designing and implementing policies and plans; and

- **Risk assessment:** the remuneration structures and rewards should meet risk-assessment tests to ensure that shareholder's interests are safeguarded and that inappropriate actions are avoided.

The Executive Directors' remuneration structure is made up of a fixed element of basic pay and two variable elements: the annual bonus (50% delivered in shares) and the Long-term Incentive Plan (LTIP). Variable pay outcomes are conditional on the successful execution of the operating plan in the short term and the delivery of strategic goals and financial outperformance over the longer term. The award of shares under the bonus and LTIP, along with significant shareholding requirements, is intended to ensure executives have a sizeable shareholding in Royal Dutch Shell plc (the Company) and experience the same outcomes as shareholders.

During 2018 and 2019, the REMCO reviewed the Remuneration Policy to ensure that the Policy continues to be aligned with Shell's strategy, including delivery of shareholder returns. REMCO determined that while the current policy remains appropriate in many respects, certain changes will support the REMCO to simplify remuneration structures and address the management of quantum. For each area of the policy, the REMCO has considered market practice, the corporate governance environment and feedback from shareholders. The Safety, Environment and Sustainability Committee (SESCO) has provided input to the development of the sustainable development and energy transition metrics. Any potential conflict of interest is mitigated by the independence of the REMCO members and the REMCO Terms of Reference.

A summary of the main proposed changes to the Policy for the Executive Directors is outlined below. No significant changes are proposed to the Policy for Non-executive Directors.

Remuneration element	Proposed Changes to Policy	Rationale for the change
Annual Bonus	<ul style="list-style-type: none"> ■ Reduction of the CEO's target bonus from 150% to 125%; and ■ Removal of the individual performance factor for Executive Directors. 	<ul style="list-style-type: none"> ■ Simplification: The asymmetry in the CEO's bonus structure and the inclusion of individual performance factors was creating undue complexity; and ■ Transparency: The annual bonus is now solely linked to the performance of Shell to support clarity and transparency of outcomes.
Long-Term Incentive Plan	<ul style="list-style-type: none"> ■ Reduction of the target LTIP grant from 400% to 300% of base salary; and ■ Inclusion of an energy transition metric. 	<ul style="list-style-type: none"> ■ Management of Quantum: To moderate the quantum of pay and assist the REMCO in managing the range of outcomes; and ■ Alignment to Strategy: Inclusion of the energy transition metric strengthens the LTIP's alignment to the strategy and purpose.
Discretion, Malus & Clawback	<ul style="list-style-type: none"> ■ After reviewing the single figure outcomes for the year, the REMCO will consider an adjustment for the purposes of managing remuneration quantum, taking into account performance, the operation of the remuneration structures and any other relevant considerations. An explanation of any discretionary adjustment would be set out in the relevant Director's Remuneration Report; ■ Alignment of malus and clawback provisions so that these are the same. Inclusion of corporate failure as an adjustment event; and ■ Amendment of provisions in the share plan such that for future grants, awards may be adjusted for any reason. 	<ul style="list-style-type: none"> ■ Corporate Governance: Assist the REMCO in managing the risks from behavioural-based incentive schemes; and ■ Management of Quantum: To assist the REMCO in managing the range of outcomes.
Pension	<ul style="list-style-type: none"> ■ New Executive Directors who are members of a defined benefit pension arrangement will have their pensionable salary capped at the salary applicable immediately prior to appointment, with the exception of existing US base country participants who will have the bonus removed from the definition of pensionable base salary instead. The Executive Director will join a defined contribution scheme in their base country for contributions made in respect of salary above the defined benefit pensionable salary, or in exceptional circumstances, receive a cash allowance equivalent to the contribution above the cap; and ■ For recruitment: Explicit confirmation that new appointees, whether internally promoted or newly hired, will be provided with a pension in line with the wider workforce in their base country. 	<ul style="list-style-type: none"> ■ Management of Quantum: To moderate the quantum of pay and assist the REMCO in managing the range of outcomes; and ■ Corporate Governance: To adopt best practice in line with external guidelines.
Shareholding Requirement	<ul style="list-style-type: none"> ■ CFO requirement increased to 500% of base salary; and ■ Extended to apply for a period of two years post-employment (at the lower of the shareholding requirement or the number of shares held at departure). 	<ul style="list-style-type: none"> ■ Alignment with Shareholders: Further aligns executives with the long-term interests of shareholders.

DIRECTORS' REMUNERATION POLICY continued

EXECUTIVE DIRECTORS

Executive Directors' remuneration policy table

Purpose and link to strategy	Maximum opportunity	Operation and performance management
Salary and pensionable base salary		
Provides a fixed level of earnings to attract and retain Executive Directors.	€2,000,000	<p>Reviewed annually with adjustments effective from January 1.</p> <p>In making salary determinations, the REMCO will consider:</p> <ul style="list-style-type: none"> ■ the market positioning of the compensation packages; ■ comparison with Senior Management salaries; ■ the employee context, and planned average salary increase for other employees across the Netherlands, the UK and the USA; ■ the experience, skills and performance of the Executive Director, or any change in the scope and responsibility of their role; ■ general economic conditions, Shell's financial performance, and governance trends; and ■ the impact of salary increases on pension benefits and other elements of the package. <p>For Executive Directors employed outside their base country, euro base salaries are translated into their home currency for pension purposes. Pensionable base salaries are maintained in line with euro base salaries taking into account exchange rate fluctuations and other factors as determined by the REMCO.</p>
Benefits		
Provides benefits, in line with those applicable to the wider workforce, in order to attract and retain Executive Directors.	<p>The maximum opportunity is the cost of providing the benefit under Shell's standard policy. These costs can vary.</p> <p>For certain benefits, for example, relocation and tax equalisation, the maximum opportunity will be the grossed-up cost of meeting the specific Executive Director's costs.</p>	<p>Typical benefits include car allowances and home-to-office transport, risk benefits (for example ill-health, disability or death-in-service), security provision, and employer contributions to insurance plans (such as medical). Precise benefits will depend on the Executive Director's specific circumstances. Post-retirement benefits such as healthcare and ongoing security provision may be applicable. Shell's mobility policies may apply, such as for relocation and tax return preparation support, as may tax equalisation related to expatriate employment prior to Board appointment, or in other limited circumstances to offset double taxation. The REMCO may adjust the range and scope of the benefits offered in the context of developments for other employees in relevant countries. Personal loans or guarantees are not provided to Executive Directors.</p>
Annual bonus		
<p>Rewards the delivery of short-term operational targets as derived from Shell's operating plan.</p> <p>To reinforce alignment with shareholder interests, 50% is delivered in cash and 50% is delivered in shares. The shares are subject to a three-year holding period, which applies beyond an Executive Director's tenure.</p>	<p>Maximum bonus (as a percentage of base salary):</p> <ul style="list-style-type: none"> ■ Chief Executive Officer (CEO): 250% ■ Chief Financial Officer (CFO): 240% <p>Target levels (as a percentage of base salary):</p> <ul style="list-style-type: none"> ■ CEO: 125% ■ CFO: 120% 	<ul style="list-style-type: none"> ■ The bonus is determined by reference to performance from January 1 to December 31 each year; ■ Annual bonus = base salary x target bonus % x scorecard result (0–2); ■ Taking the Shell operating plan into consideration, REMCO sets stretching scorecard targets and weightings which support the delivery of the strategy. Measures are related to financial performance, operational excellence and sustainable development. Indicative weightings are 30%, 50% and 20% respectively. This balance ensures that the achievement of short-term financial performance does not undermine future shareholder value creation; ■ Scorecard targets will be disclosed in a subsequent Directors' Remuneration Report when they are no longer deemed to be commercially sensitive; ■ There are no prescribed thresholds or minimum levels of performance that equate to a prescribed payment under the Policy and this structure can result in no bonus being awarded; ■ The annual bonus is subject to malus provisions before it is delivered and to clawback provisions thereafter; ■ The REMCO retains the ability to adjust performance measure targets and weightings year-by-year within the overall target and maximum payouts approved in the Policy; and ■ In the event that another Executive Director joins the Board, the REMCO will determine their target and maximum bonus, which will not exceed the target and maximum for the CEO.

Executive Directors' remuneration policy table *continued*

Purpose and link to strategy	Maximum opportunity	Operation and performance management
Long-Term Incentive Plan (LTIP)		
<p>Rewards longer-term value creation linked to Shell's strategy. The measures predominantly focus on financial growth and increases in value compared with the other oil majors, supported by measures focused on the achievement of Shell's ambitions in the energy transition.</p> <p>To reinforce alignment with shareholder interests, shares delivered from vested LTIP awards are subject to a three-year holding period, which applies beyond an Executive Director's tenure.</p>	<p>Target award of 300% base salary.</p> <p>Awards may vest at up to 200% of the shares originally awarded, plus dividends.</p>	<ul style="list-style-type: none"> ■ Award levels are determined annually by the REMCO within the approved policy maximum; ■ Awards may vest between 0% and 200% of the initial award depending on Shell's performance assessed on either an absolute basis against strategic targets, or on a relative basis against the other oil majors; ■ Performance metrics and targets are set by the REMCO at the beginning of the relevant performance period. When setting performance targets, the REMCO allocates weightings to each metric as it considers appropriate taking into account strategic priorities; ■ For 2020, performance is assessed over three years based 90% on financial metrics (TSR, ROACE, FCF and CFFO) which support our strategic ambition to be a world-class investment case and 10% on a measure focused on thriving in the energy transition; ■ Additional shares are released representing the value of dividends payable on the vested shares, as if these had been owned from the award date; ■ LTIP awards (net of tax) must be held for a further three years to align with Shell's longer-term time horizon and strategy; ■ The LTIP award is subject to malus provisions before it is delivered and to clawback provisions thereafter; ■ The REMCO may adjust or change the LTIP measures, targets and weightings to ensure continued alignment with Shell's strategy; and ■ In the event that another Executive Director joins the Board the REMCO will determine their award level.
Discretion, Malus and Clawback		
<p>Enables the management of risks from behavioural-based incentive schemes and the REMCO to manage the range of pay outcomes.</p>	<p>Adjustment events exist for the purposes of applying malus and clawback.</p> <p>The REMCO retains discretion to adjust pay outcomes.</p>	<p>The REMCO retains the discretion to adjust mathematical outcomes of the annual bonus scorecard and / or LTIP vesting for any Executive Director if and to the extent that it considers this appropriate at their sole discretion.</p> <p>The use of any discretion will be disclosed and explained.</p> <p>The REMCO may adjust pay outcomes for the purposes of managing quantum. This would be done at the REMCO's discretion after considering single figure outcome for the year, taking into account Shell's performance, the operation of the remuneration structures and any other relevant considerations.</p> <p>Please refer to page 159 for a summary of the defined adjustment events.</p>
Pension		
<p>Provides a competitive retirement provision under the individual's base country benefits policy, to attract and retain Executive Directors.</p>	<p>Determined by the rules of the base country pension plan of which the Executive Director is a member.</p>	<p>Executive Directors' retirement benefits are maintained in line with those of the wider workforce in their base country. Only base salary is pensionable, unless country plan regulations specify otherwise and cannot legally be disappplied. The rules of the relevant plans detail the pension benefits which members can receive. The REMCO retains the right to amend the form of any Executive Director's pension arrangements where appropriate, for example in response to changes in legislation to ensure the original objective of this element of remuneration is preserved.</p> <p>New Executive Directors, whether internal appointees or external hires, will be provided with a retirement benefit in line with the wider workforce in their base country. For individuals who are members of a defined benefit pension arrangement:</p> <ul style="list-style-type: none"> ■ The pensionable salary will be capped at the salary applicable immediately prior to appointment, with the exception of existing US base country participants who will have the bonus removed from the definition of pensionable base salary instead; and ■ The Executive Director will join a defined contribution scheme in their base country for contributions made in respect of salary above the defined benefit pensionable salary, or in exceptional circumstances, receive a cash allowance equivalent to the contribution above the cap.
Shareholding requirement		
<p>Aligns interests of Executive Directors with those of shareholders by creating a connection between individual wealth and Shell's long-term performance.</p>	<p>Shareholding (% of base salary):</p> <ul style="list-style-type: none"> ■ CEO: 700% ■ CFO: 500% 	<p>Executive Directors are expected to build up their shareholding to the required level over a period of five years from appointment and, once reached, to maintain this level for the full period of their appointment. The intention is for the shareholding guideline to be reached through retention of vested shares from share plans. The REMCO will monitor individual progress and retains the ability to adjust the guideline in special circumstances on an individual basis.</p> <p>The Executive Director will be required to maintain their shareholding requirement (or existing shareholding if lower) for a period of two years from the date they cease to be an employee.</p> <p>In the event that another Executive Director joins the Board the REMCO will determine their Shareholding requirement level, which will not be less than 200% in line with corporate governance best practice.</p>

DIRECTORS' REMUNERATION POLICY continued

Notes to the Executive Directors' remuneration policy table

Comparator group

The benchmarking comparator group consists of the other oil majors (BP, Chevron, ExxonMobil, and Total) and a selection of major Europe-based companies.

The comparator companies are reviewed by the REMCO as part of the Remuneration Policy review every three years. The last review took place in 2019 in preparation for the 2020 Directors' Remuneration Policy vote. No changes to the comparator group are proposed.

The other oil majors are included in the comparator group as these represent our closest direct competitors operating in similar market conditions. The Europe-based companies are selected based on their size, complexity and global reach. The REMCO uses benchmark data from these companies only as a guide to the competitiveness of the remuneration packages. We do not seek to position our remuneration at any defined point against the benchmarked positions.

The REMCO retains the right to alter the comparator group as it sees fit in order to ensure it remains an appropriate and relevant benchmark.

2020 European comparator group

Allianz	Daimler	Rio Tinto
AstraZeneca	Diageo	Roche
BAT	GlaxoSmithKline	Siemens
Bayer	Nestle	Unilever
BHP Billiton	Novartis	Vodafone

Benefits

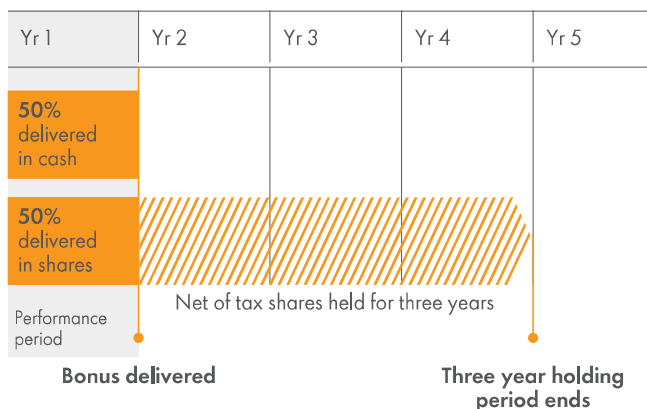
Benefits for Executive Directors deemed taxable in the UK are included as taxable benefits in the single total figure of remuneration table. These elements may include transport to and from home and office, the provision of home security, and occasional business-required partner travel, which are generally considered legitimate business expenses rather than components of remuneration.

Annual bonus

For the 2020 performance year, the scorecard framework will consist of cash flow from operating activities (30% weight), operational excellence (50% weight) and sustainable development (20% weight). Targets are derived from the annual business plan. These measures are designed to drive focus on the financial and operational performance critical to our success as a world-class investment case and to maintain a strong licence to operate, underpinned by our commitment to safety and journey to thrive in the energy transition. The REMCO believes it is important for annual variable pay to remain balanced, with operational and environmental components, complementing the LTIP's focus on longer-term financial and strategic outcomes. The same annual bonus scorecard applies to the majority of group employees, supporting consistency of remuneration and alignment of objective across employees and senior management.

For future years, the specific measures and weightings for the annual bonus scorecard will be reviewed annually by the REMCO and adjusted accordingly to evolve with Shell's strategy and circumstances. The annual review will also consider the scorecard target and outcome history over a decade to ensure that the targets set remain stretching but realistic. The REMCO retains the right to exercise its judgement to adjust the mathematical bonus scorecard outcome to ensure that the bonus scorecard outcome for Executive Directors reflects other aspects of Shell's performance which the REMCO deems appropriate for the reported year.

Annual bonus – time horizon



Long-term Incentive Plan

The LTIP rewards longer-term performance linked to Shell's strategy, which includes cash generation, capital discipline, value created for shareholders as well as progress towards meeting our ambition to thrive in the energy transition.

For 2020, the absolute measures will be FCF and energy transition, and relative growth compared with our peers will be based on: TSR, ROACE and CFFO. The relative measures, which focus on outperforming our closest competitors on key financial metrics, are supported by the absolute FCF metric which provides cash to service and repay debt, make shareholder distributions and fund capital investment. These are aligned with our strategic ambition to be a world-class investment case, and are supported by an energy transition measure focused on thriving in the energy transition and delivering our NCF target.

For the relative measures, 200% vests for first position, 150% for second, 80% for third and 0% for ranking fourth or fifth. The comparator group consists of four of the strongest companies in our industry (BP, Chevron, ExxonMobil and Total). Outperforming Shell's closest competitors on key financial metrics is challenging. A vesting outcome of 80% for median performance (40% of maximum) in a small comparator group is considered appropriate by the REMCO. The REMCO is aware that vesting for median performance is generally set at a limit of 25% of maximum for other UK companies. However, these are typically applied against a larger comparator group.

The REMCO will regularly review the measures, weightings and comparator group, and retains the right to adjust these to ensure that the LTIP continues to serve its intended purpose with a stretching level of challenge. If the REMCO was to propose any material changes to the LTIP performance metrics, it would consult with major shareholders.

TSR underpin

If the TSR ranking is fourth or fifth, the level of the award that can vest on the basis of the other measures will be capped at 50% of the maximum payout for the LTIP.

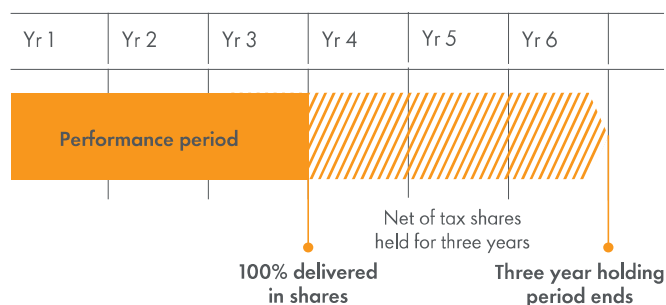
The detailed weightings and metrics applicable to the 2020 bonus scorecard are set out on page 152.

The detailed weightings and metrics applicable to the 2020 grant are set out on page 153.

Performance Period

LTIP performance is assessed over a three-year period. Vested shares from the LTIP are subject to a further three-year holding period post-vesting. This holding period commences on the date of vesting and remains in force beyond an Executive Director's tenure. This time horizon is deemed to be suitable for incentive purposes but is recognised as short relative to some of Shell's operations. However, the REMCO believes that it provides for broad alignment with shareholder interests when coupled with significant shareholding requirements.

LTIP time horizon



Discretion, malus and clawback

Variable pay awards may be made subject to adjustment events. At the discretion of REMCO, such an award may be adjusted before delivery (malus) or reclaimed after delivery (clawback) if an adjustment event occurs.

Adjustment events will be specified in award documentation and it is intended that they will, for example, relate to restatement of financial statements due to material non-compliance with a financial reporting requirement; misconduct by an Executive Director or misconduct through their direction or non-direction; any material breach of health and safety or environment regulations; serious reputational damage to Shell; material failure of risk management; corporate failure; or other exceptional events as determined at the discretion of the REMCO. The REMCO retains the right to alter the list of adjustment events in respect of future awards.

In addition, the REMCO retains the discretion to adjust mathematical outcomes if and to the extent that it considers this appropriate. This power to adjust the outcomes is broad and includes adjusting the outcomes to zero. For example, an adjustment might be made if the REMCO considers:

- The mathematical outcomes do not reflect the wider financial or non-financial performance of RDS or the participant over the performance period;
- The LTIP vesting percentage is not appropriate in the context of circumstances that were unexpected or unforeseen at award; and
- There is any other reason why an adjustment is appropriate.

It is not anticipated that discretion would be used for upwards adjustment. If, in exceptional circumstances, it was considered, this would be done only after consultation with major shareholders.

Performance outcomes and/or share price appreciation make it difficult to predict the final amounts delivered under the LTIP at the time of award. In years where the vesting outcome makes the total remuneration inappropriate for any Executive Director, the REMCO will consider an adjustment to the annual bonus outcome or the LTIP vesting outcome

for the purposes of managing remuneration quantum. In making any adjustment to the annual bonus or LTIP vesting outcome for this purpose REMCO will consider the overall level of remuneration for the Executive Director, the operation of the annual bonus, the operation of the LTIP, the wider performance of Shell over the performance periods, as well as the internal context for other employees.

An explanation of any discretionary adjustment would be set out in the relevant Directors' Remuneration Report.

Treatment of outstanding awards

Awards granted prior to the approval and implementation of this Policy and/or prior to an individual becoming an Executive Director will continue to vest and be delivered in accordance with the terms of the original award even if this is not consistent with the terms of this Policy.

As at March 10, 2020, this applies to Executive Directors Ben van Beurden and Jessica Uhl who each have outstanding awards under the LTIP.

Shareholding

The REMCO believes significant shareholding by Executive Directors is an important way of ensuring that shareholders and Executive Directors share the same priorities. Shareholding is one of Shell's core remuneration principles as it creates a balanced connection between individual wealth and Shell's long-term performance. This will support effective governance and an ownership mindset. Significant shareholding requirements reflect the performance timescales of Shell and are aligned with absolute shareholder return.

The CEO is expected to build up a shareholding of seven times their base salary over five years from appointment. The CFO is expected to build up a shareholding of five times their base salary over the same period. In the event of an increase to the guideline multiple of salary, for every additional multiple of salary required, the director will have one extra year to reach the increased guideline, subject to a maximum of five years from the date of the change.

Executive Directors will be required to maintain their shareholding requirement (or their existing shareholding if less than the guideline) for a period of two years post-employment.

The holding periods for LTIP vested shares and shares delivered as part of the annual bonus continue to apply after Executive Directors leave employment.

Differences for Executive Directors from other employees

The remuneration structure and approach to setting remuneration levels is consistent across Shell, with consideration given to location, seniority and responsibilities. However, a higher proportion of total remuneration is tied to variable pay for Executive Directors and members of Senior Management.

The salary for each Executive Director is determined based on the indicators in the "Executive Directors' remuneration policy table", which reflect the international nature of the Executive Directors' labour market. The salary for other employees is normally set on a country basis.

DIRECTORS' REMUNERATION POLICY continued

Executive Directors are eligible to receive the standard benefits and allowances provided to other employees. The provisions which are not generally available for other employees are described in "Benefits".

The methodology used for determining the annual bonus for Executive Directors is broadly consistent with the approach for Shell employees generally. However, bonuses for the majority of Shell employees are determined taking into account individual and business performance, whereas bonuses for Executive Directors are based solely on business performance. Although the makeup and weightings scorecard used for the majority of Shell employees is currently aligned with the scorecard, these scorecards may differ if required to support the achievement of business objectives. All Executive Directors and Executive Committee members receive 50% of their annual bonus in shares, which are subject to a three-year holding period.

Executive Directors are not eligible to receive new awards under employee share plans other than the LTIP, although awards previously granted will continue to vest in accordance with the terms of the original award. Selected employees participate in the Performance Share Plan (PSP). The operation of the PSP is similar to the LTIP, but currently differs, for example, in some performance measures and their relative weightings. As at March 2020, around 51,000 employees participate in one or more of Shell's global share plans and/or incentive plans, further supporting alignment with shareholder interests.

Executive Directors' retirement benefits are maintained in line with those of the wider workforce in their base country.

Illustration of potential remuneration outcomes

The charts on this page represent estimates under four performance scenarios ("Minimum", "On-target", "Maximum" and "Maximum, assuming a 50% share price appreciation between award and vest") of the potential remuneration outcomes for each Executive Director resulting from the application of 2020 base salaries to awards made in accordance with the proposed Policy. The majority of Executive Directors' remuneration is delivered through variable pay elements, which are conditional on the achievement of stretching targets.

The REMCO will review the formulaic Single Figure outcome relative to the quality of performance outcomes and adjust these, taking into account Shell's performance, shareholder experience, the operation of the remuneration structures and any other relevant factors, to ensure that the highest variable pay outcomes are only achieved in years with the highest quality performance.

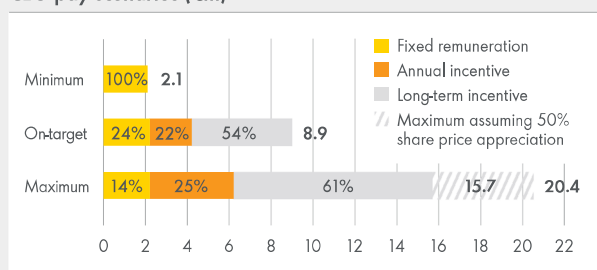
The scenario charts are based on future Policy award levels and are combined with projected single total figures of remuneration. The pay scenarios are forward-looking and only serve to illustrate the future Policy. For simplicity, the minimum, on-target and maximum scenarios assume no share price movement and exclude dividend accrual, for the portion of the bonus paid in shares and the LTIP, although dividend accrual during the performance and holding period applies. The scenarios are based on the current CEO (Ben van Beurden) and CFO (Jessica Uhl) roles.

Performance scenarios

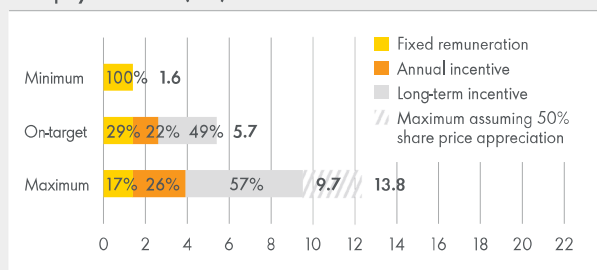
	Minimum	Target	Maximum[A]
Base salary (2020)	✓	✓	✓
Benefits (2019 actual)	✓	✓	✓
Pension (2020 estimate)	✓	✓	✓
Bonus	NIL	125% CEO 120% CFO	250% CEO 240% CFO
LTIP	NIL	300% CEO 270% CFO	600% CEO 540% CFO

[A] Maximum assuming 50% share price appreciation.

CEO pay scenarios (€m)



CFO pay scenarios (€m)



Recruitment

The REMCO determines the remuneration package for new Executive Director appointments. These appointments may involve external or internal recruitment or reflect a change in role of a current Executive Director.

When determining remuneration packages for new Executive Directors, the REMCO will seek a balanced outcome which allows Shell to:

- attract and motivate candidates of the right quality;
- take into account the individual's current remuneration package and other contractual entitlements;
- seek a competitive pay position relative to our comparator group, without overpaying;
- encourage relocation if required; and
- honour entitlements (for example, variable remuneration) of internal candidates before their promotion to the Board. The REMCO will follow the approach set out in the table below when determining the remuneration package for a new Executive Director.

Recruitment – Remuneration package

Component	Approach	Maximum
Ongoing remuneration	The salary, benefits, annual bonus, long-term incentives and pension benefits will be positioned and delivered within the framework of the Executive Directors' remuneration policy.	As stated in the "Executive Directors' remuneration policy table".
Compensation for the forfeiture of any awards under variable remuneration arrangements	To facilitate external recruitment, one-off compensation in consideration for forfeited awards under variable remuneration arrangements entered into with a previous employer may be required. The REMCO will use its judgement to determine the appropriate level of compensation by matching the value of any lost awards under variable remuneration arrangements with the candidate's previous employer. This compensation may take the form of a one-off cash payment or an additional award under the LTIP. The compensation can alternatively be based on a newly created long-term incentive plan arrangement where the only participant is the new director. The intention is that any such compensation would, as far as possible, align to the duration and structure of the award being forfeited.	An amount equal to the value of the forfeited variable remuneration awards, as assessed by the REMCO. Consideration will be given to appropriate performance conditions, performance periods and clawback arrangements.
Replacement of forfeited entitlements other than any awards under variable remuneration arrangements	There may also be a need to compensate a new Executive Director in respect of forfeited entitlements other than any awards under variable remuneration arrangements. This could include, for example, pension or contractual entitlements, or other benefits. On recruitment, these entitlements may be replicated within the Executive Directors' remuneration policy or valued by the REMCO and compensated in cash. In cases of internal promotion to the Board, any commitments made which cannot be effectively replaced within the Executive Directors' remuneration policy may, at the REMCO's discretion, continue to be honoured.	An amount equal to the value of the forfeited entitlements, as assessed by the REMCO.
Exceptional recruitment incentive	Apart from the ongoing annual remuneration package and any compensation in respect of the replacement of forfeited entitlements, there may be circumstances in which the REMCO needs to offer a one-off recruitment incentive in the form of cash or shares to ensure the right external candidate is attracted (e.g. to the industry). The REMCO recognises the importance of internal succession planning but it must also have the ability to compete for talent with other global companies. The necessity and level of this incentive will depend on the individual's circumstances. The intention will be that this is only used in genuinely exceptional circumstances.	Subject to the limits set out in the "Executive Directors' remuneration policy table".
Pension	New appointees will be provided with a pension in line with the wider workforce in their base country. For defined benefit members: <ul style="list-style-type: none"> ■ The pensionable salary is capped at executive committee level pay for defined benefit purposes (with the exception of participants in the US plan where the bonus is removed from the definition of pensionable pay; and ■ The member joins an appropriate base country defined contribution mechanism in excess of the cap, or exceptionally a pension cash allowance equivalent to the defined contribution level is payable in excess of the cap. 	In accordance with the pension provision applicable to the wider workforce in the base country.

Executive Directors' employment arrangements and letters of appointment

The Dutch Executive Directors are employed for an indefinite period. Executive Directors with the Netherlands as their base country will be employed on the basis of a contract of employment governed by Dutch employment law. For Executive Directors with a base country other than the Netherlands, REMCO will determine their employment arrangements based on a number of considerations, including Dutch immigration requirements and base country retirement benefits. Executive Directors' employment arrangements are available for inspection at the AGM or on request. For further details on appointment and re-appointment of Directors, see the "Governance Framework" on page 118 and "Other Regulatory and Statutory Information" on page 170.

End of employment Notice period

Employment arrangements of Executive Directors can generally end by either the employee or the employer providing one month's notice, or the applicable statutory notice period. For example, under Dutch law, the statutory notice period for the employer will vary in line with the length of service, with the maximum being four months' notice. Under Dutch law, termination payments are not linked to the contract's notice period.

The Netherlands statutory end-of-employment compensation

With effect from July 1, 2015, employment legislation in the Netherlands introduced statutory end-of-employment compensation. Under this legislation, every termination (other than following retirement or for cause) of a Dutch employment contract that has continued for a minimum of two years will give rise to an obligation to pay the departing employee transition compensation ("transitievergoeding"). The statutory compensation is capped at one times the annual salary, which is deemed to include variable pay such as the annual bonus. Executive Directors are expected not to claim transition compensation or any other applicable statutory compensation over and above the agreed compensation for loss of office as set out in the "End of employment" table on page 162.

Outstanding entitlements

In cases of resignation or dismissal for cause, fixed remuneration (base salary, benefits, and employer pension contributions) will cease on the last day of employment, variable remuneration elements will generally lapse and the Executive Director is not eligible for compensation for loss of office.

The information, on page 162, generally applies to termination of employment by Shell giving notice, by mutual agreement, or in situations where the employment terminates because of retirement with Shell consent at a date other than the normal retirement date, redundancy or in other similar circumstances at the REMCO's discretion.

DIRECTORS' REMUNERATION POLICY continued

End of employment

Provision	Policy
Compensation for loss of office	<p>For Executive Directors appointed between January 1, 2011 and December 31, 2016, employment contracts include a cap on termination payments of one times annual pay (base salary plus target bonus). Delivery of compensation is mitigated by a contractual obligation for the Executive Director to seek alternative employment and Shell's ability to implement phased payment terms.</p> <p>For Executive Directors appointed on or after January 1, 2017, the REMCO may offer a termination payment of up to one times base salary (target bonus will not be included). However, REMCO may be obligated to pay statutory compensation over and above the compensation for loss of office to a departing Executive Director who asserts a statutory claim thereto. Delivery of compensation is mitigated by a contractual obligation for the Executive Director to seek alternative employment and Shell's ability to implement phased payment terms.</p> <p>The provision of standard end-of-employment benefits such as repatriation costs, security provision and outplacement support may also be included, as deemed reasonable by the REMCO.</p> <p>The REMCO may adjust the termination payment for any situation where a full payment is inappropriate, taking into consideration applicable law, corporate governance provisions, the applicability of any statutory compensation and the best interests of Shell and shareholders as a whole.</p>
Annual bonus	<p>Any annual bonus in the year of departure is prorated based on service. Depending on the timing of the departure, the REMCO may consider the latest scorecard position or defer payment until the full-year scorecard result is known.</p> <p>Bonuses delivered in shares represent the bonus which a participant has already earned and carry no further performance conditions; therefore, these shares will be unrestricted at the conclusion of the normal deferral or holding period respectively and no proration will apply.</p>
LTIP	<p>Outstanding awards are prorated on a monthly basis, by reference to the Executive Director's service within the performance period. They will generally survive the end of employment and will remain subject to the same vesting performance conditions, and malus and clawback provisions, as if the Executive Director had remained in employment. The three-year holding period will also remain in force for any awards made on or after January 1, 2017. If the participant dies before the end of the performance period, the award will vest at the target level on the date of death. In case of death after the end of the performance period, the award will vest as described in this Policy.</p>

NON-EXECUTIVE DIRECTORS

Non-executive Directors' remuneration policy table

Fee structure	Approach to setting fees	Other remuneration
<p>Non-executive Directors (NEDs) receive a fixed annual fee for their directorship. The size of the fee will differ based on the position on the Board: Chair of the Board fee or standard Non-executive Director fee.</p> <p>Additional annual fee(s) are payable to any Director who serves as Senior Independent Director, a Board committee chair, or a Board committee member.</p> <p>A NED receives either a chair or member fee for each committee. This means that a chair of a committee does not receive both fees.</p> <p>NEDs receive an additional fee for any Board meeting involving intercontinental travel – except for one meeting a year held in a location other than The Hague.</p>	<p>The Chair's fee is determined by the REMCO. The Board determines the fees payable to NEDs. The maximum aggregate annual fees will be within the limit specified by the Articles of Association and in accordance with the NEDs' responsibilities and time commitments.</p> <p>The Board reviews NED fees periodically to ensure that they are aligned with those of other major listed companies.</p>	<p>Business expenses incurred in respect of the performance of their duties as a NED will be paid or reimbursed by Shell. Such expenses could include transport between home and office and occasional business-required partner travel. NEDs may receive a token of recognition on retirement from the board. The maximum value for this is €300. Where required, the Chair is offered Shell-provided accommodation in The Hague. The REMCO has the discretion to offer other benefits to the Chair as appropriate to their circumstances. Where business expenses or benefits create a personal tax liability to the Director, Shell may cover the associated tax.</p> <p>The Chair and the other NEDs cannot receive awards under any incentive or performance-based remuneration plans, and personal loans or guarantees are not granted to them.</p> <p>NEDs do not accrue any retirement benefits as a result of their non-executive directorships with Shell.</p> <p>NEDs are encouraged to hold shares with a value equivalent to 100% of their fixed annual fee and maintain that holding during their tenure.</p>

Non-executive Directors' letters of appointment

NEDs, including the Chair, have letters of appointment. NEDs' letters of appointment are available for inspection at the AGM or on request. For further details on appointment and re-appointment of Directors, see the "Governance Framework" on page 118 and "Other Regulatory and Statutory Information" on page 170.

Non-executive Director recruitment

The REMCO's approach to setting the remuneration package for NEDs is to offer fee levels and specific benefits (where appropriate) in line with the "Non-executive Directors' remuneration policy table" and subject to the Articles of Association. NEDs are not offered variable remuneration or retention awards.

When determining the benefits for a new Chair, the individual circumstances of the future Chair will be taken into account.

Non-executive Director termination of office

No payments for loss of office will be made to NEDs.

Consideration of overall pay and employment conditions

When setting the Policy, no specific employee groups were consulted. However, Shell seeks to promote and maintain good relations with employee representative bodies as part of its employee engagement strategy, and consults on matters affecting employees and business performance as required.

When determining Executive Directors' remuneration structure and outcomes, the REMCO reviews a set of information, including relevant reference points and trends, which includes internal data on employee remuneration (for example, employee relations matters in respect of remuneration and average salary increases applying in the Netherlands, UK and the USA). During the Policy review, pay and employment conditions of the wider Shell employee population were taken into account by adhering to the same performance, rewards and benefits philosophy for the Executive Directors, as well as overall benchmarking principles. Furthermore, any potential differences from other employees (see "Differences for Executive Directors from other employees") were taken into account when providing the REMCO with advice in the formation of this Policy.

Dialogue between management and employees is important, with the annual Shell People Survey being one of the principal means of gathering employee views on a range of matters. The Shell People Survey includes

questions inviting employees' views on their pay and benefit arrangements. Shell also encourages share ownership among employees, and many are shareholders who are able to participate in the vote on the Policy at the AGM.

The REMCO is kept informed by the CEO, the Chief Human Resources & Corporate Officer and the Executive Vice President Remuneration and HR Operations on the bonus scorecard and any relevant remuneration matters affecting other senior executives, extending to multiple levels below the Board and Executive Committee.

Consideration of shareholder views

The REMCO engages with major shareholders on a regular basis throughout the year and this allows it to hear views on Shell's remuneration approach and test proposals when developing or evolving the Policy. Recent examples of the REMCO responding to shareholder views include: considering the quantum of executive pay and the use of alternative reward structures; introducing the Energy Transition metric to the LTIP in line with our strategic ambitions; removing the individual performance modifier from the calculation of annual bonus outcomes to make remuneration structures simpler and more transparent to shareholders; reducing the CEO's target bonus from 150% to 125%; reducing the CEO's LTIP grant; and enabling the broader use of discretion to manage remuneration outcomes.

The REMCO will review the Policy regularly to ensure it continues to reinforce Shell's long-term strategy and remains closely aligned with shareholders' interests.

Additional policy statement

The REMCO reserves the right to make payments outside the Policy in limited exceptional circumstances, such as for regulatory, tax or administrative purposes or to take account of a change in legislation or exchange controls, and only where the REMCO considers such payments are necessary to give effect to the intent of the Policy.

Signed on behalf of the Board

/s/ Linda M. Coulter

LINDA M. COULTER

Company Secretary
March 11, 2020

OTHER REGULATORY AND STATUTORY INFORMATION

This section of the Annual Report contains the remaining information which the Directors are required to report on each year and for the year ended December 31, 2019. There are other matters that are required to be reported on and that have been disclosed in other sections of the Annual Report, as summarised below:

Management Report	This Directors' Report, together with the Strategic Report, serves as the Management Report for the purpose of Disclosure Guidance and Transparency Rule 4.1.8R. Both the Directors' Report and Strategic Report have been presented in accordance with and reliance on English law, and the liabilities of the Directors in connection with those reports shall be subject to the limitations and restrictions provided by such law.	Directors' Report: pages 113-163 Strategic Report: pages 6-101
Corporate governance	The Company's statement on corporate governance, as required by DTR7.2.3R, is incorporated in this Directors' Report by way of reference.	Directors' Report: pages 104-171
Business relationships [A]	A statement, summarising the Directors' business relationships with suppliers, customers and others.	Strategic Report: pages 6-101
Employee engagement	Information on how the Directors have engaged with employees.	
Directors' interests [B]	The interests (in shares of the Company or calculated equivalents) of the Directors in office at the end of the year, including any interests of a "connected person". Changes in Directors' share interests during the period from December 31, 2019, to March 11, 2020.	Annual Report on Remuneration: pages 148
Likely future developments	Information relating to likely future developments.	Provided throughout the Strategic Report: pages 6-101
Research and development	Information relating to Shell's research and development, including expenditure.	Shell Story: pages 12-18
Diversity and inclusion	Information concerning diversity and inclusion. This includes information on the equal opportunities in recruitment, career development, promotion, training and rewards for all our people, including those with disabilities.	Our people: pages 99-101
Employee communication and involvement	Information concerning employee communication and involvement.	Our people: pages 99-101
Corporate social responsibility	A summary of Shell's approach to corporate social responsibility. Further details will be available in the Shell Sustainability Report 2019.	Environment and society: pages 84-90 Our people: pages 99-101
Branches	A list of our subsidiaries, joint ventures and associates. Our activities and interests are operated through subsidiaries, branches of subsidiaries, joint ventures and associates which are subject to the laws and regulations of many different jurisdictions.	Additional Information, Appendix 1: pages 282-306
Greenhouse gas emissions	Information relating to greenhouse gas emissions.	Climate change and energy transition: pages 84-98
Risk management	Detail on risk factors Information on emerging risks	pages 27-36 of the Strategic Report Other regulatory and statutory information: pages 164-171
Financial risk management, objectives and policies	Descriptions of the use of financial instruments and Shell's financial risk management objectives and policies, and exposure to market risk (including price risk), credit risk and liquidity risk.	Consolidated Financial Statements: Note 19, pages 227-231
Listing rule information [C]	Information concerning the amount of interest capitalised by Shell.	Consolidated Financial Statements: Note 6, page 209
Listing rule information [C]	The Remuneration Committee Report	Directors' Remuneration Report: pages 135-163
Listing rule information [C]	Details of the Company's long-term incentive schemes as required by LR 9.4.3R	Directors' Remuneration Report: pages 135-163
Significant shareholdings	Information concerning significant shareholdings.	Additional information: page 274-275

[A] This meets the purposes of Schedule 7 to The Companies (Miscellaneous Reporting) Regulations 2018.

[B] "Connected person" has the meaning given to "person closely associated" within the Market Abuse Regulation.

[C] This information is given in accordance with Listing Rule 9.8.4R. Further information in connection with Listing Rule 9.8.4R is contained in the remainder of "Other Statutory Information" which follows on pages 165-171.

DISCLOSURE OF INFORMATION TO AUDITORS

In accordance with section 418 of the Act, each of the persons who is a Director at the date of approval of this Report confirms that, so far as the Director is aware, there is no relevant audit information of which the Company's auditor is unaware. The Director has taken all steps that he or she ought to have taken as a Director in order to make himself or herself aware of any relevant audit information and to establish that the Company's auditor is aware of that information.

FINANCIAL STATEMENTS, DIVIDENDS AND DIVIDEND POLICY

The "Consolidated Statement of Income" and "Consolidated Balance Sheet" can be found on pages 191 and 192 respectively.

The Board aims to grow the dividend per share through time in line with its view of the underlying business earnings and cash flow of the Shell group. When setting dividends, the Board looks at a range of factors, including the macro-environment and the Company's current balance sheet, future investment plans and existing commitments. In addition, the Board could choose to return cash through share buybacks, subject to the capital requirements of the Shell group.

The Board is aware of a consultation undertaken in 2019 by the Investment Association on behalf of BEIS to review the practice of shareholder distributions being made that have not been voted on by shareholders. The Board will consider the outcome of this review once it is published.

Interim dividends are currently declared by the Board and paid on a quarterly basis. Shell does not currently pay a "final" dividend, which would need to be voted on by shareholders, requiring the introduction of a resolution at the AGM. This would delay the payment of the fourth quarter dividend (currently paid in late March) until after the AGM, which is towards the end of May, a delay of around seven weeks. Our approach to dividend payments is not uncommon for companies distributing returns to shareholders on a quarterly basis.

On December 18, 2019, Shell announced the introduction of US dollar as additional currency election for the payment of dividends, alongside euro and sterling, and highlighted that its dividend will be settled with its shareholders fully electronically either in CREST or via interbank transfers.

The Directors have announced a fourth-quarter interim dividend as set out in the table below, payable on March 23, 2020, to shareholders on the Register of Members at close of business on February 14, 2020. The closing date for dividend currency elections was February 28, 2020 [A] and the euro and sterling equivalents announcement date was March 9, 2020.

[A] A different dividend currency election date may apply to shareholders holding shares in a securities account with a bank or financial institution ultimately through Euroclear Nederland. This may also apply to other shareholders who do not hold their shares either directly on the Register of Members or in the corporate sponsored nominee arrangement. Such shareholders can contact their broker, financial intermediary, bank or financial institution for the election deadline that applies.

VIABILITY STATEMENT

The "Strategic Report" includes information about Shell's strategy, financial condition, cash flows and liquidity, as well as the factors, including the principal risks, likely to affect Shell's future development. "Shell story" describes Shell's business model, including competitive advantages and key strengths. The Directors assess Shell's prospects at both an operating and strategic level, each involving different time horizons. To this end, the Directors assess Shell's portfolio and strategy against a wide range of outlooks, including assessing the potential impacts of various possible energy transition pathways and scenarios for changes in societal expectations in relation to climate change. Shell recognises in its strategy that the world is transitioning to a lower-carbon energy system (see "Climate change and energy transition"). The Risk Factors section provides an overview of the principal risks Shell is exposed to in its operations.

On an annual basis, the Directors approve a detailed three-year operating plan, which forecasts Shell's cash flows and ability to service financing requirements, pay dividends and fund investing activities during the period. Shell's three-year operating plan includes assumptions in relation to internal and external parameters. Some of the key assumptions include the impact of commodity prices, exchange rates, future carbon costs, agreements like LNG contract renewals, and schedules of growth programmes. Considering the degree of change possible in these parameters, Shell has deemed a three-year period of assessment appropriate for the longer-term viability statement.

Dividends

	A shares			B shares [A]			2019	
							A ADSs	B ADSs
	\$	€	pence	\$	pence	€	\$	\$
Q1	0.47	0.42	36.97	0.47	36.97	0.42	0.94	0.94
Q2	0.47	0.43	38.01	0.47	38.01	0.43	0.94	0.94
Q3	0.47	0.42	35.73	0.47	35.73	0.42	0.94	0.94
Q4 [A]	0.47	0.42	36.40	0.47	36.40	0.42	0.94	0.94
Total announced in respect of the year [A]	1.88	1.68	147.11	1.88	147.11	1.68	3.76	3.76
Amount paid during the year [A]	1.88	1.68	146.65	1.88	146.65	1.68	3.76	3.76

[A] It is expected that holders of B shares will receive dividends through the dividend access mechanism applicable to such shares. The dividend access mechanism is described more fully on page 268.

OTHER REGULATORY AND STATUTORY INFORMATION continued

In making the viability assessment, the Directors have also considered the financial impact of each of the following severe but possible scenarios that could threaten Shell's viability. In reviewing these stress tests, the Directors have considered possible mitigation steps and have made certain assumptions regarding the availability of future funding options, including credit lines and debt facilities, possible assets disposals, and the ability to flex the levels of shareholder returns and to raise future financing in line with the operating plan window.

Scenario	Link to principal risks
A significant HSSE event	[A]
A low oil and gas price environment with \$40/bbl Brent (nominal prices) over the three year planning period	[B]
A significant HSSE event in a low oil and gas price environment	[A] and [B]
Sustained impact from politically adverse developments, lower growth in developing countries, as well as lower growth in Europe	[B] and [C]
Unplanned shut down of a major cash generating asset for a year	[A]

[A] The nature of our operations exposes us, and the communities in which we work, to a wide range of health, safety, (cyber) security and environment risks.

[B] We are exposed to macro-economic risks including fluctuating prices of crude oil, natural gas, oil products and chemicals.

[C] We are exposed to treasury and trading risks, including liquidity risk, interest rate risk, foreign exchange risk and credit risk. We are affected by the global macroeconomic environment as well as financial and commodity market conditions.

Taking account of Shell's position and principal risks at December 31, 2019, the Directors have a reasonable expectation that Shell will be able to continue in operation and meet its liabilities as they fall due over its three-year operating plan period.

NON-FINANCIAL INFORMATION STATEMENT

The Non-Financial Information Statement below forms part of the Strategic Report on pages 6-101.

Non-Financial Information Statement

Reporting requirement	Where to read more in this report	Page
Business model	The Shell Story	16
Non-financial KPIs	Performance indicators	42
Environmental matters	Environment and society, Climate change and energy transition	84-98
Employees	Our people and Directors Report	99-101
Social matters	Environment and society	84-90
Respect for human rights	Environment and society	90
Anti-corruption and anti-bribery matters	Our people	99-101

REPURCHASES OF SHARES

The Group announced, on July 26, 2018, the start of a share buyback programme of at least \$25 billion by the end of 2020 subject to further progress with debt reduction and oil price conditions. At the 2019 AGM, shareholders granted an authority for the Company to repurchase up to a maximum of 815 million of its shares (excluding purchases for employee share plans). This authority expires on the earlier of the close of business on August 21, 2020, or the end of the 2020 AGM.

During 2019, 320.1 million A shares, and 16.1 million B shares, with nominal values of €23.6 million (\$28.4 million) respectively (4.27% of the Company's total issued share capital at December 31, 2019) were purchased and cancelled for a total cost of \$10.2 billion including expenses, at an average price of \$30.25 per share. The purpose of the shares repurchased in 2019 under the share buyback programme is to reduce the issued share capital of the Company. This is to offset the number of shares issued under the Scrip Dividend Programme and to significantly reduce the equity issued in connection with the Company's combination with BG Group. The Scrip Dividend Programme was cancelled with effect from the fourth quarter 2017 interim dividend. More information can be found at www.shell.com/scrip. From January 1, 2020, to January 24, 2020, the end of the sixth tranche of the share buyback programme, a further 23.2 million A shares (0.29% of the Company's total issued share capital at December 31, 2019) were purchased for cancellation for a total cost of \$0.7 billion including expenses, at an average price of \$29.63 per share. This means that 624 million shares could still be repurchased under the current AGM authority.

The Board continues to regard the ability to repurchase issued shares in suitable circumstances as an important part of Shell's financial management. A resolution will be proposed at the 2020 AGM to renew the authority for the Company to purchase its own share capital, up to specified limits, for a further year. This proposal will be described in more detail in the Notice of Annual General Meeting.

BOARD OF DIRECTORS

The names of the Directors that held office during the year can be found on pages 104-112. Information on the Directors who are seeking appointment or reappointment is included in the Notice of Annual General Meeting.

QUALIFYING THIRD-PARTY INDEMNITIES

The Company has entered into a Deed of Indemnity (Deed) with each Director of the Company who served during the year. The terms of each of these Deeds are identical and they reflect the statutory provisions on indemnities contained in the Companies Act 2006 (CA 2006). Under the terms of each Deed, the Company has agreed to indemnify the Director, to the widest extent permitted by the CA 2006, against any loss, liability or damage, howsoever caused (including in respect of a Director's own negligence), suffered or incurred by a Director in respect of their acts or omissions while or in the course of acting as a Director or employee of the Company, any associated company or affiliate (within the meaning of the CA 2006). In addition, the Company shall lend funds to Directors as required to meet reasonable costs and expenses incurred or to be incurred by them in defending any criminal or civil proceedings brought against them in their capacity as a Director or employee of the Company, associated company or affiliate, or, in connection with certain applications brought under the CA 2006. The provisions in the Company's Articles relating to arbitration and exclusive jurisdiction are incorporated, mutatis mutandis, into the Deeds entered into by each Director and the Company.

RELATED PARTY TRANSACTIONS

Other than disclosures given in Notes 9, 27 and 29 to the "Consolidated Financial Statements" on pages 213, 237, and 238, there were no transactions or proposed transactions that were material to either the Company or any related party. Nor were there any transactions with any related party that were unusual in their nature or conditions.

POLITICAL CONTRIBUTIONS

No donations were made by the Company or any of its subsidiaries to political parties or organisations during the year. Shell Oil Company administers the non-partisan Shell Oil Company Employees' Political Awareness Committee (SEPAC), a political action committee registered with the US Federal Election Commission. Eligible employees may make voluntary personal contributions to the SEPAC.

RECENT DEVELOPMENTS AND POST-BALANCE SHEET EVENTS

See Note 29 to the "Consolidated Financial Statements" on page 238.

SHARE CAPITAL

The Company's issued share capital at December 31, 2019, is set out in Note 20 to the "Parent Company Financial Statements" on pages 257-265. The percentage of the total issued share capital represented by each class of share is given below.

Share capital percentage

Share class	%
A	52.68
B	47.32
Sterling deferred	de minimis

TRANSFER OF SECURITIES

There are no restrictions on transfer or limitations on the holding of the ordinary shares other than under the Articles, under restrictions imposed by law or regulation (for example, insider trading laws) or pursuant to the Company's Share Dealing Code.

SHARE OWNERSHIP TRUSTS AND TRUST-LIKE ENTITIES

Shell has three primary employee share ownership trusts and trust-like entities: a Dutch foundation (stichting) and two US Rabbi Trusts. The shares held by the Dutch foundation are voted by its Board and the shares in the US Rabbi Trusts are voted by the Voting Trustee, Newport Trust Company. Both the Board of the Dutch foundation and the Voting Trustee are independent of Shell.

The UK Shell All Employee Share Ownership Plan has a separate related share ownership trust. Shares held by the trust are voted by its trustee, Computershare Trustees Limited, as directed by the participants.

AUDITOR

A resolution relating to the appointment of Ernst & Young LLP as auditor for the financial year 2020 will be proposed at the 2020 AGM.

ANNUAL GENERAL MEETING

The AGM will be held on May 19, 2020, at the Circustheater, Circusstraat 4, 2586 CW, The Hague, the Netherlands. The Notice of Annual General Meeting will include details of the business to be put to shareholders at the AGM.

CONFLICTS OF INTEREST

In accordance with the Act and the Articles, the Board may authorise any matter that otherwise may involve any of the Directors breaching their duty to avoid conflicts of interest. The Board has adopted a procedure to address these requirements. Detailed conflict of interest questionnaires are reviewed by the Board and, if considered appropriate, authorised. Conflicts of interest as well as any gifts and hospitality received by and provided by Directors are kept under review by the Board. Further information relating to conflicts of interest can be found in the Articles, available on the website.

SIGNIFICANT COMMITMENTS OF THE CHAIR

The Chair's other significant commitments are given in his biography on page 104.

SHELL GENERAL BUSINESS PRINCIPLES

The Shell General Business Principles define how Shell subsidiaries are expected to conduct their affairs and are underpinned by the Shell core values of honesty, integrity and respect for people. These principles include, among other things, Shell's commitment to support fundamental human rights in line with the legitimate role of business and to contribute to sustainable development. They are designed to mitigate the risk of damage to our business reputation and to prevent violations of local and international legislation. They can be found at www.shell.com/sgbp. See "Risk factors" on page 27-36.

SHELL CODE OF CONDUCT

Directors, officers, employees and contract staff are required to comply with the Shell Code of Conduct, which instructs them on how to behave in line with the Shell General Business Principles. This Code clarifies the basic rules and standards they are expected to follow and the behaviour expected of them. These individuals must also complete mandatory Code of Conduct training.

Designated individuals are required to complete additional mandatory training on antitrust and competition laws, anti-bribery, anti-corruption and anti-money laundering laws, financial crime, data protection laws and trade compliance requirements (see "Risk factors" on page 35). The Shell Code of Conduct can be found at www.shell.com/codeofconduct.

CODE OF ETHICS

Executive Directors and Senior Financial Officers of Shell must also comply with the Code of Ethics. This Code is specifically intended to meet the requirements of Section 406 of the Sarbanes-Oxley Act. It can be found at www.shell.com/codeofethics.

OTHER REGULATORY AND STATUTORY INFORMATION continued

INDEPENDENT PROFESSIONAL ADVICE

All Directors may seek independent professional advice in connection with their role as a Director. All Directors have access to the advice and services of the Company Secretary. The Company has provided both indemnities and directors' and officers' insurance to the Directors in connection with the performance of their responsibilities. Copies of these indemnities and the directors' and officers' insurance policies are open to inspection. A copy of the form of these indemnities has been previously filed with the Securities and Exchange Commission.

RESULTS PRESENTATIONS AND ANALYSTS' MEETINGS

The planned dates of the quarterly, half-yearly and annual results presentations, as well as all major analysts' meetings, are announced in advance on the Shell website and through a regulatory release. Generally, presentations are broadcast live via webcast and teleconference. Other meetings with analysts or investors are not normally announced in advance, nor can they be followed remotely by webcast or any other means. Procedures are in place to ensure that discussions in such meetings are always limited to non-material information or information already in the public domain.

Results and meeting presentations can be found at www.shell.com/investor. This is in line with the requirement to ensure that all shareholders and other parties in the financial market have equal and simultaneous access to information that may influence the price of the Company's securities.

CONTROLS AND PROCEDURES

The Board is responsible for maintaining a sound system of risk management and internal control, and for regularly reviewing its effectiveness. It has delegated authority to the Audit Committee to assist it in fulfilling its responsibilities in relation to internal control and financial reporting (see "Audit Committee Report" on pages 129-134).

A single overall control framework is in place for the Company and its subsidiaries that is designed to manage rather than eliminate the risk of failure to achieve business objectives. It therefore only provides a reasonable and not an absolute assurance against material misstatement or loss.

The diagram below illustrates the Control Framework's key components: "Foundations", "Management processes" and "Structural". "Foundations" comprises the objectives, principles and rules that underpin and establish boundaries for Shell activities. "Management processes" refers to the more significant management processes, including how strategy, planning and appraisal are used to improve performance and how risks are to be managed through effective controls and assurance. The "Structural" component defines how Businesses and Functions facilitate achievement of the Shell group's overall business objectives.

CONTROL FRAMEWORK



The Audit Committee met six times this year and received regular reports from the Chief Internal Auditor on notable internal audits and those with a significant impact on control effectiveness. The Audit Committee also reviewed significant financial, business and compliance control incidents and received regular reports on business integrity issues. The Audit Committee also requested updates on specific financial, operational and compliance control issues throughout the year. The Audit Committee Chair provided an update to the Board after every Audit Committee meeting.

During and after such reports, the Board has an opportunity to request further information and/or ask clarifying questions, which it does to varying degrees depending on the issue. Similarly, the Chairs of the Safety, Environment and Sustainability Committee (SESCO) and the Nigeria Special Litigation Committee, an ad hoc Board Committee, also provide regular updates after each of their respective meetings covering, among other matters, the respective aspects of controls that they monitor pursuant to their Terms of Reference. The Audit Committee and SESO minutes, once approved, are further provided to the Board and incorporated into Board minutes to ensure full access to and review by

all Directors. These aspects, together with the 2019 Reports respectively submitted to the Board by the Chief Internal Auditor, the External Auditors, the Disclosure Committee Chairman and the Chief Ethics & Compliance Officer, as well as summaries of the Annual Proved Reserves Disclosure and the Full Year HSSE & Social Performance Assurance Report, enable the Board's ongoing monitoring and annual review of material controls.

An annual review of the effectiveness of risk management and internal control was carried out by both the Executive Committee and the Audit Committee. This was based on their own insights and experience throughout the year as well as outcomes from the Group Assurance Letter process, a structured internal assessment of compliance with legal and ethical requirements and the Shell Control Framework carried out by each Executive Director. As part of their annual review, the Executive Committee and Audit Committee also considered annual reports from the Chief Internal Auditor, Chief Ethics & Compliance Officer and the External Auditor. The insights and conclusions from this annual assessment were reviewed and discussed by the Board.

The system of risk management and internal control over financial reporting is an integral part of the Control Framework. Regular reviews are performed to identify the significant risks to financial reporting and the key controls designed to address them. These controls are documented, responsibility is assigned, and they are monitored for design and operating effectiveness. Controls found to be ineffective are remediated. The principal risks faced by Shell are set out in "Risk factors" on pages 27-36.

Shell has a variety of processes for obtaining assurance on the adequacy of risk management and internal control. Emerging risks are identified through (among others) the monitoring of external developments, risk indicators, learnings from incidents and assurance findings, and through the appraisal of Shell's forward-looking plans. A broad array of measures are used to manage Shell's various risks which are set out in the relevant sections of this Report. There are also risks that Shell accepts or does not seek to fully mitigate. The Executive Committee and the Board regularly consider group-level risks and associated control mechanisms.

Shell has developed a risk appetite framework that considers three distinct factors: Strategic Risk Appetite, Operational Risk Appetite and Conduct Risk Appetite. These three factors aim to capture the range and variety of risks affecting Shell, with specific risk appetite parameters identified and monitored for each one.

Strategic Risk Appetite is about current and future portfolio considerations, examining parameters such as country concentration or exposure to higher-risk countries. It also considers "long-range" developments in order to test key assumptions or beliefs in relation to energy markets.

Operational Risk Appetite is about material operational exposures, and promotes a more granular assessment of key risks facing the organisation. Conduct Risk Appetite brings together leading and lagging risk indicators to provide an overall view of the culture of the organisation.

The Financial Framework sets certain boundary conditions in the consideration of risk appetite, as the financial resilience of Shell should logically inform the aggregate level of risk appetite that could be sustained.

Shell has a climate change risk management structure which is supported by standards, policies and controls (see "Risk factors" on page 34 and "Climate change and energy transition" on pages 91-98). Climate change and risks resulting from greenhouse gas emissions have been identified as significant risk factors for Shell and are managed in accordance with other significant risks through the Board and Executive Committee.

Many of our major projects and operations are conducted in joint arrangements or associates, which may reduce the degree of control and ability to identify and manage risks (see "Risk factors" on page 27-36). In each case, Shell appoints a representative to manage its interests who seeks to ensure that such projects operate under equivalent standards to Shell.

We operate in more than 70 countries that have differing degrees of political, legal and fiscal stability. This exposes us to a wide range of political developments that could result in changes to contractual terms, laws and regulations. In addition, we and our joint arrangements and associates face the risk of litigation and disputes worldwide (see "Risk factors" on page 27-36). We continuously monitor geopolitical developments and societal issues relevant to our interests. Employees who engage with government officials are subject to specific training programmes, procedures and regular communications, in addition to Shell General Business Principles and Shell Code of Conduct compliance. We are prepared to exit a country if we believe we can no longer operate in that country in accordance with our standards and applicable law, and we have done so in the past.

The Board confirms that there is a robust process for identifying, evaluating and managing the principal risks. Further, the Board confirms it carries out a robust assessment of Shell's emerging risks, the procedures in place to identify the emerging risks, and how the risks are being managed or mitigated to the achievement of Shell's objectives. This has been in place throughout 2019 and up to the date of this Report and is regularly reviewed by the Board and accords with the FRC Guidance on Risk Management, Internal Control and Related Financial and Business Reporting.

The Board has conducted its annual review of the effectiveness of Shell's system of risk management and internal control in respect of 2019, such review covering all material controls, including financial, operational and compliance controls.

MANAGEMENT'S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES OF SHELL

Shell's CEO and CFO have evaluated the effectiveness of Shell's disclosure controls and procedures at December 31, 2019. Based on that evaluation, they concluded that Shell's disclosure controls and procedures are effective.

OTHER REGULATORY AND STATUTORY INFORMATION continued

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING OF SHELL

Management, including the CEO and CFO, is responsible for establishing and maintaining adequate internal control over Shell's financial reporting and the preparation of the "Consolidated Financial Statements". It conducted an evaluation of the effectiveness of Shell's internal control over financial reporting and the preparation of the "Consolidated Financial Statements" based on the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). On the basis of this evaluation, management concluded that, at December 31, 2019, the Company's internal control over financial reporting and the preparation of the "Consolidated Financial Statements" was effective.

THE TRUSTEE'S AND MANAGEMENT'S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES FOR THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST

The Trustee of the Royal Dutch Shell Dividend Access Trust (the Trustee) and Shell's CEO and CFO have evaluated the effectiveness of the disclosure controls and procedures in respect of the Dividend Access Trust (the Trust) at December 31, 2019. On the basis of this evaluation, these officers have concluded that the disclosure controls and procedures of the Trust are effective.

THE TRUSTEE'S AND MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING OF THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST

The Trustee and the Company's management are responsible for establishing and maintaining adequate internal control over the Trust's financial reporting. The Trustee and the Company's management conducted an evaluation of the effectiveness of internal control over financial reporting based on the Internal Control – Integrated Framework (2013) issued by COSO. On the basis of this evaluation, the Trustee and management concluded that, at December 31, 2019, the Trust's internal control over financial reporting was effective.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There has not been any change in the internal control over financial reporting of Shell or the Trust that occurred during the period covered by this Report that has materially affected, or is reasonably likely to materially affect, the internal control over financial reporting of Shell or the Trust. Material financial information of the Trust is included in the "Consolidated Financial Statements" and is therefore subject to the same disclosure controls and procedures as Shell. See the "Royal Dutch Shell Dividend Access Trust Financial Statements" on pages 268 for additional information.

ARTICLES OF ASSOCIATION

The Company's Articles of Association (Articles) were adopted at the 2019 AGM. The Articles may only be amended by a special resolution of the shareholders in a general meeting. A full version of the Company's Articles can be found at www.shell.com/investors.

MANAGEMENT AND DIRECTORS

The Company has a single-tier Board of Directors headed by a Chair, with management led by a CEO. See "Governance Framework" on pages 117-118.

DIRECTORS' SHAREHOLDING QUALIFICATION

The Directors are not required to hold any shares in the Company. While the Articles do not require Directors to hold shares in the Company, the Remuneration Committee believes that Executive Directors should align their interests with those of shareholders by holding shares in the Company. The CEO is expected to build up a shareholding of seven times his base salary over five years from appointment and from 2020, the CFO is expected to build up a shareholding of five times their base salary over the same period. In the event that another Executive Director joins the Board, the Remuneration Committee will determine their shareholding requirement, which will not be less than 200% of their base salary. Executive Directors will be required to maintain their requirement (or existing shareholding if less than the guideline) for a period of two years post-employment. Non-executive Directors are encouraged to hold shares with a value equivalent to 100% of their fixed annual fee and maintain that holding during their tenure. All Directors hold shares and such interests can be found in the "Directors' Remuneration Report" on pages 135-138.

APPOINTMENT AND RETIREMENT OF DIRECTORS

The Company's Articles, the Corporate Governance Code and the Companies Act 2006 govern the appointment and retirement of Directors. Board membership and biographical details of the Directors are provided on pages 104-109. However, Directors follow the direction laid out in the Code and stand for re-election annually.

During the year, Neil Carson was appointed to the Board on June 1, 2019.

RIGHTS ATTACHING TO SHARES

The full rights attaching to shares are set out in the Company's Articles of Association. The Company can issue shares with any rights or restrictions attached to them as long as this is not restricted by any rights attached to existing shares. These rights or restrictions can be decided either by an ordinary resolution passed by the shareholders or by the Board as long as there is no conflict with any resolution passed by the shareholders.

VOTING

Currently, only the A and B shares have voting rights. The voting rights of each A share and each B share are equal and carry one vote at a general meeting of the Company.

The sterling deferred shares are not ordinary shares and therefore have different rights and restrictions attached to them.

CHANGE OF CONTROL

There are no provisions in the Articles that would delay, defer or prevent a change of control.

DIRECTORS' RESPONSIBILITIES IN RESPECT OF THE PREPARATION OF THE ANNUAL REPORT AND ACCOUNTS

The Directors are responsible for preparing the Annual Report, including the financial statements, in accordance with applicable laws and regulations. These require the Directors to prepare financial statements for each financial year. As such, the Directors have prepared the Consolidated and Parent Company Financial Statements in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU). In preparing these financial statements, the Directors have also elected to comply with IFRS as issued by the International Accounting Standards Board (IASB). The Directors must not approve the financial statements unless they are satisfied that they give a true and fair view of the state of affairs of Shell and the Company and of the profit or loss of Shell and the Company for that period. In preparing these financial statements, the Directors are required to:

- adopt the going concern basis unless it is inappropriate to do so;
- select suitable accounting policies and then apply them consistently;
- make judgements and accounting estimates that are reasonable and prudent; and
- state whether IFRS as adopted by the EU and IFRS as issued by the IASB have been followed.

The Directors are responsible for keeping adequate accounting records that are sufficient to show and explain the transactions of Shell and the Company and disclose with reasonable accuracy, at any time, the financial position of Shell and the Company and to enable them to ensure that the financial statements comply with the Companies Act 2006 (the Act) and, as regards the Consolidated Financial Statements, with Article 4 of the IAS Regulation and therefore are in accordance with IFRS as adopted by the EU. The Directors are also responsible for safeguarding the assets of Shell and the Company and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

Each of the Directors, whose names and functions can be found on pages 111-112, confirms that, to the best of their knowledge:

- the financial statements, which have been prepared in accordance with IFRS as adopted by the EU and with IFRS as issued by the IASB give a true and fair view of the assets, liabilities, financial position and profit of Shell and the Company; and
- the Management Report includes a fair review of the development and performance of the business and the position of Shell, together with a description of the principal risks and uncertainties that it faces.

Furthermore, so far as each of the Directors is aware, there is no relevant audit information of which the auditors are unaware, and each of the Directors has taken all the steps that ought to have been taken in order to become aware of any relevant audit information and to establish that the auditors are aware of that information.

The Directors consider that the Annual Report, including the financial statements, taken as a whole, is fair, balanced and understandable and provides the information necessary for shareholders to assess Shell's position and performance, business model and strategy.

The Directors consider it appropriate to continue to adopt the going concern basis of accounting in preparing the financial statements.

The Directors are responsible for the maintenance and integrity of the Shell website (www.shell.com). Legislation in the UK governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

Signed on behalf of the Board

/s/ Linda M. Coulter

LINDA M. COULTER

Company Secretary
March 11, 2020

FINANCIAL STATEMENTS AND SUPPLEMENTS

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268	Royal Dutch Shell Dividend Access Trust Financial Statements

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC

1. OUR OPINIONS AND CONCLUSIONS ARISING FROM OUR AUDIT

1.1 Our unmodified opinion on the financial statements

In our opinion, the financial statements of Royal Dutch Shell plc (the Parent Company) and its subsidiaries (collectively, Shell):

- give a true and fair view of the state of Shell's and of the Parent Company's affairs as at December 31, 2019, and of Shell's and the Parent Company's income for the year then ended;
- have been properly prepared both in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU) and IFRS as issued by the International Accounting Standards Board (IASB); and
- have been prepared in accordance with the requirements of the Companies Act 2006, and, as regards Shell's financial statements, Article 4 of the IAS Regulation.

1.2 What we have audited

We have audited Royal Dutch Shell plc's financial statements for the year ended December 31, 2019, which are included in the Annual Report and comprise:

Shell	Parent Company
Consolidated Balance Sheet as at December 31, 2019	Balance Sheet as at December 31, 2019
Consolidated Statement of Income for the year then ended	Statement of Income for the year then ended
Consolidated Statement of Comprehensive Income for the year then ended	Statement of Comprehensive Income for the year then ended
Consolidated Statement of Changes in Equity for the year then ended	Statement of Changes in Equity for the year then ended
Consolidated Statement of Cash Flows for the year then ended	Statement of Cash Flows for the year then ended
Related Notes 1 to 29 to the Consolidated Financial Statements, including a summary of significant accounting policies	Related Notes 1 to 14 to the Parent Company Financial Statements

The financial reporting framework that has been applied in the preparation of the financial statements is applicable law and both IFRS as adopted by the EU and IFRS as issued by the IASB.

2. BASIS FOR OUR OPINION

We conducted our audit in accordance with International Standards on Auditing (UK) (ISA (UK)) and applicable law. Our responsibilities under those standards are further described in the 'Our responsibilities for the audit of the financial statements' section of our report below. We are independent of Shell and the Parent Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in the UK, including the Financial Reporting Council's Ethical Standard as applied to listed public interest entities, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained during the planning, execution and conclusion of our audit is sufficient and appropriate to provide a suitable basis for our opinion.

3. OVERVIEW OF OUR AUDIT APPROACH

<p>UPDATING OUR UNDERSTANDING OF SHELL'S BUSINESS AND ITS ENVIRONMENT</p>	<p>Our global audit team has deep industry experience through working for many years on the audits of large integrated international oil and gas companies. Our audit planning starts with updating our view on external market factors, for example geopolitical risk, the potential impact of climate change and the energy transition, commodity price risk and major trends in the industry. Building on this knowledge, we updated our understanding of Shell's strategy and business model. This was achieved through the review of external data, enquiry, analytical procedures, observation and visiting several of Shell's operating units.</p> <p>In planning our 2019 audit, we were mindful of the fact that the outlook for both oil and gas commodity prices continued to narrow. Refining margins remained under pressure due to a number of factors, including the energy transition. The fundamentals of cost control, capital spending, operational excellence, cash flow and capital return continued to be a focus in the industry. Climate change and the energy transition are becoming increasingly important for the sector. As part of our audit, we assessed whether Shell's energy transition assumptions used in setting oil and gas commodity price assumptions and refining margin assumptions were reasonable in the light of the commitments that Shell have made with respect to decarbonisation in accordance with the Paris Agreement. Our updated understanding of Shell's business and the environment in which it operates informed our risk assessment procedures.</p>
<p>IDENTIFYING AND ASSESSING THE RISKS OF MATERIAL MISSTATEMENT</p>	<p>The results of our 2018 audit, together with our risk assessment procedures, provided a renewed basis for the identification and assessment of risks of material misstatement for our 2019 audit. Whilst our assessment of risks requiring special audit attention remained consistent with 2018, the impact of the energy transition has increased the inherent risk in estimating both oil and gas reserves and the recoverable amount of oil and gas properties. The risks we identified were as follows:</p> <ul style="list-style-type: none"> ■ the estimation of oil and gas reserves used in the calculation of the recoverable amount of exploration and production assets, depreciation, depletion and amortisation and the estimation of decommissioning and restoration provisions; ■ the risk of unrealised trading gains and losses being recognised as a result of errors, unauthorised trading activity or deliberate misstatement of Shell's trading position; and ■ risk of fraud through management override within other significant revenue streams. <p>Our additional areas of audit focus were:</p> <ul style="list-style-type: none"> ■ the recoverable amount of exploration and production assets, and investments in joint ventures and associates; ■ the impact of the energy transition on the estimation of refining margins and their potential impact on the carrying value of Shell's refineries, the expected lives of the refineries, whether there is a need for environmental clean up cost provisions and the valuation of deferred tax assets; ■ the estimation of decommissioning and restoration provisions; ■ legal proceedings and other contingencies, with specific emphasis on Nigeria; ■ uncertain tax positions; ■ recognition and measurement of deferred tax assets; ■ pension assumptions; ■ the adoption of the new accounting standard on leases (IFRS 16); and ■ the dividend distribution process, including the determination of realised profits and losses for the purposes of making distributions under the Companies Act 2006 (this area of audit focus relates to the parent company only). <p>We have expanded further our integration of analytical tools and technology into our audit. Not only do these tools deliver to us more efficient and secure access to Shell's data, but they provide us with an integrated view of risk, thus enabling us to focus our audit effort on operating units with higher risk profiles. They also enable us to perform risk-led analyses of entire populations of data.</p>
<p>ASSESSING MATERIALITY (SECTION 4)</p>	<p>When we established our audit strategy, we determined overall materiality for the financial statements. The key criterion in determining materiality is the auditor's perception of the needs of investors. We considered which earnings, activity or capital-based measure aligned best with the expectations of those charged with governance at Shell and users of Shell's financial statements. In so doing, we applied a 'reasonable investor perspective', which reflected our understanding of the common financial information needs of the members of Shell as a group. We also made judgements about the size of misstatements that would be considered material.</p> <p>Our assessment of overall materiality was derived from an average of Shell's earnings for the prior two years and the estimated result for the current year on a current cost of supplies basis (CCS earnings), excluding identified items reported by Shell in its quarterly results announcements, and adjusted for an effective tax rate. In our judgement, an averaging approach reflects the nature of Shell, the oil and gas industry and the economic environment in which Shell operates.</p> <p>This approach – which is unchanged from 2018 – resulted in the following materiality measures for 2019:</p> <ul style="list-style-type: none"> ■ planning materiality: \$1,200 million (2018: \$1,000 million); ■ performance materiality: \$900 million (2018: \$750 million); and ■ reporting differences threshold: \$60 million (2018: \$50 million). <p>Our determination of performance materiality was underpinned by our assessment of the strength of Shell's control environment. We confirmed with the Audit Committee that they were satisfied that these levels of materiality were appropriate. We kept our assessment of materiality under review throughout the year.</p>

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

3. OVERVIEW OF OUR AUDIT APPROACH continued

<p>DETERMINING THE SCOPE OF OUR AUDIT (SECTION 5)</p>	<p>Our scope is tailored to the circumstances of our audit of Shell and is influenced by our determination of materiality and our assessed risks of material misstatement.</p> <p>We performed audits of the complete financial information of 17 operating units and specific audit procedures on an additional 32 operating units. In selecting the operating units to be brought into audit scope, we assessed the risks of material misstatement of the financial statements based on size, complexity and risk, including the risk of fraud, and designed and implemented appropriate responses to the assessed risks. We performed procedures at a further 133 operating units that were specified by the group audit engagement in response to specific risk factors. In addition, we performed other group audit procedures at the consolidated level – see section 5 below.</p> <p>In order to reflect changes brought about by enhancements to Shell's finance function, changes to accounting standards and to introduce an appropriate level of unpredictability and rotation in our audit, we made the following refinements to our audit scope in 2019 compared to 2018:</p> <ul style="list-style-type: none"> ■ in order to recognise the increased amount of audit work that we would be carrying out at Shell's business service centres (BSCs), we transferred audit activity from onshore to our business service centre audit teams. For example, our work related to Germany was carried out mainly in Krakow, other than the physical inventory verification, which continued to be performed by our German team. The same applied to US downstream, where much of the activity was transferred to Manila; ■ IFRS 16: we revised our audit procedures to reflect the requirements of the new standard. Also, we brought into scope three new entities in order to obtain sufficient audit coverage of the 'right of use assets'; and ■ we revised our tax audit procedures to test centrally the main consolidated tax regimes (fiscal unities), including the US, UK and Netherlands.
<p>IDENTIFYING KEY AUDIT MATTERS (SECTION 6)</p>	<p>We have identified the following key audit matters that, in our professional judgement, had the greatest effect on our overall audit strategy, the allocation of resources in the audit and in directing the global audit team's efforts:</p> <ul style="list-style-type: none"> ■ the estimation of oil and gas reserves, including reserves used in the calculation of depreciation, depletion and amortisation (DD&A), impairment testing to evaluate the recoverable amounts of production assets and the estimation of decommissioning and restoration (D&R) provisions; ■ the recoverable amounts of exploration and production assets, and investments in joint ventures and associates; ■ the estimation of future refining margins to evaluate the recoverability of manufacturing, supply and distribution assets; ■ the recognition and measurement of deferred tax assets; ■ revenue recognition: the risk of unrealised trading gains and losses being recognised as a result of errors, unauthorised trading activity or deliberate misstatement of Shell's trading position; and ■ the dividend distribution process, including the determination of realised profits and losses for the purposes of making distributions under the Companies Act 2006 (this key audit matter relates to the Parent Company only). <p>In 2018, our auditor's report included two key audit matters that have not been reported as key audit matters in our 2019 report. These relate to: (1) Enhancements to Shell's system of IT general controls, and (2) The recognition, measurement, presentation and disclosure of leases (IFRS 16).</p> <p>Although IFRS 16 was adopted on January 1, 2019, most of our audit effort was carried out in 2018 in order to audit the impact of the new standard, which was disclosed in the 2018 Annual Report. Consequently, we reported the adoption of IFRS 16 as a key audit matter in our 2018 report, and not in 2019.</p> <p>In the current year, we have added two key audit matters that were not reported as key audit matters in our 2018 report. These relate to: (1) The estimation of future refining margins to evaluate the recoverability of manufacturing, supply and distribution assets, and (2) The dividend distribution process (Parent Company only).</p>

4. OUR APPLICATION OF MATERIALITY

The scope of our work is influenced by our view of materiality and our assessed risks of material misstatement. As we develop our audit strategy, we determine materiality at the overall level and at the individual account level (referred to as our 'performance materiality' (see below)).



Overall materiality

What we mean

We apply the concept of materiality both in planning and performing our audit, as well as in evaluating the effect of identified misstatements (including omissions) on our audit and in forming our audit opinion. For the purposes of determining whether or not Shell's financial statements are free from material misstatement (whether due to fraud or error), we define materiality as the magnitude of misstatements that, individually or in the aggregate, could reasonably be expected to influence the economic decisions of the users of these financial statements. We are required to establish a materiality level for the financial statements as a whole that is appropriate in the light of Shell's particular circumstances.

Our overall materiality provides a basis for identifying and assessing the risk of material misstatement and determining the nature and extent of our audit procedures. Our evaluation of materiality requires professional judgement and necessarily takes into account qualitative as well as quantitative considerations. It also considers our assessment of the expectations of those charged with governance at Shell and users of Shell's financial statements.

As required by auditing standards, we reassess materiality throughout the duration of the audit.

Level set

Group materiality

We set our preliminary overall materiality for Shell's Consolidated Financial Statements at \$1,200 million (2018: \$1,000 million). We kept this under review throughout the year and reassessed the appropriateness of our original assessment in the light of Shell's results and external market conditions. Based on these reviews and reassessments, we did not find it necessary to revise our level of overall materiality.

Parent Company materiality

We determined materiality for the Parent Company to be \$2.6 billion (2018: \$2.6 billion), which is 1% (2018: 1%) of equity. Equity is an appropriate basis to determine materiality for an investment holding company, and 1% is a typical percentage of equity to use to determine materiality. Any balances in the parent company financial statements that were relevant to our audit of the consolidated group were audited using an allocation of group performance materiality.

Our basis for determining materiality

Our assessment of overall materiality was \$1,200 million. This was derived from an average of Shell's earnings for 2017 and 2018 and the estimated result for 2019 on a current cost of supplies basis (CCS earnings), excluding identified items reported by Shell in its quarterly results announcements, and adjusted for an effective tax rate.

This approach of averaging over three years is consistent with the approach adopted by many large, international groups and moderates the effect of oil and gas price volatility.

The \$1,200 million was determined by applying a percentage to the calculated average CCS earnings. When using an earnings-related measure to determine overall materiality, the norm is to apply a benchmark percentage of 5% of the pre-tax measure. In setting overall materiality, we applied a more prudent rate that was below the 5% benchmark. Our overall materiality is less than 5% of the 2019 income before taxation.

In determining materiality, auditing standards require us to use benchmark measures, such as pre-tax income, gross profit and total revenue. Nevertheless, we have to exercise considerable judgement, including which earnings, activity or capital based measure aligns best with the expectations of users of Shell's financial statements and the Audit Committee. In determining the most appropriate benchmark on which to base our materiality assessment, we have applied a 'reasonable investor perspective'. This reflects our understanding of the common financial information needs of Shell's investors as a group, which we believe is CCS earnings, excluding identified items. Shell's quarterly results announcements feature CCS earnings excluding identified items as the primary measure for earnings.

CCS earnings excluding identified items removes both the effects of changes in oil price on inventory carrying amounts and items disclosed as identified items that can significantly distort Shell's results in any one particular year. In our view, the use of CCS earnings excluding identified items allows investors to understand how management has performed despite the commodity price environment, as opposed to because of it. Furthermore, analyst forecasts predominately feature CCS earnings, excluding identified items, as the basis for earnings. The analyst consensus data supports our judgement that CCS earnings, excluding identified items, is the key indicator of performance from a reasonable investor perspective.

The identified items, reported by Shell in its quarterly results announcements, were: net divestment gains (\$2.6 billion), net impairments (\$4.2 billion charge), fair value accounting of commodity derivatives and certain gas contracts (\$0.6 billion gain), redundancy and restructuring (\$0.1 billion charge), and the aggregate of other individually small items (net \$0.8 billion charge).

The identified items excluded in 2018 were: net divestment gains (\$3.3 billion), net impairments (\$1.0 billion charge), fair value accounting of commodity derivatives and certain gas contracts (\$1.1 billion gain), redundancy and restructuring (\$0.2 billion charge), and the aggregate of other individually small items (net \$0.1 billion charge).

The identified items excluded in 2017 were: net divestment gains (\$1.6 billion), impairments (\$3.0 billion charge), fair value accounting of commodity derivatives and certain gas contracts (\$0.3 billion loss), redundancy and restructuring (\$0.4 billion charge), impact of exchange rate movements on tax balances (\$0.6 billion gain), impact arising from the US tax reform legislation (\$2.0 billion charge) and the aggregate of other individually small items (net \$0.2 billion charge).

On the basis of our analysis of these factors, we concluded that we should focus on Shell's CCS earnings, excluding identified items reported by Shell in its quarterly results announcements, and adjusted for an effective tax rate.

Performance materiality

What we mean

Having established overall materiality, we determined 'performance materiality', which represents our tolerance for misstatement in an individual account. It is calculated as a percentage of overall materiality in order to reduce to an appropriately low level the probability that the aggregate of uncorrected and undetected misstatements exceeds overall materiality of \$1,200 million for Shell's financial statements as a whole.

Once we determined our audit scope, we then assigned performance materiality to our various in-scope operating units. Our in-scope operating unit audit teams used this assigned performance materiality in performing their group audit procedures. The performance materiality allocation is dependent on the size of the operating unit, measured by its contribution of earnings to Shell, or other appropriate metric, and the risk associated with the operating unit.

Level set

On the basis of our risk assessment, our judgement was that performance materiality should be 75% (2018: 75%) of our overall materiality, namely \$900 million (2018: \$750 million). In assessing the appropriate level, we consider the nature, the number and impact of the audit differences identified in 2018 as well as the overall control environment.

In 2019, the range of performance materiality allocated to operating units was \$135 million to \$450 million (2018: \$113 million to \$375 million). This is set out in more detail in section 5 below.

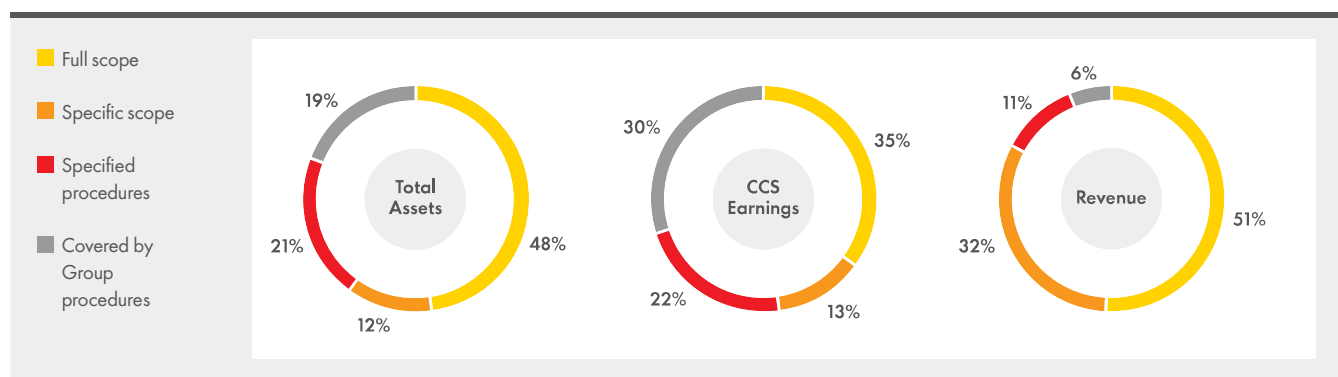
INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

4. OUR APPLICATION OF MATERIALITY continued

Audit difference reporting threshold	
What we mean	
This is the amount below which identified misstatements are considered to be clearly trivial.	We also report differences below that threshold that, in our view, warrant reporting on qualitative grounds. We evaluate any uncorrected misstatements against both the quantitative measures of materiality discussed above and in the light of other relevant qualitative considerations in forming our opinion.
The threshold is the level above which we collate and report audit differences to the Audit Committee.	
Level set	
We agreed with the Audit Committee that we would report to the Committee all audit differences more than \$60 million (2018: \$50 million), as well as differences below that threshold that, in our view, warranted reporting on qualitative grounds.	

5. OUR SCOPE OF THE AUDIT OF SHELL'S FINANCIAL STATEMENTS

What we mean	We are required to establish an overall audit strategy that sets the scope, timing and direction of our audit, and that guides the development of our audit plan. Audit scope comprises the physical locations, operating units, activities and processes to be audited that, in aggregate, are expected to provide sufficient coverage of the financial statements for us to express an audit opinion.
Criteria for determining our audit scope	<p>Our assessment of audit risk and our evaluation of materiality determined our audit scope for each operating unit within Shell which, when taken together, enabled us to form an opinion on the financial statements under ISA (UK). Our audit effort was focused towards higher risk areas, such as management judgements, and on operating units that we considered significant based upon size, complexity or risk.</p> <p>The factors that we considered when assessing the scope of the Shell audit, and the level of work to be performed at the operating units that were in scope for group reporting purposes, included the following:</p> <ul style="list-style-type: none"> ■ the financial significance of an operating unit to Shell's earnings, total assets or total liabilities, including consideration of the financial significance of specific account balances or transactions; ■ the significance of specific risks relating to an operating unit, history of unusual or complex transactions, identification of significant audit issues or the potential for, or a history of, material misstatements; ■ the effectiveness of the control environment and monitoring activities, including entity-level controls; ■ our assessment of locations that carry a higher than normal audit risk in relation to fraud, bribery or corruption; and ■ the findings, observations and audit differences that we noted as a result of our 2018 audit.
Selection of in-scope operating units	<p>We reassessed our audit scope for 2019 compared to 2018. In particular, we considered Shell's continued enhancement of their finance function and processes, which included the further standardisation and migration of processes to their BSCs. This enabled us further to centralise our audit procedures and refocus our scope, reducing the audit involvement at a component level and the number of operating units in our audit scope.</p> <p>We kept our audit scope under review throughout the year to reflect changes in Shell's underlying business and risks; however no significant changes were required.</p>
Full and specific scope	We selected 49 operating units (2018: 52) across 11 countries (2018: 11) based on their size or risk characteristics. We performed full scope audits of the complete financial information of 17 operating units (2018: 19). For 32 operating units (2018: 33) we performed specific scope audit procedures on individual account balances within the operating unit based on their size and risk profiles.
Specified procedures	<p>In addition to the 49 operating units (2018: 52) discussed above, we selected a further 41 operating units (2018: 38) where we performed procedures at the operating unit level that were specified by the group engagement team in response to specific risk factors and in order to ensure that, at the overall group level, we reduced and appropriately covered the residual risk of error.</p> <p>In addition, specified procedures were performed at the group level on a further 92 (2018: 62) operating units. These procedures included the testing of Shell's centralised activities addressing the implications of significant and complex accounting matters across all operating units, our centralised revenue and accounts receivable analytics program, testing controls for the revenue and purchase to pay processes, including IT general and IT application controls, segment level impairment reviews, procedures over the forecasts as they relate to deferred tax asset recoverability and review of pension scheme assumptions.</p>
Group procedures	<p>For the remaining 614 operating units (2018: 637), we performed supplementary audit procedures in relation to Shell's centralised group accounting and reporting processes. These included, but were not limited to, Shell's activities addressing the appropriate elimination of intercompany balances and the completeness of provisions for litigation and other claims. We performed testing of both manual and consolidation journal entries through the year, homogenous processes and controls at the BSCs and testing of group wide IT systems. We performed disaggregated analytical reviews on each financial statement line item and also tested Shell's analytical procedures performed at a group, segment and function level.</p> <p>In addition to this testing, we applied our Risk Scan analytics techniques, which consolidate internal and external data to identify potential risks of material misstatement. This allowed us to risk rate each of the 706 operating units whereby we identified 210 operating units where we believed that it was appropriate to carry out targeted testing. This included the audit of manual journal entries and/or the testing of payments to third party vendors to ensure that these had been approved in line with Shell's policies and had an appropriate business rationale.</p> <p>Our coverage by full, specific, specified and group procedures is illustrated below. The summary is by Total assets, CCS earnings and Revenue. Overall, our full, specific and specified procedures accounted for 70% of Shell's absolute CCS earnings, excluding identified items reported by Shell in its quarterly results announcements and adjusted for an effective tax rate. The remaining CCS earnings were covered by Group wide procedures.</p> <p>The Parent Company is located in the United Kingdom and audited directly by the Group engagement team.</p>



Allocation of performance materiality to the in-scope operating units

The level of materiality that we applied in undertaking our audit work at the operating unit level was determined by applying a percentage of our total performance materiality. This percentage is based on the significance of the operating unit relative to Shell as a whole and our assessment of the risk of material misstatement at that operating unit. In 2019 the range of materiality applied at the operating unit level was \$135 million to \$450 million (2018: \$113 million to \$375 million). The operating units selected, together with the ranges of materiality applied, were:

Location	Segment / Function	No. of operating units	Range of materiality applied \$ million
Full scope operating units:			
Australia, Qatar	Integrated gas	4	180-270
Brazil, Nigeria, USA	Upstream	4	180-270
USA	Downstream	2	180-270
Barbados, Singapore, The Netherlands, UAE, UK, USA	Trading and Supply	7	135-450
Total full scope operating units		17	
Specific scope operating units:			
Malaysia, UK	Upstream	3	180
Singapore, USA	Downstream	6	180
Singapore, The Netherlands, UK, USA	Corporate	12	180
Canada, Singapore, UAE, UK, USA	Trading and Supply	11	135-180
Total specific scope operating units		32	
Total full and specific scope operating units		49	

Integrated group engagement team structure

The group engagement partner and Senior Statutory Auditor, Allister Wilson, has overall responsibility for the direction, supervision and performance of the Shell audit engagement in compliance with professional standards and applicable legal and regulatory requirements. He is supported by 24 segment and function partners and associate partners, who are based in the Netherlands and the UK, and who together with related staff comprise the integrated group engagement team. This group engagement team established the overall group audit strategy, communicated with component auditors, performed work on the consolidation process, and evaluated the conclusions drawn from the audit evidence as the basis for forming Ernst & Young's (EY) opinion on the group financial statements.

For the purpose of the group audit, the group engagement team is responsible for directing, supervising, evaluating and reviewing the work of EY global network firms operating under their instruction (local EY teams) to assess whether:

- the work was performed and documented to a sufficiently high standard;
- the local EY audit team demonstrated that they had challenged management sufficiently and had executed their audit procedures with a sufficient level of scepticism; and
- there is sufficient appropriate audit evidence to support the conclusions reached.

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

5. OUR SCOPE OF THE AUDIT OF SHELL'S FINANCIAL STATEMENTS continued

Involvement with local EY teams

Shell has centralised processes and controls over key areas within its BSCs. Members of the group engagement team provide direct oversight, review, and coordination of our BSC audit teams. Our BSC teams performed centralised testing in the BSCs for certain accounts, including revenue, cash and payroll. In establishing our overall approach to the group audit, we determined the type of work that needed to be undertaken at each of the operating units or BSCs by the group engagement team or by auditors from other local EY teams.

The group engagement team performed procedures directly on 92 of the in-scope operating units. For the operating units where the work was performed by local EY auditors, we determined the appropriate level of involvement of the group engagement team to enable us to conclude that sufficient appropriate audit evidence had been obtained.

The group engagement team interacted regularly with the local EY teams during each stage of the audit, were responsible for the scope and direction of the audit process and reviewed key working papers. This, together with the additional procedures performed at the group level, gave us sufficient appropriate audit evidence for our opinion on Shell's Consolidated Financial Statements. We maintained continuous dialogue with our local EY teams in addition to holding formal meetings each quarter to ensure that we were fully aware of their progress and the results of their audit procedures.

During 2019, the Senior Statutory Auditor and other group audit partners, associate partners and directors visited operating units across eight countries as well as each of Shell's four BSCs. These visits included discussing the audit approach with the local EY teams and any issues arising from their work, meetings with Shell local management, attending planning and closing meetings, and reviewing key audit working papers on selected areas of audit risk. The visits also promoted deeper engagement with our local EY audit teams, ensuring that a consistent and cohesive audit approach was adopted so as to drive a high-quality audit. The countries and the BSC locations visited were as follows:

Countries visited	BSCs
Australia	India [A]
Brazil [A]	Malaysia [A]
India [A]	Philippines [A]
Nigeria [A]	Poland [A]
The Netherlands [A]	
Trinidad and Tobago	
UK [A]	
USA [A]	

[A] These locations were visited multiple times.

6. OUR ASSESSMENT OF KEY AUDIT MATTERS

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial statements of the current period and include the most significant assessed risks of material misstatement (whether or not due to fraud) that we identified. As Shell's auditors, we are required to determine – from the matters communicated by us to the Audit Committee during the year – those matters that required significant attention from us in performing our audit of Shell's 2019 Consolidated and Parent Company Financial Statements. In making this determination we took the following into account:

- the risks that we believed were significant to our audit and therefore required special audit consideration;
- areas of higher assessed risk of material misstatement that influenced our audit focus;
- significant audit judgements relating to areas in Shell's Consolidated and Parent Company Financial Statements including accounting estimates that we identified as having high estimation uncertainty;
- the effect on our audit of significant events or transactions that occurred during the period; and
- those assessed risks of material misstatement that had the greatest effect on the allocation of resources in the audit and directing the efforts of the audit team.

On this basis, we identified the following key audit matters that, in our professional judgement, were of most significance in our audit of Shell's 2019 Consolidated and Parent Company Financial Statements. These matters included those that had the greatest effect on:

- our overall strategy;
- the allocation of resources in the audit; and
- directing the efforts of our audit team.

The key audit matters have been addressed in the context of the audit of Shell's Consolidated and Parent Company Financial Statements as a whole, and in forming our opinions thereon, and we do not provide a separate opinion on these matters. The table below describes the key audit matters, a summary of our procedures carried out and our key observations that we communicated to the Audit Committee.

In 2018, our auditor's report included two key audit matters that have not been reported as key audit matters in our 2019 report. These relate to: (1) Enhancements to Shell's system of IT general controls, and (2) The recognition, measurement, presentation and disclosure of leases (IFRS 16). In the current year, we have added two key audit matters that were not reported as key audit matters in our 2018 report. These relate to: (1) The estimation of future refining margins to evaluate the recoverability of manufacturing, supply and distribution assets, and (2) The dividend distribution process, including the determination of realised profits and losses for the purposes of making distributions under the Companies Act 2006 (Parent Company only).

THE ESTIMATION OF OIL AND GAS RESERVES, INCLUDING RESERVES USED IN THE CALCULATION OF DEPRECIATION, DEPLETION AND AMORTISATION (DD&A), IMPAIRMENT TESTING TO EVALUATE THE RECOVERABLE AMOUNTS OF PRODUCTION ASSETS AND THE ESTIMATION OF DECOMMISSIONING AND RESTORATION (D&R) PROVISIONS

Description of the key audit matter

This is a subjective estimate. Risk is unchanged compared to 2018.

As described in Note 8 to the Consolidated Financial Statements, production assets amounted to \$150,366 million, and have an associated DD&A charge of \$19,346 million. The accounting for these financial statement amounts relies on management's estimation of proved oil and gas reserves. As described in Note 8, impairment charges of \$3,639 million were recorded during the year. As described in Note 18, D&R provisions amounted to \$19,019 million.

At December 31, 2019, Shell reported 11,096 million barrels of oil equivalent of proved developed and undeveloped reserves.

Auditing the estimation of oil and gas reserves is complex as there is significant estimation uncertainty in assessing the quantities of Shell's reserves and resources. The estimates are based on a central group of experts' assessments of petroleum initially in place, production curves and certain inputs, including future capital and operating cost assumptions and future carbon costs.

In-year movements are driven by revisions of previous estimates resulting from reclassifications, improved recovery assumptions, extensions and discoveries and purchases and sales of reserves in place. Revisions generally arise from new information, for example additional drilling results, changes in production patterns and changes to development plans.

Auditing these financial statement areas is complex because of the use of the work of reservoir engineers and the evaluation of the inputs selected by management described above, which are used by reservoir engineers in estimating proved oil and gas reserves.

Our response to the risk

Our reserves audit team includes auditors with substantial oil and gas reserves expertise, valuation experience and relevant qualifications in energy economics.

The procedures we carried out included the following:

- we obtained an understanding of the controls over Shell's oil and gas reserves estimation process. We then evaluated the design of these controls and tested their operating effectiveness. For example, we tested management's controls over completeness and accuracy of the financial data provided to the reservoir engineers for use in estimating proved oil and gas reserves;
- we tested that significant additions or reductions in proved reserves had been made in the period in which the new information became available;
- we evaluated the professional qualifications and objectivity of Shell's internal reservoir engineers:
 - who provide the detailed preparation of the reserve estimates; and
 - those who are primarily responsible for providing independent review and challenge, and ultimately endorsement of, the reserve estimates;
- we evaluated the completeness and accuracy of the inputs used by the internal reservoir engineers in estimating the economic limit test for proved oil and gas reserves determination by agreeing the inputs to source documentation. The economic limit of a project is reached when the operating cash flow from a project becomes negative. The economic limit test has a direct impact on DD&A and impairment. Where relevant, we assessed whether the economic limit test incorporated Shell's estimate of future carbon costs to reflect the potential impact of climate change and the energy transition. We also identified and evaluated corroborative and contrary evidence by comparing actual to prior year forecasts;
- for proved undeveloped reserves, we evaluated management's development plan for compliance with the SEC rule that undrilled locations must be scheduled to be drilled within five years, unless specific circumstances justify a longer time. This evaluation was made by assessing consistency of the development projections with Shell's drilling, development and capital expenditure plans;
- we tested the proved undeveloped reserves recognised. Where volumes recognised remained undeveloped for more than five years from the date they were booked, or where development was not expected for at least five years, we assessed whether or not Shell was still working towards development by comparing to future development plans, including capital expenditure plans. Also, where reserves are recognised beyond current licence terms, we obtained evidence to support the assumption that the licence would be renewed; and
- we assessed whether the energy transition assumptions incorporate the commitments that Shell have made with respect to decarbonisation in accordance with the Paris Agreement, specifically considering reserve volumes expected to be lifted beyond 2030.

Our procedures were led by the group engagement team, with input from our teams in Australia, Brazil, Canada, Kazakhstan, the Netherlands, Nigeria, Norway, Qatar, Russia and USA.

Key observations communicated to the Shell Audit Committee

In January 2020 we communicated to the Audit Committee that, based on the testing performed, we had not identified any significant errors in the oil and gas reserves estimates and concluded that the inputs and assumptions used to estimate proved reserves were reasonable. We also reported that we saw no evidence that the recognition of the reserve volumes expected to be lifted beyond 2030 results in the overstatement of Shell's balance sheet by overstating the recoverable amounts of Shell's production assets or understatement of D&R liabilities.

Cross-reference: See the Audit Committee Report on page 130 for details on how the Audit Committee reviewed assurances for proved oil and gas reserves. Also, see Notes 2A and 8 to the "Consolidated Financial Statements", and Supplementary information – oil and gas (unaudited) on page 239.

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

6. OUR ASSESSMENT OF KEY AUDIT MATTERS continued

THE RECOVERABLE AMOUNTS OF EXPLORATION AND PRODUCTION ASSETS, AND INVESTMENTS IN JOINT VENTURES AND ASSOCIATES

Description of the key audit matter

This is a forecast-based valuation. Risk is elevated compared to 2018 due to increased focus on the energy transition.

As described in Note 8 to the Consolidated Financial Statements, at December 31, 2019, Shell recognised \$165 billion of exploration and production assets within property, plant and equipment (PP&E). As described in Note 9 Shell also recognised investments in joint ventures and associates of \$23 billion.

Assets' operational performance and external factors have a significant impact on the estimate of the recoverable amounts of Shell's Upstream and Integrated Gas assets.

Auditing the recoverable amounts of assets and investments is complex and subjective due to the significant amount of judgement involved. As described in Note 2A, the most critical assumptions in forecasting future cash flows are management's view on the long-term oil and gas price outlook, future expected production volumes and the discount rate used. Forming a view on long-term oil and gas prices is inherently difficult, in particular with significant demand uncertainty due to factors such as world trade disputes, political instability, fears over a global recession and the pace of decarbonisation.

The audit procedures were performed by our group engagement team as well as our local audit teams in Australia, Brazil, Malaysia, Nigeria, Qatar, the UK and USA, which covered 72% of PP&E and investments in joint ventures and associates in Upstream and Integrated Gas segments.

We also performed specified procedures over the recoverability of PP&E balances in Argentina, Bolivia, Brunei, Canada, Egypt, UAE, Iraq, Italy, Malaysia, the Netherlands, Nigeria, Oman, Qatar, Russia, Tunisia, Trinidad and Tobago and USA which covered an additional 16% of PP&E in the Upstream and Integrated Gas segments.

Our response to the risk

We obtained an understanding of the controls over Shell's asset impairment process. We then evaluated the design of these controls and tested their operating effectiveness. For example, we tested controls over the identification of cash generating units, of indicators of impairment and reversals of impairment and the approval of key inputs to impairment assessments, including oil and gas prices, discount rates and oil and gas reserves.

We evaluated Shell's asset impairment methodology for both exploration and production assets within PP&E and investments in joint ventures and associates. Where impairment assessments were carried out, we tested the mathematical accuracy and completeness of the models used. For those assets or investments impaired previously, we evaluated the actual results versus the assumptions made and considered if reversals were required.

To test price assumptions, we compared future short and long-term commodity prices to consensus analysts' forecasts and those adopted by other international oil companies; we evaluated whether prices were used consistently across Shell, including pricing differentials, and evaluated whether Shell's long-term price assumptions incorporated the potential impact of climate change and the energy transition by comparing the assumptions to the International Energy Agency price outlook in the Energy Outlook scenarios.

To test the discount rate used for impairment testing, we involved our oil and gas valuations specialists to assist in evaluating, amongst other things, the methodology applied and assumptions made. We also tested the underlying data used to support the discount rate calculation.

In order to evaluate the cash flow inputs of the impairment models, our procedures included the following:

- tested that operating expenditure profiles and capital costs to complete construction agreed to approved operator budgets and management forecasts;
- tested that carbon pricing was included in cash flows, where applicable;
- reconciled reserves volumes in the impairment models and tested that the life-of-field assumptions were consistent with those applied in the decommissioning and restoration provision models; and
- performed sensitivity analyses on key variables in the base case cash flow models to understand the impact of changes in certain assumptions (including oil and gas prices, production and operating expenditure levels).

We assessed the basis for adjusting the cash flows to reflect the risks of each individual asset. In so doing, we considered the stage of the life of the asset, country risk and compared the consistency of management assumptions across similar fields.

Where impairment tests were undertaken, we performed sensitivity analyses of the models using different price scenarios and discount rates taking into account the nature of the asset, its location, its stage of development and associated risks.

Key observations communicated to the Shell Audit Committee

We reported that our price analysis provided strong independent evidence to support the reasonableness of Shell's commodity price assumptions in relation to comparator benchmarks. Both oil and gas price assumptions have been reduced year on year and we noted that Shell's oil price assumption was conservative versus the sector and analysts; however, we noted that the gas price assumption remained at the top of sector estimates.

We confirmed that we were satisfied that the cash flows used in the impairment tests had been risked appropriately and that the discount rate applied was appropriate.

We concluded that the impairments recorded were appropriately determined. Also, we reported that we were satisfied that there were not material impairment reversals that were required to be recognised. Where impairment tests were undertaken and no impairment was recorded, we performed specific sensitivity analyses on the key assumptions that drive the impairment analysis, and concluded that it was reasonable and supportable not to record an impairment charge.

Since early 2020, the COVID-19 (coronavirus) outbreak across China and elsewhere has caused disruption to business and economic activity and may ultimately impact Shell's future performance and asset values. In addition, an international dispute on or about March 7, 2020 has triggered an oil price war that caused the largest one-day fall in the oil price since 1991. As part of our post balance sheet audit procedures, we have considered whether or not these events provide evidence of conditions that existed at the balance sheet date. On March 10, 2020, we reported to the Audit Committee orally that both events are indicative of conditions that arose after the balance sheet date, and that therefore they are both non-adjusting events that have no impact on our conclusions concerning the recoverable amounts of Shell's assets at the balance sheet date.

Cross-reference: See the Audit Committee Report on page 133 for details on how the Audit Committee considered impairments. Also, see Notes 2A, 8, 9 and 29 to the "Consolidated Financial Statements".

THE ESTIMATION OF FUTURE REFINING MARGINS TO EVALUATE THE RECOVERABILITY OF MANUFACTURING, SUPPLY AND DISTRIBUTION ASSETS

Description of the key audit matter

This is a forecast-based assumption. Risk is elevated compared to 2018 due to increased focus on the energy transition.

As described in Note 8 to the Consolidated Financial Statements, manufacturing, supply and distribution assets amounted to \$56 billion. As described in Note 2A, forecast refining margins are a key input to:

- assessing whether or not there are indicators that refining assets might be impaired; and
- whether there is a need for environmental provisions.

Auditing future refining margins is inherently complex as the margins are influenced by regional factors and there is limited external refining margin forecast data available. Shell's approach to estimating long-term refining margins focuses on the concept of mean reversion of markets, unless a fundamental shift in markets has been identified, over an asset's life, as opposed to attempting to forecast refining cycles. This approach is consistent with prior years, which is based on Shell statistical analysis showing that refinery margins and product cracking spreads have generally reverted either to a constant mean or trending mean, thus supporting the continued application of the mean reversion methodology. Mean reversion methodology assumes that the refining margin will revert to the average over time. In other words, deviations from the average are expected to revert to the average.

Our response to the risk

We obtained an understanding of the controls over Shell's process for the estimation of refining margins. We then evaluated the design of these controls and tested their operating effectiveness. For example, we tested controls over the approval of refining margins.

Our other procedures included the following:

- we read Shell's documentation with respect to their methodology for determining refining margins and held discussions with the Shell individuals responsible for the analysis and implementing Shell's established methodology;
- we involved our oil and gas valuations specialists to assess the reasonableness of Shell's refining margin estimation methodology, particularly in light of the expected impacts of a lower carbon economy, by performing an independent research exercise based on third party information to identify the long-term outlook for refining margins;
- we assessed whether or not mean reversion is a valid methodology for forecasting refining margins by performing several statistical tests over different time spans to examine possible mean-reverting behaviour over the long-term as well as the short-term;
- we independently calculated mean refining margins for the regional refining hubs of North West Europe, Singapore-Dubai and United States Gulf Coast incorporating 14 years of data covering the period 2006-2019;
- we assessed the extent to which the reversion to mean analysis is compatible with the potential of future energy transition by performing quantitative and qualitative analysis of refining margins, which included developing econometric and machine learning models to project refining margins, which incorporated the findings from the mean reversion trends;
- to test the uncertainty related to how oil demand and refining capacity may evolve in the future, we developed different sets of scenarios that are consistent with differing rates of renewable energy adoption, including Shell's "Sky Scenario" and compared to management's refining margin forecast;
- we considered the impact of oil demand, refining capacity, business cycles, environmental regulation, upcoming regulations, technology substitution and policy changes in our performance of over 900 statistical tests;
- In evaluating the refining margins, we read third party research papers that examine the behaviour of refining margins from a statistical perspective; and
- we used external broker reports to support our expectations with respect to future refining margins and assessed whether or not management's projections aligned with our independent analysis.

The audit procedures were performed principally by the group engagement team.

Key observations communicated to the Shell Audit Committee

We reported to the Audit Committee in January 2020 that management's approach to estimating refining margins is consistent with industry valuation practice for refining assets. Our own empirical analysis corroborates Shell's view that refining margins exhibit mean reversion in the long-term. It also indicates that, in the long-term, falling refined product demand could create structural change in the refining sector (including the closure of higher-cost refineries), which will result in asset returns that are commensurate with the underlying operating and financial risks.

Cross-reference: See the Audit Committee Report on page 133 for details on how the Audit Committee reviewed refining margins. Also see Notes 2A and 8 to the "Consolidated Financial Statements".

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

6. OUR ASSESSMENT OF KEY AUDIT MATTERS continued

RECOGNITION AND MEASUREMENT OF DEFERRED TAX ASSETS

Description of the key audit matter	Our response to the risk
<p>This is an estimation based on uncertain outcomes. The realisation of these assets is largely dependent on generating substantial future profits. Risk is elevated compared to 2018 due to increased focus on the energy transition.</p> <p>As described in Note 16 of the Consolidated Financial Statements, at December 31, 2019, Shell recognised gross DTAs totalling \$28 billion, which are recognised within two balance sheet line items, deferred tax assets and as an offset against deferred tax liabilities, depending on the overall tax position in a particular jurisdiction. A significant proportion of DTA balances is supported by forecast future taxable profits, which are derived from Shell's commodity price assumptions and business plans.</p> <p>Auditing the recognition and measurement of DTAs is complex because the estimation requires significant judgement, including the timing of reversals of deferred tax liabilities (DTL) and the availability of future profits against which tax deductions represented by the DTA can be offset.</p>	<p>We obtained an understanding of the controls over Shell's process for the estimation of deferred tax assets. We then evaluated the design of these controls and tested their operating effectiveness. For example, we tested controls over projected sources of taxable income and the deferred tax calculations that support the recognition of DTAs.</p> <p>We considered the expected timing of utilisation of the DTA, including the relevant country tax laws that apply to the utilisation of tax losses. This included the ability to carry tax losses forward or back and any restrictions arising from ring fencing tax losses to particular projects.</p> <p>We tested the forecast timing of the unwinding of taxable temporary differences by evaluating the projected sources of taxable income and considering the nature of the temporary differences and the relevant tax law.</p> <p>For DTAs that are supported by forecast taxable profits or tax planning strategies, our procedures included the following:</p> <ul style="list-style-type: none"> ■ we performed sensitivity analyses over the commodity price and/or other key assumptions that underpin Shell's assessment of forecast probable taxable profits; ■ we evaluated the extent to which sufficient probable taxable profits would arise in the period within which the related losses would be available for utilisation, considering, for example, limits on the length of time that losses can be carried forward, if applicable, or if losses are ring fenced for tax purposes; and ■ we considered whether the tax balances were calculated using substantively enacted tax laws and rates. <p>For the tax planning strategies necessary to justify the recognition of the DTA, we involved our tax professionals to evaluate the application of tax law in the Company's available tax planning strategies, Shell's assessment of its ability to carry forward losses, the scheduling of the reversal of existing temporary taxable differences and carry forward amounts, and the evaluation of the carry forward lives of its deferred tax assets.</p> <p>Our audit procedures over the recognition and valuation of DTAs were performed by our tax specialist teams in Australia, Brazil, Canada, Kazakhstan, Malaysia, The Netherlands, Nigeria, Singapore, Qatar, the UK and USA, which covered 81% of the gross DTA balance. We also performed specified procedures over the recognition and valuation of DTAs in Albania, Austria, China, Egypt, France, Germany, Norway, Oman, Spain, Switzerland, Tanzania, Trinidad & Tobago, Tunisia and Turkey, which covered an additional 22% of the gross DTA balance.</p>

Key observations communicated to the Shell Audit Committee

We reported to the January 2020 meeting of the Audit Committee that we had challenged the robustness of the key management judgements and confirmed that we were satisfied that where DTAs recognised are based on income forecast to arise beyond Shell's planning horizon, we consider that there was sufficient future taxable profit that is probable to support the DTAs; however, we noted that a greater degree of judgement is required in recognising DTAs beyond Shell's planning horizon.

We also reported to the Audit Committee that the DTAs were appropriately recognised and valued at the year end.

Cross-reference: See the Audit Committee Report on page 133 for details on how the Audit Committee reviewed certain tax matters, in particular the recoverability of deferred tax assets. Also see Notes 2A and 16 to the "Consolidated Financial Statements".

REVENUE RECOGNITION: THE RISK OF UNREALISED TRADING GAINS AND LOSSES BEING RECOGNISED AS A RESULT OF ERRORS, UNAUTHORISED TRADING ACTIVITY OR DELIBERATE MISSTATEMENT OF SHELL'S TRADING POSITION

Description of the key audit matter

This is a risk of error in revenue due to the complexity of Shell's trading and supply function. Risk is unchanged compared to 2018.

As described in Note 4 to the Consolidated Financial Statements, at December 31, 2019, Shell recognised \$345 billion of revenue. As described in Note 19, Shell recognised derivative financial instrument assets of \$8 billion and \$7 billion of derivative financial instrument liabilities.

The recognition of unrealised trading gains and losses is a complex audit area. There is an inherently higher risk of error, of unauthorised trading activity or of deliberate misstatement of the group's overall trading position.

Shell's trading and supply function is integrated within the Downstream, Integrated Gas and Upstream segments and is spread across multiple regions. The trading and supply function is inherently complex due to, amongst other things, the fact that trading is not always carried out in active markets where prices are readily available. This exposes Shell to risks that are not normally associated with core oil and gas activities.

Auditing unrealised trading gains and losses is complex because of the significant judgement used in determining the key assumptions used in valuing the trades, the risk of error, of unauthorised trading activity or of deliberate misstatement of Shell's trading positions.

The deliberate misstatement of Shell's trading positions or mismarking of positions could result in understated trading losses, overstated trading profits and/or individual bonuses being manipulated through inappropriate inter-period profit/loss allocations.

Our response to the risk

We obtained an understanding of the controls over Shell's process for the recognition of revenue relating to unrealised trading gains and losses. We then evaluated the design of these controls and tested their operating effectiveness. For example, we tested controls within the front-to-end deal lifecycle across the trading and supply function around the review of valuation models.

Our trading audit professionals comprise of individuals who have significant experience of auditing both large commodity trading organisations and financial institutions.

The other procedures we performed included the following:

- we enquired whether or not there were any breakdowns of trading controls or instances of rogue trading reported or known or suspected frauds;
- we obtained external confirmation of a sample of open trading positions with brokers and counterparties;
- where external confirmations were not received, we tested the existence of the deal by agreement to signed contracts;
- we compared the price curves used by Shell to value the trading positions to external data;
- we performed independent testing of valuation models, evaluating contract terms and key assumptions to independent market quotes; and
- we tested the completeness of the amounts recorded in the financial statements through procedures to search for unrecorded liabilities by comparing sales and trade receivables and purchases and trade payables that occurred near the end of the financial year to evaluate whether or not transactions were recorded in the correct period.

The audit procedures were performed principally by the group engagement team and the UK and US component teams.

Key observations communicated to the Shell Audit Committee

In March 2020, we reported to the Audit Committee that:

- the valuation of derivative contracts as at December 31, 2019 was appropriate;
- our testing – through a combination of controls testing and substantive audit procedures – satisfied us that the models used to value contracts were appropriate for the purposes of the valuations included in Shell's Consolidated Financial Statements;
- the unrealised gains and losses had been recorded appropriately; and
- our completeness testing did not identify any unrecorded liabilities or significant cut-off issues.

Cross-reference: See the Audit Committee Report on page 130 on how the Audit Committee reviewed Trading and Supply's control framework. Also see Note 19 to the "Consolidated Financial Statements".

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

6. OUR ASSESSMENT OF KEY AUDIT MATTERS continued

THE DIVIDEND DISTRIBUTION PROCESS, INCLUDING THE DETERMINATION OF REALISED PROFITS AND LOSSES FOR THE PURPOSES OF MAKING DISTRIBUTIONS UNDER THE COMPANIES ACT 2006

Description of the key audit matter

This is a risk of non-compliance with laws and regulations. This key audit matter relates to the Parent Company only.

RDS plc has \$19 billion of distributable profits. At December 31, 2019, Shell distributed \$15 billion of dividends and repurchased \$10 billion of shares.

There is considerable public interest in ensuring that companies pay dividends and buy back shares out of profits available for distribution. Shell is both one of the world's highest dividend-paying companies and has a significant share buyback programme.

The legal framework applicable to UK companies for determining profits available for distribution is contained in both the Companies Act 2006 and complementary technical guidance. Under this framework, distributions are made by individual companies and not by groups. The Shell Consolidated Financial Statements are therefore not relevant for the purpose of determining Shell's profits available for distribution. Whether or not a distribution may be made by Shell is determined by reference to Shell's 'relevant accounts', which are the Parent Company financial statements.

Our response to the risk

The procedures we performed included the following:

- We obtained an understanding of the procedures performed by management to monitor the profits available for distribution of the Parent Company. This included understanding the processes to monitor profits available for distribution of the subsidiary entities paying significant dividends to the Parent Company;
- We tested management's distributable reserve controls at both the Parent Company and subsidiary entities that pay significant dividends, which are designed to ensure that there are sufficient profits available for distribution prior to a dividend being proposed and approved. Our testing included a review of management's analysis of non-distributable profits or losses. We also assessed the completeness of the non-distributable profits or losses identified;
- We analysed transactions that impacted significantly the retained earnings of the Parent Company and subsidiary entities paying significant dividends and considered whether any of these transactions do not meet the criteria of distributable profits or losses. We considered whether operating and financial circumstances existed that could result in a dividend block within the group structure;
- We reviewed management's analysis of profits available for distribution in the Parent Company and compared this to the expected future dividends and share buy-back commitments. We also reperformed the calculation of distributable profits available for distribution of the Parent Company by reference to the relevant accounts;
- We compared the market capitalisation of Shell with the carrying amount of the investment held by the Parent Company that directly and indirectly holds the investments of Shell to assess whether there was any indication that the asset may be impaired. We compared the carrying value of the investment to its recoverable amount in order to identify any impairment that could have a direct impact on profits available for distribution; and
- We satisfied ourselves that dividends paid and shares repurchased in 2019 were allowable, by reference to the most recent relevant accounts, for the purposes of making distributions under the Companies Act 2006.

The audit procedures were performed principally by the group engagement team and the UK component team.

Key observations communicated to the Shell Audit Committee

In January 2020, we reported to the Audit Committee that:

- the procedures performed by management to monitor the profits available for distribution of the Parent Company and subsidiary entities paying significant dividends to the Parent Company were appropriate;
- the analysis performed by management to identify non-distributable profits or losses and expected future commitments or operating and financial circumstances that could result in a dividend block is appropriate; and
- through a combination of controls testing and substantive audit procedures, we are satisfied that the profits available for distribution, by reference to the relevant accounts, were sufficient to support the dividends paid and declared and share buy-backs made by the Parent Company.

Cross-reference: See Note 23 to the "Consolidated Financial Statements" and Note 8 to the "Parent Company Financial Statements".

7. OTHER INFORMATION AND MATTERS ON WHICH WE ARE REQUIRED TO REPORT BY EXCEPTION

The other information comprises the information included in the Annual Report set out on pages 1 to 171 and 239 to 256 including the Strategic Report, Governance and Additional Information sections, other than the financial statements and our auditor's report thereon. The Directors are responsible for the other information.

Our opinion on the financial statements does not cover the other information and, except to the extent otherwise explicitly stated in this report, we do not express any form of assurance conclusion thereon. In the table below, we have outlined our responsibility for the other information in the Annual Report and the matters we would like to draw to your attention.

STRATEGIC REPORT AND THE DIRECTORS' REPORT

Our responsibility

We are required to report whether, based on the work undertaken in the course of the audit:

- the information given in the strategic report and the directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements; and
- the strategic report and the directors' report have been prepared in accordance with applicable legal requirements.

We are required to report by exception whether, in the light of the knowledge and understanding of the group and the parent company and its environment obtained in the course of the audit, we have identified material misstatements in the strategic report or the directors' report.

Our reporting

In our opinion, based on the work undertaken in the course of the audit, the information given in the strategic report and the directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements and they have been prepared in accordance with applicable legal requirements.

Our reporting

We have nothing to report by exception.

PRINCIPAL RISKS, GOING CONCERN AND VIABILITY STATEMENT

Our responsibility

ISA(UK) requires us to report to you whether we have anything material to add or draw attention to:

- the disclosures in the Annual Report set out on pages 27 to 36 that describe the principal risks and cross refer to where there are explanations of how the risks are being managed or mitigated;
- the Directors' confirmation set out on page 169 in the Annual Report that they have carried out a robust assessment of the principal risks facing the entity, including those that would threaten its business model, future performance, solvency or liquidity;
- the Directors' statement set out on page 171 in the financial statements about whether they considered it appropriate to adopt the going concern basis of accounting in preparing them, and their identification of any material uncertainties to the entity's ability to continue to do so over a period of at least twelve months from the date of approval of the financial statements;
- whether the Directors' statement in relation to going concern required under the Listing Rules in accordance with Listing Rule 9.8.6R(3) is materially inconsistent with our knowledge obtained in the audit; or
- the Directors' explanation set out on pages 165 to 166 in the Annual Report as to how they have assessed the prospects of the entity, over what period they have done so and why they consider that period to be appropriate, and their statement as to whether they have a reasonable expectation that the entity will be able to continue in operation and meet its liabilities as they fall due over the period of their assessment, including any related disclosures drawing attention to any necessary qualifications or assumptions.

Our reporting

We have nothing material to add or draw attention to with regard to any of these matters.

FAIR, BALANCED AND UNDERSTANDABLE SET OUT ON PAGE 171

Our responsibility

We are required to consider whether the statement given by the Directors that they consider the Annual Report and financial statements taken as a whole is fair, balanced and understandable and provides the information necessary for shareholders to assess Shell's performance, business model and strategy, is materially inconsistent with our knowledge obtained in the audit.

Our reporting

In the context of our responsibilities on other information, we have nothing to report.

OTHER INFORMATION

Our responsibility

In connection with our audit of the financial statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated. If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether there is a material misstatement in the financial statements or a material misstatement of the other information. If, based on the work we have performed, we conclude that there is a material misstatement of the other information, we are required to report that fact.

Our reporting

We have nothing to report in this regard.

DIRECTORS' REMUNERATION REPORT

Our responsibility

We are required to report whether the part of the Directors' Remuneration Report to be audited has been properly prepared in accordance with the Companies Act 2006.

We are also required to report by exception whether certain disclosures of directors' remuneration specified by law are not made.

Our reporting

In our opinion, the part of the Directors' Remuneration Report to be audited has been properly prepared in accordance with the Companies Act 2006.

Our reporting

We have nothing to report by exception.

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

7. OTHER INFORMATION AND MATTERS ON WHICH WE ARE REQUIRED TO REPORT BY EXCEPTION continued

DIRECTORS' STATEMENT OF COMPLIANCE WITH THE UK CORPORATE GOVERNANCE CODE SET OUT ON PAGES 115 to 116

Our responsibility

We are required to consider whether the parts of the Directors' statement required under the Listing Rules relating to Shell's compliance with the UK Corporate Governance Code containing provisions specified for review by the auditor in accordance with Listing Rule 9.8.10R(2) do properly disclose a departure from a relevant provision of the UK Corporate Governance Code.

Our reporting

In the context of our responsibilities on other information, we have nothing to report.

AUDIT COMMITTEE REPORTING SET OUT ON PAGES 139 TO 134

Our responsibility

We are required to consider whether the section describing the work of the Audit Committee does not appropriately address matters communicated by us to the Audit Committee.

Our reporting

We have nothing to report by exception.

OTHER REPORTING

Our responsibility

Under the Companies Act 2006, we are required to report to you by exception if, in our opinion:

- adequate accounting records have not been kept by the Parent Company, or returns adequate for our audit have not been received from branches not visited by us; or
- the Parent Company financial statements and the part of the Directors' Remuneration Report to be audited are not in agreement with the accounting records and returns; or
- we have not received all the information and explanations we require for our audit.

Our reporting

We have nothing to report by exception.

8. RESPONSIBILITIES OF THE DIRECTORS

As explained more fully in the statement of Directors' responsibilities set out on page 171, the Directors are responsible for the preparation of the Consolidated Financial Statements and for being satisfied that they give a true and fair view, and for such internal control as the Directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the Directors are responsible for assessing Shell and the Parent Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors either intend to liquidate Shell or the Parent Company or to cease operations, or have no realistic alternative but to do so.

9. OUR RESPONSIBILITIES FOR THE AUDIT OF THE FINANCIAL STATEMENTS

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISA (UK) will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

10. EXPLANATION AS TO WHAT EXTENT THE AUDIT WAS CONSIDERED CAPABLE OF DETECTING IRREGULARITIES, INCLUDING FRAUD

The objectives of our audit, in respect to fraud, are: to identify and assess the risks of material misstatement of the financial statements due to fraud; to obtain sufficient appropriate audit evidence regarding the assessed risks of material misstatement due to fraud, through designing and implementing appropriate responses; and to respond appropriately to fraud or suspected fraud identified during the audit. However, the primary responsibility for the prevention and detection of fraud rests with both those charged with governance of the entity and management.

Our approach was as follows:

- We obtained an understanding of the legal and regulatory frameworks that are applicable to Shell and determined that the most significant are those that relate to the reporting framework (IFRS, Companies Act 2006, the UK Corporate Governance Code, the US Securities Exchange Act of 1934 and the Listing Rules of the UK Listing Authority) and the relevant tax compliance regulations in the jurisdictions in which Shell operates. In addition, we concluded that there are certain significant laws and regulations that may have an effect on the determination of the amounts and disclosures in the financial statements and those laws and regulations relating to health and safety, employee matters, environmental, and bribery and corruption practices;
- We understood how Shell is complying with those frameworks by making enquiries of management, internal audit, those responsible for legal and compliance procedures and the Company Secretary. We corroborated our enquiries through our review of Board minutes, papers provided to the Audit Committee and correspondence received from regulatory bodies and noted that there was no contradictory evidence;

- We assessed the susceptibility of Shell's Consolidated Financial Statements to material misstatement, including how fraud might occur, by embedding forensic specialists into our group engagement team. Our forensic specialists worked with the group engagement team to identify the fraud risks across various parts of the business. In addition, we utilised internal and external information to perform a fraud risk assessment for each of the countries of operation. We considered the risk of fraud through management override and, in response, we incorporated data analytics across manual journal entries into our audit approach. We also considered the possibility of fraudulent or corrupt payments made through third parties and conducted detailed analytical testing on third party vendors in high risk jurisdictions. Where instances of risk behaviour patterns were identified through our data analytics, we performed additional audit procedures to address each identified risk. These procedures included testing of transactions back to source information and were designed to provide reasonable assurance that the financial statements were free from fraud or error. We also conducted specific audit procedures in relation to the risk of bribery and corruption across various countries of operation determined by a risk-based process;
- Based on the results of our risk assessment we designed our audit procedures to identify non-compliance with such laws and regulations identified above. Our procedures involved journal entry testing, with a focus on journals meeting our defined risk criteria based on our understanding of the business; enquiries of legal counsel, group management, internal audit and all full and specific scope management; review of the volume and nature of complaints received by the whistleblowing hotline during the year; and
- If any instances of non-compliance with laws and regulations were identified, these were communicated to the relevant local EY teams who performed sufficient and appropriate audit procedures, supplemented by audit procedures performed at the group level. Where appropriate we consulted our forensic specialists.

A further description of our responsibilities for the audit of the financial statements is located on the Financial Reporting Council's website at <https://www.frc.org.uk/auditorsresponsibilities>. This description forms part of our auditor's report.

11. OTHER MATTERS WE ARE REQUIRED TO ADDRESS

Following the recommendation of the Audit Committee we were re-appointed by Royal Dutch Shell plc's Annual General Meeting (AGM) on May 21, 2019, as auditors of Royal Dutch Shell to hold office until the conclusion of the next AGM of the Company, and signed an engagement letter on May 22, 2019. Our total uninterrupted period of engagement is four years covering periods from our appointment through to the period ending December 31, 2019.

The non-audit services prohibited by the FRC's Ethical Standard were not provided to Shell or the Parent Company and we remain independent of Shell and the Parent Company in conducting the audit.

Our audit opinion is consistent with our additional report to the Audit Committee explaining the results of our audit.

12. USE OF OUR REPORT

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

/s/ Allister Wilson (Senior Statutory Auditor)
for and on behalf of Ernst & Young LLP

ALLISTER WILSON

Senior Statutory Auditor
for and on behalf of Ernst & Young LLP
London
March 11, 2020

[A] The maintenance and integrity of the Shell website are the responsibility of the Directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.

[B] Legislation in the UK governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

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CONSOLIDATED STATEMENT OF INCOME

			\$ million	
	Notes	2019	2018	2017
Revenue	4	344,877	388,379	305,179
Share of profit of joint ventures and associates	9	3,604	4,106	4,225
Interest and other income	5	3,625	4,071	2,466
Total revenue and other income		352,106	396,556	311,870
Purchases		252,983	294,399	223,447
Production and manufacturing expenses	4	26,438	26,970	26,652
Selling, distribution and administrative expenses	4	10,493	11,360	10,509
Research and development	4	962	986	922
Exploration	4	2,354	1,340	1,945
Depreciation, depletion and amortisation	4	28,701	22,135	26,223
Interest expense	6	4,690	3,745	4,042
Total expenditure		326,621	360,935	293,740
Income before taxation		25,485	35,621	18,130
Taxation charge	16	9,053	11,715	4,695
Income for the period	4	16,432	23,906	13,435
Income attributable to non-controlling interest		590	554	458
Income attributable to Royal Dutch Shell plc shareholders		15,842	23,352	12,977
Basic earnings per share (\$)	24	1.97	2.82	1.58
Diluted earnings per share (\$)	24	1.95	2.80	1.56

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

			\$ million	
	Notes	2019	2018	2017
Income for the period	4	16,432	23,906	13,435
Other comprehensive income, net of tax				
Items that may be reclassified to income in later periods:				
Currency translation differences	22	344	(3,172)	5,156
Unrealised gains on securities [A]				593
Debt instruments remeasurements [A]	22	29	(15)	
Cash flow and net investment hedging (losses)/gains	22	(267)	730	(552)
Deferred cost of hedging [A]	22	66	(209)	
Share of other comprehensive (loss)/income of joint ventures and associates	9	(76)	(10)	170
Total		96	(2,676)	5,367
Items that are not reclassified to income in later periods:				
Retirement benefits remeasurements	22	(2,102)	3,588	604
Equity instruments remeasurements [A]	22	(30)	(153)	
Share of other comprehensive income of joint ventures and associates [A]	9	2	193	
Total		(2,130)	3,628	604
Other comprehensive (loss)/income for the period	22	(2,034)	952	5,971
Comprehensive income for the period		14,398	24,858	19,406
Comprehensive income attributable to non-controlling interest		625	383	578
Comprehensive income attributable to Royal Dutch Shell plc shareholders		13,773	24,475	18,828

[A] Changes in line items from 2018 onwards compared with 2017 are the result of the implementation of IFRS 9 *Financial Instruments*, effective from January 1, 2018.

CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEET

		\$ million	
	Notes	Dec 31, 2019	Dec 31, 2018
Assets			
Non-current assets			
Intangible assets	7	23,486	23,586
Property, plant and equipment	8	238,349	223,175
Joint ventures and associates	9	22,808	25,329
Investments in securities	10	2,989	3,074
Deferred tax	16	10,524	12,097
Retirement benefits	17	4,717	6,051
Trade and other receivables	11	8,085	7,826
Derivative financial instruments	19	689	574
		311,647	301,712
Current assets			
Inventories	12	24,071	21,117
Trade and other receivables	11	43,414	42,431
Derivative financial instruments	19	7,149	7,193
Cash and cash equivalents	13	18,055	26,741
		92,689	97,482
Total assets		404,336	399,194
Liabilities			
Non-current liabilities			
Debt	14	81,360	66,690
Trade and other payables	15	2,342	2,735
Derivative financial instruments	19	1,209	1,399
Deferred tax	16	14,522	14,837
Retirement benefits	17	13,017	11,653
Decommissioning and other provisions	18	21,799	21,533
		134,249	118,847
Current liabilities			
Debt	14	15,064	10,134
Trade and other payables	15	49,208	48,888
Derivative financial instruments	19	5,429	7,184
Taxes payable	16	6,693	7,497
Retirement benefits	17	419	451
Decommissioning and other provisions	18	2,811	3,659
		79,624	77,813
Total liabilities		213,873	196,660
Equity			
Share capital	20	657	685
Shares held in trust		(1,063)	(1,260)
Other reserves	22	14,451	16,615
Retained earnings		172,431	182,606
Equity attributable to Royal Dutch Shell plc shareholders		186,476	198,646
Non-controlling interest		3,987	3,888
Total equity		190,463	202,534
Total liabilities and equity		404,336	399,194

Signed on behalf of the Board

/s/ Jessica Uhl

JESSICA UHL

Chief Financial Officer

March 11, 2020

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

\$ million

	Equity attributable to Royal Dutch Shell plc shareholders					Non-controlling interest	Total equity
	Share capital (see Note 20)	Shares held in trust	Other reserves (see Note 22)	Retained earnings	Total		
At January 1, 2019 (as previously published)	685	(1,260)	16,615	182,606	198,646	3,888	202,534
Impact of IFRS 16 [A]	-	-	-	4	4	-	4
At January 1, 2019 (as revised)	685	(1,260)	16,615	182,610	198,650	3,888	202,538
Comprehensive income/(loss) for the period	-	-	(2,069)	15,842	13,773	625	14,398
Transfer from other comprehensive income	-	-	(74)	74	-	-	-
Dividends (see Note 23)	-	-	-	(15,198)	(15,198)	(537)	(15,735)
Repurchases of shares [B]	(28)	-	28	(10,286)	(10,286)	-	(10,286)
Share-based compensation	-	197	(49)	(613)	(465)	-	(465)
Other changes in non-controlling interest	-	-	-	2	2	11	13
At December 31, 2019	657	(1,063)	14,451	172,431	186,476	3,987	190,463
At January 1, 2018 (as previously published)	696	(917)	16,932	177,645	194,356	3,456	197,812
Impact of IFRS 9	-	-	(138)	88	(50)	-	(50)
At January 1, 2018 (as revised)	696	(917)	16,794	177,733	194,306	3,456	197,762
Comprehensive income for the period	-	-	1,123	23,352	24,475	383	24,858
Transfer from other comprehensive income	-	-	(971)	971	-	-	-
Dividends (see Note 23)	-	-	-	(15,675)	(15,675)	(586)	(16,261)
Repurchases of shares [B]	(11)	-	11	(4,519)	(4,519)	-	(4,519)
Share-based compensation [C]	-	(343)	(342)	693	8	-	8
Other changes in non-controlling interest	-	-	-	51	51	635	686
At December 31, 2018	685	(1,260)	16,615	182,606	198,646	3,888	202,534
At January 1, 2017	683	(901)	11,298	175,566	186,646	1,865	188,511
Comprehensive income for the period	-	-	5,851	12,977	18,828	578	19,406
Dividends (see Note 23)	-	-	-	(15,628)	(15,628)	(406)	(16,034)
Scrip dividends	13	-	(13)	4,751	4,751	-	4,751
Share-based compensation	-	(16)	(204)	(74)	(294)	-	(294)
Other changes in non-controlling interest	-	-	-	53	53	1,419	1,472
At December 31, 2017	696	(917)	16,932	177,645	194,356	3,456	197,812

[A] See Note 3.

[B] The repurchase of shares recognised through retained earnings includes the aggregate maximum consideration to which Shell is contractually bound under the current tranche of the buyback programme, plus associated stamp duty (see Note 20).

[C] The amendments to IFRS 2 *Share-based payment* became effective January 1, 2018. Following adoption of the amendments, components of share-based payments (related to tax) that were previously classified as cash-settled are classified as equity-settled from 2018 onwards.

CONSOLIDATED FINANCIAL STATEMENTS continued**CONSOLIDATED STATEMENT OF CASH FLOWS**

		\$ million		
	Notes	2019	2018	2017
Income before taxation for the period [A]	4	25,485	35,621	18,130
Adjustment for:				
Interest expense (net)		3,705	2,878	3,365
Depreciation, depletion and amortisation	8	28,701	22,135	26,223
Exploration well write-offs	8	1,218	449	897
Net gains on sale and revaluation of non-current assets and businesses		(2,519)	(3,265)	(1,640)
Share of profit of joint ventures and associates		(3,604)	(4,106)	(4,225)
Dividends received from joint ventures and associates		4,139	4,903	4,998
(Increase)/decrease in inventories		(2,635)	2,823	(2,079)
(Increase)/decrease in current receivables		(921)	1,955	(2,577)
(Decrease)/increase in current payables		(1,223)	(1,336)	2,406
Derivative financial instruments		(1,484)	799	(1,039)
Retirement benefits [A]		(365)	390	(654)
Decommissioning and other provisions [A]		(686)	(1,754)	(1,706)
Other [A]		(28)	1,264	(142)
Tax paid		(7,605)	(9,671)	(6,307)
Cash flow from operating activities		42,178	53,085	35,650
Capital expenditure		(22,971)	(23,011)	(20,845)
Investments in joint ventures and associates		(743)	(880)	(595)
Investment in equity securities [A]		(205)	(187)	(93)
Proceeds from sale of property, plant and equipment and businesses		4,803	4,366	8,808
Proceeds from sale of joint ventures and associates		2,599	1,594	2,177
Proceeds from sale of equity securities [A]		469	4,505	2,636
Interest received		911	823	724
Other investing cash inflows [A]		2,921	1,373	2,909
Other investing cash outflows [A]		(3,563)	(2,242)	(3,750)
Cash flow from investing activities		(15,779)	(13,659)	(8,029)
Net decrease in debt with maturity period within three months		(308)	(396)	(869)
Other debt:				
New borrowings		11,185	3,977	760
Repayments		(14,292)	(11,912)	(11,720)
Interest paid		(4,649)	(3,574)	(3,550)
Derivative financial instruments [B]		(48)		
Change in non-controlling interest		-	678	293
Cash dividends paid to:				
Royal Dutch Shell plc shareholders	23	(15,198)	(15,675)	(10,877)
Non-controlling interest		(537)	(584)	(406)
Repurchases of shares		(10,188)	(3,947)	-
Shares held in trust: net purchases and dividends received		(1,174)	(1,115)	(717)
Cash flow from financing activities		(35,209)	(32,548)	(27,086)
Currency translation differences relating to cash and cash equivalents		124	(449)	647
(Decrease)/increase in cash and cash equivalents		(8,686)	6,429	1,182
Cash and cash equivalents at beginning of year		26,741	20,312	19,130
Cash and cash equivalents at end of year	13	18,055	26,741	20,312

[A] With effect from 2019, the starting point for the Consolidated Statement of Cash Flows is 'Income before taxation' (previously 'Income'). Furthermore, to improve transparency, 'Retirement benefits' and 'Decommissioning and other provisions' have been separately disclosed. The 'Other' component of cash flow from investing activities has been expanded to distinguish between cash inflows and outflows. Prior period comparatives for these line items have been revised to conform with current year presentation. Overall, the revisions do not have an impact on cash flow from operating activities, cash flow from investing activities or cash flow from financing activities, as previously published.

[B] As from 2019, a new line item 'Derivative financial instruments' has been introduced for derivatives related to debt.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1 – BASIS OF PREPARATION

The Consolidated Financial Statements of Royal Dutch Shell plc (the “Company”) and its subsidiaries (collectively referred to as “Shell”) have been prepared in accordance with the provisions of the Companies Act 2006 (the “Act”) and Article 4 of the IAS Regulation, and therefore in accordance with International Financial Reporting Standards (“IFRS”) as adopted by the European Union. As applied to Shell, there are no material differences from IFRS as issued by the International Accounting Standards Board (“IASB”); therefore, the Consolidated Financial Statements have been prepared in accordance with IFRS as issued by the IASB.

As described in the accounting policies in Note 2A, the Consolidated Financial Statements have been prepared under the historical cost convention except for certain items measured at fair value. Those accounting policies have been applied consistently in all periods, except for those accounting standards that were adopted from January 1, 2019 (see Note 3 below).

The Consolidated Financial Statements were approved and authorised for issue by the Board of Directors on March 11, 2020.

2A – SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS AND ESTIMATES

This Note describes Shell’s significant accounting policies, which are those relevant to an understanding of the Consolidated Financial Statements. It includes the measurement bases used in preparing the Consolidated Financial Statements. It allows an understanding as to how transactions, other events and conditions are reported. It also describes: (a) judgements, apart from those involving estimations, that management makes in applying the policies that have the most significant effect on the amounts recognised in the Consolidated Financial Statements; and (b) estimations, including assumptions about the future, that management makes in applying the policies. The sources of estimation uncertainty that have a significant risk of a material adjustment to the carrying amounts of assets and liabilities within the next financial year are specifically identified as a significant estimate.

The accounting policies applied are consistent with those of the previous financial years except for the adoption as from January 1, 2019 of IFRS 16 *Leases* (“IFRS 16”), amendments to IAS 19 *Employee Benefits* (“IAS 19”) and the Annual Improvement Cycle 2015-2017.

Mandatory

The impact of the transition to the accounting pronouncements as listed below have an immaterial impact other than for IFRS 16.

IFRS 16 *Leases*

Under IFRS 16, all lease contracts, with limited exceptions, are recognised in the financial statements by way of right-of-use assets and corresponding lease liabilities. Shell applied the modified retrospective transition method, and consequently comparative information is not restated. As a practical expedient, no reassessment was performed of contracts that were previously identified as leases and contracts that were not previously identified as containing a lease applying IAS 17 *Leases* (“IAS 17”) and IFRIC 4 *Determining whether an Arrangement contains a Lease*. At the adoption date, additional lease liabilities were recognised for leases previously classified as operating leases applying IAS 17 (see Note 3). These lease liabilities were measured at the present value of the remaining lease payments and discounted using entity-specific incremental borrowing rates at January 1, 2019. In general, a corresponding right-of-use asset was recognised for an amount equal to each lease liability, adjusted by the amount of any prepaid or accrued lease payment relating to the specific lease contract, as recognised on the balance sheet at December 31, 2018. Provisions for onerous lease contracts at December 31, 2018 were adjusted to the respective right-of-use assets recognised at January 1, 2019.

The adoption of the new standard had an accumulated impact of \$4 million on equity following the recognition of lease liabilities of \$16.0 billion and additional right-of-use assets of \$15.6 billion and reclassifications mainly related to pre-paid leases and onerous contracts previously recognised (see Note 3).

IAS 19 *Employee Benefits*

IAS 19 specifies how a company accounts for a defined benefit plan. When a plan event (i.e., a plan amendment, curtailment or settlement) occurs, IAS 19 requires a company to update its assumptions and remeasure its net defined benefit liability or asset. The IAS 19 amendments that are adopted clarify that after a plan event, entities would use these updated assumptions to measure current service cost and net interest for the remainder of the reporting period after the plan event. These amendments had no impact on Shell.

Annual Improvement Cycle 2015-2017

The Annual Improvements to IFRS Standards 2015-2017 Cycle includes minor amendments affecting IFRS 3 *Business combinations*, IFRS 11 *Joint arrangements*, IAS 12 *Income taxes*, and IAS 23 *Borrowing costs*. None of the amendments had a material impact on Shell.

IFRIC 23 *Uncertainty over income tax treatments* (“IFRIC 23”)

IFRIC 23 clarifies the recognition and measurement for income tax when it is unclear whether a taxation authority will accept the tax treatment claimed. An uncertain tax position arises where there is more than one possible interpretation of how tax regulations apply to a given transaction or event. The interpretation requires the Company to determine whether uncertain tax treatments are assessed separately or as a group. The interpretation also requires an assumption that a taxation authority has full knowledge of all relevant information. Where it is not probable that a taxation authority will accept an uncertain tax treatment, it requires the Company to reflect the effect of the uncertainty in the accounting tax position. Finally, reassessment should be performed on a yearly basis in the event of changes in facts and circumstances.

Based on the assessment performed, this interpretation had no material impact on Shell’s uncertain income tax accounting positions recognised.

NATURE OF THE CONSOLIDATED FINANCIAL STATEMENTS

The Consolidated Financial Statements are presented in US dollars (dollars) and comprise the financial statements of the Company and its subsidiaries, being those entities over which the Company has control, either directly or indirectly, through exposure or rights to their variable returns and the ability to affect those returns through its power over the entities. Information about subsidiaries at December 31, 2019, can be found in ‘Appendix 1: Significant Subsidiaries and Other Related Undertakings’.

Subsidiaries are consolidated from the date on which control is obtained until the date that such control ceases, using consistent accounting policies. All inter-company balances and transactions, including unrealised profits arising from such transactions, are eliminated. Unrealised losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. Non-controlling interest represents the proportion of income, other comprehensive income and net assets in subsidiaries that is not attributable to the Company’s shareholders.

CURRENCY TRANSLATION

Foreign currency transactions are translated using the exchange rate at the dates of the transactions or valuation where items are re-measured. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at quarter-end exchange rates of monetary assets and liabilities denominated in foreign currencies (including those in respect of inter-company balances, unless related to loans of a long-term investment nature) are recognised in income. This is

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

2A – SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS AND ESTIMATES continued

except when recognised in other comprehensive income in respect of cash flow or net investment hedges, and presented within interest and other income or within purchases where not related to financing. Share capital issued in currencies other than the dollar is translated at the exchange rate at the date of issue.

On consolidation, assets and liabilities of non-dollar entities are translated to dollars at year-end rates of exchange, while their statements of income, other comprehensive income and cash flows are translated at quarterly average rates. The resulting translation differences are recognised as currency translation differences within other comprehensive income. Upon sale of all or part of an interest in, or upon liquidation of, an entity, the appropriate portion of cumulative currency translation differences related to that entity are generally recognised in income.

REVENUE RECOGNITION (from January 1, 2018)

Revenue from sales of oil, natural gas, chemicals and other products is recognised at the transaction price to which Shell expects to be entitled, after deducting sales taxes, excise duties and similar levies. For contracts that contain separate performance obligations, the transaction price is allocated to those separate performance obligations by reference to their relative standalone selling prices.

Revenue is recognised when control of the products has been transferred to the customer. For sales by Integrated Gas and Upstream operations, this generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism; for sales by refining operations, it is either when the product is placed onboard a vessel or offloaded from the vessel, depending on the contractually agreed terms; and for sales of oil products and chemicals, it is either at the point of delivery or the point of receipt, depending on contractual conditions.

Revenue resulting from hydrocarbon production from properties in which Shell has an interest with partners in joint arrangements is recognised on the basis of Shell's volumes lifted and sold. Revenue resulting from the production of oil and natural gas under production-sharing contracts ("PSCs") is recognised for those amounts relating to Shell's cost recoveries and Shell's share of the remaining production. Gains and losses on derivative contracts and the revenue and costs associated with other contracts that are classified as held primarily for the purpose of being traded are reported on a net basis in the Consolidated Statement of Income. Purchases and sales of hydrocarbons under exchange contracts that are necessary to obtain or reposition feedstocks for refinery operations are presented net in the Consolidated Statement of Income.

Revenue resulting from arrangements that are not considered contracts with customers is presented as revenue from other sources.

REVENUE RECOGNITION (prior to January 1, 2018)

Revenue from sales of oil, natural gas, chemicals and other products is recognised at the fair value of consideration received or receivable, after deducting sales taxes, excise duties and similar levies, when the significant risks and rewards of ownership have been transferred, which is when title passes to the customer. For sales by Integrated Gas and Upstream operations, this generally occurs when product is physically transferred into a vessel, pipe or other delivery mechanism; for sales by refining operations, it is either when product is placed onboard a vessel or offloaded from the vessel, depending on the contractually agreed terms; and for sales of oil products and chemicals, it is either at the point of delivery or the point of receipt, depending on contractual conditions.

Revenue resulting from hydrocarbon production from properties in which Shell has an interest with partners in joint arrangements is recognised on the basis of Shell's working interest (entitlement method). Revenue resulting from the production of oil and natural gas under PSCs is recognised for those amounts relating to Shell's cost recoveries and Shell's share of the remaining production. Gains and losses on derivative contracts and the revenue and costs associated with other contracts that are classified as held for trading purposes are reported on a net basis in the Consolidated Statement of Income. Purchases and sales of hydrocarbons under exchange contracts that are necessary to obtain or reposition feedstocks for refinery operations are presented net in the Consolidated Statement of Income.

RESEARCH AND DEVELOPMENT

Development costs that are expected to generate probable future economic benefits are capitalised as intangible assets. All other research and development expenditure is recognised in income as incurred.

EXPLORATION COSTS

Hydrocarbon exploration costs are accounted for under the successful efforts method: exploration costs are recognised in income when incurred, except that exploratory drilling costs, including in respect of the recapitalisation of depreciation, are included in property, plant and equipment pending determination of proved reserves. Exploration costs capitalised in respect of exploration wells that are more than 12 months old are written off unless: (a) proved reserves are booked; or (b) (i) they have found commercially producible quantities of reserves and (ii) they are subject to further exploration or appraisal activity in that either drilling of additional exploratory wells is under way or firmly planned for the near future or other activities are being undertaken to sufficiently progress the assessing of reserves and the economic and operating viability of the project.

PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLE ASSETS

Recognition

Property, plant and equipment comprise assets owned by Shell, assets held by Shell under lease contracts, and assets operated by Shell as contractor in PSCs. They include rights and concessions in respect of properties with proved reserves ("proved properties") and with no proved reserves ("unproved properties"). Property, plant and equipment, including expenditure on major inspections, and intangible assets are initially recognised in the Consolidated Balance Sheet at cost where it is probable that they will generate future economic benefits. This includes capitalisation of decommissioning and restoration costs associated with provisions for asset retirement (see 'Provisions'), certain development costs (see 'Research and development') and the effects of associated cash flow hedges (see 'Financial instruments (from January 1, 2018)') as applicable. The accounting for exploration costs is described separately (see 'Exploration costs'). Intangible assets include goodwill, liquefied natural gas ("LNG") off-take and sales contracts obtained through acquisition, software costs and trademarks. Interest is capitalised as an increase in property, plant and equipment, on major capital projects during construction.

Property, plant and equipment and intangible assets are subsequently carried at cost less accumulated depreciation, depletion and amortisation (including any impairment). Gains and losses on sale are determined by comparing the proceeds with the carrying amounts of assets sold and are recognised in income, within interest and other income.

An asset is classified as held for sale if its carrying amount will be recovered principally through sale rather than through continuing use, which is when the sale is highly probable, and it is available for immediate sale. Assets classified as held for sale are measured at the lower of the carrying amount upon classification and the fair value less costs to sell.

Depreciation, depletion and amortisation

Property, plant and equipment related to hydrocarbon production activities are in principle depreciated on a unit-of-production basis over the proved developed reserves of the field concerned, other than assets whose useful lives differ from the lifetime of the field which are depreciated applying the straight-line method. However, for certain Upstream assets, the use for this purpose of proved developed reserves, which are determined using the SEC-mandated yearly average oil and gas prices, would result in depreciation charges for these assets which do not reflect the pattern in which their future economic benefits are expected to be consumed as, for example, it may result in assets with long-term expected lives being depreciated in full within one year. Therefore, in these instances, other approaches are applied to determine the reserves base for the purpose of calculating depreciation, such as using management's expectations of future oil and gas prices rather than yearly average prices, to provide a phasing of periodic depreciation charges that more appropriately reflects the expected utilisation of the assets concerned.

Rights and concessions in respect of proved properties are depleted on the unit-of-production basis over the total proved reserves of the relevant area. Where individually insignificant, unproved properties may be grouped and depreciated based on factors such as the average concession term and past experience of recognising proved reserves.

Property, plant and equipment held under leases contracts and capitalised LNG off-take and sales contracts are depreciated or amortised over the term of the respective contract. Other property, plant and equipment and intangible assets are depreciated or amortised on a straight-line basis over their estimated useful lives, except for goodwill, which is not amortised. They include refineries and chemical plants (for which the useful life is generally 20 years), retail service stations (15 years), upgraders (30 years) and major inspection costs, which are depreciated over the estimated period before the next planned major inspection (three to five years).

On classification of an asset as held for sale, depreciation ceases.

Estimates of the useful lives and residual values of property, plant and equipment and intangible assets are reviewed annually and adjusted if appropriate.

Impairment

The carrying amount of goodwill is tested for impairment annually; in addition, assets other than unproved properties (see 'Exploration costs') are tested for impairment whenever events or changes in circumstances indicate that the carrying amounts for those assets may not be recoverable. On classification as held for sale, the carrying amounts of property, plant and equipment and intangible assets are also reviewed. If assets are determined to be impaired, the carrying amounts of those assets are written down to their recoverable amount, which is the higher of fair value less costs to sell (see 'Fair value measurements') and value in use.

Value in use is determined as the amount of estimated risk-adjusted discounted future cash flows. For this purpose, assets are grouped into cash-generating units based on separately identifiable and largely independent cash inflows. Estimates of future cash flows used in the evaluation of impairment of assets are made using management's forecasts of commodity prices, market supply and demand, potential costs associated with operational GHG emissions, and forecast product and refining margins. In addition, management takes into consideration the expected useful lives of the refineries, and exploration and production assets, and expected production volumes. The latter takes into account assessments of field and reservoir performance and includes expectations about both proved reserves and volumes that are expected to constitute proved reserves in the future (unproved volumes), which are risk-weighted utilising geological, production, recovery and economic projections. Cash flow estimates are risk-adjusted to reflect local conditions as appropriate and discounted at a rate based on Shell's marginal cost of debt.

Impairments, except those related to goodwill, are reversed as applicable to the extent that the events or circumstances that triggered the original impairment have changed.

Impairment losses and reversals are reported within depreciation, depletion and amortisation.

Judgements and estimates

Proved oil and gas reserves

Unit-of-production depreciation, depletion and amortisation charges are principally measured based on management's estimates of proved developed oil and gas reserves. Also, exploration drilling costs are capitalised pending the results of further exploration or appraisal activity, which may take several years to complete and before any related proved reserves can be booked.

Proved reserves are estimated by a central group of reserves experts. The estimated proved reserves are made by reference to available geological and engineering data and only include volumes for which access to market is assured with reasonable certainty. Yearly average oil and gas prices are applied in the determination of proved reserves. Estimates of proved reserves are inherently imprecise, require the application of judgement and are subject to regular revision, either upward or downward, based on new information such as from the drilling of additional wells, observation of long-term reservoir performance under producing conditions and changes in economic factors, including product prices, contract terms, legislation or development plans.

Changes to estimates of proved developed reserves affect prospectively the amounts of depreciation, depletion and amortisation charged and, consequently, the carrying amounts of exploration and production assets. It is expected, however, that in the normal course of business the diversity of the asset portfolio will limit the effect of such revisions. The outcome of, or assessment of plans for, exploration or appraisal activity may result in the related capitalised exploration drilling costs being recognised in income in that period.

Judgement is involved in determining when to use an alternative reserves base in order to appropriately reflect the expected utilisation of the assets concerned (see 'Depreciation, depletion and amortisation').

Information about the carrying amounts of exploration and production assets and the amounts charged to income, including depreciation, depletion and amortisation and the quantitative impact of the use of an alternative reserve base, is presented in Note 8.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

2A – SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS AND ESTIMATES continued

Judgements and estimates continued

Impairment

For the purposes of determining whether impairment of assets has occurred, and the extent of any impairment loss or its reversal, the key assumptions management uses in estimating risk-adjusted future cash flows for value-in-use measures are future oil and gas prices, potential costs associated with operational GHG emissions, expected production volumes and refining margins appropriate to the local circumstances and environment. These assumptions and the judgements of management that are based on them are subject to change as new information becomes available. Changes in economic conditions can affect the rate used to discount future cash flow estimates or the risk-adjustment in the future cash flows.

Estimation is involved with respect to the expected life of refineries and chemicals sites, and also including management's view on the future development of refining margins.

The determination of cash-generating units requires judgement. Changes in this determination could impact the calculation of value in use and therefore the conclusion on the recoverability of assets' carrying amounts when performing an impairment test.

Judgement, which is subject to change as new information becomes available, can be required in determining when an asset is classified as held for sale. A change in that judgement could result in impairment charges affecting income, depending on whether classification requires a write down of the asset to its fair value less costs to sell.

Significant estimates

Future commodity price assumptions, presented in Note 8, tend to be stable because management does not consider short-term increases or decreases in prices as being indicative of long-term levels, but they are nonetheless subject to change. Expected production volumes, which comprise proved reserves and unproved volumes, are used for impairment testing because management believes this to be the most appropriate indicator of expected future cash flows. As discussed in 'Proved oil and gas reserves' above, reserves estimates are inherently imprecise. Furthermore, projections about unproved volumes are based on information that is necessarily less robust than that available for mature reservoirs. Due to the nature and geographical spread of the business activity in which those assets are used, it is typically not practicable to estimate the likelihood or extent of impairments under different sets of assumptions for Shell overall.

Changes in assumptions could affect the carrying amounts of assets, and any impairment losses and reversals will affect income.

Forecast refining margins are a key input for impairment testing in Downstream. Management's estimate of longer-term refining margins is based on the mean reversion of markets, unless a fundamental shift in markets has been identified, over the life of the refineries. Under this approach, that is consistently applied, it is assumed that refining margins will revert to historical averages over time.

Changes in assumptions could affect the carrying amounts of assets and estimation of environmental provisions. Any impairment losses and reversals will affect income.

Information about the carrying amounts of assets and impairments is presented in Notes 7 and 8.

LEASES (from January 1, 2019)

A contract or parts of contracts, that conveys the right to control the use of an identified asset for a period of time in exchange for payments to be made to the owners (lessors) are accounted for as leases. Contracts are assessed to determine whether a contract is, or contains, a lease at the inception of a contract or when the terms and conditions of a contract are significantly changed. The lease term is the non-cancellable period of a lease, together with contractual options to extend or to terminate the lease early, where it is reasonably certain that an extension option will be exercised or a termination option will not be exercised.

At the commencement of a lease contract, a right-of-use asset and a corresponding lease liability are recognised, unless the lease term is 12 months or less. The commencement date of a lease is the date the underlying asset is made available for use. The lease liability is measured at an amount equal to the present value of the lease payments during the lease term that are not paid at that date. The lease liability includes contingent rentals and variable lease payments that depend on an index, rate, or where they are fixed payments in substance. The lease liability is remeasured when the contractual cash flows of variable lease payments change due to a change in an index or rate when the lease term changes following a reassessment.

Lease payments are discounted using the interest rate implicit in the lease. If that rate is not readily available, the incremental borrowing rate is applied. The incremental borrowing rate reflects the rate of interest that the lessee would have to pay to borrow over a similar term, with a similar security, the funds necessary to obtain an asset of a similar nature and value to the right-of-use asset in a similar economic environment.

In general, a corresponding right-of-use asset is recognised for an amount equal to each lease liability, adjusted by the amount of any pre-paid lease payment relating to the specific lease contract. The depreciation on right-of-use assets is recognised in income unless capitalised as exploration drilling cost (see 'Exploration cost') or capitalised when the right-of-use asset is used to construct another asset.

Where Shell is the lessor in a lease arrangement at inception, the lease arrangement will be classified as a finance lease or an operating lease. Classification is based on the extent to which the risks and rewards incidental to ownership of the underlying asset lie with the lessor or the lessee.

Where Shell, usually in its capacity as operator, has entered into a lease contract on behalf of a joint arrangement, a lease liability is recognised to the extent that Shell has primary responsibility for the lease liability. A finance sub-lease is subsequently recognised if the related right-of-use asset is subleased to the joint arrangement. This is usually the case when the joint arrangement has the right to direct the use of the asset.

Impairment of the right-of-use asset

Right-of-use assets are subject to existing impairment requirements as set out in 'Property, plant and equipment' (see Note 8).

Judgements and estimates

A lease term includes optional lease periods where it is reasonably certain to exercise the option to extend or not to exercise the option to terminate the lease. Determination of the lease term is subject to judgement and has an impact on the measurement of the lease liability and related right-of-use asset.

Where the rate implicit in the lease is not readily available, an incremental borrowing rate is applied. This incremental borrowing rate reflects the rate of interest that the lessee would have to pay to borrow over a similar term, with a similar security, the funds necessary to obtain an asset of a similar nature and value to the right-of-use asset in a similar economic environment. Determination of the incremental borrowing rate requires estimation. The incremental borrowing rate is determined using the risk-free rate over a matched term, adjusted for factors such as the credit rating of the lessee and the borrowing currency.

Significant estimate

The operating leases that were recognised on the balance sheet following the adoption of IFRS 16 (see Note 3) were measured applying an incremental borrowing rate at transition date to the future payments under these lease contracts. To determine the incremental borrowing rate for each lease contract, a risk-free rate at transition date was applied, adjusted for other factors such as the credit rating of the entity that entered into the lease contract, a country risk premium, the impact of currency, an asset specific element and the term of the lease contract. All factors are subject to estimation. If a higher or lower incremental borrowing rate had been applied, the lease liability and corresponding right-of-use asset would respectively have been lower or higher. The incremental borrowing rate will not be revised each period and will not result in a material adjustment to the carrying amount of lease liability and right-of-use asset in the future years.

LEASES (prior to January 1, 2019)

Agreements under which payments are made to owners in return for the right to use an asset for a period are accounted for as leases. Leases that transfer substantially all the risks and rewards of ownership are recognised at the commencement of the lease term as finance leases within property, plant and equipment and debt at the fair value of the leased asset or, if lower, at the present value of the minimum lease payments. Finance lease payments are apportioned between interest expense and repayments of debt. All other leases are classified as operating leases and the cost is recognised in income on a straight-line basis, except where capitalised as exploration drilling costs (see 'Exploration costs').

JOINT ARRANGEMENTS AND ASSOCIATES

Arrangements under which Shell has contractually agreed to share control (see 'Nature of the Consolidated Financial Statements' for the definition of control) with another party or parties are joint ventures where the parties have rights to the net assets of the arrangement, or joint operations where the parties have rights to the assets and obligations for the liabilities relating to the arrangement. Investments in entities over which Shell has the right to exercise significant influence but neither control nor joint control are classified as associates. Information about incorporated joint arrangements and associates at December 31, 2019, can be found in 'Appendix 1: Significant Subsidiaries and Other Related Undertakings'.

Investments in joint ventures and associates are accounted for using the equity method, under which the investment is initially recognised at cost and subsequently adjusted for the Shell share of post-acquisition income less dividends received and the Shell share of other comprehensive income and other movements in equity, together with any loans of a long-term investment nature. Where necessary, adjustments are made to the financial statements of joint ventures and associates to bring the accounting policies used into line with those of Shell. In an exchange of assets and liabilities for an interest in a joint venture, the non-Shell share of any excess of the fair value of the assets and liabilities transferred over the pre-exchange carrying amounts is recognised in income. Unrealised gains on other transactions between Shell and its joint ventures and associates are eliminated to the extent of Shell's interest in them; unrealised losses are treated similarly but may also result in an assessment of whether the asset transferred is impaired.

Shell recognises its assets and liabilities relating to its interests in joint operations, including its share of assets held jointly and liabilities incurred jointly with other partners.

INVENTORIES

Inventories are stated at cost or net realisable value, whichever is lower. Cost comprises direct purchase costs (including transportation), and associated costs incurred in bringing inventories to their present condition and location, and is determined using the first-in, first-out ("FIFO") method for oil, gas and chemicals and by the weighted average cost method for materials.

TAXATION

The charge for current tax is calculated based on the income reported by the Company and its subsidiaries, as adjusted for items that are non-taxable or disallowed and using rates that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is determined, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the Consolidated Balance Sheet and on unused tax losses and credits carried forward.

Deferred tax assets and liabilities are calculated using the enacted or substantively enacted rates that are expected to apply when an asset is realised or a liability is settled. They are not recognised where they arise on the initial recognition of goodwill or of an asset or liability in a transaction (other than in a business combination) that, at the time of the transaction, affects neither accounting nor taxable profit, or in respect of taxable temporary differences associated with subsidiaries, joint ventures and associates where the reversal of the respective temporary difference can be controlled by Shell and it is probable that it will not reverse in the foreseeable future.

Deferred tax assets are recognised to the extent that it is probable that future taxable profits will be available against which the deductible temporary differences, unused tax losses and credits carried forward can be utilised.

Income tax receivables and payables as well as deferred tax assets and liabilities include provisions for uncertain income tax positions/treatments.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

2A – SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS AND ESTIMATES continued

Income taxes are recognised in income except when they relate to items recognised in other comprehensive income, in which case the tax is recognised in other comprehensive income. Income tax assets and liabilities are presented separately in the Consolidated Balance Sheet except where there is a right of offset within fiscal jurisdictions and an intention to settle such balances on a net basis.

Judgements and estimates

Tax liabilities are recognised when it is considered probable that there will be a future outflow of funds to a taxing authority. In such cases, provision is made for the amount that is expected to be settled, where this can be reasonably estimated. Provisions for uncertain income tax positions/treatments are measured at the most likely amount or the expected value, whichever method is more appropriate. Generally, uncertain tax treatments are assessed on an individual basis, except where they are expected to be settled collectively. It is assumed that taxing authorities will examine positions taken if they have the right to do so and that they have full knowledge of the relevant information. A change in estimate of the likelihood of a future outflow and/or in the expected amount to be settled would be recognised in income in the period in which the change occurs. This requires the application of judgement as to the ultimate outcome, which can change over time depending on facts and circumstances. Judgements mainly relate to transfer pricing, including inter-company financing, interpretation of PSCs, expenditure deductible for tax purposes and taxation arising on disposal.

Deferred tax assets are recognised only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those assets are likely to reverse, and a judgement as to whether or not there will be sufficient taxable profits available to offset the assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognised in respect of deferred tax assets as well as in the amounts recognised in income in the period in which the change occurs.

Taxation information, including charges and deferred tax assets and liabilities, is presented in Note 16. Income taxes include taxes at higher rates levied on income from certain Integrated Gas and Upstream activities.

RETIREMENT BENEFITS

Benefits in the form of retirement pensions and healthcare and life insurance are provided to certain employees and retirees under defined benefit and defined contribution plans.

Obligations under defined benefit plans are calculated annually by independent actuaries using the projected unit credit method, which takes into account employees' years of service and, for pensions, average or final pensionable remuneration, and are discounted to their present value using interest rates of high-quality corporate bonds denominated in the currency in which the benefits will be paid and of a duration consistent with the plan obligations. Where plans are funded, payments are made to independently managed trusts; assets held by those trusts are measured at fair value. Defined benefit plan surpluses are recognised as assets to the extent that they are considered recoverable, which is generally by way of a refund or lower future employer contributions.

The amounts recognised in income in respect of defined benefit plans mainly comprise service cost and net interest. Service cost comprises principally the increase in the present value of the obligation for benefits resulting from employee service during the period (current service cost) and also amounts relating to past service and settlements or amendments of plans. Plan amendments are changes to benefits and are generally recognised when all legal and regulatory approvals have been received and the effects have been communicated to members. Net interest is calculated using the net defined benefit liability or asset matched against the discount rate yield curve at the beginning of each year for each plan. Remeasurements of the net defined benefit liability or asset resulting from actuarial gains and losses, and the return on plan assets excluding the amount recognised in income, are recognised in other comprehensive income.

For defined contribution plans, pension expense represents the amount of employer contributions payable for the period.

Significant judgements and estimates

Defined benefit obligations and plan assets, and the resulting liabilities and assets that are recognised, are subject to significant volatility as actuarial assumptions regarding future outcomes and market values change. Substantial judgement is required in determining the actuarial assumptions, which vary for the different plans to reflect local conditions but are determined under a common process in consultation with independent actuaries. The assumptions applied in respect of each plan are reviewed annually and adjusted where necessary to reflect changes in experience and actuarial recommendations.

Information about the amounts reported in respect of defined benefit pension plans, assumptions applicable to the principal plans and their sensitivity to changes are presented in Note 17.

PROVISIONS

Provisions are recognised at the balance sheet date at management's best estimate of the expenditure required to settle the present obligation. Non-current amounts are discounted at a rate intended to reflect the time value of money. The carrying amounts of provisions are regularly reviewed and adjusted for new facts or changes in law or technology.

Provisions for decommissioning and restoration costs, which arise principally in connection with hydrocarbon production facilities and pipelines, are measured on the basis of current requirements, technology and price levels; the present value is calculated using amounts discounted over the useful economic life of the assets. The liability is recognised (together with a corresponding amount as part of the related property, plant and equipment) once an obligation crystallises in the period when a reasonable estimate can be made. The effects of changes resulting from revisions to the timing or the amount of the original estimate of the provision are reflected on a prospective basis, generally by adjustment to the carrying amount of the related property, plant and equipment. However, where there is no related asset, or the change reduces the carrying amount to nil, the effect, or the amount in excess of the reduction in the related asset to nil, is recognised in income.

Redundancy provisions are recognised when a detailed formal plan identifies the business or part of the business concerned, the location and number of employees affected, a detailed estimate of the associated costs and an appropriate timeline, and the employees affected have been notified of the plan's main features.

Other provisions are recognised in income in the period in which an obligation arises and the amount can be reasonably estimated. Provisions are measured based on current legal requirements and existing technology where applicable. Recognition of any joint and several liability is based on management's best estimate of the final pro rata share of the liability. Provisions are determined independently of expected insurance recoveries. Recoveries are recognised when virtually certain of realisation.

Significant estimates

Estimates of provisions for future decommissioning and restoration costs are recognised and based on current legal and constructive requirements, technology and price levels. Because actual outflows can differ from estimates due to changes in laws, regulations, public expectations, technology, prices and conditions, and can take place many years in the future, the carrying amounts of provisions are regularly reviewed and adjusted to take account of such changes. The discount rate applied is reviewed annually.

Information about decommissioning and restoration provisions is presented in Note 18.

FINANCIAL INSTRUMENTS (from January 1, 2018)

Financial assets and liabilities are presented separately in the Consolidated Balance Sheet except where there is a legally enforceable right of offset and Shell has the intention to settle on a net basis or realise the asset and settle the liability simultaneously.

Financial Assets

Financial assets are classified at initial recognition and subsequently measured at amortised cost, fair value through other comprehensive income or fair value through profit or loss. The classification of financial assets is determined by the contractual cash flows and where applicable the business model for managing the financial assets.

A financial asset is measured at amortised cost, if the objective of the business model is to hold the financial asset in order to collect contractual cash flows and the contractual terms give rise to cash flows that are solely payments of principal and interest. It is initially recognised at fair value plus or minus transaction costs that are directly attributable to the acquisition or issue of the financial asset. Subsequently the financial asset is measured using the effective interest method less any impairment. Gains and losses are recognised in profit or loss when the asset is derecognised, modified or impaired.

All equity instruments and other debt instruments are recognised at fair value. For equity instruments, on initial recognition, an irrevocable election (on an instrument-by-instrument basis) can be made to designate these as at fair value through other comprehensive income instead of fair value through profit and loss. Dividends received on equity instruments are recognised as other income in profit or loss when the right of payment has been established, except when Shell benefits from such proceeds as a recovery of part of the cost of the financial asset, in which case, such gains are recorded in other comprehensive income.

Investments in securities

Investments in securities ("securities") comprise equity and debt securities. Equity securities are carried at fair value. Generally, unrealised holding gains and losses are recognised in other comprehensive income. On sale, net gains and losses previously accumulated in other comprehensive income are transferred to retained earnings. Debt securities are generally carried at fair value with unrealised holding gains and losses recognised in other comprehensive income. On sale, net gains and losses previously accumulated in other comprehensive income are recognised in income.

Impairment of financial assets

The expected credit loss model is applied for recognition and measurement of impairments in financial assets measured at amortised cost or at fair value through other comprehensive income. The expected credit loss model is also applied for financial guarantee contracts to which IFRS 9 applies and are not accounted for at fair value through profit or loss. The loss allowance for the financial asset is measured at an amount equal to the 12-month expected credit losses. If the credit risk on the financial asset has increased significantly since initial recognition, the loss allowance for the financial asset is measured at an amount equal to the lifetime expected credit losses. Changes in loss allowances are recognised in profit and loss. For trade receivables, a simplified impairment approach is applied recognising expected lifetime losses from initial recognition.

Financial Liabilities

Financial liabilities are measured at amortised cost, unless they are required to be measured at fair value through profit or loss, such as instruments held for trading, or Shell has opted to measure them at fair value through profit or loss. Debt and trade payables are recognised initially at fair value based on amounts exchanged, net of transaction costs, and subsequently at amortised cost except for fixed rate debt subject to fair value hedging which is remeasured for the hedged risk (see below). Interest expense on debt is accounted for using the effective interest method, and other than interest capitalised, is recognised in income. For financial liabilities that are measured under the fair value option, the change in the fair value related to own credit risk is recognised in other comprehensive income. The remaining fair value change is recognised to fair value through profit and loss.

Derivative contracts and hedges

Derivative contracts are used in the management of interest rate risk, foreign exchange risk, commodity price risk, and foreign currency cash balances. Derivatives that are not closely related to the host contract in terms of economic characteristics and risks of which the host contract is not a financial asset, are separated from their host contract and recognised at fair value with the associated gains and losses recognised in income.

Certain derivative contracts qualify and are designated either as a "fair value" hedge of the change in fair value of a recognised asset or liability or an unrecognised firm commitment or as a "cash flow" hedge for the change in cash flows to be received or paid relating to a recognised asset or liability or a highly probable forecast transaction.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS *continued*

2A – SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS AND ESTIMATES *continued*

A change in the fair value of a fair value hedge is recognised in income, together with the consequential adjustment to the carrying amount of the hedged item. The effective portion of a change in fair value of a derivative contract designated as a cash flow hedge is recognised in other comprehensive income until the hedged transaction occurs; any ineffective portion is recognised in income. Where the hedged item is a non-financial asset or liability, the amount in accumulated other comprehensive income is transferred to the initial carrying amount of the asset or liability (reclassified to the balance sheet); for other hedged items, the amount in accumulated other comprehensive income is reclassified to income when the hedged transaction affects income.

The effective portion of a change due to retranslation at quarter-end exchange rates in the carrying amount of debt and the principal amount of derivative contracts used to hedge net investments in foreign operations is recognised in other comprehensive income until the related investment is sold or liquidated; any ineffective portion is recognised in income.

All relationships between hedging instruments and hedged items are documented, as well as risk management objectives and strategies for undertaking hedge transactions. The effectiveness of hedges is also continually assessed and hedge accounting is discontinued when there is a change in the risk management strategy.

Unless designated as hedging instruments, contracts to sell or purchase non-financial items that can be settled net as if the contracts were financial instruments and that do not meet expected own use requirements (typically, forward sale and purchase contracts for commodities in trading operations), and contracts that are or contain written options, are recognised at fair value; associated gains and losses are recognised in income.

Derivatives that are held primarily for the purpose of trading are presented as current in the Consolidated Balance Sheet.

FINANCIAL INSTRUMENTS (prior to January 1, 2018)

Financial assets and liabilities are presented separately in the Consolidated Balance Sheet except where there is a legally enforceable right of offset and Shell has the intention to settle on a net basis or realise the asset and settle the liability simultaneously.

Financial assets

Investments in securities

Investments in securities (also referred to as “securities”) comprise equity and debt securities classified on initial recognition as available-for-sale and are carried at fair value, except where their fair value cannot be measured reliably, in which case they are carried at cost, less any impairment. Unrealised holding gains and losses other than impairments are recognised in other comprehensive income, except for translation differences arising on foreign currency debt securities, which are recognised in income. On maturity or sale, net gains and losses previously deferred in accumulated other comprehensive income are recognised in income.

Interest income on debt securities is recognised in income using the effective interest method. Dividends on equity securities are recognised in income when receivable.

Cash and cash equivalents

Cash and cash equivalents comprise cash at bank and in hand, including offsetting bank overdrafts, short-term bank deposits, money market funds, reverse repos and similar instruments that have a maturity of three months or less at the date of purchase.

Trade receivables

Trade receivables are recognised initially at fair value based on amounts exchanged and subsequently at amortised cost less any impairment.

Financial liabilities

Debt and trade payables are recognised initially at fair value based on amounts exchanged, net of transaction costs, and subsequently at amortised cost except for fixed rate debt subject to fair value hedging which is remeasured for the hedged risk (see below). Interest expense on debt is accounted for using the effective interest method and, other than interest capitalised, is recognised in income.

Derivative contracts and hedges

Derivative contracts are used in the management of interest rate risk, foreign exchange risk and commodity price risk, and in the management of foreign currency cash balances. These contracts are recognised at fair value.

Certain derivative contracts qualify and are designated either as a “fair value” hedge of the change in fair value of a recognised asset or liability or an unrecognised firm commitment or as a “cash flow” hedge of the change in cash flows to be received or paid relating to a recognised asset or liability or a highly probable forecast transaction.

A change in the fair value of a hedging instrument designated as a fair value hedge is recognised in income, together with the consequential adjustment to the carrying amount of the hedged item. The effective portion of a change in fair value of a derivative contract designated as a cash flow hedge is recognised in other comprehensive income until the hedged transaction occurs; any ineffective portion is recognised in income. Where the hedged item is a non-financial asset or liability, the amount in accumulated other comprehensive income is transferred to the initial carrying amount of the asset or liability (reclassified to the balance sheet); for other hedged items, the amount in accumulated other comprehensive income is reclassified to income when the hedged transaction affects income.

The effective portion of a change due to retranslation at quarter-end exchange rates in the carrying amount of debt and the principal amount of derivative contracts used to hedge net investments in foreign operations is recognised in other comprehensive income until the related investment is sold or liquidated; any ineffective portion is recognised in income.

All relationships between hedging instruments and hedged items are documented, as well as risk management objectives and strategies for undertaking hedge transactions. The effectiveness of hedges is also continually assessed and hedge accounting is discontinued when a hedge ceases to be highly effective.

Gains and losses on derivative contracts not qualifying and designated as hedges, including forward sale and purchase contracts for commodities in trading operations that may be settled by the physical delivery or receipt of the commodity, are recognised in income.

Unless designated as hedging instruments, contracts to sell or purchase non-financial items that can be settled net as if the contracts were financial instruments and that do not meet expected own use requirements (typically, forward sale and purchase contracts for commodities in trading operations), and contracts that are or contain written options, are recognised at fair value; associated gains and losses are recognised in income.

Derivatives embedded within contracts that are not already required to be recognised at fair value, and that are not closely related to the host contract in terms of economic characteristics and risks, are separated from their host contract and recognised at fair value; associated gains and losses are recognised in income.

FAIR VALUE MEASUREMENTS

Fair value measurements are estimates of the amounts for which assets or liabilities could be transferred at the measurement date, based on the assumption that such transfers take place between participants in principal markets and, where applicable, taking highest and best use into account.

Judgements and estimates

Where available, fair value measurements are derived from prices quoted in active markets for identical assets or liabilities. In the absence of such information, other observable inputs are used to estimate fair value. Inputs derived from external sources are corroborated or otherwise verified, as appropriate. In the absence of publicly available information, fair value is determined using estimation techniques that take into account market perspectives relevant to the asset or liability, in as far as they can reasonably be ascertained, based on predominantly unobservable inputs. For derivative contracts where publicly available information is not available, fair value estimations are generally determined using models and other valuation methods, the key inputs for which include future prices, volatility, price correlation, counterparty credit risk and market liquidity, as appropriate; for other assets and liabilities, fair value estimations are generally based on the net present value of expected future cash flows.

SHARE-BASED COMPENSATION PLANS

The fair value of share-based compensation expense arising from the Performance Share Plan ("PSP") and the Long-term Incentive Plan ("LTIP") – Shell's main equity-settled plans – is estimated using a Monte Carlo option pricing model and is recognised in income from the date of grant over the vesting period with a corresponding increase directly in equity. The model projects and averages the results for a range of potential outcomes for the vesting conditions, the principal assumptions for which are the share price volatility and dividend yields for Shell and four of its main competitors over the last three years and the last 10 years. Prior to the adoption of the IFRS 2 amendments in 2018, changes in the fair value of share-based compensation for cash-settled plans were recognised in income with a corresponding change in liabilities.

SHARES HELD IN TRUST

Shares in the Company, which are held by employee share ownership trusts and trust-like entities, are not included in assets but are reflected at cost as a deduction from equity as shares held in trust.

ACQUISITIONS AND SALES OF INTERESTS IN A BUSINESS

Assets acquired and liabilities assumed when control is obtained over a business, and when an interest or an additional interest is acquired in a joint operation which is a business, are recognised at their fair value at the date of the acquisition; the amount of the purchase consideration above this value is recognised as goodwill. When control is obtained, any non-controlling interest is recognised as the proportionate share of the identifiable net assets. The acquisition of a non-controlling interest in a subsidiary and the sale of an interest while retaining control are accounted for as transactions within equity. The difference between the purchase consideration or sale proceeds after tax and the relevant proportion of the non-controlling interest, measured by reference to the carrying amount of the interest's net assets at the date of acquisition or sale, is recognised in retained earnings as a movement in equity attributable to Royal Dutch Shell plc shareholders.

CONSOLIDATED STATEMENT OF INCOME PRESENTATION

Purchases reflect all costs related to the acquisition of inventories and the effects of the changes therein, and include associated costs incurred in conversion into finished or intermediate products. Production and manufacturing expenses are the costs of operating, maintaining and managing production and manufacturing assets. Selling, distribution and administrative expenses include direct and indirect costs of marketing and selling products.

2B – CHANGES TO IFRS NOT YET ADOPTED

Inter-Bank Offered Rate ("IBOR") Reform – Phase 1

Amendments to IFRS 9 *Financial Instruments* ("IFRS 9") and IFRS 7 *Financial Instruments: Disclosures* ("IFRS 7") were issued in September 2019. The amendments contain a temporary exception from applying specific hedge accounting requirements pre-IBOR reform (Phase 1). Further amendments to IFRS standards (Phase 2) are expected to address potential financial reporting implications when an existing interest rate benchmark is replaced with an alternative.

Shell's fixed rate debt hedged to floating rate will be affected by the market-wide replacement of London Inter-Bank Offered Rate ("LIBOR") to alternative risk-free reference rates, most significantly by reform of dollar LIBOR.

The majority of Shell's debt related interest rate and currency swaps were designated in fair value hedge relationships at December 31, 2019. In relation to the required prospective assessment of the existence of an economic relationship between the hedged items and hedging instruments for these hedge relationships, Shell will apply the temporary exception in IFRS 9 on hedge relationships directly affected by the IBOR reform. By applying the exception, Shell anticipates that the interest rate benchmark on which the hedged risk is based is not altered as a result of the IBOR reform.

The notional amount of hedging instruments designated in hedge relationships affected by the reform, at December 31, 2019, was \$31,823 million.

A Group-wide project is in progress to manage the transition to alternative benchmark rates.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

2B – CHANGES TO IFRS NOT YET ADOPTED continued IFRS 17 Insurance contracts (“IFRS 17”)

IFRS 17 was issued in 2017, and is currently envisaged to become effective for annual reporting periods beginning on or after January 1, 2021 (the IASB is presently reviewing the effective date, with a potential extension by one or two years). The IFRS 17 model combines a current balance sheet measurement of insurance contracts with recognition of profit over the period that services are provided. The general model in the standard requires insurance contract liabilities to be measured using probability-weighted current estimates of future cash flows, an adjustment for risk, and a contractual service margin representing the profit expected from fulfilling the contracts. Effects of changes in the estimates of future cash flows and the risk adjustment relating to future services are recognised over the period services are provided rather than immediately in profit or loss. Shell is in the process of evaluating the initial impact of this pronouncement.

3 – ADOPTION OF IFRS 16 LEASES

IFRS 16 was adopted as from January 1, 2019. All operating lease contracts, with limited exceptions, were recognised on the balance sheet by recognising right-of-use assets and corresponding lease liabilities at the transition date. Shell applied the modified retrospective transition method, and consequently comparative information is not restated. As a practical expedient, no reassessment was performed of contracts that were previously identified as leases and contracts that were not previously identified as containing a lease applying IAS 17 Leases (“IAS 17”) and IFRIC 4 Determining whether an Arrangement contains a Lease. At the adoption date, additional lease liabilities were recognised for leases previously classified as operating leases applying IAS 17. These lease liabilities were measured at the present value of the remaining lease payments and discounted using entity-specific incremental borrowing rates at January 1, 2019. In general, a corresponding right-of-use asset was recognised for an amount equal to each lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to the specific lease contract, as recognised on the balance sheet at December 31, 2018. Provisions for onerous lease contracts at December 31, 2018 were adjusted to the respective right-of-use assets recognised at January 1, 2019. As a practical expedient the recognition exemption for leases with a remaining term of less than 12 months from the adoption date was applied upon adoption.

At the transition date, the remaining lease payments were discounted, as required under the transition approach chosen, using the incremental borrowing rate as per the transition date of January 1, 2019. To determine the incremental borrowing rate for each lease contract, a risk-free rate at transition date was applied, adjusted for other factors such as the credit rating of the entity that entered into the lease contract, a country risk premium, the impact of currency, an asset specific element and the term the lease contract. The weighted average incremental borrowing rate applied upon transition was 7.2%.

Compared with the previous accounting for operating leases under IAS 17, the application of the new standard has a significant impact on the classification of expenditures and cash flows. It also impacts the timing of expenses recognised in the statement of income. With effect from 2019, expenses related to leases previously classified as operating leases are presented under ‘Depreciation, depletion and amortisation’ and ‘Interest expense’. Before 2019, these were mainly included in ‘Purchases, Production and manufacturing expenses’, and ‘Selling, distribution and administrative expenses’. Payments related to leases previously classified as operating leases are presented under ‘Cash flow from financing activities’ (before 2019 these were included in ‘Cash flow from operating activities’ and ‘Cash flow from investing activities’).

The adoption of the new standard had an accumulated impact at January 1, 2019 of \$4 million on equity following the recognition of lease liabilities of \$16.0 billion and additional right-of-use assets of \$15.6 billion and reclassifications mainly related to pre-paid leases and onerous contracts previously recognised.

The reconciliation of differences between the operating lease commitments disclosed under the prior standard and the additional lease liabilities recognised on the balance sheet at January 1, 2019 is as follows:

Lease liabilities reconciliation

	\$ million
Undiscounted future minimum lease payments under operating leases at December 31, 2018	24,219
Impact of discounting	(5,167)
Leases not yet commenced at January 1, 2019	(2,586)
Short-term leases	(277)
Long-term leases expiring before December 31, 2019	(192)
Other reconciling items (net)	40
Additional lease liability at January 1, 2019	16,037
Finance lease liability at December 31, 2018	14,026
Total lease liability at January 1, 2019	30,063

The detailed impact on the balance sheet at January 1, 2019, is as follows:

Consolidated Balance Sheet

	Dec 31, 2018	IFRS 16 impact	\$ million Jan 1, 2019
Assets			
Non-current assets			
Intangible assets	23,586	-	23,586
Property, plant and equipment	223,175	15,558	238,733
Joint ventures and associates	25,329	-	25,329
Investments in securities	3,074	-	3,074
Deferred tax	12,097	-	12,097
Retirement benefits	6,051	-	6,051
Trade and other receivables [A]	7,826	(814)	7,012
Derivative financial instruments	574	-	574
	301,712	14,744	316,456
Current assets			
Inventories	21,117	-	21,117
Trade and other receivables	42,431	69	42,500
Derivative financial instruments	7,193	-	7,193
Cash and cash equivalents	26,741	-	26,741
	97,482	69	97,551
Total assets	399,194	14,813	414,007
Liabilities			
Non-current liabilities			
Debt	66,690	13,125	79,815
Trade and other payables [B]	2,735	(540)	2,195
Derivative financial instruments	1,399	-	1,399
Deferred tax	14,837	-	14,837
Retirement benefits	11,653	-	11,653
Decommissioning and other provisions [C]	21,533	(347)	21,186
	118,847	12,238	131,085
Current liabilities			
Debt	10,134	2,912	13,046
Trade and other payables	48,888	(23)	48,865
Derivative financial instruments	7,184	-	7,184
Taxes payable	7,497	-	7,497
Retirement benefits	451	-	451
Decommissioning and other provisions [C]	3,659	(318)	3,341
	77,813	2,571	80,384
Total liabilities	196,660	14,809	211,469
Equity			
Share capital	685	-	685
Shares held in trust	(1,260)	-	(1,260)
Other reserves	16,615	-	16,615
Retained earnings	182,606	4	182,610
Equity attributable to Royal Dutch Shell plc shareholders	198,646	4	198,650
Non-controlling interest	3,888	-	3,888
Total equity	202,534	4	202,538
Total liabilities and equity	399,194	14,813	414,007

[A] Mainly in respect of pre-paid leases.

[B] Mainly related to operating lease contracts that were measured at fair value under IFRS 3 Business Combinations following the acquisition of BG in 2016.

[C] Mainly in respect of onerous contracts.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

4 – SEGMENT INFORMATION

General Information

Shell is an international energy company engaged in the principal aspects of the oil and gas industry and reports its business through the segments: Integrated Gas, Upstream, Downstream, and Corporate.

The Integrated Gas segment covers liquefied natural gas (“LNG”) activities and the conversion of natural gas into gas-to-liquids fuels and other products, as well as the New Energies portfolio. It includes natural gas exploration and extraction and the operation of the upstream and midstream infrastructure necessary to deliver gas to market. It markets and trades natural gas, LNG, electricity and carbon-emission rights and also markets and sells LNG as a fuel for heavy-duty vehicles and marine vessels.

Upstream combines the following two operating segments: 1) Upstream, which is engaged in the exploration for and extraction of crude oil, natural gas and natural gas liquids, and the marketing and transportation of oil and gas, and 2) Oil Sands, which is engaged in the extraction of bitumen from mined oil sands and conversion into synthetic crude oil. These operating segments have similar economic characteristics because their earnings are significantly dependent on crude oil and natural gas prices and production volumes.

The Downstream segment is engaged in oil products and chemicals manufacturing, marketing and trading activities, that turn crude oil and other feedstocks into a range of products which are moved and marketed around the world for domestic, industrial and transport use.

The Corporate segment covers the non-operating activities supporting Shell, comprising Shell’s holdings and treasury organisation, its self-insurance activities and its headquarters and central functions.

Basis of Segmental Reporting

Sales between segments are based on prices generally equivalent to commercially available prices. Third-party revenue and non-current assets information by geographical area are based on the country of operation of the group subsidiaries that report this information. Separate disclosure is provided for the UK as this is the Company’s country of domicile.

Segment earnings are presented on a current cost of supplies basis (“CCS earnings”), which is the earnings measure used by the Chief Executive Officer for the purposes of making decisions about allocating resources and assessing performance. On this basis, the purchase price of volumes sold during the period is based on the current cost of supplies during the same period after making allowance for the tax effect. CCS earnings therefore exclude the effect of changes in the oil price on inventory carrying amounts.

With the adoption of IFRS 16, the interest expense on leases, formerly classified as operating leases, is reported under the Corporate segment, while depreciation related to the respective right-of-use assets is reported in the segment making use of the assets. This treatment is consistent with how formerly classified finance leases were treated.

Information by segment on a current cost of supplies basis is as follows:

2019

	Integrated Gas	Upstream	Downstream	Corporate	Total	\$ million
Revenue:						
Third-party	41,322	9,965	293,545	45	344,877	[A][B]
Inter-segment	4,280	36,448	1,132	–	41,860	
Share of profit/(loss) of joint ventures and associates (CCS basis)	1,791	379	1,725	(307)	3,588	
Interest and other income, of which:	263	2,180	266	916	3,625	
Interest income	–	–	–	899	899	
Net gains on sale and revaluation of non-current assets and businesses	282	1,888	297	52	2,519	
Other	(19)	292	(31)	(35)	207	
Third-party and inter-segment purchases (CCS basis)	23,498	7,168	264,966	(6)	295,626	
Production and manufacturing expenses	5,768	11,545	9,088	37	26,438	
Selling, distribution and administrative expenses	716	48	9,280	449	10,493	
Research and development expenses	181	452	329	–	962	
Exploration expenses	281	2,073	–	–	2,354	
Depreciation, depletion and amortisation charge, of which:	6,238	17,003	5,413	47	28,701	
Impairment losses	579	2,576	627	–	3,782	[C]
Impairment reversals	–	–	(190)	–	(190)	[D]
Interest expense	104	534	74	3,978	4,690	
Taxation charge/(credit) (CCS basis)	2,242	5,954	1,241	(578)	8,859	
CCS earnings	8,628	4,195	6,277	(3,273)	15,827	

[A] Includes \$3,760 million of revenue from sources other than from contracts with customers, which mainly comprises the impact of fair value accounting of commodity derivatives.

[B] In March 2019, the IFRS Interpretation Committee (“IFRIC”) finalised an agenda decision regarding ‘Physical settlement of contracts to buy or sell a non-financial item (IFRS 9)’.

This agenda decision has been analysed and will be prospectively implemented from January 1, 2020. The impact will be limited to a reclassification within total revenue.

[C] Impairment losses comprise Property, plant and equipment (\$3,639 million) and Intangible assets (\$143 million).

[D] See Note 8.

2018

	Integrated Gas	Upstream	Downstream	Corporate	\$ million Total
Revenue:					
Third-party	43,764	9,892	334,680	43	388,379 [A]
Inter-segment	5,031	37,841	917	-	43,789 [B]
Share of profit/(loss) of joint ventures and associates (CCS basis)	2,273	285	1,785	(222)	4,121
Interest and other income, of which:	2,230	600	345	896	4,071
Interest income	-	-	-	772	772
Net gains on sale and revaluation of non-current assets and businesses	2,231	712	302	20	3,265
Other	(1)	(112)	43	104	34
Third-party and inter-segment purchases (CCS basis)	27,775	6,144	303,709	1	337,629
Production and manufacturing expenses	5,370	11,463	10,294	(157)	26,970
Selling, distribution and administrative expenses	458	200	10,142	560	11,360
Research and development expenses	186	493	307	-	986
Exploration expenses	208	1,132	-	-	1,340
Depreciation, depletion and amortisation charge, of which:	4,850	13,006	4,064	215	22,135
Impairment losses	200	1,065	424	7	1,696 [C]
Impairment reversals	-	(1,265)	-	-	(1,265) [D]
Interest expense	212	591	95	2,847	3,745 [E]
Taxation charge/(credit) (CCS basis)	2,795	8,791	1,515	(1,270)	11,831
CCS earnings	11,444	6,798	7,601	(1,479)	24,364

[A] Includes \$3,348 million of revenue from sources other than from contracts with customers, which mainly comprises the impact of fair value accounting of commodity derivatives.

[B] Inter-segment revenue has been revised to amend for transactions within segments that were previously reported as inter-segment revenue, and vice versa.

[C] Impairment losses comprise Property, plant and equipment (\$1,515 million) and Intangible assets (\$181 million).

[D] See Note 8.

[E] Interest expense has been reclassified between segments compared with prior year.

2017

	Integrated Gas	Upstream	Downstream	Corporate	\$ million Total
Revenue:					
Third-party	32,674	7,723	264,731	51	305,179
Inter-segment	4,096	32,469	1,090	-	37,655 [A]
Share of profit/(loss) of joint ventures and associates (CCS basis)	1,714	623	1,956	(129)	4,164
Interest and other income, of which:	687	1,188	154	437	2,466
Interest income	-	-	-	677	677
Net gains on sale and revaluation of non-current assets and businesses	301	1,189	136	14	1,640
Other	386	(1)	18	(254)	149
Third-party and inter-segment purchases (CCS basis)	22,478	5,535	234,321	20	262,354
Production and manufacturing expenses	5,120	12,119	9,519	(106)	26,652
Selling, distribution and administrative expenses	237	5	9,789	478	10,509
Research and development expenses	114	533	275	-	922
Exploration expenses	141	1,804	-	-	1,945
Depreciation, depletion and amortisation charge, of which:	4,965	17,303	3,877	78	26,223
Impairment losses	302	4,118	385	-	4,805 [B]
Impairment reversals	(10)	(605)	-	-	(615) [C]
Interest expense	248	744	109	2,941	4,042
Taxation charge/(credit) (CCS basis)	790	2,409	1,783	(636)	4,346
CCS earnings	5,078	1,551	8,258	(2,416)	12,471

[A] Inter-segment revenue has been revised to amend for transactions within segments that were previously reported as inter-segment revenue, and vice versa.

[B] Impairment losses comprise Property, plant and equipment (\$4,572 million) and Intangible assets (\$233 million).

[C] See Note 8.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

4 – SEGMENT INFORMATION continued

Reconciliation of CCS earnings to income for the period

	2019	2018	2017
	\$ million		
CCS earnings	15,827	24,364	12,471
Current cost of supplies adjustment:			
Purchases	784	(559)	1,252
Taxation	(194)	116	(349)
Share of profit of joint ventures and associates	15	(15)	61
	605	(458)	964
Income for the period	16,432	23,906	13,435

Information by geographical area is as follows:

2019

	Europe	Asia, Oceania, Africa	USA	Other Americas	Total
	\$ million				
Third-party revenue, by origin	98,455 [A]	139,916 [B]	83,212	23,294	344,877
Intangible assets, property, plant and equipment, joint ventures and associates at December 31	43,262 [C]	119,732	67,105	54,544	284,643

[A] Includes \$41,094 million that originated from the UK.

[B] Includes \$84,282 million that originated from Singapore.

[C] Includes \$24,696 million located in the UK.

2018

	Europe	Asia, Oceania, Africa	USA	Other Americas	Total
	\$ million				
Third-party revenue, by origin	118,960 [A]	153,716 [B]	89,876	25,827	388,379
Intangible assets, property, plant and equipment, joint ventures and associates at December 31	38,617 [C]	117,127	59,625	56,721	272,090

[A] Includes \$54,659 million that originated from the UK.

[B] Includes \$89,811 million that originated from Singapore.

[C] Includes \$21,863 million located in the UK.

2017

	Europe	Asia, Oceania, Africa	USA	Other Americas	Total
	\$ million				
Third-party revenue, by origin	100,609 [A]	114,683 [B]	66,854	23,033	305,179
Intangible assets, property, plant and equipment, joint ventures and associates at December 31	41,416 [C]	122,345	55,898	58,828	278,487

[A] Includes \$49,370 million that originated from the UK.

[B] Includes \$62,046 million that originated from Singapore.

[C] Includes \$22,734 million located in the UK.

5 – INTEREST AND OTHER INCOME

	\$ million		
	2019	2018	2017
Interest income	899	772	677
Dividend income (from investments in equity securities)	23	104	375
Net gains on sale and revaluation of non-current assets and businesses	2,519	3,265	1,640
Net foreign exchange gains/(losses) on financing activities	5	(174)	(453)
Other	179	104	227
Total	3,625	4,071	2,466

In 2019, net gains on sale of non-current assets and businesses arose mainly in respect of gains on the sale of Upstream assets in the USA and Denmark, as well as Downstream assets in Saudi Arabia and China and Integrated Gas assets in Australia.

In 2018, net gains on sale of non-current assets and businesses arose mainly in respect of gains on the sale of Integrated Gas assets in Thailand, Malaysia, Oman and New Zealand, as well as Upstream assets in Iraq and Malaysia and a Downstream divestment in Argentina, partly offset by a charge related to the disposal of our Upstream assets in Ireland.

In 2017, net gains on sale of non-current assets and businesses arose mainly in respect of gains on the sale of Upstream assets in the UK and the USA as well as Downstream assets in Australia and Saudi Arabia, partly offset by a loss on the Motiva transaction. Net foreign exchange losses on financing activities in 2017 includes a charge of \$545 million from the release of cumulative currency translation differences following the restructuring of funding for our North America businesses.

6 – INTEREST EXPENSE

	\$ million		
	2019	2018	2017
Interest incurred and similar charges	4,592 [A]	3,550	3,448
Less: interest capitalised	(752)	(876)	(622)
Other net losses on fair value hedges of debt	132	169	114
Accretion expense	718	902	1,102
Total	4,690	3,745	4,042

[A] Includes \$2,186 million of interest expenses related to leases of which \$1,137 million related to those leases which formerly would have been classified as operating leases (see Note 3).

The rate applied in determining the amount of interest capitalised in 2019 was 4.5% (2018: 4.0%; 2017: 3.0%). The rate increase in 2019 was mainly driven by the weighted average rate for leases recognised upon the adoption of IFRS 16 Leases (see Note 3).

7 – INTANGIBLE ASSETS

2019

	\$ million			
	Goodwill	LNG off-take and sales contracts	Other	Total
Cost				
At January 1	14,338	10,365	6,392	31,095
Additions	674	-	586	1,260
Sales, retirements and other movements	(46)	(154)	(122)	(322)
Currency translation differences	7	-	10	17
At December 31	14,973	10,211	6,866	32,050
Depreciation, depletion and amortisation, including impairments				
At January 1	622	3,293	3,594	7,509
Charge for the year	135	876	354	1,365
Sales, retirements and other movements	(1)	(155)	(172)	(328)
Currency translation differences	12	-	6	18
At December 31	768	4,014	3,782	8,564
Carrying amount at December 31	14,205	6,197	3,084	23,486

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

7 – INTANGIBLE ASSETS continued

2018

				\$ million
	Goodwill	LNG off-take and sales contracts	Other	Total
Cost				
At January 1	14,154	10,429	6,106	30,689
Additions	331	–	659	990
Sales, retirements and other movements	(75)	(64)	(253)	(392)
Currency translation differences	(72)	–	(120)	(192)
At December 31	14,338	10,365	6,392	31,095
Depreciation, depletion and amortisation, including impairments				
At January 1	492	2,432	3,585	6,509
Charge for the year	173	925	370	1,468
Sales, retirements and other movements	(21)	(64)	(275)	(360)
Currency translation differences	(22)	–	(86)	(108)
At December 31	622	3,293	3,594	7,509
Carrying amount at December 31	13,716	7,072	2,798	23,586

Goodwill at December 31, 2019, principally related to the acquisition of BG Group plc in 2016, allocated to Integrated Gas (\$4,897 million) and Upstream (\$5,967 million) at the operating segment level, and to Pennzoil-Quaker State Company (\$1,609 million), a lubricants business in the Downstream segment based largely in North America. Information on annual impairment testing is included in Note 8.

8 – PROPERTY, PLANT AND EQUIPMENT

2019

					\$ million
	Exploration and evaluation	Exploration and production Production	Manufacturing, supply and distribution	Other	Total
Cost					
At January 1 (as previously published)	21,181	280,381	91,235	22,040	414,837
Impact of IFRS 16 [A]	–	4,871	6,459	4,228	15,558
At January 1 (as revised)	21,181	285,252	97,694	26,268	430,395
Additions	2,659	11,374	10,945	3,145	28,123
Sales, retirements and other movements	(5,442)	(11,253)	(3,683)	(456)	(20,834)
Currency translation differences	198	1,293	(139)	124	1,476
At December 31	18,596	286,666	104,817	29,081	439,160
Depreciation, depletion and amortisation, including impairments					
At January 1	3,287	131,692	46,218	10,465	191,662
Charge for the year	1,096	19,346	5,742	1,573	27,757
Sales, retirements and other movements	(440)	(15,567)	(2,981)	(437)	(19,425)
Currency translation differences	67	829	(107)	28	817
At December 31	4,010	136,300	48,872	11,629	200,811
Carrying amount at December 31	14,586	150,366	55,945	17,452	238,349

[A] See Note 3.

2018

	Exploration and production		Manufacturing, supply and distribution	Other	Total
	Exploration and evaluation	Production			
\$ million					
Cost					
At January 1	22,510	292,256	86,948	22,355	424,069
Additions	3,514	12,596	6,438	1,594	24,142
Sales, retirements and other movements	(4,443)	(19,643)	(667)	(814)	(25,567)
Currency translation differences	(400)	(4,828)	(1,484)	(1,095)	(7,807)
At December 31	21,181	280,381	91,235	22,040	414,837
Depreciation, depletion and amortisation, including impairments					
At January 1	5,060	137,525	44,483	10,621	197,689
Charge for the year	(979)	16,551	4,000	1,095	20,667
Sales, retirements and other movements	(608)	(19,631)	(1,353)	(756)	(22,348)
Currency translation differences	(186)	(2,753)	(912)	(495)	(4,346)
At December 31	3,287	131,692	46,218	10,465	191,662
Carrying amount at December 31	17,894	148,689	45,017	11,575	223,175

Sales, retirements and other movements in 2019 related to sales of Shell's 36.8% non-operating interest in the Danish Underground Consortium, its 50% interest in the SASREF joint venture in Saudi Arabia and its 22.45% non-operating interest in the Caesar-Tonga asset in the Gulf of Mexico.

The carrying amount of property, plant and equipment at December 31, 2019, included \$27,779 million (2018: \$33,451 million) of assets under construction. This amount excludes exploration and evaluation assets. The carrying amount at December 31, 2019, also included \$1,401 million of assets classified as held for sale (2018: \$705 million).

The carrying amount of exploration and production assets at December 31, 2019, included rights and concessions in respect of proved and unproved properties of \$14,355 million (2018: \$15,860 million). Exploration and evaluation assets principally comprise rights and concessions in respect of unproved properties and capitalised exploration drilling costs.

The carrying amount of assets at December 31, 2019, for which an alternative reserves base was applied in the calculation of the depreciation charge (see Note 2A), was \$173 million (2018: \$5,838 million). If no alternative reserves base had been used, the pre-tax depreciation charge for the year ended December 31, 2019, would have been \$77 million higher (2018: \$1,003 million, 2017: \$5,558 million).

Contractual commitments for the purchase and lease of property, plant and equipment at December 31, 2019, amounted to \$5,519 million. In 2018, the contractual commitments for the purchase of property, plant and equipment amounted to \$4,783 million.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

8 – PROPERTY, PLANT AND EQUIPMENT continued

Within property, plant and equipment the following amounts relate to leases:

Right-of-use assets

	Exploration and production				\$ million
	Exploration and evaluation	Production	Manufacturing, supply and distribution	Other	Total
Cost					
At January 1 (as previously published)	–	11,508	4,259	789	16,556
Impact of IFRS 16 [A]	–	4,871	6,459	4,228	15,558
At January 1 (as revised)	–	16,379	10,718	5,017	32,114
Additions	5	664	3,124	917	4,710
Sales, retirements and other movements	–	(1,867)	(268)	(157)	(2,292)
Currency translation differences	–	37	–	(18)	19
At December 31	5	15,213	13,574	5,759	34,551
Depreciation, depletion and amortisation, including impairments					
At January 1	–	5,209	1,110	589	6,908
Charge for the year	–	1,632	1,855	703	4,190
Sales, retirements and other movements	–	(1,091)	(30)	(128)	(1,249)
Currency translation differences	–	11	1	–	12
At December 31	–	5,761	2,936	1,164	9,861
Carrying amount at December 31	5	9,452	10,638	4,595	24,690

[A] Up to and including 2018, Shell recognised lease assets and liabilities that were classified as finance leases under IAS 17 *Leases* (see Note 3).

Impairments

	2019	2018	2017
Impairment losses [A]			
Exploration and production	2,983	1,066	4,187
Manufacturing, supply and distribution	654	441	376
Other	2	8	9
Total	3,639	1,515	4,572
Impairment reversals [A]			
Exploration and production	–	1,265	615
Manufacturing, supply and distribution	190	–	–
Total	190	1,265	615

[A] See Note 4.

Impairment losses in 2019 were mainly triggered by the revision to Shell's long-term oil and gas price outlook and change to future capital expenditure plans. The impairment losses related primarily to Upstream shale and deep-water properties in North and South America, in Integrated Gas to properties in Australia and in Downstream to the refining portfolio. Impairment losses in 2018 were mainly in Upstream, and principally related to the disposal of Shell's interests in Norway and Ireland and related to assets in the Gulf of Mexico. Impairment reversals in 2018 were mainly related to assets in North America. Impairment losses in 2017 were mainly in Upstream, and principally related to the disposal of interests in Canada and interests in Ireland classified as held for sale.

For impairment testing purposes, the respective carrying amounts of property, plant and equipment and intangible assets were compared with their value in use. Cash flow projections used in the determination of value in use were made using management's forecasts of commodity prices, market supply and demand, potential costs associated with operational GHG emissions, product margins including forecast refining margins and expected production volumes (see Note 2A). These cash flows were adjusted for the risks specific to the assets, and therefore these risks were not included in the determination of the discount rate applied. The nominal pre-tax rate applied in 2019 was 6% (2018: 6%; 2017: 6%).

Oil and gas price assumptions applied for impairment testing are reviewed and, where necessary, adjusted on a periodic basis. Reviews include comparison with available market data and forecasts that reflect developments in demand such as global economic growth, technology efficiency, policy measures and, in supply, consideration of investment and resource potential, cost of development of new supply, and behaviour of major resource holders. The near-term commodity price assumptions applied in impairment testing in 2019 were as follows:

Commodity price assumptions [A]

	2020	2021	2022
Brent crude oil (\$/b)	60	60	60
Henry Hub natural gas (\$/MMBtu)	2.75	2.75	3.00

[A] Money of the day.

For periods after 2022, the real terms long-term price assumptions applied were \$60 per barrel (/b) (2018: \$70/b after 2021) for Brent crude oil and \$3.00 per million British thermal units (/MMBtu) (2018: \$3.50/MMBtu after 2021) for Henry Hub natural gas.

Capitalised exploration drilling costs

	\$ million		
	2019	2018	2017
At January 1	6,629	6,981	7,910
Additions pending determination of proved reserves	2,036	2,588	1,708
Amounts charged to expense	(1,218)	(449)	(897)
Reclassifications to productive wells on determination of proved reserves	(1,655)	(2,461)	(1,894)
Other movements	(124)	(30)	154
At December 31	5,668	6,629	6,981

	Projects		Wells	
	Number	\$ million	Number	\$ million
Between 1 and 5 years	45	3,195	150	2,117
Between 6 and 10 years	10	961	74	1,746
Between 11 and 15 years	5	237	25	495
Between 16 and 20 years	-	-	2	35
Total	60	4,393	251	4,393

Exploration drilling costs capitalised for periods greater than one year at December 31, 2019, analysed according to the most recent year of activity, are presented in the table above. They comprise \$284 million relating to five projects where drilling activities were under way or firmly planned for the future, and \$4,109 million relating to 55 projects awaiting development concepts.

9 – JOINT VENTURES AND ASSOCIATES

Shell share of comprehensive income of joint ventures and associates

	2019			2018			2017		
	Joint ventures	Associates	Total	Joint ventures	Associates	Total	Joint ventures	Associates	Total
Income for the period	1,121	2,483	3,604	1,307	2,799	4,106	2,102	2,123	4,225
Other comprehensive (loss)/income for the period	(82)	8	(74)	172	11	183	164	6	170
Comprehensive income for the period	1,039	2,491	3,530	1,479	2,810	4,289	2,266	2,129	4,395

Carrying amount of interests in joint ventures and associates

	Dec 31, 2019			Dec 31, 2018		
	Joint ventures	Associates	Total	Joint ventures	Associates	Total
Net assets	13,426	9,382	22,808	14,263	11,066	25,329

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

9 – JOINT VENTURES AND ASSOCIATES continued

Transactions with joint ventures and associates

	\$ million		
	2019	2018	2017
Sales and charges to joint ventures and associates	7,748	8,270	13,121
Purchases and charges from joint ventures and associates	9,573	11,212	10,680

These transactions principally comprise sales and purchases of goods and services in the ordinary course of business. Related balances outstanding at December 31, 2019, and 2018, are presented in Notes 11 and 15.

Other arrangements in respect of joint ventures and associates

	\$ million	
	Dec 31, 2019	Dec 31, 2018
Commitments to make purchases from joint ventures and associates [A]	2,177	1,823 [B]
Commitments to provide debt or equity funding to joint ventures and associates	897	638

[A] Commitments to make purchases from joint ventures and associates mainly relate to contracts associated with LNG processing fees and transportation capacity. Shell has other purchase obligations related to joint ventures and associates that are not fixed or determinable and are principally intended to be resold in a short period of time through sales agreements with third parties. These include long-term LNG and natural gas purchase commitments and commitments to purchase refined products or crude oil at market prices.

[B] As revised to include commitments of \$569 million.

10 – INVESTMENTS IN SECURITIES

Investment in securities

	\$ million	
	Dec 31, 2019	Dec 31, 2018
Equity securities:	1,437	1,823
Equity securities at fair value through other comprehensive income	1,437	1,823
Debt securities:	1,552	1,251
Debt securities at amortised cost	11	8
Debt securities at fair value through other comprehensive income	1,086	953
Debt securities at fair value through profit and loss	455	290
Total	2,989	3,074
At fair value		
Measured by reference to prices in active markets for identical assets	1,725	1,873
Measured using predominantly unobservable inputs	1,253	1,193
Total	2,978	3,066
At cost	11	8
Total	2,989	3,074

Equity securities at December 31, 2019, principally comprised interests below 5%, in various investments. Debt securities principally comprised a portfolio required to be held by the Company's internal insurance entities as security for their activities.

Investments in securities measured using predominantly unobservable inputs [A]

	\$ million	
	2019	2018
At January 1	1,193	1,268
(Losses)/Gains recognised in other comprehensive income	(42)	212
Other movements	102	(287)
At December 31	1,253	1,193

[A] Based on expected dividend flows, adjusted for country and other risks as appropriate and discounted to their present value.

11 – TRADE AND OTHER RECEIVABLES

	Dec 31, 2019		Dec 31, 2018	
	Current	Non-current	Current	Non-current
Trade receivables	30,216	–	27,541	–
Lease receivables [A]	213	1,528		
Other receivables [A]	7,791	4,039	8,543	4,823
Amounts due from joint ventures and associates	912	1,078	992	1,183
Prepayments and deferred charges	4,282	1,440	5,355	1,820
Total	43,414	8,085	42,431	7,826

[A] In 2018 'Lease receivables' were included in 'Other receivables'.

The fair value of financial assets included above approximates the carrying amount and was determined from predominantly unobservable inputs.

Other receivables at December 31, 2019, include receivables from certain governments in their capacity as joint arrangement partners, of \$1,209 million (2018: \$1,449 million), after provisions for impairments, that are overdue in part or in full. Recoverability and timing thereof is subject to uncertainty, however, the ultimate risk of default on the carrying amount is considered to be low. Other receivables also include income tax and other tax receivables (see Note 16).

Provisions for impairments deducted from trade and other receivables amounted to \$649 million at December 31, 2019 (2018: \$790 million).

Shell uses a provision matrix to calculate expected credit losses ("ECLs") for trade receivables. The provision matrix is initially based on Shell's historical observed default rates. Shell calculates the ECL to adjust the historical credit loss experienced with forward-looking information. The ECL at December 31, 2019 is \$83 million (2018: \$23 million) which represents 0.08%-0.27% of all trade receivables.

A loss allowance provision of \$193 million (2018: \$243 million) was established, in addition to all other impairments to trade receivables as at December 31, 2019, that are outside of the provision matrix calculations.

Lease receivables

Lease contracts where Shell is the lessor are classified as finance lease or operating lease. Receivables for lease contracts classified as finance leases are as follows:

Finance lease

	\$ million
	Dec 31, 2019
Less than one year	305
Between 1 and 5 years	953
5 years and later	1,019
Total undiscounted lease payments receivable	2,277
Unearned finance income	536
Net investment in the lease	1,741

In addition at December 31, 2019, Shell is entitled to contractual payments under operating leases of \$344 million.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued**12 – INVENTORIES**

	\$ million	
	Dec 31, 2019	Dec 31, 2018
Oil, gas and chemicals	22,654	19,516
Materials	1,417	1,601
Total	24,071	21,117

Inventories at December 31, 2019, include write-downs to net realisable value of \$546 million (2018: \$1,473 million).

13 – CASH AND CASH EQUIVALENTS

	\$ million	
	Dec 31, 2019	Dec 31, 2018
Cash	4,168	4,034
Short-term bank deposits	2,665	3,655
Money market funds, reverse repos and other cash equivalents	11,222	19,052
Total	18,055	26,741

Included in cash and cash equivalents at December 31, 2019, were amounts totalling \$431 million (2018: \$443 million as revised) subject to currency controls or other legal restrictions. Information about credit risk is presented in Note 19.

14 – DEBT AND LEASE ARRANGEMENTS**DEBT****Debt**

	Dec 31, 2019			Dec 31, 2018		
	Debt (excluding lease liabilities)	Lease liabilities [A]	Total	Debt (excluding lease liabilities)	Finance lease liabilities	Total
Short-term debt	3,962	–	3,962	693	–	693
Long-term debt due within 1 year	6,146	4,956	11,102	8,419	1,022	9,441
Current debt	10,108	4,956	15,064	9,112	1,022	10,134
Non-current debt	55,779	25,581	81,360	53,686	13,004	66,690
Total	65,887	30,537	96,424	62,798	14,026	76,824

[A] See Note 3.

Net debt

				\$ million	
	Current debt	Non-current debt	Derivative financial instruments	Cash and cash equivalents (see Note 13)	Net debt
At January 1, 2019 (as previously published)	(10,134)	(66,690)	(1,345)	26,741	(51,428)
Impact of IFRS 16 [A]	(2,912)	(13,125)			(16,037)
At January 1, 2019 (as revised)	(13,046)	(79,815)	(1,345)	26,741	(67,465)
Cash flow	10,333	(7,269)	351	(8,810)	(5,395)
Lease additions	(971)	(3,547)			(4,518)
Other movements [B]	(11,453)	9,179	453	-	(1,821)
Currency translation differences and foreign exchange gains/(losses)	73	92	(183)	124	106
At December 31, 2019	(15,064)	(81,360)	(724)	18,055	(79,093)
At January 1, 2018	(11,795)	(73,870)	(591)	20,312	(65,944)
Cash flow	10,392	(2,418)	446	6,878	15,298
Finance lease additions	(51)	(652)			(703)
Other movements	(8,939)	9,270	(261)	-	70
Currency translation differences and foreign exchange gains/(losses)	259	980	(939)	(449)	(149)
At December 31, 2018	(10,134)	(66,690)	(1,345)	26,741	(51,428)

[A] See Note 3.

[B] 'Other movements' includes \$1,618 million relating to existing leases entered into on behalf of certain joint operations.

Management's financial strategy is to manage Shell's assets and liabilities with the aim that, across the business cycle, 'cash in' at least equals 'cash out' while maintaining a strong balance sheet.

Gearing is a key measure of Shell's capital structure and is defined as net debt as a percentage of total capital. Net debt is defined as the sum of current and non-current debt, less cash and cash equivalents, adjusted for the fair value of derivative financial instruments used to hedge foreign exchange and interest rate risks relating to debt, and associated collateral balances. Across the business cycle, management aims to return to a gearing level within a range of 15%-25%.

Gearing

	\$ million, except where indicated	
	Dec 31, 2019	Dec 31, 2018 [A]
Net debt	79,093	51,428
Total equity	190,463	202,534
Total capital	269,556	253,962
Gearing	29.3% [B]	20.3%

[A] Shell used the modified retrospective transition method for implementing IFRS 16 Leases (see Note 3). Comparative information was not restated, and continues to be presented as previously reported under IAS 17 Leases.

[B] Gearing increased to 29.3%, at December 31, 2019, comparable with 25.0% on an IAS 17 basis (2018: 20.3%).

Management's priorities for applying Shell's cash are the servicing and reduction of debt commitments, payment of dividends, followed by a balance of capital investment and share buybacks. Management's policy is to grow the dollar dividend through time, in line with its view of Shell's underlying earnings and cash flow.

Shell has access to international debt capital markets via two commercial paper ("CP") programmes, a Euro medium-term note ("EMTN") programme and a US universal shelf ("US shelf") registration. Issuances under the CP programmes are supported by a committed credit facility and cash.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

14 – DEBT AND LEASE ARRANGEMENTS continued

Borrowing facilities and amounts undrawn

	Facility		Amount undrawn	
	Dec 31, 2019	Dec 31, 2018	Dec 31, 2019	Dec 31, 2018
CP programmes	20,000	20,000	16,610	20,000
EMTN programme	unlimited	unlimited	N/A	N/A
US shelf registration	unlimited	unlimited	N/A	N/A
Committed credit facilities	10,000	8,840	10,000	8,840

Under the CP programmes, Shell can issue debt of up to \$10 billion with maturities not exceeding 270 days and \$10 billion with maturities not exceeding 397 days. The EMTN programme is updated each year, most recently in July 2019. In 2019, debt issued under this programme amounted to \$3 billion (2018: \$nil). The US shelf registration provides Shell with the flexibility to issue debt securities, ordinary shares, preferred shares and warrants. The registration is updated every three years and was last updated in December 2017. During 2019, debt totalling \$4 billion (2018: \$3 billion) was issued under the registration. On December 13, 2019, Shell entered into \$10 billion revolving credit facilities, which in anticipation of the LIBOR reform (see Note 2B), were linked to the new Secured Overnight Financing Rate ("SOFR"). Under the terms of the facilities, the LIBOR interest rate will be replaced by SOFR as early as the first anniversary of the signing date of these revolving credit facilities. The committed credit facilities are available at pre-agreed margins, with \$2 billion expiring in 2020 and \$8 billion expiring in 2024. Each facility includes two one-year extension options at the discretion of each lender. The terms and availability are not conditional on Shell's financial ratios nor its financial credit ratings. The interest and fees paid on both facilities are linked to Shell's progress towards reaching its short-term Net Carbon Footprint intensity target.

In addition, other subsidiaries have access to undrawn short-term bank facilities totalling \$2,784 million at December 31, 2019 (2018: \$3,035 million).

The following tables compare contractual cash flows for debt excluding lease liabilities at December 31, with the carrying amount in the Consolidated Balance Sheet. Contractual amounts reflect the effects of changes in foreign exchange rates; differences from carrying amounts reflect the effects of discounting, premiums and, where fair value hedge accounting is applied, fair value adjustments. Interest is estimated assuming interest rates applicable to variable rate debt remain constant and there is no change in aggregate principal amounts of debt other than repayment at scheduled maturity, as reflected in the table.

2019

	Contractual payments							Difference from carrying amount	Carrying amount
	Less than 1 year	Between 1 and 2 years	Between 2 and 3 years	Between 3 and 4 years	Between 4 and 5 years	5 years and later	Total		
Commercial paper	3,390	–	–	–	–	–	3,390	(38)	3,352
Bonds	5,900	4,971	4,392	4,326	2,091	38,323	60,003	694	60,697
Bank and other borrowings	859	425	56	71	15	412	1,838	–	1,838
Total (excluding interest)	10,149	5,396	4,448	4,397	2,106	38,735	65,231	656	65,887
Interest	1,665	1,559	1,430	1,357	1,263	14,618	21,892		

2018

	Contractual payments							Difference from carrying amount	Carrying amount
	Less than 1 year	Between 1 and 2 years	Between 2 and 3 years	Between 3 and 4 years	Between 4 and 5 years	5 years and later	Total		
Bonds	8,163	5,900	4,993	4,458	4,312	33,162	60,988	181	61,169
Bank and other borrowings	945	39	209	50	27	359	1,629	–	1,629
Total (excluding interest)	9,108	5,939	5,202	4,508	4,339	33,521	62,617	181	62,798
Interest	1,780	1,555	1,426	1,319	1,244	14,406	21,730		

Interest rate swaps have been entered into against certain fixed rate debt affecting the effective interest rate on these balances (see Note 19). The fair value of debt excluding lease liabilities at December 31, 2019, was \$71,163 million (2018: \$64,708 million), mainly determined from the prices quoted for those securities.

LEASE ARRANGEMENTS

From January 1, 2019, leases are recognised as a right-of-use asset (see Note 8) and a corresponding liability at the date which the lease asset is available for the use by Shell (see Note 3). Lease liabilities are secured on the leased assets. Shell has lease contracts in Upstream and Integrated Gas for floating production storage and offloading units, subsea equipment, power generation for drilling and ancillary equipment, service vessels, LNG vessels and land and buildings; in Downstream, principally for tankers, storage capacity and retail sites; and in Corporate, principally for land and buildings.

Lease expenses not included in the measurement of lease liability

	\$ million
	2019
Expense relating to short-term leases	834
Expense relating to variable lease payments not included in the lease liabilities	1,091

The total cash outflow in respect of leases representing repayment of principal and payment of interest in 2019 was \$7,866 million, recognised in the Consolidated Statement of Cash Flows from financing activities.

The future lease payments under lease contracts and the present value of future lease payments at December 31, by payment date are as follows:

2019

	Contractual lease payments	Interest	\$ million Lease liabilities [A]
Less than 1 year	7,337	2,381	4,956
Between 1 and 5 years	17,435	6,141	11,294
5 years and later	21,340	7,053	14,287
Total	46,112 [B]	15,575	30,537

[A] See Note 3.

[B] Future cash outflows in respect of leases may differ from lease liabilities recognised due to future decisions that may be taken by Shell in respect of the use of leased assets. These decisions may result in variable lease payments to be made. In addition, Shell may reconsider whether it will exercise extension options or termination options, where future reconsideration is not reflected in the lease liabilities. There is no exposure to these potential additional payments in excess of the recognised lease liabilities until these decisions have been taken by Shell.

2018

	Finance leases [A]		Operating leases [A]
	Future minimum lease payments	Interest	Present value of future minimum lease payments
Less than 1 year	2,061	1,039	1,022
Between 1 and 5 years	7,508	3,391	4,117
5 years and later	13,370	4,483	8,887
Total	22,939	8,913	14,026

[A] Shell used the modified retrospective transition method for the adoption of IFRS 16 Leases (see Note 3). Comparative information is not restated and continues to be presented as previously reported under IAS 17 Leases.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

15 – TRADE AND OTHER PAYABLES

	Dec 31, 2019		Dec 31, 2018	
	Current	Non-current	Current	Non-current
Trade payables	29,497	–	30,351	–
Other payables	6,356	2,060	5,597	2,413
Amounts due to joint ventures and associates	3,312	40	2,851	33
Accruals and deferred income	10,043	242	10,089	289
Total	49,208	2,342	48,888	2,735

\$ million

The fair value of financial liabilities included above approximates the carrying amount and was determined from predominantly unobservable inputs.

Other payables include amounts due to joint arrangement partners and in respect of other project-related items.

Information about offsetting, collateral and liquidity risk is presented in Note 19.

16 – TAXATION

Taxation charge

	2019	2018	2017
Current tax:			
Charge in respect of current period	7,597	10,415	7,204
Adjustments in respect of prior periods	(1)	60	(613)
Total	7,596	10,475	6,591
Deferred tax:			
Relating to the origination and reversal of temporary differences, tax losses and credits	1,377	1,438	(4,102)
Relating to changes in tax rates and legislation	(67)	(157)	2,004 [A]
Adjustments in respect of prior periods	147	(41)	202
Total	1,457	1,240	(1,896)
Total taxation charge	9,053	11,715	4,695

\$ million

[A] Mainly in respect of the US Tax Cuts and Jobs Act.

Adjustments in respect of prior periods relate to events in the current period and reflect the effects of changes in rules, facts or other factors compared with those used in establishing the current tax position or deferred tax balance in prior periods.

Reconciliation of applicable tax charge at statutory tax rates to taxation charge

	2019	2018	2017
Income before taxation	25,485	35,621	18,130
Less: share of profit of joint ventures and associates	(3,604)	(4,106)	(4,225)
Income before taxation and share of profit of joint ventures and associates	21,881	31,515	13,905
Applicable tax charge at standard statutory tax rates [A]	7,214	11,641	4,709
Adjustments in respect of prior periods	146	19	(411)
Tax effects of: [B]			
Expenses not deductible for tax purposes	1,493	1,176	1,000
Derecognition/(recognition) of deferred tax assets	846	(381)	(957)
Incentives for investment and development [A]	(757)	(557)	(527)
Disposals	(235)	(524)	(910)
Income not subject to tax at standard statutory rates	159	(286)	(359)
Changes in tax rates and legislation	(67)	(157)	2,004
Exchange rate differences	(34)	623	320
Other reconciling items	288	161	(174)
Taxation charge	9,053	11,715	4,695

\$ million

[A] Incentives for investment and development include conditional preferential tax rates to attract investment, uplift on carried forward losses and capital expenditure, investment tax allowances and credits for research and development. Up to and including 2018, preferential tax rates were reported within the applicable tax charge at standard statutory tax rates. Comparative numbers for 2018 and 2017 were reclassified to conform with the current year presentation.

[B] The tax effect categories have changed to provide better insights. Comparative numbers for 2018 and 2017 were reclassified to conform with the current year presentation.

The weighted average of statutory tax rates was 33% in 2019 (2018: 37% as revised; 2017: 34% as revised). Compared with 2018, the decrease in the rate reflects a higher proportion of earnings in the Downstream and Integrated Gas segments, subject to relatively lower tax rates than earnings in the Upstream segment. In addition, a higher proportion of Integrated Gas income was earned in countries with relatively lower statutory tax rates.

Taxes payable

	\$ million	
	Dec 31, 2019	Dec 31, 2018
Income taxes	3,478	3,990
Sales taxes, excise duties and similar levies	3,215	3,507
Total	6,693	7,497

Included in other receivables at December 31, 2019 was income tax receivable of \$1,328 million (2018: \$1,042 million) (see Note 11).

2019 – Deferred tax

	\$ million					
	Decommissioning and other provisions	Property, plant and equipment	Tax losses and credits carried forward	Retirement benefits	Other	Total
Deferred tax asset						
At January 1, 2019 (as previously published)	5,902	3,718	12,167	3,310	4,233	29,330
Impact of IFRS 16	(43)	–	–	–	43	–
At January 1, 2019 (as revised)	5,859	3,718	12,167	3,310	4,276	29,330
(Charge)/credit to income	15	(521)	(647)	(76)	10	(1,219)
Currency translation differences	56	6	57	(8)	(2)	109
Other	(550)	(189)	52	434	77	(176)
At December 31, 2019	5,380	3,014	11,629	3,660	4,361	28,044
Deferred tax liability						
At January 1, 2019 (as previously published)		(27,771)		(1,674)	(2,625)	(32,070)
Impact of IFRS 16		144		–	(144)	–
At January 1, 2019 (as revised)		(27,627)		(1,674)	(2,769)	(32,070)
(Charge)/credit to income		(227)		46	(57)	(238)
Currency translation differences		(129)		(6)	(5)	(140)
Other		(57)		541	(78)	406
At December 31, 2019		(28,040)		(1,093)	(2,909)	(32,042)
Net deferred tax liability at December 31, 2019						(3,998)
Deferred tax asset/liability as presented in the balance sheet at December 31, 2019						
Deferred tax asset						10,524
Deferred tax liability						(14,522)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

16 – TAXATION continued

2018 – Deferred tax

						\$ million
Deferred tax asset	Decommissioning and other provisions	Property, plant and equipment	Tax losses and credits carried forward	Retirement benefits	Other	Total
At January 1, 2018	6,182	3,379	13,684	3,868	4,144	31,257
(Charge)/credit to income	166	345	(553)	14	119	91
Currency translation differences	(177)	(32)	(462)	(93)	(42)	(806)
Other	(269)	26	(502)	(479)	12	(1,212)
At December 31, 2018	5,902	3,718	12,167	3,310	4,233	29,330
Deferred tax liability						
At January 1, 2018		(26,904)		(742)	(2,827)	(30,473)
(Charge)/credit to income		(1,751)		180	240	(1,331)
Currency translation differences		409		24	36	469
Other		475		(1,136)	(74)	(735)
At December 31, 2018		(27,771)		(1,674)	(2,625)	(32,070)
Net deferred tax liability at December 31, 2018						(2,740)
Deferred tax asset/liability as presented in the balance sheet at December 31, 2018						
Deferred tax asset						12,097
Deferred tax liability						(14,837)

The presentation in the balance sheet takes into consideration the offsetting of deferred tax assets and deferred tax liabilities within the same tax jurisdiction, where this is permitted. The overall deferred tax position in a particular tax jurisdiction determines if a deferred tax balance related to that jurisdiction is presented within deferred tax assets or deferred tax liabilities.

Other movements in deferred tax assets and liabilities principally relate to acquisitions, sales of non-current assets and businesses, and amounts recognised in other comprehensive income.

The deferred tax category 'Other' primarily includes deferred tax positions in respect of leases, financial assets and liabilities, inventories, intangible assets and investments in subsidiaries, joint ventures and associates.

The amount of deferred tax assets dependent on future taxable profits not arising from the reversal of existing deferred tax liabilities, and which relate to tax jurisdictions where Shell has suffered a loss in the current or preceding year, was \$8,773 million at December 31, 2019 (2018: \$9,979 million). It is considered probable based on business forecasts that such profits will be available.

Unrecognised taxable temporary differences associated with undistributed retained earnings of investments in subsidiaries, joint ventures and associates amounted to \$6,356 million at December 31, 2019 (2018: \$3,951 million). These retained earnings are subject to withholding tax upon distribution. The increase of the amount compared with 2018 is related to a change in the withholding tax legislation, as a result of which a larger part of the undistributed retained earnings will be subject to withholding tax.

Unrecognised deductible temporary differences, unused tax losses and credits carried forward amounted to \$33,068 million at December 31, 2019 (2018: \$30,010 million as revised) including amounts of \$24,295 million (2018: \$22,704 million as revised) that are subject to time limits for utilisation of five years or later, or are not time limited.

Furthermore, there are unrecognised losses for Petroleum Resource Rent Tax ("PRRT") in Australia, amounting to \$36,905 million as at the end of the most recent PRRT fiscal year (June 30, 2019). In 2018, a portion of the PRRT losses amounting to \$4,900 million was included in the amount of the unrecognised deductible temporary differences, unused tax losses and credits carried forward. Based on business forecasts at existing commodity price levels, and the annual augmentation of the unused PRRT losses, this amount is expected to increase in the near future.

17 – RETIREMENT BENEFITS

Retirement benefits are provided through a number of funded and unfunded defined benefit plans and defined contribution plans, the most significant of which are in the Netherlands, UK and USA. Benefits comprise principally pensions; retirement healthcare and life insurance are also provided in certain countries.

Retirement benefit expense

	2019	2018	\$ million 2017
Defined benefit plans:			
Current service cost, net of plan participants' contributions	1,188	1,494	1,500
Interest expense on obligations	2,364	2,282	2,309
Interest income on plan assets	(2,253)	(2,087)	(2,019)
Other	26	(221)	(404)
Total	1,325	1,468	1,386
Defined contribution plans	428	410	429
Total retirement benefit expense	1,753	1,878	1,815

Retirement benefit expense is presented principally within production and manufacturing expenses and selling, distribution and administrative expenses in the Consolidated Statement of Income. Interest income on plan assets is calculated using the same rate as that applied to the related defined benefit obligations for each plan to determine interest expense.

Remeasurements

	2019	2018	\$ million 2017
Actuarial gains/(losses) on obligations:			
Due to changes in financial assumptions [A]	(11,711)	8,186	(4,495)
Due to experience adjustments [B]	232	(268)	37
Due to changes in demographic assumptions [C]	(75)	(459)	933
Total	(11,554)	7,459	(3,525)
Return on plan assets in excess/(shortage) of interest income	8,460	(2,312)	4,942
Other movements	(12)	66	50
Total remeasurements	(3,106)	5,213	1,467

[A] Primarily relates to changes in the discount rate assumptions.

[B] Experience adjustments arise from differences between the actuarial assumptions made in respect of the year and actual outcomes.

[C] Primarily relates to updates in mortality assumptions.

Defined benefit plans

	Dec 31, 2019	Dec 31, 2018	\$ million
Obligations	(103,545)	(91,856)	
Plan assets	94,826	85,803	
Net liability	(8,719)	(6,053)	
Retirement benefits in the Consolidated Balance Sheet:			
Non-current assets	4,717	6,051	
Non-current liabilities	(13,017)	(11,653)	
Current liabilities	(419)	(451)	
Total	(8,719)	(6,053)	

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

17 – RETIREMENT BENEFITS continued

Defined benefit plan obligations

	\$ million, except where indicated	
	2019	2018
At January 1	91,856	104,285
Current service cost	1,186	1,491
Interest expense	2,364	2,282
Actuarial losses/(gains)	11,554	(7,459)
Benefit payments	(3,961)	(4,435)
Other movements	194	(360)
Currency translation differences	352	(3,948)
At December 31	103,545	91,856
Comprising:		
Funded pension plans	93,727	83,276
Weighted average duration	17 years	17 years
Unfunded pension plans	4,793	4,359
Weighted average duration	13 years	13 years
Other unfunded plans	5,025	4,221
Weighted average duration	14 years	12 years

Defined benefit plan assets

	\$ million, except where indicated	
	2019	2018
At January 1	85,803	93,243
Return on plan assets in excess/(shortage) of interest income	8,460	(2,312)
Interest income	2,253	2,087
Employer contributions	1,462	763
Plan participants' contributions	42	47
Benefit payments	(3,741)	(4,123)
Other movements	160	(102)
Currency translation differences	387	(3,800)
At December 31	94,826	85,803
Comprising:		
Quoted in active markets:		
Equities	26%	24%
Debt securities	51%	53%
Real estate	1%	1%
Other	0%	1%
Other:		
Equities	8%	8%
Debt securities	4%	3%
Real estate	6%	6%
Investment funds	3%	3%
Cash	1%	1%

Long-term investment strategies of plans are generally determined by the relevant pension plan trustees using a structured asset/liability modelling approach to define the asset mix that best meets the objectives of optimising returns within agreed risk levels while maintaining adequate funding levels.

Employer contributions to defined benefit pension plans are based on actuarial valuations in accordance with local regulations and are estimated to be \$0.7 billion in 2020.

Significant funding requirements:

- Additional contributions to the Netherlands defined benefit pension plan would be required if the 12-month rolling average local funding percentage falls below 105% for six months or more. At the most recent (2019) funding valuation the local funding percentage was above this level;
- There are no set minimum statutory funding requirements for the UK plans. Under an agreement with the trustee of the main UK defined benefit plan, Shell will provide additional contributions if the funding position falls below a certain level, although this is currently not anticipated; and
- Under the Pension Protection Act, US pension plans are subject to minimum required contribution levels based on the funding position. No contributions are required based on the most recent funding valuation.

The principal assumptions applied in determining the present value of defined benefit obligations and their bases were as follows:

- rates of increase in pensionable remuneration, pensions in payment and healthcare costs: historical experience and management's long-term expectation;
- discount rates: prevailing long-term AA corporate bond yields, chosen to match the currency and duration of the relevant obligation; and
- mortality rates: published standard mortality tables for the individual countries concerned adjusted for Shell experience where statistically significant.

The weighted averages for those assumptions and related sensitivity information at December 31 are presented below. Sensitivity information indicates by how much the defined benefit obligations would increase or decrease if a given assumption were to increase or decrease with no change in other assumptions.

\$ million, except where indicated

	Assumptions used		Effect of using alternative assumptions		
			Increase/(decrease) in defined benefit obligations		
	2019	2018	Range of assumptions	2019	2018
Rate of increase in pensionable remuneration	4.1%	4.1%	-1% to +1%	(1,975) to 2,266	(1,576) to 1,819
Rate of increase in pensions in payment	1.6%	1.8%	-1% to +1%	(9,541) to 11,757	(8,304) to 10,104
Rate of increase in healthcare costs	6.1%	6.3%	-1% to +1%	(546) to 675	(410) to 496
Discount rate for pension plans	2.1%	2.9%	-1% to +1%	18,431 to (14,155)	15,606 to (12,078)
Discount rate for healthcare plans	3.2%	4.2%	-1% to +1%	704 to (558)	536 to (436)
Expected age at death for persons aged 60:					
Men	87 years	87 years	-1 year to +1 year	(1,717) to 1,782	(1,538) to 1,583
Women	89 years	89 years	-1 year to +1 year	(1,631) to 1,694	(1,436) to 1,476

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

18 – DECOMMISSIONING AND OTHER PROVISIONS

\$ million

	Decommissioning and restoration	Legal	Environmental	Redundancy	Other	Total
At January 1, 2019						
Current (as previously published)	876	213	264	491	1,815	3,659
Impact of IFRS 16 [A]	-	-	-	(50)	(268)	(318)
Current (as revised)	876	213	264	441	1,547	3,341
Non-current (as previously published)	17,057	1,247	1,074	468	1,687	21,533
Impact of IFRS 16 [A]	-	-	-	(188)	(159)	(347)
Non-current (as revised)	17,057	1,247	1,074	280	1,528	21,186
	17,933	1,460	1,338	721	3,075	24,527
Additions	625	585	229	290	535	2,264
Amounts charged against provisions	(797)	(216)	(223)	(304)	(562)	(2,102)
Accretion expense	644	28	16	3	25	716
Disposals	(1,238) [B]	-	(8)	-	(14)	(1,260)
Remeasurements and other movements	1,696	(45)	(155)	(192)	(988) [C]	316
Currency translation differences	156	(1)	-	(3)	(3)	149
	1,086	351	(141)	(206)	(1,007)	83
At December 31, 2019						
Current	755	626	263	295	872	2,811
Non-current	18,264	1,185	934	220	1,196	21,799
	19,019	1,811	1,197	515	2,068	24,610
At January 1, 2018						
Current	817	423	287	758	1,180	3,465
Non-current	19,767	1,095	1,218	560	2,326	24,966
	20,584	1,518	1,505	1,318	3,506	28,431
Additions	418	196	191	535	1,070	2,410
Amounts charged against provisions	(497)	(200)	(212)	(504)	(887)	(2,300)
Accretion expense	755	17	17	15	48	852
Disposals	(1,781)	(14)	(11)	(3)	(49)	(1,858)
Remeasurements and other movements	(1,065)	(47)	(130)	(367)	(122)	(1,731)
Currency translation differences	(481)	(10)	(22)	(35)	(64)	(612)
	(2,651)	(58)	(167)	(359)	(4)	(3,239)
At December 31, 2018						
Current	876	213	264	491	1,815	3,659
Non-current	17,057	1,247	1,074	468	1,687	21,533
	17,933	1,460	1,338	959	3,502	25,192

[A] Following the implementation of IFRS 16 Leases (see Note 3) provisions related to onerous operating lease contracts at December 31, 2018 were derecognised and related right-of-use assets were adjusted accordingly. Certain operating lease contracts, mainly related to office buildings became onerous following restructuring and these onerous operating lease contracts were included in the provision for redundancy.

[B] Mainly related to the disposal of interests in Denmark and Canada.

[C] Mainly related to reclassifications to Trade and other payables.

The amount and timing of settlement in respect of these provisions are uncertain and dependent on various factors that are not always within management's control. Reviews of estimated future decommissioning and restoration costs and the discount rate applied are carried out annually. The discount rate applied at December 31, 2019 was 3% (December 31, 2018: 4%). This decrease resulted from the decrease in capital markets rates in 2019.

In 2019, there was an increase of \$2,241 million (2018: \$nil) in the decommissioning and restoration provision as a result of the change in the discount rate, partly offset by a decrease in the provision resulting from changes in cost estimates of \$545 million (2018: \$982 million), reported within re-measurements and other movements.

Of the decommissioning and restoration provision at December 31, 2019, an estimated \$2,869 million is expected to be utilised within one to five years, \$2,432 million within six to 10 years, and the remainder in later periods.

Other provisions include amounts recognised in respect of employee benefits.

19 – FINANCIAL INSTRUMENTS

Financial instruments in the Consolidated Balance Sheet include investments in securities (see Note 10), cash and cash equivalents (see Note 13), debt (see Note 14) and derivative contracts.

Risks

In the normal course of business, financial instruments of various kinds are used for the purposes of managing exposure to interest rate, foreign exchange and commodity price movements.

Treasury standards are applicable to all subsidiaries and each subsidiary is required to adopt a treasury policy consistent with these standards. These policies cover: financing structure; interest rate and foreign exchange risk management; insurance; counterparty risk management; and use of derivative contracts. Wherever possible, treasury operations are carried out through specialist regional organisations without removing from each subsidiary the responsibility to formulate and implement appropriate treasury policies.

Apart from forward foreign exchange contracts to meet known commitments, the use of derivative contracts by most subsidiaries is not permitted by their treasury policy.

Other than in exceptional cases, the use of external derivative contracts is confined to specialist trading and central treasury organisations that have appropriate skills, experience, supervision, control and reporting systems.

Shell's operations expose it to market, credit and liquidity risk, as described below.

Market risk

Market risk is the possibility that changes in interest rates, foreign exchange rates or the prices of crude oil, natural gas, LNG, refined products, chemical feedstocks, power and carbon-emission rights will adversely affect the value of assets, liabilities or expected future cash flows.

Interest rate risk

Most debt is raised from central borrowing programmes. Shell's policy continues to be to have debt principally denominated in dollars and to maintain a largely floating interest rate exposure profile; however, Shell has issued a significant amount of fixed rate debt in recent years, taking advantage of historically low interest rates available in debt markets. As a result, a substantial portion of the debt portfolio at December 31, 2019, is at fixed rates and this reduces Shell's exposure to the dollar LIBOR interest rate (see Note 2B).

The financing of most subsidiaries is structured on a floating-rate basis, and any further interest rate risk management is only applied under exceptional circumstances.

On the basis of the floating-rate net debt position at December 31, 2019 (both issued and hedged), and assuming other factors (principally foreign exchange rates and commodity prices) remained constant and that no further interest rate management action was taken, an increase in interest rates of 1% would have decreased 2019 income before taxation by \$98 million (2018: \$37 million, based on the floating rate position at December 31, 2018).

The carrying amounts and maturities of debt and borrowing facilities are presented in Note 14. Interest expense is presented in Note 6.

Foreign exchange risk

Many of the markets in which Shell operates are priced, directly or indirectly, in dollars. As a result, the functional currency of most Integrated Gas and Upstream entities and those with significant cross-border business is the dollar. For Downstream entities, the functional currency is typically the local currency. Consequently, Shell is exposed to varying levels of foreign exchange risk when an entity enters into transactions that are not denominated in its functional currency, when foreign currency monetary assets and liabilities are translated at the balance sheet date and as a result of holding net investments in operations that are not dollar-functional. Each entity is required to adopt treasury policies that are designed to measure and manage its foreign exchange exposures by reference to its functional currency.

Foreign exchange gains and losses arise in the normal course of business from the recognition of receivables and payables and other monetary items in currencies other than an entity's functional currency. Foreign exchange risk may also arise in connection with capital expenditure. For major projects, an assessment is made at the final investment decision stage whether to hedge any resulting exposure.

Assuming other factors (principally interest rates and commodity prices) remained constant and that no further foreign exchange risk management action were taken, a 10% appreciation against the dollar at December 31 of the main currencies to which Shell is exposed would have the following effects:

	\$ million			
	Increase/(decrease) in income before taxation		Increase in net assets	
	2019	2018	2019	2018
10% appreciation against the dollar of:				
Canadian dollar	(97)	(40)	1,380	1,245
Euro	36	65	1,227	1,190
Australian dollar	(55)	(109)	835	835
Sterling	(58)	(46)	581	779

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

19 – FINANCIAL INSTRUMENTS continued

The above sensitivity information was calculated by reference to carrying amounts of assets and liabilities at December 31 only. The effect on income before taxation arises in connection with monetary balances denominated in currencies other than an entity's functional currency; the effect on net assets arises principally from the translation of assets and liabilities of entities that are not dollar-functional.

Foreign exchange gains and losses included in income are presented in Note 5.

Commodity price risk

Certain subsidiaries have a mandate to trade crude oil, natural gas, LNG, refined products, chemical feedstocks, power and carbon-emission rights, and to use commodity derivative contracts (forwards, futures, swaps and options) as a means of managing price and timing risks arising from this trading activity. In effecting these transactions, the entities concerned operate within procedures and policies designed to ensure that risks, including those relating to the default of counterparties, are managed within authorised limits.

Value-at-risk ("VAR") techniques based on variance/covariance or Monte Carlo simulation models are used to make a statistical assessment of the market risk arising from possible future changes in market values over a 1-day holding period and within a 95% confidence level. The calculation of potential changes in fair value takes into account positions, the history of price movements and the correlation of these price movements. Models are regularly reviewed against actual fair value movements to ensure integrity is maintained. The VAR year-end positions in respect of commodities traded in active markets, which are presented in the table below, are calculated on a diversified basis in order to reflect the effect of offsetting risk within combined portfolios.

Value-at-risk (pre-tax)

	\$ million	
	December 31, 2019	December 31, 2018
Global oil	22	28
North America gas and power	12	11
Europe gas and power	5	3
Carbon-emission rights	4	2

Credit risk

Policies are in place to ensure that sales of products are made to customers with appropriate creditworthiness. These policies include detailed credit analysis and monitoring of trading partners against counterparty credit limits. Credit information is regularly shared between business and finance functions, with dedicated teams in place to quickly identify and respond to cases of credit deterioration. Mitigation measures are defined and implemented for high-risk business partners and customers, and include shortened payment terms, collateral or other security posting and vigorous collections. In addition, policies limit the amount of credit exposure to any individual financial institution. There are no material concentrations of credit risk, with individual customers or geographically, and there has been no significant level of counterparty default in recent years.

Surplus cash is invested in a range of short-dated, secure and liquid instruments including short-term bank deposits, money market funds, reverse repos and similar instruments. The portfolio of these investments is diversified to avoid concentrating risk in any one instrument, country or counterparty. Management monitors the investments regularly and adjusts the investment portfolio in light of new market information where necessary to ensure credit risk is effectively diversified.

In commodity trading, counterparty credit risk is managed within a framework of credit limits with utilisation being regularly reviewed. Credit risk exposure is monitored and the acceptable level is determined by a credit committee. Credit checks are performed by a department independent of traders, and are undertaken before contractual commitment. Where appropriate, netting arrangements, credit insurance, prepayments and collateral are used to manage specific risks.

Shell routinely enters into offsetting, master netting and similar arrangements with trading and other counterparties to manage credit risk. Where there is a legally enforceable right of offset under such arrangements and Shell has the intention to settle on a net basis or realise the asset and settle the liability simultaneously, the net asset or liability is recognised in the Consolidated Balance Sheet, otherwise assets and liabilities are presented gross. These amounts, as presented net and gross within trade and other receivables, trade and other payables and derivative financial instruments in the Consolidated Balance Sheet at December 31, were as follows:

2019

						\$ million
	Amounts offset			Amounts not offset		
	Gross amounts before offset	Amounts offset	Net amounts as presented	Cash collateral received/pledged	Other offsetting instruments	Net amounts
Assets:						
Within trade receivables	13,821	8,975	4,846	54	101	4,691
Within derivative financial instruments	12,995	7,310	5,685	531	2,262	2,892
Liabilities:						
Within trade payables	13,335	9,029	4,306	11	101	4,194
Within derivative financial instruments	12,355	7,253	5,102	706	2,262	2,134

2018

\$ million

	Amounts offset			Amounts not offset		Net amounts
	Gross amounts before offset	Amounts offset	Net amounts as presented	Cash collateral received/pledged	Other offsetting instruments	
Assets:						
Within trade receivables	12,697	8,340	4,358	62	221	4,075
Within derivative financial instruments	12,323	6,353	5,970	437	2,653	2,880
Liabilities:						
Within trade payables	12,931	8,264	4,667	97	221	4,349
Within derivative financial instruments	12,227	5,044	7,183	1,115	2,653	3,415

Amounts not offset principally relate to contracts where the intention to settle on a net basis was not clearly established at December 31.

The carrying amount of financial assets pledged as collateral for liabilities or contingent liabilities at December 31, 2019, presented within trade and other receivables, was \$1,948 million (2018: \$3,094 million). The carrying amount of collateral held at December 31, 2019, presented within trade and other payables, was \$718 million (2018: \$535 million). Collateral mainly relates to initial margins held with commodity exchanges and over-the-counter counterparty variation margins. Some derivative contracts are fully cash collateralised, thereby eliminating both counterparty risk and the Group's own non-performance risk

Liquidity risk

Liquidity risk is the risk that suitable sources of funding for Shell's business activities may not be available. Management believes that it has access to sufficient debt funding sources (capital markets), and to undrawn committed borrowing facilities to meet foreseeable requirements. Information about borrowing facilities is presented in Note 14.

DERIVATIVE CONTRACTS AND HEDGES

Derivative contracts are used principally as hedging instruments, however, because hedge accounting is not always applied, movements in the carrying amounts of derivative contracts that are recognised in income are not always matched in the same period by the recognition of the income effects of the related hedged items.

Carrying amounts, maturities and hedges

The carrying amounts of derivative contracts at December 31, designated and not designated as hedging instruments for hedge accounting purposes, were as follows:

2019

\$ million

	Assets			Liabilities			Net
	Designated	Not designated	Total	Designated	Not designated	Total	
Interest rate swaps	227	8	235	34	24	58	177
Forward foreign exchange contracts	7	236	243	2	309	311	(68)
Currency swaps and options	90	15	105	932	56	988	(883)
Commodity derivatives	-	6,914	6,914	-	5,281	5,281	1,633
Other contracts	-	341	341	-	-	-	341
Total	324	7,514	7,838	968	5,670	6,638	1,200

2018

\$ million

	Assets			Liabilities			Net
	Designated	Not designated	Total	Designated	Not designated	Total	
Interest rate swaps	86	3	89	174	14	188	(99)
Forward foreign exchange contracts	-	331	331	33	264	297	34
Currency swaps and options	186	26	212	1,202	203	1,405	(1,193)
Commodity derivatives	-	6,864	6,864	-	6,637	6,637	227
Other contracts	-	271	271	-	56	56	215
Total	272	7,495	7,767	1,409	7,174	8,583	(816)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

19 – FINANCIAL INSTRUMENTS continued

Net losses before tax on derivative contracts, excluding realised commodity contracts and those accounted for as hedges, were \$2,004 million in 2019 (2018: \$1,818 million losses; 2017: \$1,321 million losses).

Certain contracts, mainly to hedge price risk relating to forecast commodity transactions which mature in 2020-2021, were designated in cash flow hedging relationships. The net carrying amount of commodity derivative contracts designated as cash flow hedging instruments at December 31, 2019, was a liability of \$101 million (2018: \$120 million asset) (see Note 22), and was presented after the offset of related margin balances maintained with exchanges.

Certain interest rate and currency swaps were designated in fair value hedges, principally in respect of debt for which the net carrying amount of the related derivative contracts, net of accrued interest, at December 31, 2019, was a liability of \$518 million (2018: \$1,242 million).

In the course of trading operations, certain contracts are entered into for delivery of commodities that are accounted for as derivatives. The resulting price exposures are managed by entering into related derivative contracts. These contracts are managed on a fair value basis and the maximum exposure to liquidity risk is the undiscounted fair value of derivative liabilities.

For a minority of commodity derivative contracts, carrying amounts cannot be derived from quoted market prices or other observable inputs, in which case fair value is estimated using valuation techniques such as Black-Scholes, option spread models and extrapolation using quoted spreads with assumptions developed internally based on observable market activity.

Other contracts include certain contracts that are held to sell or purchase commodities and others containing embedded derivatives, which are required to be recognised at fair value because of pricing or delivery conditions, even though they were entered into to meet operational requirements. These contracts are expected to mature in 2020-2025, with certain contracts having early termination rights (for either party). Valuations are derived from quoted market prices.

The contractual maturities of derivative liabilities at December 31 compare with their carrying amounts in the Consolidated Balance Sheet as follows:

2019

	Contractual maturities							Difference from carrying amount [A]	Carrying amount
	Less than 1 year	Between 1 and 2 years	Between 2 and 3 years	Between 3 and 4 years	Between 4 and 5 years	5 years and later	Total		
Interest rate swap	35	8	4	4	5	4	60	(2)	58
Forward foreign exchange contracts	214	40	8	–	118	–	380	(69)	311
Currency swaps and options	255	475	444	201	204	1,777	3,356	(2,368)	988
Commodity derivatives	3,472	756	349	189	123	511	5,400	(119)	5,281
Total	3,976	1,279	805	394	450	2,292	9,196	(2,558)	6,638

[A] Mainly related to the effect of discounting.

2018

	Contractual maturities							Difference from carrying amount [A]	Carrying amount
	Less than 1 year	Between 1 and 2 years	Between 2 and 3 years	Between 3 and 4 years	Between 4 and 5 years	5 years and later	Total		
Interest rate swap	101	68	20	1	1	1	192	(4)	188
Forward foreign exchange contracts	177	(24)	33	(1)	(5)	(15)	165	132	297
Currency swaps and options	605	265	474	405	198	1,715	3,662	(2,257)	1,405
Commodity derivatives	4,733	978	422	213	138	382	6,866	(229)	6,637
Other contracts	58	–	–	–	–	–	58	(2)	56
Total	5,674	1,287	949	618	332	2,083	10,943	(2,360)	8,583

[A] Mainly related to the effect of discounting.

Fair value measurements

The net carrying amounts of derivative contracts held at December 31, categorised according to the predominant source and nature of inputs used in determining the fair value of each contract, were as follows:

2019

	Prices in active markets for identical assets/liabilities	Other observable inputs	Unobservable inputs	Total
\$ million				
Interest rate swaps	-	177	-	177
Forward foreign exchange contracts	-	(68)	-	(68)
Currency swaps and options	-	(883)	-	(883)
Commodity derivatives	(6)	895	744	1,633
Other contracts	27	304	10	341
Total	21	425	754	1,200

2018

	Prices in active markets for identical assets/liabilities	Other observable inputs	Unobservable inputs	Total
\$ million				
Interest rate swaps	-	(99)	-	(99)
Forward foreign exchange contracts	-	34	-	34
Currency swaps and options	-	(1,193)	-	(1,193)
Commodity derivatives	(52)	431	(152)	227
Other contracts	-	90	125	215
Total	(52)	(737)	(27)	(816)

Net carrying amounts of derivative contracts measured using predominantly unobservable inputs

	2019	2018
\$ million		
At January 1	(27)	297
Net gains/(losses) recognised in revenue	1,085	(258)
Purchases	453	461
Sales	(633)	(540)
Recategorisations (net)	(125)	18
Currency translation differences	1	(5)
At December 31	754	(27)

Included in net gains recognised in revenue in 2019 were unrealised net gains totalling \$612 million relating to assets and liabilities held at December 31, 2019 (2018: \$36 million losses).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

20 – SHARE CAPITAL

Issued and fully paid ordinary shares of €0.07 each [A]

	Number of shares		Nominal value (\$ million)		
	A	B	A	B	Total
At January 1, 2019	4,471,889,296	3,745,486,731	376	309	685
Repurchases of shares	(320,101,779)	(16,079,624)	(27)	(1)	(28)
At December 31, 2019	4,151,787,517	3,729,407,107	349	308	657
At January 1, 2018	4,597,136,050	3,745,486,731	387	309	696
Repurchases of shares	(125,246,754)	-	(11)	-	(11)
At December 31, 2018	4,471,889,296	3,745,486,731	376	309	685

[A] Share capital at December 31, 2019, and 2018, also included 50,000 issued and fully paid sterling deferred shares of £1 each.

At the Company's Annual General Meeting ("AGM") on May 21, 2019, the Board was authorised to allot ordinary shares in the Company, and to grant rights to subscribe for or to convert any security into ordinary shares in the Company, up to an aggregate nominal amount of €190.3 million (representing 2,720 million ordinary shares of €0.07 each), and to list such shares or rights on any stock exchange. This authority expires at the earlier of the close of business on August 21, 2020, and the end of the AGM to be held in 2020, unless previously renewed, revoked or varied by the Company in a general meeting.

At the May 21, 2019 AGM, shareholders granted the Company the authority to repurchase up to 815 million ordinary shares (excluding any treasury shares), renewing the authority granted by the shareholders at previous AGMs. The authority will expire at the earlier of the close of business on August 21, 2020, and the end of the AGM of the Company to be held in 2020. Ordinary shares purchased by the Company pursuant to this authority will either be cancelled or held in treasury. Treasury shares are shares in the Company which are owned by the Company itself. The minimum price, exclusive of expenses, which may be paid for an ordinary share is €0.07. The maximum price, exclusive of expenses, which may be paid for an ordinary share is the higher of: (i) an amount equal to 5% above the average market value for an ordinary share for the five business days immediately preceding the date of the purchase; and (ii) the higher of the price of the last independent trade and the highest current independent bid on the trading venues where the purchase is carried out.

21 – SHARE-BASED COMPENSATION PLANS AND SHARES HELD IN TRUST

Share-based compensation expense

	\$ million		
	2019	2018	2017
Equity-settled	537	531	422
Cash-settled [A]	-	-	380
Total	537	531	802

[A] As from 2018 onwards, components of share-based payments (related to tax) that were previously classified as cash-settled are classified as equity-settled. On an incidental basis awards may be cash settled, where an equity settlement is not possible under local regulations.

The principal share-based employee compensation plans are the PSP and LTIP. Awards of shares and American Depositary Shares ("ADSs") of the Company under the PSP and LTIP are granted upon certain conditions to eligible employees. The actual amount of shares that may vest ranges from 0% to 200% of the awards, depending on the outcomes of prescribed performance conditions over a three-year period beginning on January 1 of the award year. Shares and ADSs vest for nil consideration.

Share awards under the PSP and LTIP

	Number of A shares (million)	Number of B shares (million)	Number of A ADSs (million)	Weighted Average remaining contractual life (years)
At January 1, 2019	30	12	8	1.0
Granted	11	3	3	
Vested	(11)	(5)	(3)	
Forfeited	(1)	-	-	
At December 31, 2019	29	10	8	1.0
At January 1, 2018	33	12	9	0.9
Granted	10	4	3	
Vested	(12)	(4)	(4)	
Forfeited	(1)	-	-	
At December 31, 2018	30	12	8	1.0

Other plans offer eligible employees opportunities to acquire shares and ADSs of the Company or receive cash benefits measured by reference to the Company's share price.

Shell employee share ownership trusts and trust-like entities purchase the Company's shares in the open market to meet delivery commitments under employee share plans. At December 31, 2019, they held 17.4 million A shares (2018: 19.6 million), 6.5 million B shares (2018: 7.1 million) and 5.3 million A ADSs (2018: 5.9 million).

22 – OTHER RESERVES

Other reserves attributable to Royal Dutch Shell plc shareholders

					\$ million	
	Merger reserve	Share premium reserve	Capital redemption reserve	Share plan reserve	Accumulated other comprehensive income	Total
At January 1, 2019	37,298	154	95	1,098	(22,030)	16,615
Other comprehensive loss attributable to Royal Dutch Shell plc shareholders	-	-	-	-	(2,069)	(2,069)
Transfer from other comprehensive income	-	-	-	-	(74)	(74)
Repurchases of shares	-	-	28	-	-	28
Share-based compensation	-	-	-	(49)	-	(49)
At December 31, 2019	37,298	154	123	1,049	(24,173)	14,451
At January 1, 2018 (as previously published)	37,298	154	84	1,440	(22,044)	16,932
Impact of IFRS 9	-	-	-	-	(138)	(138)
At January 1, 2018 (as revised)	37,298	154	84	1,440	(22,182)	16,794
Other comprehensive income attributable to Royal Dutch Shell plc shareholders	-	-	-	-	1,123	1,123
Transfer from other comprehensive income	-	-	-	-	(971)	(971)
Repurchases of shares	-	-	11	-	-	11
Share-based compensation	-	-	-	(342)	-	(342)
At December 31, 2018	37,298	154	95	1,098	(22,030)	16,615
At January 1, 2017	37,311	154	84	1,644	(27,895)	11,298
Other comprehensive loss attributable to Royal Dutch Shell plc shareholders	-	-	-	-	5,851	5,851
Scrip dividends	(13)	-	-	-	-	(13)
Share-based compensation	-	-	-	(204)	-	(204)
At December 31, 2017	37,298	154	84	1,440	(22,044)	16,932

The merger reserve and share premium reserve were established as a consequence of the Company becoming the single parent company of Royal Dutch Petroleum Company and The "Shell" Transport and Trading Company, plc, now The Shell Transport and Trading Company Limited, in 2005. The capital redemption reserve was established in connection with repurchases of shares of the Company. The share plan reserve is in respect of equity-settled share-based compensation plans (see Note 21). The movement represents the net of the charge for the year and the release as a result of vested awards and is after deduction of tax of \$45 million in 2019 (2018: \$71 million; 2017: \$11 million).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

22 – OTHER RESERVES continued

Accumulated other comprehensive income comprises the following:

Accumulated other comprehensive income attributable to Royal Dutch Shell plc shareholders

\$ million

	Currency translation differences	Unrealised gains/ (losses) on securities	Debt instruments remeasurements	Cash flow and net investment hedging gains/(losses)	Deferred cost of hedging	Retirement benefits remeasurements	Equity instrument remeasurements	Total
At January 1, 2019	(11,747)		(21)	117	(353)	(10,932)	906	(22,030)
Recognised in other comprehensive income	302		24	(579)	9	(3,106)	(17)	(3,367)
Reclassified to income	38		5	268	86	-	-	397
Reclassified to the balance sheet	-		-	11	-	-	-	11
Reclassified to retained earnings	-		-	-	-	11	(85)	(74)
Tax on amounts recognised/reclassified	4		-	33	(29)	1,004	(13)	999
Total, net of tax	344		29	(267)	66	(2,091)	(115)	(2,034)
Share of joint ventures and associates	(2)		-	(74)	-	-	2	(74)
Other comprehensive income/(loss) for the period	342		29	(341)	66	(2,091)	(113)	(2,108)
Less: non-controlling interest	(35)		-	-	-	-	-	(35)
Attributable to Royal Dutch Shell plc shareholders	307		29	(341)	66	(2,091)	(113)	(2,143)
At December 31, 2019	(11,440)		8	(224)	(287)	(13,023)	793	(24,173)
At January 1, 2018 (as previously published)	(8,735)	1,969	-	(633)	-	(14,645)	-	(22,044)
Impact of IFRS 9	-	(1,969)	(6)	6	(144)	-	1,975	(138)
At January 1, 2018 (as revised)	(8,735)		(6)	(627)	(144)	(14,645)	1,975	(22,182)
Recognised in other comprehensive income	(3,794)		(15)	50	(362)	5,213	(147)	945
Reclassified to income	651		-	722	95	-	-	1,468
Reclassified to the balance sheet	-		-	(30)	-	-	-	(30)
Reclassified to retained earnings	-		-	-	-	137	(1,108)	(971)
Tax on amounts recognised/reclassified	(29)		-	(12)	58	(1,625)	(6)	(1,614)
Total, net of tax	(3,172)		(15)	730	(209)	3,725	(1,261)	(202)
Share of joint ventures and associates	(25)		-	14	-	1	193	183
Other comprehensive loss for the period	(3,197)		(15)	744	(209)	3,726	(1,068)	(19)
Less: non-controlling interest	185		-	-	-	(13)	(1)	171
Attributable to Royal Dutch Shell plc shareholders	(3,012)		(15)	744	(209)	3,713	(1,069)	152
At December 31, 2018	(11,747)		(21)	117	(353)	(10,932)	906	(22,030)
At January 1, 2017	(13,831)	1,321	-	(144)	-	(15,241)	-	(27,895)
Recognised in other comprehensive income	4,513	796	-	(467)	-	1,467	-	6,309
Reclassified to income	610	(211)	-	(87)	-	-	-	312
Reclassified to the balance sheet	-	-	-	(18)	-	-	-	(18)
Tax on amounts recognised/reclassified	33	8	-	20	-	(863)	-	(802)
Total, net of tax	5,156	593	-	(552)	-	604	-	5,801
Share of joint ventures and associates	53	55	-	63	-	(1)	-	170
Other comprehensive income/(loss) for the period	5,209	648	-	(489)	-	603	-	5,971
Less: non-controlling interest	(113)	-	-	-	-	(7)	-	(120)
Attributable to Royal Dutch Shell plc shareholders	5,096	648	-	(489)	-	596	-	5,851
At December 31, 2017	(8,735)	1,969	-	(633)	-	(14,645)	-	(22,044)

23 – DIVIDENDS

Interim dividends

	2019	2018	\$ million 2017
A shares:			
Cash: \$1.88 per share (2018: \$1.88; 2017: \$1.88)	8,147	8,605	4,919
Scrip: none (2018: none; 2017: \$1.88 per share)	–	–	3,558
Total – A shares	8,147	8,605	8,477
B shares:			
Cash: \$1.88 per share (2018: \$1.88; 2017: \$1.88)	7,051	7,070	5,958
Scrip: none (2018: none; 2017: \$1.88 per share)	–	–	1,193
Total – B shares	7,051	7,070	7,151
Total	15,198	15,675	15,628

In addition, on January 30, 2020, the Directors announced a further interim dividend in respect of 2019 of \$0.47 per A share and \$0.47 per B share. The total dividend is estimated to be \$3,691 million and is payable on March 23, 2020, to shareholders on the register at February 14, 2020. The Scrip Dividend Programme has been cancelled with effect from the fourth quarter 2017 interim dividend.

Dividends on A shares are by default paid in euros, although holders may elect to receive dividends in US dollars or in sterling. Dividends on B shares are by default paid in sterling, although holders may elect to receive dividends in US dollars or in euros. Dividends on ADSs are paid in dollars.

24 – EARNINGS PER SHARE

	2019	2018	2017
Income attributable to Royal Dutch Shell plc shareholders (\$ million)	15,842	23,352	12,977
Weighted average number of A and B shares used as the basis for determining:			
Basic earnings per share (million)	8,058.3	8,282.8	8,223.4
Diluted earnings per share (million)	8,112.5	8,348.7	8,299.0

Basic earnings per share are calculated by dividing the income attributable to Royal Dutch Shell plc shareholders for the year by the weighted average number of A and B shares outstanding during the year. The weighted average number of shares outstanding excludes shares held in trust.

Diluted earnings per share are based on the same income figures. The weighted average number of shares outstanding during the year is increased by dilutive shares related to share-based compensation plans.

Earnings per share are identical for A and B shares.

25 – LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

General

In the ordinary course of business, Shell subsidiaries are subject to a number of contingencies arising from litigation and claims brought by governmental, including tax authorities, and private parties. The operations and earnings of Shell subsidiaries continue, from time to time, to be affected to varying degrees by political, legislative, fiscal and regulatory developments, including those relating to the protection of the environment and indigenous groups in the countries in which they operate. The industries in which Shell subsidiaries are engaged are also subject to physical risks of various types.

The amounts claimed in relation to such events and, if such claims against Shell were successful, the costs of implementing the remedies sought in the various cases could be substantial. Based on information available to date and taking into account that in some cases it is not practicable to estimate

the possible magnitude or timing of any resultant payments, management believes that the foregoing are not expected to have a material adverse impact on Shell's Consolidated Financial Statements. However, there remains a high degree of uncertainty around these contingencies, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition.

In certain divestment transactions, liabilities related to dismantling and restoration are de-recognised upon transfer of these obligations to the buyer. For certain of these obligations Shell has issued guarantees to third parties and continues to be liable in case that the primary obligator is not able to meet its obligation. These potential obligations arising from issuance of these guarantees are assessed to be remote.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

Pesticide litigation

Shell Oil Company ("SOC"), along with another agricultural chemical pesticide manufacturer and several distributors, has been sued by public and quasi-public water purveyors alleging responsibility for groundwater contamination caused by applications of chemical pesticides. There are approximately 36 such cases currently pending. These suits assert various theories of strict liability and negligence, and seek to recover actual damages, including drinking well treatment and remediation costs. Most assert claims for punitive damages. While the Company continues to vigorously defend these lawsuits, a new environmental regulatory standard became effective in the State of California, where a majority of the suits are pending. The new standard requires public water systems state wide to perform quarterly or monthly sampling of their drinking water sources for a chemical contained in certain pesticides, beginning in January 2018. Water systems deemed out of compliance with the new five parts per trillion regulatory standard must take corrective action to resolve the exceedance or take the potable water source out of service. In response to this new regulatory standard, the Company is monitoring the sampling results to determine the number of wells potentially impacted. Based on the claims asserted and SOC's track record, with regard to amounts paid to resolve varying claims, management does not expect the outcome of these lawsuits pending at December 31, 2019, to have a material adverse impact on Shell. However, there remains a high degree of uncertainty regarding the potential outcome of some of these pending lawsuits, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition.

Climate change litigation

In the USA, 12 lawsuits have been filed by several municipalities and one state against oil and gas companies, including Royal Dutch Shell plc. The plaintiffs seek damages for claimed harm to their public and private infrastructure from rising sea levels allegedly due to climate change caused by the defendants' fossil fuel products. A similar suit has been filed by a crab fishing industry group claiming harm to their fisheries as a result of alleged ocean-related impacts of climate change. In the Netherlands a case has been filed against Shell by a group of environmental non-governmental organisations ("eNGOs") and individual claimants seeking a court order that Shell reduce by (net) 100% by 2050 the emissions associated with its business activities and products. Management believes the outcome of these matters should be resolved in a manner favourable to Shell, however, there remains a high degree of uncertainty regarding the ultimate outcome of these lawsuits, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition.

Brazil tax

Pursuant to Law 7.183/2015 issued by the State of Rio de Janeiro (RJ State) and effective March 2016, a value-added levy has been imposed on oil extraction in the RJ State. The Company understands that the obligations arising from this law are not legally sustainable and Shell obtained favourable injunctions suspending the enforcement of the law in two separate lawsuits, one filed to cover year 2016 and the other covering year 2017 onwards. The injunctions remain in effect and Shell received favourable decisions on the subject matter from the RJ State Court. The RJ State has appealed against both decisions and one is pending confirmation by the State Court while the other is pending final decisions by the Brazilian Superior and Supreme Courts. In addition, and as this is an industry-wide issue, the Brazilian Association of Oil and Gas Exploration and Production Companies, of which Shell is a member, filed a suit in February 2016 before the Brazilian Supreme Court, challenging the constitutionality of the law. This matter is currently pending with the Supreme Court. Should Shell be required to pay such a levy, it could result in a potential total liability of approximately \$5,275 million as of end 2019.

Louisiana coast litigation

The State of Louisiana and multiple local governments have initiated 43 lawsuits against 200+ Oil and Gas companies claiming historical oil and gas operations caused or contributed to wide-spread contamination, land loss and the erosion of the Louisiana coastline. Shell entities are named in 14 of the suits. The amounts claimed are unspecified. The cases are of first impression, arise out of an untested 1980 Louisiana statute and represent a novel attempt to render illegal operations that federal and state agencies permitted and authorized at the time. Management believes the outcome of these matters should be resolved in a manner favourable to Shell; there remains a high degree of uncertainty, however, concerning the scope of the claims and the ultimate outcome, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition.

Nigerian litigation

Shell subsidiaries and associates operating in Nigeria are parties to various environmental and contractual disputes brought in the courts of Nigeria, England and the Netherlands. These disputes are at different stages in litigation, including at the appellate stage, where judgements have been rendered against Shell entities. If taken at face value, the aggregate amount of these judgements could be seen as material. Management, however, believes that the outcomes of these matters will ultimately be resolved in a manner favourable to Shell. However, there remains a high degree of uncertainty regarding these cases, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition.

The authorities in various countries are investigating Shell Nigeria Exploration and Production Company Ltd.'s ("SNEPCO's") investment in Nigerian oil block OPL 245 and the 2011 settlement of litigation pertaining to that block with regard to potential anti-bribery, anti-corruption and anti-money laundering laws.

On January 27, 2017, the Nigeria Federal High Court issued an Interim Order of Attachment for Oil Prospecting Licence 245 ("OPL 245"), pending the conclusion of the investigation. SNEPCO applied for and was granted a discharge of this order on constitutional and procedural grounds. Also in Nigeria, in March 2017 criminal charges alleging official corruption and conspiracy to commit official corruption were filed against SNEPCO, one current Shell employee and third parties including ENI SpA and one of its subsidiaries. Those proceedings are ongoing. In January 2020, criminal charges alleging disobeying direction of law were filed in Nigeria against Shell Nigeria Ultra Deep Ltd., SNEPCO, and third parties including Nigeria Agip Exploration Limited. Those proceedings are ongoing. In March 2017, parties alleging to be shareholders of Malabu Oil and Gas Company Ltd. (Malabu) filed two actions to challenge the 2011 settlement and the award of OPL 245 to SNEPCO and an ENI SpA subsidiary by the Federal Government of Nigeria. Those proceedings are also ongoing. On May 8, 2018, Human Environmental Development Agenda ("HEDA") sought permission from the Federal High Court of Nigeria to apply for an order to direct the Attorney General of the Federation to revoke OPL 245 on grounds that the entire Malabu transaction in relation to the OPL is unconstitutional, illegal and void as it was obtained through fraudulent and corrupt practice. On October 4, 2018, SNEPCO was joined as a defendant in the HEDA action. Those proceedings are ongoing. On December 12, 2018, the Federal Republic of Nigeria issued a claim form in the UK against Shell and six subsidiaries, ENI SpA and two of its subsidiaries, Malabu as well as two other entities for the amount of \$1,092 million plus damages for having participated in a fraudulent and corrupt scheme leading to the acquisition by Shell and ENI corporate defendants in 2011 of OPL 245. The Shell entities were served in April and May 2019. The Shell entities and other defendants have challenged the jurisdiction of the English courts to try the claims and a hearing is scheduled for April 2020. On February 14, 2017, Royal Dutch Shell plc received a notice of request for indictment from the Milan public

prosecutor with respect to this matter. On December 20, 2017, Royal Dutch Shell plc along with four former Shell employees including one former executive were remanded to trial in Milan. On May 14, 2018, a trial commenced in the Court of Milan. On September 18, 2018, Shell was joined to the proceedings as the civilly responsible party (responsabile civile) for the damages caused by the alleged illegal acts of the four former Shell employees. Three other Shell entities (Shell UK Ltd, Shell Petroleum Development Company of Nigeria Ltd. and Shell Exploration and Production Africa Ltd.) also joined the proceedings but were denied status as responsabile civile for their respective former employees at that phase of the proceedings. The trial is ongoing with closing arguments scheduled to begin on March 25, 2020. Based on Shell's review of the Prosecutor of Milan's file and all the information and facts currently available to Shell, management does not believe that there is a basis to convict Shell in Milan. Furthermore, management is not aware of any evidence to convict any former or current Shell employee in Milan.

On September 20, 2018, a guilty judgement was filed by the Milan Judge of the Preliminary Hearing in a separate OPL 245 fast track trial of two individuals, neither of whom worked on behalf of Shell. That decision is under appeal.

In February 2019, we were informed by the Dutch Public Prosecutor's Office ("DPP") that they were nearing the conclusion of their investigation and preparing to prosecute Royal Dutch Shell plc for criminal charges directly or indirectly related to the 2011 settlement of disputes over OPL 245 in Nigeria. On October 2, 2019 the U.S. Department of Justice ("DOJ") informed Shell that it was closing its inquiry into Shell in relation to OPL 245. We understand that the decision was based on the facts available to the DOJ, including ongoing legal proceedings in Europe.

There remains a high degree of uncertainty around the OPL 245 matters and contingencies discussed above, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition. Accordingly, at this time, it is not practicable to estimate the magnitude and timing of any possible obligations or payments. Any violation of the US Foreign Corrupt Practices Act or other relevant anti-bribery, anti-corruption or anti-money laundering legislation could have a material adverse effect on Royal Dutch Shell plc's earnings, cash flows and financial condition.

26 – EMPLOYEES

Employee costs

	\$ million		
	2019	2018	2017
Remuneration	10,075	10,167	10,855
Social security contributions	844	810	844
Retirement benefits (see Note 17)	1,753	1,878	1,815
Share-based compensation (see Note 21)	537	531	802
Total [A]	13,209	13,386	14,316

[A] Excludes employees seconded to joint ventures and associates.

Average employee numbers

	Thousand		
	2019	2018	2017
Integrated Gas	10	9	8
Upstream	14	14	16
Downstream	36	39	42
Corporate [A]	23	20	19
Total [B]	83	82	85

[A] Includes all employees working in business service centres irrespective of the segment they support.

[B] Excludes employees seconded to joint ventures and associates (2019: 3,000 employees, 2018: 3,000 employees, 2017: 3,000 employees).

27 – DIRECTORS AND SENIOR MANAGEMENT

Remuneration of Directors of the Company

	\$ million		
	2019	2018	2017
Emoluments	8	12	11
Value of released awards under long-term incentive plans	12	20	5
Employer contributions to pension plans	1	1	1

Emoluments comprise salaries and fees, annual bonuses (for the period for which performance is assessed) and other benefits. The value of released awards under long-term incentive plans for the period is in respect of the performance period ending in that year. In 2019, retirement benefits were accrued in respect of qualifying services under defined benefit plans by two Directors.

Further information on the remuneration of the Directors can be found in the Directors' Remuneration Report on pages 135-138.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued**27 – DIRECTORS AND SENIOR MANAGEMENT** continued**Directors and Senior Management expense**

	2019	2018	\$ million 2017
Short-term benefits	18	26	23
Retirement benefits	3	3	3
Share-based compensation	15	14	17
Termination and related amounts	2	–	3
Total	38	43	46

Directors and Senior Management comprise members of the Executive Committee and the Non-executive Directors of the Company.

Short-term benefits comprise salaries and fees, annual bonuses delivered in cash and shares (for the period for which performance is assessed), other benefits and employer social security contributions.

28 – AUDITOR'S REMUNERATION

	2019	2018	\$ million 2017
Fees in respect of the audit of the Consolidated and Parent Company Financial Statements, including audit of consolidation returns	32	31	27
Other audit fees, principally in respect of audits of accounts of subsidiaries	18	16	21
Total audit fees	50	47	48
Audit-related fees	4	5	4
Fees in respect of other non-audit services	–	1	1
Total	54	53	53

In addition, the auditor provided audit services to retirement benefit plans for employees of subsidiaries. Remuneration paid by those benefit plans amounted to \$1 million in 2019 (2018: \$1 million; 2017: \$1 million).

29 – POST-BALANCE SHEET EVENTS

On February 27, 2020 the fully-consolidated Shell Midstream Partners, L.P. ("SHLX") signed an agreement with its Shell-controlled general partner to eliminate all incentive distribution rights and economic general partner interest in SHLX and convert the general partner's two per cent general partner interest in SHLX into a non-economic general partner interest in SHLX. SHLX has also entered into a Purchase and Sale Agreement with Shell affiliates to acquire our 79% interest in the Mattox Pipeline Company LLC, which owns the Mattox Pipeline, and certain logistics assets at the Shell Norco Manufacturing Complex. As consideration for the assets and the elimination of incentive distribution rights, Shell will receive 160 million newly issued SHLX common units, plus \$1.2 billion of Series A perpetual convertible preferred units at a price of \$23.63 per unit. The transaction is expected to close in the second quarter of 2020 and is subject to regulatory approvals and other customary closing conditions.

After the balance sheet date, we have seen macro-economic uncertainty with regards to prices and demand for oil, gas and products as a result of the COVID-19 (coronavirus) outbreak. Furthermore, recent global developments and uncertainty in oil supply in March have caused further abnormally large volatility in commodity markets. The scale and duration of these developments remain uncertain but could impact our earnings, cash flow and financial condition.

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED)

The information set out on pages 239-256 is referred to as “unaudited” as a means of clarifying that it is not covered by the audit opinion of the independent registered public accounting firm that has audited and reported on the Consolidated Financial Statements.

PROVED RESERVES

Proved reserves estimates are calculated pursuant to the US Securities and Exchange Commission (“SEC”) Rules and the Financial Accounting Standard Board’s Topic 932. Proved reserves can be either developed or undeveloped. The definitions used are in accordance with the SEC Rule 4-10 (a) of Regulation S-X. We include proved reserves associated with future production that will be consumed in operations.

Proved reserves shown are net of any quantities of crude oil or natural gas that are expected to be (or could be) taken as royalties in kind. Proved reserves outside North America include quantities that will be settled as royalties in cash. Proved reserves include certain quantities of crude oil or natural gas that will be produced under arrangements that involve Shell subsidiaries, joint ventures and associates in risks and rewards but do not transfer title of the product to those entities.

Subsidiaries’ proved reserves at December 31, 2019, were divided into 79% developed and 21% undeveloped on a barrel of oil equivalent basis. For the Shell share of joint ventures and associates, the proved reserves at December 31, 2019, were divided into 86% developed and 14% undeveloped on a barrel of oil equivalent basis.

Proved reserves are recognised under various forms of contractual agreements. Shell’s proved reserves volumes at December 31, 2019, present in agreements such as production-sharing contracts (“PSC”), tax/variable royalty contracts or other forms of economic entitlement contracts, where the Shell share of reserves can vary with commodity prices, were 2,170 million barrels of crude oil and natural gas liquids, and 13,433 thousand million standard cubic feet (scf) of natural gas.

Proved reserves cannot be measured exactly because estimation of reserves involves subjective judgement (see “Risk factors” on page 27 and our “Proved reserves assurance process” below). These estimates remain subject to revision and are unaudited supplementary information.

PROVED RESERVES ASSURANCE PROCESS

A central group of reserves experts, who on average have around 28 years’ experience in the oil and gas industry, undertake the primary assurance of the proved reserves bookings. This group of experts is part of the Resources Assurance and Reporting (“RAR”) organisation within Shell. A Vice President with 34 years’ experience in the oil and gas industry currently heads the RAR organisation. He is a member of the Society of Petroleum Engineers, Society of Petroleum Evaluation Engineers and holds a BA in mathematics from Oxford University and an MEng in Petroleum Engineering from Heriot Watt University. The RAR organisation reports directly to an Executive Vice President of Finance, who is a member of the Upstream Reserves Committee (“URC”). The URC is a multidisciplinary committee consisting of senior representatives from the Finance, Legal, Projects & Technology and Upstream organisations. The URC reviews and endorses all major (larger than 20 million barrels of oil equivalent) proved reserves bookings and de-bookings and endorses the total aggregated proved reserves. Final approval of all proved reserves bookings remains with Shell’s Executive Committee, and all proved reserves bookings are reviewed by Shell’s Audit Committee. The Internal Audit function also provides secondary assurance through audits of the control framework.

CRUDE OIL, NATURAL GAS LIQUIDS, SYNTHETIC CRUDE OIL AND BITUMEN

Shell subsidiaries’ proved reserves of crude oil, natural gas liquids (“NGLs”), synthetic crude oil and bitumen at the end of the year; their share of the proved reserves of joint ventures and associates at the end of the year; and the changes in such reserves during the year are set out on pages 240-242. Significant changes in these proved reserves are discussed below, where ‘revisions and reclassifications’ are changes based on new information that resulted from development drilling, production history, and changes in economic factors.

PROVED RESERVES 2019–2018

Shell subsidiaries

Europe

The net decrease of 65 million barrels in sales and purchases resulted from divestments carried out in Denmark.

Asia

The net increase of 226 million barrels in revisions and reclassifications was mainly in Oman and Kazakhstan.

USA

The increase of 86 million barrels in revisions and reclassifications mainly resulted from field performance studies and development activities in the Permian Basin and in Mars and Ursa field in the Gulf of Mexico. The increase of 74 million barrels in extensions and discoveries was in the Permian Basin and PowerNap.

South America

The increase of 72 million barrels in revisions and reclassifications mainly resulted from field performance studies and development activities in Lula and Lapa Field (Brazil). The net increase of 60 million barrels in extensions and discoveries was mainly in Mero (Brazil).

PROVED RESERVES 2018–2017

Shell subsidiaries

Europe

The net increase of 94 million barrels in revisions and reclassifications was mainly in the UK and Denmark.

Asia

The net increase of 227 million barrels in revisions and reclassifications was mainly in Oman and Kazakhstan. The sale of minerals in place of 52 million barrels occurred in Iraq (West Qurna) and Oman (Mukhaizna).

USA

The net increase of 81 million barrels in revisions and reclassifications was mainly in the Mars and Ursa fields in the Gulf of Mexico. The increase of 179 million barrels in extensions and discoveries was mainly in the Vito field in the Gulf of Mexico and in the Permian Basin.

South America

The net increase of 139 million barrels in extensions and discoveries was mainly in Mero (Brazil) and Vaca Muerta (Argentina).

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**Proved developed and undeveloped reserves 2019**

Million barrels

	North America												Total
	Europe	Asia	Oceania	Africa	USA			Canada	South America				
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	
Shell subsidiaries													
At January 1	368	1,502	129	420	1,017	23	661	–	1,027	4,486	661	–	5,147
Revisions and reclassifications	27	226	2	33	86	(2)	(34)	–	72	444	(34)	–	410
Improved recovery	–	–	–	–	–	–	–	–	4	4	–	–	4
Extensions and discoveries	–	7	–	6	74	11	–	–	60	158	–	–	158
Purchases of minerals in place	–	–	–	–	5	–	–	–	–	5	–	–	5
Sales of minerals in place	(65)	–	–	–	(29)	(2)	–	–	–	(96)	–	–	(96)
Production [A]	(56)	(184)	(10)	(64)	(171)	(12)	(20)	–	(130)	(627)	(20)	–	(647)
At December 31	274	1,551	121	395	982	18	607	–	1,033	4,374	607	–	4,981
Shell share of joint ventures and associates													
At January 1	9	281	–	–	–	–	–	–	–	290	–	–	290
Revisions and reclassifications	4	21	–	–	–	–	–	–	–	25	–	–	25
Improved recovery	–	4	–	–	–	–	–	–	–	4	–	–	4
Extensions and discoveries	–	2	–	–	–	–	–	–	–	2	–	–	2
Purchases of minerals in place	–	–	–	–	–	–	–	–	–	–	–	–	–
Sales of minerals in place	–	–	–	–	–	–	–	–	–	–	–	–	–
Production	(1)	(37)	–	–	–	–	–	–	–	(38)	–	–	(38)
At December 31	12	271	–	–	–	–	–	–	–	283	–	–	283
Total	286	1,822	121	395	982	18	607	–	1,033	4,657	607	–	5,264
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31	–	–	–	–	–	–	304	–	–	–	304	–	304

[A] Includes 1 million barrels consumed in operations for synthetic crude oil.

Proved developed reserves 2019

Million barrels

	North America												South America	Total
	Europe	Asia	Oceania	Africa	USA			Canada	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen		
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil							
Shell subsidiaries														
At January 1	243	1,318	108	335	629	21	661	–	634	3,288	661	–	3,949	
At December 31	156	1,403	106	314	641	15	607	–	675	3,310	607	–	3,917	
Shell share of joint ventures and associates														
At January 1	8	251	–	–	–	–	–	–	–	259	–	–	259	
At December 31	11	240	–	–	–	–	–	–	–	251	–	–	251	

Proved undeveloped reserves 2019

Million barrels

	North America												Total
	Europe	Asia	Oceania	Africa	USA			Canada	South America				
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	
Shell subsidiaries													
At January 1	124	185	21	85	388	2	-	-	394	1,199	-	-	1,199
At December 31	118	149	15	80	341	3	-	-	358	1,064	-	-	1,064
Shell share of joint ventures and associates													
At January 1	1	30	-	-	-	-	-	-	-	31	-	-	31
At December 31	1	31	-	-	-	-	-	-	-	32	-	-	32

Proved developed and undeveloped reserves 2018

Million barrels

					North America				South America					Total
	Europe	Asia	Oceania	Africa	USA		Canada							
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	All products	
Shell subsidiaries														
At January 1	356	1,482	132	463	899	22	649	-	946	4,300	649	-	4,949	
Revisions and reclassifications	94	227	14	18	81	7	32	-	48	489	32	-	521	
Improved recovery	-	27	-	-	-	-	-	-	14	41	-	-	41	
Extensions and discoveries	2	3	-	-	179	6	-	-	139	329	-	-	329	
Purchases of minerals in place	-	-	-	-	-	-	-	-	3	3	-	-	3	
Sales of minerals in place	(14)	(52)	(8)	-	(2)	-	-	-	-	(76)	-	-	(76)	
Production [A]	(70)	(185)	(9)	(61)	(140)	(13)	(20)	-	(122)	(600)	(20)	-	(620)	
At December 31	368	1,502	129	420	1,017	23	661	-	1,027	4,486	661	-	5,147	
Shell share of joint ventures and associates														
At January 1	12	301	-	-	-	-	-	-	-	313	-	-	313	
Revisions and reclassifications	(2)	(2)	-	-	-	-	-	-	-	(4)	-	-	(4)	
Improved recovery	-	-	-	-	-	-	-	-	-	-	-	-	-	
Extensions and discoveries	-	18	-	-	-	-	-	-	-	18	-	-	18	
Purchases of minerals in place	-	-	-	-	-	-	-	-	-	-	-	-	-	
Sales of minerals in place	-	-	-	-	-	-	-	-	-	-	-	-	-	
Production	(1)	(37)	-	-	-	-	-	-	-	(38)	-	-	(38)	
At December 31	9	281	-	-	-	-	-	-	-	290	-	-	290	
Total	377	1,783	129	420	1,017	23	661	-	1,027	4,776	661	-	5,437	
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31	-	-	-	-	-	-	331	-	-	-	331	-	331	

[A] Includes 1 million barrels consumed in operations for synthetic crude oil.

Proved developed reserves 2018

Million barrels

	North America												South America	Total
	Europe	Asia	Oceania	Africa	USA			Canada	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen		
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil							
Shell subsidiaries														
At January 1	250	1,364	46	373	569	21	649	-	651	3,274	649	-	3,923	
At December 31	243	1,318	108	335	629	21	661	-	634	3,288	661	-	3,949	
Shell share of joint ventures and associates														
At January 1	11	253	-	-	-	-	-	-	-	264	-	-	264	
At December 31	8	251	-	-	-	-	-	-	-	259	-	-	259	

Proved undeveloped reserves 2018

Million barrels

					North America				South America				Total	
	Europe	Asia	Oceania	Africa	USA		Canada							
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen		All products
Shell subsidiaries														
At January 1	106	118	86	90	330	1	-	-	295	1,026	-	-	1,026	
At December 31	124	185	21	85	388	2	-	-	394	1,199	-	-	1,199	
Shell share of joint ventures and associates														
At January 1	1	48	-	-	-	-	-	-	-	49	-	-	49	
At December 31	1	30	-	-	-	-	-	-	-	31	-	-	31	

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**Proved developed and undeveloped reserves 2017**

Million barrels

	North America												Total
	Europe	Asia	Oceania	Africa	USA			Canada	South America				
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	
Shell subsidiaries													
At January 1	435	1,386	128	529	491	18	2,014	2	992	3,979	2,014	2	5,995
Revisions and reclassifications	61	153	13	23	235	8	(3)	2	38	531	(3)	2	530
Improved recovery	-	35	-	-	38	-	-	-	-	73	-	-	73
Extensions and discoveries	-	95	-	-	242	7	-	-	30	374	-	-	374
Purchases of minerals in place	-	-	-	-	2	-	664	-	-	2	664	-	666
Sales of minerals in place	(50)	-	-	(14)	-	-	(1,992)	(2)	-	(64)	(1,992)	(2)	(2,058)
Production [A]	(90)	(187)	(9)	(75)	(109)	(11)	(34)	(2)	(114)	(595)	(34)	(2)	(631)
At December 31	356	1,482	132	463	899	22	649	-	946	4,300	649	-	4,949
Shell share of joint ventures and associates													
At January 1	7	256	-	-	-	-	-	-	-	263	-	-	263
Revisions and reclassifications	6	76	-	-	-	-	-	-	-	82	-	-	82
Improved recovery	-	3	-	-	-	-	-	-	-	3	-	-	3
Extensions and discoveries	-	1	-	-	-	-	-	-	-	1	-	-	1
Purchases of minerals in place	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-	-	-	-	-	-	-	-
Production	(1)	(35)	-	-	-	-	-	-	-	(36)	-	-	(36)
At December 31	12	301	-	-	-	-	-	-	-	313	-	-	313
Total	368	1,783	132	463	899	22	649	-	946	4,613	649	-	5,262
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31													
	-	-	-	-	-	-	325	-	-	-	325	-	325

[A] Includes 1 million barrels consumed in operations for synthetic crude oil.

Proved developed reserves 2017

Million barrels

	North America												Total
	Europe	Asia	Oceania	Africa	USA			Canada	South America				
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	
Shell subsidiaries													
At January 1	257	1,184	36	461	437	14	1,387	2	543	2,932	1,387	2	4,321
At December 31	250	1,364	46	373	569	21	649	–	651	3,274	649	–	3,923
Shell share of joint ventures and associates													
At January 1	4	215	–	–	–	–	–	–	–	219	–	–	219
At December 31	11	253	–	–	–	–	–	–	–	264	–	–	264

Proved undeveloped reserves 2017

Million barrels

	North America												Total
	Europe	Asia	Oceania	Africa	USA			Canada	South America				
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	
Shell subsidiaries													
At January 1	178	202	92	68	54	4	627	-	449	1,047	627	-	1,674
At December 31	106	118	86	90	330	1	-	-	295	1,026	-	-	1,026
Shell share of joint ventures and associates													
At January 1	3	41	-	-	-	-	-	-	-	44	-	-	44
At December 31	1	48	-	-	-	-	-	-	-	49	-	-	49

NATURAL GAS

Shell subsidiaries' proved reserves of natural gas at the end of the year, their share of the proved reserves of joint ventures and associates at the end of the year, and the changes in such reserves during the years are set out on pages 244-246. Significant changes in these proved reserves are discussed below. Volumes are not adjusted to standard heat content. Apart from integrated projects, volumes of gas are reported on an "as-sold" basis. The price used to calculate future revenue and cash flows from proved gas reserves is the contract price or the 12-month average on "as-sold" volumes. Volumes associated with integrated projects are those measured at a designated transfer point between the upstream and downstream portions of the integrated project. Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

PROVED RESERVES 2019–2018

Shell subsidiaries

Asia

The net increase of 859 thousand million scf in revisions and reclassifications was mainly in Qatar and Malaysia (Sabah and Sarawak).

Oceania

The net increase of 699 thousand million scf in revisions and reclassifications was mainly in Surat, Gorgon and Jansz-lo.

Africa

The net increase of 290 thousand million scf in revisions and reclassifications was mainly in Bonny and Gbaran (Nigeria).

Canada

The net increase of 317 thousand million scf in extensions and discoveries was mainly in Groundbirch.

Shell share of joint ventures and associates

Europe

The net decrease of 322 thousand million scf in revisions and reclassifications was mainly in Groningen (Netherlands).

PROVED RESERVES 2018–2017

Shell subsidiaries

Europe

The net increase of 1,183 thousand million scf in revisions and reclassifications was mainly in Norway, the UK, Denmark and Germany.

Asia

The net decrease of 483 thousand million scf in revisions and reclassifications was mainly in Qatar, Malaysia and Kazakhstan. The increase of 354 thousand million scf in extensions and discoveries was in Malaysia.

Oceania

The net increase of 1,438 thousand million scf in revisions and reclassifications was mainly in the Surat Basin, Jansz-lo and Gorgon (all Australia).

Africa

The net increase of 896 thousand million scf in revisions and reclassifications was mainly in Gbaran, Assa North, Forcados-Yokri (Nigeria) and Sapphire (Egypt).

USA

The net decrease of 296 thousand million scf in revisions and reclassifications was mainly in Tioga. The increase of 283 thousand million scf in extensions and discoveries was mainly in the Permian Basin.

Shell share of joint ventures and associates

Europe

The net decrease of 3,653 thousand million scf in revisions and reclassifications was mainly in Groningen (the Netherlands). Groningen: The decrease of 3,673 thousand million scf is as a result of the Dutch cabinet's announcement on March 29, 2018, about its aspiration to end Groningen production by 2030, and an agreement signed by Shell, ExxonMobil and the Dutch government in June 2018. The proved reserves are aligned with the new regulatory framework and the updated production outlook issued in November 2018 by the Dutch Ministry of Economic Affairs.

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**Proved developed and undeveloped reserves 2019**

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	3,600	10,631	8,427	2,544	2,147	989	1,509	29,847
Revisions and reclassifications	(46)	859	699	290	114	235	29	2,180
Improved recovery	-	-	-	-	-	-	3	3
Extensions and discoveries	-	36	-	152	142	317	37	684
Purchases of minerals in place	-	-	-	-	5	-	-	5
Sales of minerals in place	(210)	-	-	-	(132)	(30)	-	(372)
Production [A]	(346)	(908)	(766)	(378)	(408)	(230)	(319)	(3,355)
At December 31	2,998	10,618	8,360	2,608	1,868	1,281	1,259	28,992
Shell share of joint ventures and associates								
At January 1	1,163	4,581	24	-	-	-	-	5,768
Revisions and reclassifications	(322)	64	34	-	-	-	-	(224)
Improved recovery	-	1	-	-	-	-	-	1
Extensions and discoveries	-	5	-	-	-	-	-	5
Purchases of minerals in place	-	-	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-	-	-
Production [B]	(246)	(453)	(22)	-	-	-	-	(721)
At December 31	595	4,198	36	-	-	-	-	4,829
Total	3,593	14,816	8,396	2,608	1,868	1,281	1,259	33,821
Reserves attributable to non-controlling interest in shell subsidiaries at December 31	-	-	-	-	-	-	-	-

[A] Includes 247 thousand million standard cubic feet consumed in operations.

[B] Includes 42 thousand million standard cubic feet consumed in operations.

Proved developed reserves 2019

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	2,658	10,092	5,820	1,573	1,706	721	1,238	23,808
At December 31	2,060	10,091	5,769	1,523	1,615	781	968	22,807
Shell share of joint ventures and associates								
At January 1	1,136	3,938	24	-	-	-	-	5,099
At December 31	555	3,519	36	-	-	-	-	4,110

Proved undeveloped reserves 2019

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	942	539	2,607	971	441	268	271	6,039
At December 31	937	528	2,591	1,085	254	499	291	6,185
Shell share of joint ventures and associates								
At January 1	27	643	-	-	-	-	-	670
At December 31	39	680	-	-	-	-	-	719

Proved developed and undeveloped reserves 2018

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	3,100	11,822	7,978	2,082	2,569	1,272	1,501	30,324
Revisions and reclassifications	1,183	(483)	1,438	896	(296)	(153)	181	2,766
Improved recovery	-	-	-	-	-	-	7	7
Extensions and discoveries	3	354	-	-	283	131	65	836
Purchases of minerals in place	-	-	-	-	-	-	14	14
Sales of minerals in place	(192)	(157)	(232)	-	(32)	-	-	(613)
Production [A]	(494)	(906)	(757)	(434)	(377)	(261)	(258)	(3,487)
At December 31	3,600	10,631	8,427	2,544	2,147	989	1,509	29,847
Shell share of joint ventures and associates								
At January 1	5,125	4,964	19	-	-	-	-	10,108
Revisions and reclassifications	(3,653)	62	25	-	-	-	-	(3,566)
Improved recovery	-	-	-	-	-	-	-	-
Extensions and discoveries	-	5	-	-	-	-	-	5
Purchases of minerals in place	-	-	-	-	-	-	-	-
Sales of minerals in place	(37)	-	-	-	-	-	-	(37)
Production [B]	(273)	(450)	(20)	-	-	-	-	(743)
At December 31	1,163	4,581	24	-	-	-	-	5,768
Total	4,763	15,212	8,451	2,544	2,147	989	1,509	35,615
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31	-	-	-	-	-	-	-	-

[A] Includes 245 thousand million standard cubic feet consumed in operations.

[B] Includes 41 thousand million standard cubic feet consumed in operations.

Proved developed reserves 2018

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	2,978	11,460	5,026	1,493	1,652	859	1,225	24,693
At December 31	2,658	10,092	5,820	1,573	1,706	721	1,238	23,808
Shell share of joint ventures and associates								
At January 1	5,055	4,275	19	-	-	-	-	9,349
At December 31	1,136	3,938	24	-	-	-	-	5,099

Proved undeveloped reserves 2018

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	122	362	2,952	589	917	413	276	5,631
At December 31	942	539	2,607	971	441	268	271	6,039
Shell share of joint ventures and associates								
At January 1	70	689	-	-	-	-	-	759
At December 31	27	643	-	-	-	-	-	670

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**Proved developed and undeveloped reserves 2017**

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	3,741	11,073	9,051	2,225	675	844	1,650	29,259
Revisions and reclassifications	197	979	(574)	287	958	412	45	2,304
Improved recovery	-	66	-	-	74	-	-	140
Extensions and discoveries	2	549	-	-	1,163	205	6	1,925
Purchases of minerals in place	-	-	204	-	3	43	27	277
Sales of minerals in place	(224)	-	-	(7)	(11)	(6)	-	(248)
Production [A]	(616)	(845)	(703)	(423)	(293)	(226)	(227)	(3,333)
At December 31	3,100	11,822	7,978	2,082	2,569	1,272	1,501	30,324
Shell share of joint ventures and associates								
At January 1	6,497	4,754	31	-	-	-	-	11,282
Revisions and reclassifications	(1,027)	652	9	-	-	-	-	(366)
Improved recovery	-	1	-	-	-	-	-	1
Extensions and discoveries	-	11	-	-	-	-	-	11
Purchases of minerals in place	-	-	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-	-	-
Production [B]	(345)	(454)	(21)	-	-	-	-	(820)
At December 31	5,125	4,964	19	-	-	-	-	10,108
Total	8,225	16,786	7,997	2,082	2,569	1,272	1,501	40,432
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31	-	2	-	-	-	-	-	2

[A] Includes 215 thousand million standard cubic feet consumed in operations.

[B] Includes 41 thousand million standard cubic feet consumed in operations.

Proved developed reserves 2017

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	3,437	10,569	3,966	1,618	563	458	1,172	21,783
At December 31	2,978	11,460	5,026	1,493	1,652	859	1,225	24,693
Shell share of joint ventures and associates								
At January 1	5,240	4,110	31	-	-	-	-	9,381
At December 31	5,055	4,275	19	-	-	-	-	9,349

Proved undeveloped reserves 2017

	Europe	Asia	Oceania	Africa	Thousand million standard cubic feet			Total
					North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	304	504	5,085	607	112	386	478	7,476
At December 31	122	362	2,952	589	917	413	276	5,631
Shell share of joint ventures and associates								
At January 1	1,257	644	-	-	-	-	-	1,901
At December 31	70	689	-	-	-	-	-	759

STANDARDISED MEASURE OF DISCOUNTED FUTURE CASH FLOWS

The SEC Form 20-F requires the disclosure of a standardised measure of discounted future net cash flows, relating to proved reserves quantities and based on a 12-month unweighted arithmetic average sales price, calculated on a first-day-of-the-month basis, with cost factors based on those at the end of each year, currently enacted tax rates and a 10% annual discount factor. In our view, the information so calculated does not provide a reliable measure of future cash flows from proved reserves, nor does it permit a realistic comparison to be made of one entity with another because the assumptions used cannot reflect the varying circumstances within each entity. In addition, a substantial but unknown proportion of future real cash flows from oil and gas production activities is expected to derive from reserves which have already been discovered, but which cannot yet be regarded as proved.

STANDARDISED MEASURE OF DISCOUNTED FUTURE CASH FLOWS RELATING TO PROVED RESERVES AT DECEMBER 31

2019 – Shell subsidiaries

					North America		South America	
	Europe	Asia	Oceania	Africa	USA	Canada		Total
Future cash inflows	33,762	111,802	71,775	31,046	55,800	31,522	64,957	400,664
Future production costs	11,818	32,581	21,589	12,158	30,139	16,651	32,362	157,298
Future development costs	6,047	13,449	10,103	4,081	11,137	4,603	13,219	62,639
Future tax expenses	9,285	25,938	7,016	10,542	2,397	2,313	5,429	62,920
Future net cash flows	6,612	39,834	33,067	4,265	12,127	7,955	13,947	117,807
Effect of discounting cash flows at 10%	1,917	17,851	13,328	377	1,815	5,571	4,094	44,953
Standardised measure of discounted future net cash flows	4,695	21,983	19,739	3,888	10,312	2,384	9,853	72,854
Non-controlling interest included	-	-	-	-	-	1,371	-	1,371

2019 – Shell share of joint ventures and associates

					North America		South America	
	Europe	Asia	Oceania	Africa	USA	Canada		Total
Future cash inflows	3,615	38,099	122	-	-	-	-	41,836
Future production costs	2,810	18,336	81	-	-	-	-	21,227
Future development costs	935	6,946	36	-	-	-	-	7,917
Future tax expenses	718	6,160	4	-	-	-	-	6,882
Future net cash flows	(848)	6,657	1	-	-	-	-	5,812
Effect of discounting cash flows at 10%	(266)	1,190	(7)	-	-	-	-	917
Standardised measure of discounted future net cash flows	(582) [A]	5,467	8	-	-	-	-	4,893

[A] While proved reserves are economically producible at the 2019 yearly average price, the standardised measure of discounted future net cash flows was negative for those proved reserves at December 31, 2019, due to addition of overhead, tax and abandonment costs and ongoing commitments post production of proved reserves.

2018 – Shell subsidiaries

					North America		South America	
	Europe	Asia	Oceania	Africa	USA	Canada		Total
Future cash inflows	50,392	122,037	72,355	36,080	68,546	34,719	74,417	458,545
Future production costs	18,400	32,773	22,219	13,237	32,533	17,378	42,301	178,842
Future development costs	8,649	12,301	11,598	4,672	11,486	4,674	6,991	60,370
Future tax expenses	12,603	30,994	5,899	12,805	1,948	3,257	7,764	75,271
Future net cash flows	10,739	45,969	32,639	5,366	22,578	9,411	17,360	144,062
Effect of discounting cash flows at 10%	3,024	20,957	12,130	572	5,039	6,446	6,048	54,217
Standardised measure of discounted future net cash flows	7,715	25,012	20,509	4,794	17,539	2,964	11,312	89,845
Non-controlling interest included	-	1	-	-	-	1,638	-	1,639

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**2018 – Shell share of joint ventures and associates**

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	5,260	44,327	104	-	-	-	-	49,691
Future production costs	2,712	20,886	80	-	-	-	-	23,677
Future development costs	1,083	6,726	36	-	-	-	-	7,844
Future tax expenses	1,136	7,128	1	-	-	-	-	8,265
Future net cash flows	329	9,588	(13)	-	-	-	-	9,904
Effect of discounting cash flows at 10%	(76)	2,759	(8)	-	-	-	-	2,675
Standardised measure of discounted future net cash flows	405	6,829	(5) [A]	-	-	-	-	7,229

[A] While proved reserves are economically producible at the 2018 yearly average price, the standardised measure of discounted future net cash flows was negative for those proved reserves at December 31, 2018, due to addition of overhead, tax and abandonment costs and ongoing commitments post production of proved reserves.

2017 – Shell subsidiaries

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	34,902	94,535	51,052	29,276	49,389	32,576	50,620	342,350
Future production costs	15,672	30,894	18,264	11,496	29,505	20,242	30,924	156,997
Future development costs	7,852	12,558	14,062	4,920	14,200	5,115	6,210	64,917
Future tax expenses	5,747	18,048	1,169	9,064	2,177	2,509	4,888	43,602
Future net cash flows	5,631	33,035	17,557	3,796	3,507	4,710	8,598	76,834
Effect of discounting cash flows at 10%	825	15,115	5,773	(9)	(796)	3,077	2,325	26,310
Standardised measure of discounted future net cash flows	4,806	17,920	11,784	3,805	4,303	1,633	6,273	50,524
Non-controlling interest included	-	1	-	-	-	870	-	871

2017 – Shell share of joint ventures and associates

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	22,725	37,954	69	-	-	-	-	60,748
Future production costs	17,442	17,592	54	-	-	-	-	35,088
Future development costs	1,051	7,605	64	-	-	-	-	8,720
Future tax expenses	1,803	5,172	-	-	-	-	-	6,975
Future net cash flows	2,429	7,585	(49)	-	-	-	-	9,965
Effect of discounting cash flows at 10%	1,008	1,862	(14)	-	-	-	-	2,856
Standardised measure of discounted future net cash flows	1,421	5,723	(35) [A]	-	-	-	-	7,109

[A] While proved reserves are economically producible at the 2017 yearly average price, the standardised measure of discounted future net cash flows was negative for those proved reserves at December 31, 2017, due to addition of overhead, tax and abandonment costs and ongoing commitments post production of proved reserves.

CHANGE IN STANDARDISED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED RESERVES

2019

			\$ million
	Shell subsidiaries	Shell share of joint ventures and associates	Total
At January 1	89,845	7,229	97,074
Net changes in prices and production costs	(18,759)	(1,017)	(19,776)
Revisions of previous reserves estimates	13,777	(293)	13,484
Extensions, discoveries and improved recovery	5,193	93	5,286
Purchases and sales of minerals in place	(2,831)	–	(2,831)
Development cost related to future production	(9,417)	(2)	(9,419)
Sales and transfers of oil and gas, net of production costs	(33,319)	(3,918)	(37,237)
Development cost incurred during the year	10,430	702	11,132
Accretion of discount	12,004	1,133	13,137
Net change in income tax	5,931	966	6,897
At December 31	72,854	4,893	77,747

2018

			\$ million
	Shell subsidiaries	Shell share of joint ventures and associates	Total
At January 1	50,524	7,109	57,633
Net changes in prices and production costs	58,128	6,156	64,284
Revisions of previous reserves estimates	15,265	(1,447)	13,818
Extensions, discoveries and improved recovery	8,936	532	9,468
Purchases and sales of minerals in place	(3,401)	(20)	(3,421)
Development cost related to future production	(3,876)	(308)	(4,184)
Sales and transfers of oil and gas, net of production costs	(38,014)	(4,858)	(42,872)
Development cost incurred during the year	10,724	666	11,390
Accretion of discount	7,060	994	8,054
Net change in income tax	(15,501)	(1,595)	(17,096)
At December 31	89,845	7,229	97,074

2017

			\$ million
	Shell subsidiaries	Shell share of joint ventures and associates	Total
At January 1	27,718	4,176	31,894
Net changes in prices and production costs	34,190	3,952	38,142
Revisions of previous reserves estimates	13,769	1,931	15,700
Extensions, discoveries and improved recovery	3,901	79	3,980
Purchases and sales of minerals in place	(2,068)	–	(2,068)
Development cost related to future production	(4,823)	461	(4,362)
Sales and transfers of oil and gas, net of production costs	(27,544)	(3,652)	(31,196)
Development cost incurred during the year	14,262	536	14,798
Accretion of discount	3,844	630	4,474
Net change in income tax	(12,725)	(1,004)	(13,729)
At December 31	50,524	7,109	57,633

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES CAPITALISED COSTS**

The aggregate amount of property, plant and equipment and intangible assets, excluding goodwill, relating to oil and gas exploration and production activities, and the aggregate amount of the related depreciation, depletion and amortisation at December 31, are shown in the tables below.

Shell subsidiaries

	\$ million	
	2019	2018
Cost		
Proved properties [A]	265,700	265,489
Unproved properties	18,669	21,256
Support equipment and facilities	11,043	6,404
	295,412	293,149
Depreciation, depletion and amortisation		
Proved properties [A]	129,809	126,641
Unproved properties	4,089	3,362
Support equipment and facilities	4,078	3,424
	137,976	133,427
Net capitalised costs	157,436	159,722

[A] Includes capitalised asset decommissioning and restoration costs and related depreciation.

Shell share of joint ventures and associates

	\$ million	
	2019	2018
Cost		
Proved properties [A]	46,895	44,331
Unproved properties	2,428	2,591
Support equipment and facilities	4,882	4,399
	54,205	51,321
Depreciation, depletion and amortisation		
Proved properties [A]	34,120	31,702
Unproved properties	–	–
Support equipment and facilities	2,817	2,586
	36,937	34,288
Net capitalised costs	17,268	17,033

[A] Includes capitalised asset decommissioning and restoration costs and related depreciation.

OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES COSTS INCURRED

Costs incurred during the year in oil and gas property acquisition, exploration and development activities, whether capitalised or charged to income currently, are shown in the tables below. As a result of the adoption of IFRS 16 Leases as of January 1, 2019, leases are included in year 2019. Development costs include capitalised asset decommissioning and restoration costs (including increases or decreases arising from changes to cost estimates or to the discount rate applied to the obligations) and exclude costs of acquiring support equipment and facilities, but include depreciation thereon.

Shell subsidiaries

								\$ million
	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Other [A]		
Acquisition of properties								
Proved	3	105	-	10	-	-	-	118
Unproved	-	11	-	67	118	5	3	204
Exploration	428	165	117	253	1,723	402	500	3,588 [B]
Development	2,054	1,434	1,225	1,480	4,455	287	2,418	13,353

[A] Comprises Canada and Mexico.

[B] Includes \$1,195 million of Shales-related exploration activities. In 2019, we participated in 231 Shales productive exploratory wells with proved reserves allocated (Shell share: 117 wells).

2018

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Other [A]		Total
Acquisition of properties								
Proved	3	3	-	596	44	-	-	646
Unproved	2	6	-	76	44	310	486	924
Exploration	384	182	49	188	1,912	251	502	3,468 [B]
Development	1,452	1,102	1,632	962	4,052	505	2,095	11,800

[A] Comprises Canada, Honduras and Mexico.

[B] Includes \$1,581 million of Shales-related exploration activities. In 2018, we participated in 234 Shales productive exploratory wells with proved reserves allocated (Shell share: 118 wells).

2017

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Other [A]		Total
Acquisition of properties								
Proved	-	-	-	10	-	2,246	19	2,275
Unproved	-	12	-	18	141	320	57	548
Exploration	329	135	38	138	1,354	235	600	2,829
Development	776	840	2,493	371	4,123	722	1,671	10,996

[A] Comprises Canada, Honduras and Mexico.

SHELL SHARE OF JOINT VENTURES AND ASSOCIATES

Joint ventures and associates did not incur costs in the acquisition of oil and gas properties in 2019, 2018 or 2017.

2019

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Canada		Total
Exploration	1	116	12	-	-	-	-	129
Development	94	1,400	65	-	-	-	-	1,559

2018

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Canada		Total
Exploration	-	90	14	-	-	-	-	104
Development	229	1,026	79	-	-	-	-	1,334

2017

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Canada		Total
Exploration	3	82	8	-	-	-	-	93
Development	(22) [A]	660	58	-	-	-	-	696

[A] Includes a revision of decommissioning and restoration provisions.

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES EARNINGS**

The results of operations for oil and gas producing activities are shown in the tables below. Taxes other than income tax include cash-paid royalties to governments outside North America.

Shell subsidiaries**2019**

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Other [A]		Total
Revenue								
Third parties	1,257	3,065	931	1,936	2,638	632	844	11,303
Sales between businesses	4,911	10,526	4,719	3,289	7,786	1,936	7,647	40,814
Total	6,168	13,591	5,650	5,225	10,424	2,568	8,491	52,117
Production costs excluding taxes	1,582	2,065	1,178	1,062	2,807	983	1,135	10,812
Taxes other than income tax	94	749	136	370	103	–	2,613	4,065
Exploration	619	583	107	187	411	159	288	2,354
Depreciation, depletion and amortisation	2,604	2,130	1,957	1,354	6,932	858	3,929	19,764
Other costs/(income)	(20)	1,599	(105)	121	(575)	818	1,379	3,217
Earnings before taxation	1,289	6,465	2,377	2,131	746	(250)	(853)	11,905
Taxation charge/(credit)	848	4,013	1,094	1,431	154	(110)	(78)	7,352
Earnings after taxation	441	2,452	1,283	700	592	(140)	(775)	4,553

[A] Comprises Canada and Mexico.

2018

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Other [A]		Total
Revenue								
Third parties	1,875	3,364	1,389	2,401	2,165	507	1,023	12,724
Sales between businesses	6,705	11,284	4,683	3,586	7,716	1,946	7,154	43,074
Total	8,580	14,648	6,072	5,987	9,881	2,453	8,177	55,798
Production costs excluding taxes	2,262	2,143	1,073	1,093	2,573	1,069	1,401	11,614
Taxes other than income tax	122	841	199	328	83	–	2,767	4,340
Exploration	277	149	78	144	341	114	237	1,340
Depreciation, depletion and amortisation	2,684	2,301	1,571	1,394	4,543	(346)	3,271	15,418
Other costs/(income)	947	(180)	(514)	609	447	667	849	2,825
Earnings before taxation	2,288	9,394	3,665	2,419	1,894	949	(348)	20,261
Taxation (credit)/charge	2,047	4,851	893	902	550	236	1,162	10,641
Earnings after taxation	241	4,543	2,772	1,517	1,344	713	(1,510)	9,620

[A] Comprises Canada, Honduras and Mexico.

2017

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Other [A]		Total
Revenue								
Third parties	1,193	2,708	1,414	1,872	1,080	339	689	9,295
Sales between businesses	7,120	9,061	2,400	3,218	5,119	2,938	5,245	35,101
Total	8,313	11,769	3,814	5,090	6,199	3,277	5,934	44,396
Production costs excluding taxes	2,509	2,469	1,110	1,365	2,558	1,571	1,218	12,800
Taxes other than income tax	89	556	119	287	98	1	1,691	2,841
Exploration	243	245	42	129	868	142	276	1,945
Depreciation, depletion and amortisation	2,560	2,892	1,777	1,863	3,410	3,886	3,374	19,762
Other costs/(income)	(157)	1,073	(382)	145	114	1,050	469	2,312
Earnings before taxation	3,069	4,534	1,148	1,301	(849)	(3,373)	(1,094)	4,736
Taxation charge/(credit)	1,689	2,969	(202)	(361)	363	(1,486)	(294)	2,678
Earnings after taxation	1,380	1,565	1,350	1,662	(1,212)	(1,887)	(800)	2,058

[A] Comprises Canada, Honduras and Mexico.

SHELL SHARE OF JOINT VENTURES AND ASSOCIATES

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Third-party revenue	1,233	5,475	81	-	-	-	-	6,789
Total	1,233	5,475	81	-	-	-	-	6,789
Production costs excluding taxes	249	669	88	-	-	-	-	1,006
Taxes other than income tax	75	1,037	6	-	-	-	-	1,118
Exploration	4	51	-	-	-	-	-	55
Depreciation, depletion and amortisation	217	949	415	-	-	-	-	1,581
Other costs/(income)	547	622	(18)	-	1	1	-	1,153
Earnings before taxation	141	2,147	(410)	-	(1)	(1)	-	1,876
Taxation charge	39	957	-	-	-	-	-	996
Earnings after taxation	102	1,190	(410)	-	(1)	(1)	-	880

2018

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Third-party revenue	1,395	5,884	79	-	-	-	-	7,358
Total	1,395	5,884	79	-	-	-	-	7,358
Production costs excluding taxes	307	674	105	-	-	-	-	1,086
Taxes other than income tax	82	1,259	4	-	-	-	-	1,345
Exploration	5	45	-	-	-	-	-	50
Depreciation, depletion and amortisation	318	1,016	163	-	-	-	-	1,497
Other costs/(income)	595	615	(26)	-	-	-	-	1,184
Earnings before taxation	88	2,275	(167)	-	-	-	-	2,196
Taxation charge	7	975	-	-	-	-	-	982
Earnings after taxation	81	1,300	(167)	-	-	-	-	1,214

2017

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Third-party revenue	1,646	4,503	58	-	-	-	-	6,207
Total	1,646	4,503	58	-	-	-	-	6,207
Production costs excluding taxes	337	729	93	-	-	-	-	1,159
Taxes other than income tax	631	705	4	-	-	-	-	1,340
Exploration	7	57	4	-	-	-	-	68
Depreciation, depletion and amortisation	188	1,654	40	-	-	-	-	1,882
Other costs/(income)	(83)	511	(60)	-	-	-	-	368
Earnings before taxation	566	847	(23)	-	-	-	-	1,390
Taxation charge	173	197	-	-	-	-	-	370
Earnings after taxation	393	650	(23)	-	-	-	-	1,020

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued

ACREAGE AND WELLS

The tables below reflect acreage and wells of Shell subsidiaries, joint ventures and associates. The term “gross” refers to the total activity in which Shell subsidiaries, joint ventures and associates have an interest. The term “net” refers to the sum of the fractional interests owned by Shell subsidiaries plus the Shell share of joint ventures and associates’ fractional interests. Data below are rounded to the nearest whole number.

Oil and gas acreage (at December 31)

	2019				2018				2017			
	Developed		Undeveloped		Developed		Undeveloped		Developed		Undeveloped	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	Thousand acres											
Europe [A]	6,289	1,915	13,864	6,082	6,022 [B]	1,954 [B]	14,385 [C]	6,540 [C]	6,214 [D]	2,051 [D]	13,079 [E]	5,823 [E]
Asia	21,387	7,672	31,486	14,880	22,087	7,885	31,676	15,433	25,975	9,139	35,305	18,730
Oceania	3,025	1,215	11,720	6,260	3,202	1,220	15,319 [F]	10,095 [F]	3,296	1,255	22,295 [G]	13,985
Africa	4,663	1,938	62,965	32,564	4,666	1,940	38,874	22,732	4,663	1,938	33,453	20,811
North America – USA	1,333	877	2,489	1,917	1,541	952	2,133	1,635	1,936	1,134	2,718	1,937
North America – Mexico	–	–	5,178	3,291	–	–	5,178	3,885	–	–	–	–
North America – Canada	483	329	1,783	1,265	1,108	752	1,681	1,193	953	651	15,818	14,468
South America	1,393	595	16,446	10,214	1,490	710	10,352	6,725	1,302	606	9,338	6,196
Total	38,573	14,541	145,931	76,473	40,116	15,413	119,598	68,238	44,339	16,774	132,006	81,950

[A] Includes Greenland for 2018 and 2017.

[B] Corrected from 6,228 (1,958 net).

[C] Corrected from 15,443 (6,913 net).

[D] Corrected from 6,463 (2,071 net).

[E] Corrected from 14,119 (6,187 net).

[F] Corrected from 15,662 (10,298 net).

[G] Corrected from 22,406.

Number of productive wells [A] (at December 31)

	2019				2018				2017			
	Oil		Gas		Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	Thousand wells											
Europe	893	217	1,091	345	1,077	277	1,201	379	1,138 [B]	299 [B]	1,255 [C]	396 [C]
Asia	7,767	2,841	336	193	7,455 [D]	2,728 [D]	331	189	9,279	3,067	682	269
Oceania	–	–	3,352	1,896	–	–	3,411	1,924	–	–	3,499	1,926
Africa	514	206	202	139	478	189	195	132	380	155	180	122
North America – USA	14,935	7,638	822	516	15,224	7,745	1,479	672	15,408	7,817	1,636	717
North America – Canada	–	–	748	676	1	1	936	846	–	–	892	794
South America	137	63	58	36	117 [E]	52 [E]	63 [F]	41	111	47	55	32
Total	24,246	10,965	6,609	3,801	24,352	10,992	7,616	4,183	26,316	11,385	8,199	4,256

[A] The number of productive wells with multiple completions at December 31, 2019, was 955 gross (418 net); December 31, 2018: 1,061 gross (454 net), corrected from 1,132 Gross (489 Net); December 31, 2017: 1,696 gross (636 net).

[B] Corrected from 1,156 (303 net).

[C] Corrected from 1,235 (392 net).

[D] Corrected from 7,498 (2,750 net).

[E] Corrected from 119 (53 net).

[F] Corrected from 62.

Number of net productive wells and dry holes drilled

	2019		2018		2017	
	Productive	Dry	Productive	Dry	Productive	Dry
Exploratory [A]						
Europe	-	4	1	2	-	1
Asia	25	17	22 [B]	11 [C]	18 [D]	5
Oceania	-	2	-	-	2	-
Africa	8	8	6	6	2	3
North America – USA	89	9	104	4	9	6
North America – Canada	24	-	14		30	5
South America	8	1	6	7	6	-
Total	154	41	153	30	67	20
Development						
Europe	4	1	4	-	5	-
Asia	182	-	198 [E]	-	291 [F]	4
Oceania	16	-	54 [G]	-	63	-
Africa	34	-	24	1	24	3
North America – USA	280	5	276	-	237	-
North America – Canada	6	-	53	-	56	1
South America	10	1	5	-	1	-
Total	532	7	614	1	677	8

[A] Productive wells are wells with proved reserves allocated. Wells in the process of drilling are excluded and presented separately below.

[B] Corrected from 9.

[C] Corrected from 10.

[D] Corrected from 3.

[E] Corrected from 222.

[F] Corrected from 312.

[G] Corrected from 41.

Number of wells in the process of exploratory drilling [A]

	At January 1		Wells in the process of drilling at January 1 and allocated proved reserves during the year		Wells in the process of drilling at January 1 and determined as dry during the year		New wells in the process of drilling at December 31		At December 31	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Europe	19	10	(1)	-	(5)	(3)	2	1	15	8
Asia	75 [B]	28 [B]	(21)	(8)	(21)	(8)	20	8	53	20
Oceania	42 [C]	15	-	-	(3)	(1)	1	1	40	15
Africa	47	31	(3)	(3)	(6)	(6)	7	6	45	28
North America – USA	239 [D]	158 [D]	(126)	(60)	(13)	(9)	97	37	197	126
North America – Canada	5 [E]	5 [E]	(5)	(5)	-	-	21	21	21	21
South America	37 [F]	19	(10)	(7)	(1)	-	7	4	33	16
Total	464	266	(166)	(83)	(49)	(27)	155	78	404	234

[A] Wells in the process of exploratory drilling includes wells pending further evaluation.

[B] Corrected from 68 (25 net).

[C] Corrected from 45.

[D] Corrected from 151 (96 net).

[E] Corrected from 0 (0 net).

[F] Corrected from 36.

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**Number of wells in the process of development drilling**

	2019			
	At January 1		At December 31	
	Gross	Net	Gross	Net
Europe	5	2	11	3
Asia	41 [A]	16 [A]	53	21
Oceania	19 [B]	8 [B]	123	71
Africa	5	5	5	2
North America – USA	40 [C]	20 [C]	41	34
North America – Canada	12 [D]	12 [D]	–	–
South America	9	4	12	8
Total	131	67	245	139

[A] Corrected from 36 (14 net).

[B] Corrected from 3 (1 net).

[C] Corrected from 64 (33 net).

[D] Corrected from 17 (17 net).

In addition to the present activities mentioned above, the following recovery methods are operational in the following countries: water flooding (Brazil (including water alternating gas), Brunei, Egypt, Malaysia, Nigeria, Norway, Oman, Russia, the UK and the USA); gas injection (Brunei, Kazakhstan, Malaysia, Nigeria and Oman); steam injection (the Netherlands, Oman and the USA), and polymer flooding (Oman).

PARENT COMPANY FINANCIAL STATEMENTS

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PARENT COMPANY FINANCIAL STATEMENTS continued**STATEMENT OF INCOME**

		\$ million	
	Notes	2019	2018
Dividend income		21,051	23,278
Interest and other income	3	101	141
Administrative expenses		(54)	(43)
Interest and other expense	3	(146)	(222)
Income before taxation		20,952	23,154
Taxation charge	6	567	44
Income for the period		20,385	23,110

STATEMENT OF COMPREHENSIVE INCOME

		\$ million	
		2019	2018
Income for the period		20,385	23,110
Comprehensive income for the period		20,385	23,110

BALANCE SHEET

		\$ million	
	Notes	Dec 31, 2019	Dec 31, 2018
Assets			
Non-current assets			
Investments in subsidiaries	4	256,654	256,920
Deferred tax	6	-	355
		256,654	257,275
Current assets			
Amounts due from subsidiaries	13	1,864	9,263
Cash and cash equivalents		4	3
		1,868	9,266
Total assets		258,522	266,541
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	5	1,775	4,862
Total liabilities		1,775	4,862
Equity			
Share capital	8	657	685
Other reserves	9	235,561	235,536
Retained earnings		20,529	25,458
Total equity		256,747	261,679
Total liabilities and equity		258,522	266,541

Signed on behalf of the Board

/s/ Jessica Uhl

JESSICA UHLChief Financial Officer
March 11, 2020

STATEMENT OF CHANGES IN EQUITY

				\$ million
	Notes	Share capital	Other reserves	Retained earnings
At January 1, 2019		685	235,536	25,458
Comprehensive income for the period		-	-	20,385
Dividends	10	-	-	(15,199)
Repurchases of shares	8	(28)	28	(10,286)
Share-based compensation	9	-	(3)	171
At December 31, 2019		657	235,561	20,529
At January 1, 2018		696	235,366	21,778
Comprehensive income for the period		-	-	23,110
Dividends	10	-	-	(15,675)
Repurchases of shares	8	(11)	11	(4,519)
Share-based compensation [A]	9	-	159	764
At December 31, 2018		685	235,536	25,458

[A] The amendments to IFRS 2 Share-based payment became effective January 1, 2018. Following adoption of the amendments, components of share-based payments (related to tax) that were previously classified as cash-settled are classified as equity-settled from 2018 onwards.

STATEMENT OF CASH FLOWS

	Notes	2019	2018
Income for the period		20,385	23,110
Adjustment for:			
Dividend income		(21,051)	(23,278)
Taxation charge		567	44
Interest income		(101)	(141)
Interest expense		111	156
Share-based compensation		19	16
Decrease/(Increase) in working capital		4,008	(3,796)
Cash flow from operating activities		3,938	(3,889)
Dividends received		21,051	23,278
Interest received		101	141
Share-based compensation		408	248
Cash flow from investing activities		21,560	23,667
Cash dividends paid	10	(15,198)	(15,675)
Shares repurchased	8	(10,188)	(3,947)
Interest and other expenses paid		(111)	(156)
Cash flow from financing activities		(25,497)	(19,778)
Change in cash and cash equivalents		1	-
Cash and cash equivalents at beginning of the year		3	3
Cash and cash equivalents at end of the year		4	3

NOTES TO THE PARENT COMPANY FINANCIAL STATEMENTS

1 BASIS OF PREPARATION

The Financial Statements of Royal Dutch Shell plc (the "Company") have been prepared in accordance with the provisions of the Companies Act 2006 (the "Act") and with International Financial Reporting Standards ("IFRS") as adopted by the European Union. As applied to the Company, there are no material differences from IFRS as issued by the International Accounting Standards Board ("IASB"); therefore, the Financial Statements have been prepared in accordance with IFRS as issued by the IASB.

As described in the accounting policies in Note 2, the Financial Statements have been prepared under the historical cost convention except for certain items measured at fair value. Those accounting policies have been applied consistently in all periods.

The Financial Statements were approved and authorised for issue by the Board of Directors on March 11, 2020.

The preparation of financial statements in conformity with IFRS requires the use of certain accounting estimates. It also requires management to exercise its judgement in the process of applying the Company's accounting policies. Actual results may differ from those estimates.

The financial results of the Company are included in the Consolidated Financial Statements on pages 190-238. The financial results of the Company incorporate the results of the Dividend Access Trust (the "Trust"), the financial statements of which are presented on pages 268-271.

The Company's principal activity is being the parent company for Shell, as described in Note 1 of the Consolidated Financial Statements (see page 195).

2 SIGNIFICANT ACCOUNTING POLICIES

The Company's accounting policies follow those of Shell as set out in Note 2A of the Consolidated Financial Statements (see pages 195-203). The following are Company-specific policies.

PRESENTATION AND FUNCTIONAL CURRENCY

The Company's presentation and functional currency is US dollars (dollars).

INVESTMENTS

Investments in subsidiaries are stated at cost, net of any impairment. Investments are tested for impairment whenever events or changes in circumstances indicate that the carrying amounts for those investments may not be recoverable. For the purposes of determining whether impairment of investments in subsidiaries has occurred, and the extent of any impairment loss or its reversal, the key assumptions management uses in estimating risk-adjusted future cash flows for value-in-use measures include future oil and gas prices, expected production volumes and refining margins appropriate to the local circumstances and environment. These assumptions and the judgements of management that are based on them are subject to change as new information becomes available. Cash flow estimates are risk-adjusted to reflect local conditions as appropriate and discounted at a rate based on Shell's marginal cost of debt. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Future price assumptions are presented in Note 8 of the Consolidated Financial Statements (see pages 210-213).

The original cost of the Company's investment in Royal Dutch Petroleum Company ("Royal Dutch") was based on the fair value of the shares transferred to the Company by the former shareholders of Royal Dutch in exchange for A shares in the Company during the public exchange offer in 2005. The original cost of the Company's investment in The "Shell" Transport and Trading Company, plc, now The Shell Transport and Trading Company Limited ("Shell Transport"), was the fair value of the shares held by the former shareholders of The "Shell" Transport and Trading Company plc transferred in consideration for the issuance of B shares as part of the Scheme of Arrangement in 2005. The Company's investments in Royal Dutch and Shell Transport now represent an investment in Shell Petroleum N.V. ("Shell Petroleum"); this change had no impact on the cost of investments in subsidiaries. On February 15, 2016 the Company acquired all the voting rights in BG Group plc via the issuance of shares and cash payments of total fair value \$53,086 million. In September 2016, the Company's shares in BG Group Limited ("BG"), formerly BG Group plc, were exchanged for an increased investment in Shell Petroleum.

DIVIDEND INCOME

Dividends are recognised on a paid basis unless the dividend has been confirmed by a general meeting of Shell Petroleum, in which case income is recognised on the date at which receipt is deemed virtually certain.

SHARE-BASED COMPENSATION PLANS

The fair value of share-based compensation for equity-settled plans granted to employees of subsidiaries under the Company's plans is recognised as an investment in subsidiaries from the date of grant over the vesting period with a corresponding increase in equity.

In the year of vesting of a plan, the costs for the actual deliveries are charged to the relevant employing subsidiaries. This is recognised as a realisation of the investment originally booked. If the actual vesting costs are higher than the cumulatively recognised share-based compensation charge, the difference is recognised in income.

Note 21 of the Consolidated Financial Statements (see page 232-233) for information on the Company's principal plan.

TAXATION

The Company is tax-resident in the Netherlands. For the assessment of corporate income tax in the Netherlands, the Company and certain of its subsidiaries form a fiscal unit, in respect of which the Company recognises any current tax receivable or payable (and deferred tax asset or liability) for the fiscal unit as a whole to the extent such balances have been settled between the Company and other members of the fiscal unit at the balance sheet date. Balances not settled with the Company at the balance sheet date are recognised in the member's financial statements and, to the extent they are material, are disclosed in the notes to the Company's financial statements.

The Company's tax charge or credit recognised in income is calculated at the statutory tax rate prevailing in the Netherlands for current tax and statutory tax rate substantively enacted in the Netherlands for deferred tax.

3 INTEREST AND OTHER INCOME/EXPENSE

	\$ million	
	2019	2018
Interest and other income:		
Interest income	101	141
Total	101	141
Interest and other expenses:		
Interest expense	(111)	(156)
Foreign exchange losses	(35)	(66)
Total	(146)	(222)

4 INVESTMENTS IN SUBSIDIARIES

	\$ million	
	2019	2018
At January 1	256,920	256,882
Share-based compensation	506	512
Recovery of vested share-based compensation	(772)	(474)
At December 31	256,654	256,920

5 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	Dec 31, 2019		Dec 31, 2018	
	Current	Non-current	Current	Non-current
Amounts due to subsidiaries (see Note 13)	750	-	3,934	-
Accruals and other liabilities	730	-	614	-
Withholding tax payable	291	-	311	-
Unclaimed dividends	4	-	3	-
Total	1,775	-	4,862	-

Accruals and other liabilities at December 31, 2019, and at December 31, 2018, principally comprise commitments for share repurchases undertaken on the Company's behalf under irrevocable, non-discretionary arrangements.

6 TAXATION

Taxation charge

	\$ million	
	2019	2018
Current tax:		
Charge in respect of current period	9	-
Total	9	-
Deferred tax:		
Relating to the origination and reversal of tax losses and credits	539	33
Relating to changes in tax rates and legislation	19	11
Total	558	44
Taxation charge	567	44

In 2019, the deferred tax charge related to derecognition of deferred tax assets on unused tax losses and tax credits carried forward.

NOTES TO THE PARENT COMPANY FINANCIAL STATEMENTS continued**6 TAXATION** continued**Reconciliation of applicable tax charge at statutory tax rate to taxation charge**

	\$ million	
	2019	2018
Income before taxation	20,952	23,154
Applicable tax charge at the statutory tax rate of 25.0% (2018: 25.0%)	5,238	5,789
Derecognition of deferred tax assets	539	-
Tax effects of:		
Income not subject to tax at statutory rates	(5,253)	(5,820)
Expenses not deductible for tax purposes	24	20
Other	19	55
Taxation charge	567	44

Taxes payable are reported within accounts payable and accrued liabilities (see Note 5).

Deferred tax assets

	\$ million	
	2019	2018
At January 1	355	598
Recognised in income	(558)	(44)
Other movements	203	(199)
At December 31	-	355

In the Company's capacity as head of the fiscal unity, no deferred tax assets have been recognised at December 31, 2019. Deferred tax assets recognised in this capacity at December 31, 2018 amounted to \$355 million and were in respect of credits carried forward and unused tax losses. At December 31, 2019, unrecognised unused tax losses amounted to \$1,683 million (2018: \$nil) and unrecognised credits carried forward amounted to \$273 million (2018: \$99 million). Unused tax losses are available for relief against future taxable profits for up to a period of six to nine years, dependent upon the year in which the losses were incurred. Unused tax credits are available indefinitely.

7 FINANCIAL INSTRUMENTS

Financial assets and liabilities measured at amortised cost in the Company's Balance Sheet comprise amounts due from subsidiaries (see Note 13) and certain amounts reported within accounts payable and accrued liabilities (see Note 5). The fair value of financial assets and liabilities at December 31, 2019, and 2018, approximates their carrying amount.

Information on financial risk management is presented in Note 19 of the Consolidated Financial Statements (see pages 227-231). Foreign currency derivatives are used by the Company to manage foreign exchange risk, which arises when certain transactions are denominated in a currency that is not the Company's functional currency. There were no derivative financial instruments held at December 31, 2019, or 2018.

8 SHARE CAPITAL**Issued and fully paid ordinary shares of €0.07 each [A]**

	Number of shares		Nominal value (\$ million)		
	A	B	A	B	Total
At January 1, 2019	4,471,889,296	3,745,486,731	376	309	685
Repurchases of shares	(320,101,779)	(16,079,624)	(27)	(1)	(28)
At December 31, 2019	4,151,787,517	3,729,407,107	349	308	657
At January 1, 2018	4,597,136,050	3,745,486,731	387	309	696
Repurchases of shares	(125,246,754)	-	(11)	-	(11)
At December 31, 2018	4,471,889,296	3,745,486,731	376	309	685

[A] Share capital at December 31, 2019, and 2018, also included 50,000 issued and fully paid sterling deferred shares of £1 each.

At the Company's Annual General Meeting ("AGM") on May 21, 2019, the Board was authorised to allot ordinary shares in the Company, and to grant rights to subscribe for or to convert any security into ordinary shares in the Company, up to an aggregate nominal amount of €190.3 million (representing 2,720 million ordinary shares of €0.07 each), and to list such shares or rights on any stock exchange. This authority expires at the earlier of the close of business on August 21, 2020, and the end of the AGM to be held in 2020, unless previously renewed, revoked or varied by the Company in a general meeting.

At the May 21, 2019 AGM, shareholders granted the Company the authority to repurchase up to 815 million ordinary shares (excluding any treasury shares), renewing the authority granted by the shareholders at previous AGMs. The authority will expire at the earlier of the close of business on August 21, 2020, and the end of the AGM of the Company to be held in 2020. Ordinary shares purchased by the Company pursuant to this authority will either be cancelled or held in treasury. Treasury shares are shares in the Company which are owned by the Company itself. The minimum price, exclusive of expenses, which may be paid for an ordinary share is €0.07. The maximum price, exclusive of expenses, which may be paid for an ordinary share is the higher of: (i) an amount equal to 5% above the average market value for an ordinary share for the five business days immediately preceding the date of the purchase; and (ii) the higher of the price of the last independent trade and the highest current independent bid on the trading venues where the purchase is carried out.

A and B shares repurchased in 2019 under the Company's share buyback programme were all cancelled.

B shares rank equally in all respects with A shares except for the dividend access mechanism described below. The Company, Shell Transport and BG, can procure the termination of the dividend access mechanism at any time. Upon such termination, B shares will form one class with A shares ranking equally in all respects and A and B shares will be known as ordinary shares without further distinction.

The sterling deferred shares are redeemable only at the discretion of the Company for £1 each and carry no voting rights. There are no further rights to participate in profits or assets, including the right to receive dividends. Upon winding up or liquidation, the shares carry a right to repayment of paid-up nominal value, ranking ahead of A and B shares.

For information on the number of shares in the Company held by Shell employee share ownership trusts and trust-like entities to meet delivery commitments under employee share plans, see Note 21 of the Consolidated Financial Statements (see pages 232-233).

DIVIDEND ACCESS MECHANISM FOR B SHARES

General

Dividends paid on A shares have a Dutch source for tax purposes and are subject to Dutch withholding tax.

It is the expectation and the intention, although there can be no certainty, that holders of B shares will receive dividends through the dividend access mechanism. Any dividends paid on the dividend access shares will have a UK source for UK and Dutch tax purposes. There will be no Dutch withholding tax on such dividends. From April 2016, there were changes to the taxation of dividends for individual shareholders resident in the UK. The dividend tax credit was abolished, and a tax-free dividend allowance introduced.

Description of dividend access mechanism

Shell Transport and BG have each issued a dividend access share to Computershare Trustees (Jersey) Limited as Trustee. Pursuant to a declaration of trust, the Trustee will hold any dividends paid in respect of the dividend access shares on trust for the holders of B shares and will arrange for prompt disbursement of such dividends to holders of B shares. Interest and other income earned on unclaimed dividends will be for the account of Shell Transport and BG and any dividends which are unclaimed after 12 years will revert to Shell Transport and BG once forfeited. Holders of B shares will not have any interest in either dividend access share and will not have any rights against Shell Transport and BG as issuers of the dividend access shares. The only assets held on trust for the benefit of the holders of B shares will be dividends paid to the Trustee in respect of the dividend access shares.

The declaration and payment of dividends on the dividend access shares will require board action by Shell Transport and BG (as applicable) and will be subject to any applicable limitations in law or in the Shell Transport or BG (as appropriate) articles of association in effect. In no event will the aggregate amount of the dividend paid by Shell Transport and BG under the dividend access mechanism for a particular period exceed the aggregate of the dividend announced by the Board of the Company on B shares in respect of the same period (after giving effect to currency conversions).

In particular, under their respective articles of association, Shell Transport and BG are each only able to pay a dividend on their respective dividend access shares which represents a proportional amount of the aggregate of any dividend announced by the Company on the B shares in respect of the relevant period, where such proportions are calculated by reference to, in the case of Shell Transport, the number of B shares in existence prior to completion of the Company's acquisition of BG and, in the case of BG, the number of B shares issued as part of the acquisition, in each case as against the total number of B shares in issue immediately following completion of the acquisition of BG.

Operation of the dividend access mechanism

If, in connection with the announcement of a dividend by the Company on B shares, the Board of Shell Transport and/or the Board of BG elects to declare and pay a dividend on their respective dividend access shares to the Trustee, the holders of B shares will be beneficially entitled to receive their share of those dividends pursuant to the declaration of trust (and arrangements will be made to ensure that the dividend is paid in the same currency in which they would have received a dividend from the Company).

If any amount is paid by Shell Transport or BG by way of a dividend on the dividend access shares and paid by the Trustee to any holder of B shares, the dividend which the Company would otherwise pay on B shares will be reduced by an amount equal to the amount paid to such holders of B shares by the Trustee.

The Company will have a full and unconditional obligation, in the event that the Trustee does not pay an amount to holders of B shares on a cash dividend payment date (even if that amount has been paid to the Trustee), to pay immediately the dividend announced on B shares. The right of holders of B shares to receive distributions from the Trustee will be reduced by an amount equal to the amount of any payment actually made by the Company on account of any dividend on B shares.

NOTES TO THE PARENT COMPANY FINANCIAL STATEMENTS continued

8 SHARE CAPITAL continued

If for any reason no dividend is paid on the dividend access shares, holders of B shares will only receive dividends from the Company directly. Any payment by the Company will be subject to Dutch withholding tax (unless an exemption is obtained under Dutch law or under the provisions of an applicable tax treaty).

The Dutch tax treatment of dividends paid under the dividend access mechanism has been confirmed by the Dutch Revenue Service in an agreement ("vaststellingsovereenkomst") with the Company and N.V. Koninklijke Nederlandsche Petroleum Maatschappij (Royal Dutch Petroleum Company) dated October 26, 2004, as supplemented and amended by an agreement between the same parties dated April 25, 2005, and a final settlement agreement in connection with the acquisition of BG dated November 9, 2015. The agreements state, among other things, that dividend distributions on the dividend access shares by Shell Transport and/or BG will not be subject to Dutch withholding tax provided that the dividend access mechanism is structured and operated substantially as set out above.

The Company may not extend the dividend access mechanism to any future issuances of B shares without prior consultation with the Dutch Revenue Service.

Accordingly, the Company would not expect to issue additional B shares unless confirmation from the Dutch Revenue Service was obtained or the Company were to determine that the continued operation of the dividend access mechanism was unnecessary. Any further issue of B shares is subject to advance consultation with the Dutch Revenue Service.

The dividend access mechanism may be suspended or terminated at any time by the Company's Directors or the Directors of Shell Transport or BG, for any reason and without financial recompense. This might, for instance, occur in response to changes in relevant tax legislation.

9 OTHER RESERVES

	Merger reserve	Share premium reserve	Capital redemption reserve	Share plan reserve	Total
At January 1, 2019	234,231	154	95	1,056	235,536
Repurchases of shares	-	-	28	-	28
Share-based compensation	-	-	-	(3)	(3)
At December 31, 2019	234,231	154	123	1,053	235,561
At January 1, 2018	234,231	154	84	897	235,366
Repurchases of shares	-	-	11	-	11
Share-based compensation	-	-	-	159	159
At December 31, 2018	234,231	154	95	1,056	235,536

\$ million

The merger reserve was established as a consequence of the Company becoming the single parent company of Royal Dutch and Shell Transport and represented the difference between the cost of the investment in those companies and the nominal value of shares issued in exchange for those investments as required by the prevailing legislation at that time, section 131 of the Companies Act 1985. On February 15, 2016, the Company acquired all shares in BG Group plc by means of a Scheme of Arrangement under Part 26 of the Act, via the issuance of 218.7 million A shares and 1,305.1 million B shares and cash payments. This resulted in an increase in the merger reserve, representing the difference between the fair value and the nominal value of the shares issued by the Company.

On January 6, 2006, loan notes were converted into 4,827,974 A shares. The difference between the carrying value of the loan notes and the nominal value of the new shares issued was credited to the share premium reserve. The capital redemption reserve was established in connection with repurchases of shares of the Company. The share plan reserve is in respect of equity-settled share-based compensation plans (see Note 21 to the Consolidated Financial Statements) and movement in share-based compensation for the year is the net of the charge to equity and the release as a result of vested awards.

10 DIVIDENDS

See Note 23 of the Consolidated Financial Statements (see page 235).

11 LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

See Note 25 of the Consolidated Financial Statements (see pages 235-237).

12 DIRECTORS AND SENIOR MANAGEMENT

See Note 27 of the Consolidated Financial Statements (see page 237) for the remuneration of Directors of the Company. In 2019, the Company recognised \$25 million (2018: \$24 million) in administrative expenses for the compensation of Directors and Senior Management.

13 RELATED PARTIES

Information about the Company's subsidiaries, and whether these are held directly or indirectly, and other related undertakings (all of which are held indirectly), at December 31, 2019, is set out in 'Appendix 1: Significant Subsidiaries and Other Related Undertakings'.

	\$ million			
	Amounts due from subsidiaries		Amounts due to subsidiaries (see Note 5)	
	2019	2018	2019	2018
Shell Petroleum	-	-	748	550
Shell Treasury Centre Limited	1,862	9,260	-	-
Shell Corporate Services Switzerland AG	-	-	-	3,384
Other	2	3	2	-
Total	1,864	9,263	750	3,934

The Company received interest income from Shell Petroleum in 2019 of \$60 million (2018: \$134 million). Interest was calculated at US LIBOR less 0.21% (December 31, 2018: US LIBOR less 0.21%). At both December 31, 2019 and 2018 the closing amount due from Shell Petroleum was \$nil.

The amount due from Shell Treasury Centre Limited ("STCL") comprises call deposits in dollars, sterling and euros. Interest is calculated at US LIBOR less 0.21% (2018: US LIBOR less 0.21%) on dollar balances, at GBP LIBOR less 0.19% (2018: GBP LIBOR less 0.19%) on sterling balances and at Euro Overnight Index Average ("EONIA") (2018: EONIA) on euro balances, unless this results in a negative interest rate in which case no interest is earned. Net interest income in 2019 from STCL was \$41 million (2018: \$7 million).

In 2019, the Company settled an interest-bearing receivable and an interest-bearing payable at fair value, equal to the carrying amount of the balances at transfer date, with Shell Corporate Services Switzerland AG ("SCSS"). The net amount due to SCSS at December 31, 2019, is \$nil (2018: interest-bearing receivable of €4,690 million and an interest-bearing payable of \$8,746 million). Interest on euro balances was calculated at EONIA (2018: EONIA) unless this resulted in a negative interest rate in which case no interest was earned. Interest on dollar balances was calculated at US LIBOR (2018: US LIBOR). Net interest expense on these balances in 2019 was \$111 million (2018: \$67 million).

OTHER TRANSACTIONS AND BALANCES

The Company periodically enters into forward and spot foreign currency contracts with Treasury companies, which are subsidiaries. There were no open foreign currency contracts at December 31, 2019, or 2018.

The Company settles general and administrative expenses of the Trust, including the auditor's remuneration.

The Company has guaranteed contractual payments totalling \$52,974 million at December 31, 2019 (2018: \$53,357 million), and related interest, in respect of listed debt issued by Shell International Finance B.V.

14 AUDITOR'S REMUNERATION

See Note 28 of the Consolidated Financial Statements (see pages 238).

INDEPENDENT AUDITOR'S REPORT TO COMPUTERSHARE TRUSTEES (JERSEY) LIMITED AS TRUSTEE OF THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST AND THE BOARD OF DIRECTORS OF ROYAL DUTCH SHELL PLC

TO COMPUTERSHARE TRUSTEES (JERSEY) LIMITED AS TRUSTEE OF THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST AND THE BOARD OF DIRECTORS AND SHAREHOLDERS OF ROYAL DUTCH SHELL PLC

Opinion on the Financial Statements

We have audited the non-statutory financial statements of the Royal Dutch Shell Dividend Access Trust (the Financial Statements) for the year ended December 31, 2019 which comprise the Statement of Income, the Statement of Comprehensive Income, the Balance Sheet, the Statement of Changes in Equity, the Statement of Cash Flows and the related notes 1 to 8. The financial reporting framework that has been applied in their preparation is International Financial Reporting Standards (IFRS) as adopted by the European Union (EU) and IFRS as issued by the International Accounting Standards Board (IASB).

In our opinion the Financial Statements:

- give a true and fair view of the Royal Dutch Shell Dividend Access Trust's (the Trust) affairs as at December 31, 2019 and of its income for the year then ended; and
- have been properly prepared both in accordance with IFRS as adopted by the EU and IFRS as issued by the IASB.

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (UK) (ISAs (UK)) and applicable law. Our responsibilities under those standards are further described in the "Auditor's responsibilities for the audit of the financial statements" section of our report below. We are independent of the Trust in accordance with the ethical requirements that are relevant to our audit of the Financial Statements in the UK, including the Financial Reporting Council's Ethical Standard, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Conclusions relating to going concern

We have nothing material to report in respect of the following matters in relation to which the ISAs (UK) require us to report to you where:

- the Trustee of Royal Dutch Shell Dividend Access Trust's (the Trustee) use of the going concern basis of accounting in the preparation of the Financial Statements is not appropriate; or
- the Trustee has not disclosed in the Financial Statements any identified material uncertainties that may cast significant doubt about the Trust's ability to continue to adopt the going concern basis of accounting for a period of at least twelve months from the date of approval of the Financial Statements.

Other information

The other information comprises the information included in the annual report, other than the Financial Statements and our auditor's report thereon. The Board of Directors of Royal Dutch Shell plc (the Directors) are responsible for the other information.

Our opinion on the Financial Statements does not cover the other information and, we do not express any form of assurance conclusion thereon.

In connection with our audit of the Financial Statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the Financial Statements or our knowledge obtained in the audit or otherwise appears to be materially misstated. If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether there is a material misstatement in the Financial Statements or a material misstatement of the other information. If, based on the work we have performed, we conclude that there is a material misstatement of the other information, we are required to report that fact.

We have nothing to report in this regard.

Responsibilities of the Trustee

The Trustee is responsible for the preparation of the Financial Statements and for being satisfied that they give a true and fair view, and for such internal control as the Trustee determines is necessary to enable the preparation of Financial Statements that are free from material misstatement, whether due to fraud or error.

In preparing the Financial Statements, the Trustee is responsible for assessing the Trust's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Trustee either intends to liquidate the Trust or to cease operations, or have no realistic alternative but to do so. The Trustee is also required to: present fairly the financial position, financial performance and cash flows of the Trust; select suitable accounting policies in accordance with IAS 8: Accounting Policies, Changes in Accounting Estimates and Errors and then apply them consistently; present information, including accounting policies, in a manner that provides relevant, reliable, comparable and understandable information; make judgements that are reasonable; provide additional disclosures when compliance with the specific requirements in IFRS as adopted by the EU and as issued by the IASB is insufficient to enable users to understand the impact of particular transactions, other events and conditions on the Trust's financial position and financial performance; and state whether the Financial Statements have been prepared in accordance with IFRS as adopted by the EU and as issued by the IASB.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the Financial Statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs (UK) will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these Financial Statements.

A further description of our responsibilities for the audit of the Financial Statements is located on the Financial Reporting Council's website at <https://www.frc.org.uk/auditorsresponsibilities>. This description forms part of our auditor's report.

Use of our report

This report is made solely to the Trustee and the Directors as a body, in accordance with our engagement letter. Our audit work has been undertaken so that we might state to the Trustee and the Directors those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the Trust and the Trustee and the Directors as a body, for our audit work, for this report, or for the opinions we have formed.

/s/ Ernst & Young LLP

London
March 11, 2019

[A] The maintenance and integrity of the Shell website are the responsibility of the Directors of Royal Dutch Shell plc; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.

[B] Legislation in the UK governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST FINANCIAL STATEMENTS

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STATEMENT OF INCOME

	2019	2018	£ million 2017
Dividend income	5,484	5,328	4,567
Income before taxation and for the period	5,484	5,328	4,567

STATEMENT OF COMPREHENSIVE INCOME

	2019	2018	£ million 2017
Income for the period	5,484	5,328	4,567
Comprehensive income for the period	5,484	5,328	4,567

BALANCE SHEET

	Notes	Dec 31, 2019	£ million Dec 31, 2018
Assets			
Current assets		-	-
Cash and cash equivalents		3	3
Total assets		3	3
Liabilities			
Current liabilities		-	-
Unclaimed dividends	4	3	3
Total liabilities		3	3
Equity			
Capital account	5	-	-
Revenue account		-	-
Total equity		-	-
Total liabilities and equity		3	3

Signed on behalf of Computershare Trustees (Jersey) Limited
as Trustee of the Royal Dutch Shell Dividend Access Trust

/s/ Karen Kurys

KAREN KURYS

March 11, 2020

/s/ Martin Fish

MARTIN FISH

ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST FINANCIAL STATEMENTS continued

STATEMENT OF CHANGES IN EQUITY

	Notes	Capital account	Revenue account	£ million Total equity
At January 1, 2019		-	-	-
Comprehensive income for the period		-	5,484	5,484
Distributions made	6	-	(5,484)	(5,484)
At December 31, 2019		-	-	-
At January 1, 2018		-	-	-
Comprehensive income for the period		-	5,328	5,328
Distributions made	6	-	(5,328)	(5,328)
At December 31, 2018		-	-	-
At January 1, 2017		-	-	-
Comprehensive income for the period		-	4,567	4,567
Distributions made	6	-	(4,567)	(4,567)
At December 31, 2017		-	-	-

STATEMENT OF CASH FLOWS

	2019	2018	£ million 2017
Income for the period	5,484	5,328	4,567
Adjustment for:			
Dividends received	(5,484)	(5,328)	(4,567)
Cash flow from operating activities	-	-	-
Dividends received	5,484	5,328	4,567
Cash flow from investing activities	5,484	5,328	4,567
Cash distributions made	(5,484)	(5,327)	(4,567)
Cash flow from financing activities	(5,484)	(5,327)	(4,567)
Change in cash and cash equivalents	-	1	-
Cash and cash equivalents at January 1	3	2	2
Cash and cash equivalents at December 31	3	3	2

NOTES TO THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST

FINANCIAL STATEMENTS

1 THE TRUST

The Royal Dutch Shell Dividend Access Trust (the "Trust") was established on May 19, 2005, by The "Shell" Transport and Trading Company plc, now The Shell Transport and Trading Company Limited ("Shell Transport"), and Royal Dutch Shell plc (the "Company"). The Trust is governed by the applicable laws of England and Wales and is resident and domiciled in Jersey. The Trust is not subject to taxation. The Trustee of the Trust is Computershare Trustees (Jersey) Limited, registration number 92182 (the "Trustee"), Queensway House, Hilgrove Street, St Helier, Jersey, JE1 1ES. The Trust was established as part of a dividend access mechanism.

Shell Transport and BG Group Limited ("BG"), have each issued a dividend access share to the Trustee. Following the announcement of a dividend by the Company on the B shares, Shell Transport and BG may declare a dividend on their dividend access shares.

The primary purposes of the Trust are to receive, on behalf of the B shareholders of the Company and in accordance with their respective holdings of B shares in the Company, any amounts paid by way of dividend on the dividend access shares and to pay such amounts to the B shareholders on the same pro rata basis. The Trust is not subject to significant market risk, credit risk or liquidity risk.

The Trust shall not endure for a period in excess of 80 years from May 19, 2005, being the date on which the Trust Deed was executed.

2 THE BASIS OF PREPARATION

The Financial Statements of the Trust have been prepared in accordance with International Financial Reporting Standards ("IFRS") as adopted by the European Union. As applied to the Trust, there are no material differences from IFRS as issued by the International Accounting Standards Board ("IASB"); therefore, the Financial Statements have been prepared in accordance with IFRS as issued by the IASB.

The Financial Statements have been prepared under the historical cost convention. The accounting policies described in Note 3 have been applied consistently in all periods presented.

The Financial Statements were approved and authorised for issue by the Trustee on March 11, 2020.

The financial results of the Trust are included in the Consolidated and Parent Company Financial Statements on pages 190-238 and pages 257-265 respectively.

3 SIGNIFICANT ACCOUNTING POLICIES

The Trust's accounting policies follow those of Shell as set out in Note 2A of the Consolidated Financial Statements (see pages 195-203). The following are Trust-specific policies.

Presentation and functional currency

The Trust's presentation and functional currency is sterling. The Trust's dividend income and dividends paid are principally in sterling.

Dividend income

Dividends on the dividend access shares are recognised on a paid basis unless the dividend has been confirmed by a general meeting of Shell Transport or BG, in which case income is recognised on the date on which receipt is deemed virtually certain.

Distributions made

Amounts are recorded as distributed once a wire transfer or cheque is issued. To the extent that cheques expire or are returned unpresented, the Trust records a liability for unclaimed dividends and a corresponding amount of cash.

4 UNCLAIMED DIVIDENDS

Unclaimed dividends of £3,456,974 (2018: £2,816,655) include any dividend cheque payments that have not been presented within 12 months, have expired or have been returned unpresented. Dividends which are unclaimed after 12 years will revert to Shell Transport and BG once forfeited.

5 CAPITAL ACCOUNT

The capital account is represented by the dividend access share of 25 pence settled in the Trust by Shell Transport and the dividend access share of 10 pence settled in the Trust by BG. There have been no changes in the capital account in the current or prior year.

6 DISTRIBUTIONS MADE

Distributions are made to the B shareholders of the Company in accordance with the Trust Deed. See Note 23 of the Consolidated Financial Statements (see pages 235) for information about dividends per share. Any wire transfers that are not completed are replaced by cheques.

7 RELATED PARTIES

The Trust received dividend income of £3,573 million (2018: £3,470 million; 2017: £2,970 million) in respect of the dividend access share from Shell Transport and £1,911 million (2018: £1,858 million; 2017: £1,597 million) in respect of the dividend access share from BG. The Trust made distributions of £5,484 million (2018: £5,328 million; 2017: £4,567 million) to the B shareholders of the Company.

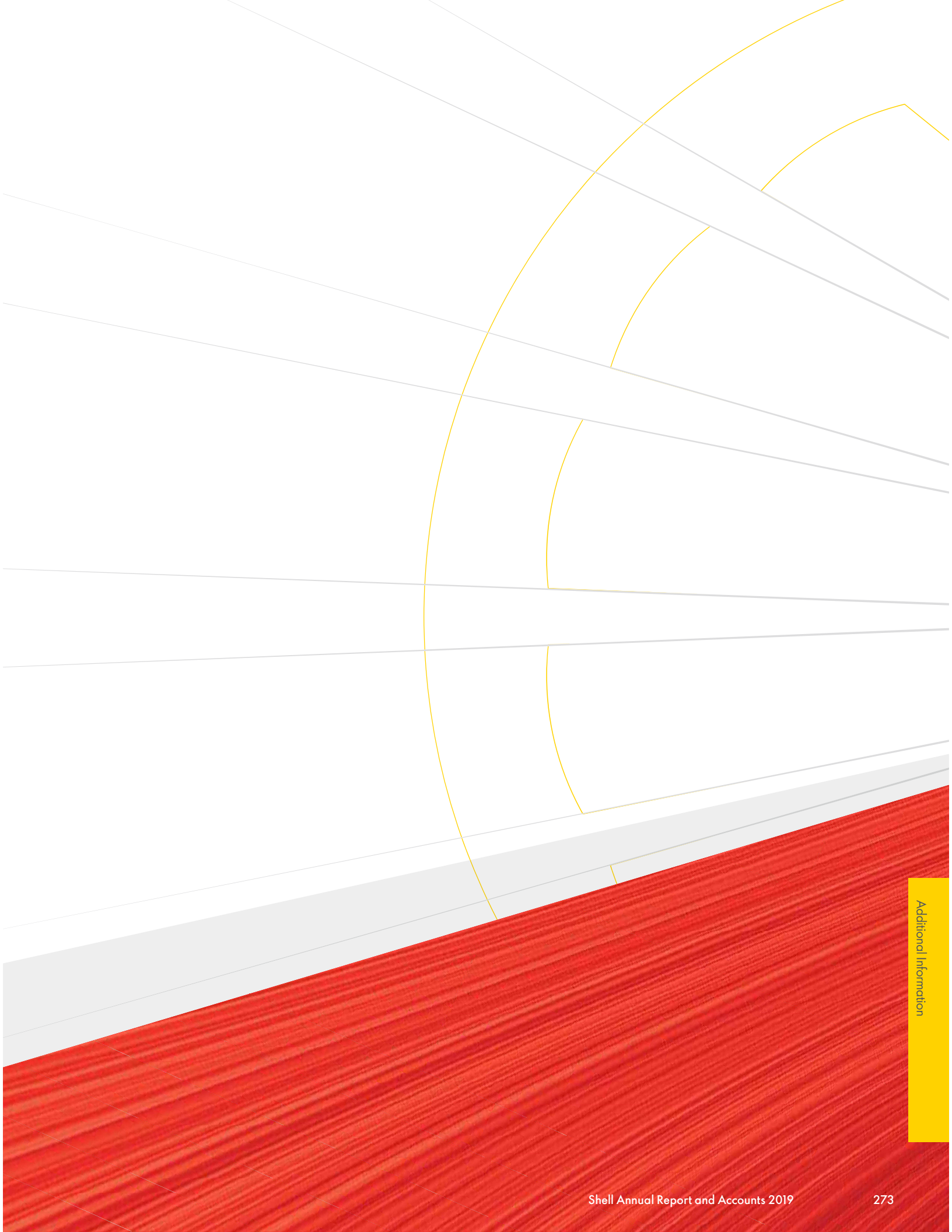
The Company pays the general and administrative expenses of the Trust, including the auditor's remuneration.

8 AUDITOR'S REMUNERATION

Auditor's remuneration for 2019 audit services was £33,750 (2018: £33,750; 2017: £33,750).

ADDITIONAL INFORMATION

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SHAREHOLDER INFORMATION

Royal Dutch Shell plc (the Company) was incorporated in England and Wales on February 5, 2002, as a private company under the Companies Act 1985, as amended. On October 27, 2004, the Company was re-registered as a public company limited by shares and changed its name from Forthdeal Limited to Royal Dutch Shell plc. The Company is registered at Companies House, Cardiff, under company number 4366849, and at the Chamber of Commerce, The Hague, under company number 34179503. The Legal Entity Identifier (LEI) issued by the London Stock Exchange is 21380068PIDRHMJ8KU70. The business address for the Directors and Senior Management is Carel van Bylandtlaan 30, 2596 HR, The Hague, The Netherlands.

The Company is resident in the Netherlands for Dutch and UK tax purposes and its primary objective is to carry on the business of a holding company. It is not directly or indirectly owned or controlled by another corporation or by any government and does not know of any arrangements that may result in a change of control of the Company.

NATURE OF TRADING MARKET

The Company has two classes of ordinary shares: A and B shares. The principal trading market for A shares is Euronext Amsterdam and the principal trading market for B shares is the London Stock Exchange. Ordinary shares are traded in registered form.

A and B American Depositary Shares (ADSs) are listed on the New York Stock Exchange [A]. A depositary receipt is a certificate that evidences ADSs. Depositary receipts are issued, cancelled and exchanged at the office of JP Morgan Chase Bank, N.A., 383 Madison Avenue, New York, New York 10179, USA, as depositary (the Depositary), under a deposit agreement between the Company, the Depositary and the holders of ADSs. Each ADS represents two €0.07 shares of Royal Dutch Shell plc deposited under the agreement. More information relating to ADSs is given on pages 274-278.

[A] At February 14, 2020, 395,595,127 A ADSs and 322,677,233 B ADSs were outstanding, representing 5.04% and 4.11% of the respective share capital class, held by 5,003 and 912 holders of record with an address in the USA, respectively. In addition to holders of ADSs, at February 14, 2020, 21,380 A shares and 920,170 B shares of €0.07 each were outstanding, representing 0.0003% and 0.0117% of the respective share capital class, held by 299 and 3,061 holders of record registered with an address in the USA, respectively.

Listing information

	A shares	B shares
Ticker symbol London	RDSA	RDSB
Ticker symbol Amsterdam	RDSA	RDSB
Ticker symbol New York (ADS [A])	RDS.A	RDS.B
ISIN Code	GB00B03MLX29	GB00B03MM408
CUSIP	G7690A100	G7690A118
SEDOL Number London	B03MLX2	B03MM40
SEDOL Number Euronext	B09CBL4	B09CBN6
Weighting on FTSE at 31/12/19	4.97%	4.44%
Weighting on AEX at 31/12/19	11.9%	not included

[A] Each A ADS represents two A shares of €0.07 each and each B ADS represents two B shares of €0.07 each.

SHARE CAPITAL

The issued and fully paid share capital of the Company at February 14, 2020, was as follows:

Share capital

	Issued and fully paid	
	Number	Nominal value
Ordinary shares of €0.07 each		
A shares	4,125,109,180	€ 288,757,643
B shares	3,727,267,215	€ 260,908,705
Sterling deferred shares of £1 each	50,000	£50,000

The Directors may only allot new ordinary shares if they have authority from shareholders to do so. The Company seeks to renew this authority annually at its AGM. Under the resolution passed at the Company's 2019 AGM, the Directors were granted authority to allot ordinary shares up to an aggregate nominal amount equivalent to approximately one-third of the issued ordinary share capital of the Company (in line with the guidelines issued by institutional investors).

The following is a summary of the material terms of the Company's ordinary shares, including brief descriptions of the provisions contained in the Articles of Association (the Articles) and applicable laws of England and Wales in effect on the date of this document. This summary does not purport to include complete statements of these provisions:

- upon issuance, A and B shares are fully paid and free from all liens, equities, charges, encumbrances and other interest of the Company and not subject to calls of any kind;
- all A and B shares rank equally for all dividends and distributions on ordinary share capital; and
- A and B shares are admitted to the Official List of the UK Financial Conduct Authority and to trading on the market for listed securities of the London Stock Exchange. A and B shares are also admitted to trading on Euronext Amsterdam. A and B ADSs are listed on the New York Stock Exchange.

At December 31, 2019, trusts and trust-like entities holding shares for the benefit of employee share plans of Shell held (directly and indirectly) 35 million shares of the Company with an aggregate market value of \$1,021 million and an aggregate nominal value of €3 million.

SIGNIFICANT SHAREHOLDINGS

The Company's A and B shares have identical voting rights, and accordingly the Company's major shareholders do not have different voting rights.

Significant direct shareholdings

Direct holdings of 3% or more of A and B shares combined held by registered members representing the interests of underlying investors at February 14, 2020 are given below.

	A shares		B shares		Total	
	Number	%	Number	%	Number	%
Nederlands Centraal Instituut Voor Giraal Effectenverkeer Bv	1,648,160,815.00	39.95	15,631,116.00	0.42	1,663,791,931.00	21.19
Guaranty Nominees Limited	780,888,066.00	18.93	635,107,032.00	17.04	1,415,995,098.00	18.03
State Street Nominees Limited	153,192,955.00	3.71	176,114,622.00	4.73	329,307,577.00	4.19
Chase Nominees Limited	39,792,354.00	0.96	223,049,935.00	5.98	262,842,289.00	3.35

Significant indirect shareholdings

Interests of investors with 3% or more of A and B shares combined at February 14, 2020 are given below.

	A shares		B shares		Total	
	Number	%	Number	%	Number	%
The Capital Group [A]	42,482,002	0.54	349,161,475	4.45	391,643,477	4.99
The Vanguard Group	197,154,328	4.75	141,041,343	3.78	338,195,671	4.29
BlackRock Inc	304,037,938	7.32	259,041,285	6.95	563,079,223	7.14

[A] Information presented as at February 24, 2020.

Notification of major shareholdings

The Company received two notifications pursuant to Disclosure Guidance and Transparency Rule (DTR) 5 during the year and up to February 14, 2020, (being a date not more than one month prior to the date of the Company's Notice of Annual General Meeting). The information provided includes the percentage of issued capital as at the date of the notifications.

Investor

	A shares		B shares		Total [A]	
	Number	%	Number	%	Number	%
The Capital Group Companies, Inc.[B]	64,854,057	0.80	337,594,482	4.19	402,448,539	4.99
The Capital Group Companies, Inc. [C] [D]	51,230,530	0.65	342,234,201	4.35	393,464,731	5.00

[A] Excludes financial instruments according to Art. 13(1)(a) of Directive 2004/109/EC (DTR 5.3.1.1 (a)) and financial instruments with similar economic effect according to Art. 13(1)(b) of Directive 2004/109/EC (DTR 5.3.1.1 (b)).

[B] The notification was announced on 9 July 2019.

[C] The notification was announced on 20 January 2020.

[D] On 24 February 2020, Royal Dutch Shell plc announced receipt of a notification from The Capital Group Companies Inc. disclosing a holding of 31,948,156 A shares and 10,533,846 A DR shares (0.54%) and 166,464,737 B shares and 182,696,738 B ADR shares (4.45%) being a total of 391,643,477 shares held (4.99%).

DIVIDENDS

The following tables show the dividends on each class of share and each class of ADS for the years 2015–2019.

A and B shares

	2019	2018	2017	2016	2015
Q1	0.47	0.47	0.47	0.47	0.47
Q2	0.47	0.47	0.47	0.47	0.47
Q3	0.47	0.47	0.47	0.47	0.47
Q4	0.47	0.47	0.47	0.47	0.47
Total announced in respect of the year	1.88	1.88	1.88	1.88	1.88

SHAREHOLDER INFORMATION continued**A shares**

	€ [A]				
	2019	2018	2017	2016	2015
Q1	0.42	0.40	0.42	0.42	0.42
Q2	0.43	0.40	0.39	0.42	0.42
Q3	0.42	0.41	0.40	0.44	0.43
Q4	0.42	0.42	0.38	0.44	0.42
Total announced in respect of the year	1.68	1.64	1.59	1.72	1.69
Amount paid during the year	1.68	1.60	1.65	1.70	1.71

[A] Euro equivalent, rounded to the nearest euro cent.

B shares

	Pence [A]				
	2019	2018	2017	2016	2015
Q1	36.97	35.18	37.12	32.98	30.75
Q2	38.01	36.50	36.28	35.27	30.92
Q3	35.73	36.77	35.02	37.16	31.07
Q4	36.40	35.94	33.91	38.64	32.78
Total announced in respect of the year	147.11	144.39	142.33	144.05	125.52
Amount paid during the year	146.65	142.36	147.06	138.19	123.94

[A] Sterling equivalent.

A and B ADSs

	\$				
	2019	2018	2017	2016	2015
Q1	0.94	0.94	0.94	0.94	0.94
Q2	0.94	0.94	0.94	0.94	0.94
Q3	0.94	0.94	0.94	0.94	0.94
Q4	0.94	0.94	0.94	0.94	0.94
Total announced in respect of the year	3.76	3.76	3.76	3.76	3.76
Amount paid during the year	3.76	3.76	3.76	3.76	3.76

METHOD OF HOLDING SHARES OR AN INTEREST IN SHARES

There are several ways in which Royal Dutch Shell plc registered shares or an interest in these shares can be held, including:

- directly as registered shares either in uncertificated form or in certificated form in a shareholder's own name;
- indirectly through Euroclear Nederland (in respect of which the Dutch Securities Giro Act ("Wet giraal effectenverkeer") is applicable);
- through the Royal Dutch Shell Corporate Nominee Service;
- through another third-party nominee or intermediary company; and
- as a direct or indirect holder of either an A or a B ADS with the Depositary.

AMERICAN DEPOSITARY SHARES

The Depositary is the registered shareholder of the shares underlying the A or B ADSs and enjoys the rights of a shareholder under the Articles. Holders of ADSs will not have shareholder rights. The rights of the holder of an A or a B ADS are specified in the Deposit Agreement with the Depositary and are summarised below.

The Depositary will receive all cash dividends and other cash distributions made on the deposited shares underlying the ADSs and, where possible and on a reasonable basis, will distribute such dividends and distributions to holders of ADSs. Rights to purchase additional shares will also be made available to the Depositary who may make such rights available to holders of ADSs. All other distributions made on the Company's shares

will be distributed by the Depositary in any means that the Depositary thinks is equitable and practical. The Depositary may deduct its fees and expenses and the amount of any taxes owed from any payments to holders and it may sell a holder's deposited shares to pay any taxes owed. The Depositary is not responsible if it decides that it is unlawful or impractical to make a distribution available to holders of ADSs.

The Depositary will notify holders of ADSs of shareholders' meetings of the Company and will arrange to deliver voting materials to such holders of ADSs if requested by the Company. Upon request by a holder, the Depositary will endeavour to appoint such holder as proxy in respect of such holder's deposited shares entitling such holder to attend and vote at shareholders' meetings. Holders of ADSs may also instruct the Depositary to vote their deposited securities and the Depositary will try, as far as practical and lawful, to vote deposited shares in accordance with such instructions. The Company cannot ensure that holders will receive voting materials or otherwise learn of an upcoming shareholders' meeting in time to ensure that holders can instruct the Depositary to vote their shares.

Upon payment of appropriate fees, expenses and taxes: (i) shareholders may deposit their shares with the Depositary and receive the corresponding class and amount of ADSs; and (ii) holders of ADSs may surrender their ADSs to the Depositary and have the corresponding class and amount of shares credited to their account.

Further, subject to certain limitations, holders may, at any time, cancel ADSs and withdraw their underlying shares or have the corresponding class and amount of shares credited to their account.

FEES PAID BY HOLDERS OF ADSs

The Depositary collects its fees for delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal or from intermediaries acting for them. The Depositary collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of distributable property to pay the fees. The Depositary may generally refuse to provide fee-attracting services until its fees for those services are paid. See page 278.

Persons depositing or withdrawing shares must pay:

\$5.00 or less per 100 ADSs (or portion of 100 ADSs)

Registration and transfer fees

Expenses of the Depositary

Taxes and other governmental charges the Depositary or the custodian has to pay on any ADS or share underlying an ADS, for example, share transfer taxes, stamp duty or withholding taxes

PAYMENTS BY DEPOSITARY TO THE COMPANY

J.P. Morgan Chase Bank, N.A., as Depositary, has agreed to share with the Company portions of certain fees collected, less ADS programme expenses paid by the Depositary. For example, these expenses include the Depositary's annual programme fees, transfer agency fees, custody fees, legal expenses, postage and envelopes for mailing annual and interim financial reports, printing and distributing dividend cheques, electronic filing of US federal tax information, mailing required tax forms, stationery, postage, facsimile and telephone calls and the standard out-of-pocket maintenance costs for the ADSs. From January 1, 2019, to February 14, 2020, the Company received \$1,320,599 from the Depositary.

For:

- Issuance of ADSs, including those resulting from a distribution of shares, rights or other property;
 - Cancellation of ADSs for the purpose of their withdrawal, including if the deposit agreement terminates; and
 - Distribution of securities to holders of deposited securities by the Depositary to ADS registered holders.
-
- Registration and transfer of shares on the share register to or from the name of the Depositary or its agent when they deposit or withdraw shares.
-
- Cable, telex and facsimile transmissions (when expressly provided in the deposit agreement); and
 - Converting foreign currency into dollars.
-
- As necessary.

In addition to the above, the Depositary may charge: (i) a dividend fee of \$5.00 or less per 100 ADSs (or portion of 100 ADSs) for cash dividends or issuance of ADSs resulting from share dividends and (ii) an administrative fee of \$5.00 or less per 100 ADSs (or portion of 100 ADSs) per calendar year. The Company and Depositary have agreed not to charge these fees at this time.

DIVIDEND REINVESTMENT PLAN

Equiniti Financial Services Limited, part of the same group of companies as the Company's Registrar, Equiniti Limited, operates a Dividend Reinvestment Plan ("DRIP") which enables RDS shareholders to elect to have their dividend payments used to purchase RDS shares of the same class as those already held by them. More information can be found at www.shareview.co.uk/info/drip or by contacting Equiniti.

ABN AMRO Bank N.V. and JP Morgan Chase Bank, N.A. also operate dividend reinvestment options. More information can be found by contacting the relevant provider.

EXCHANGE CONTROLS AND OTHER LIMITATIONS AFFECTING SECURITY HOLDERS

Other than restrictions affecting those individuals, entities, government bodies, corporations or agencies that are subject to European Union (EU) sanctions for example, regarding Syria, and those sanctions adopted by the government of the UK, and the general EU prohibition to transfer funds to and from for example, North Korea, we are not aware of any other legislative or other legal provision currently in force in the UK, the Netherlands or arising under the Articles restricting remittances to holders of the Company's ordinary shares who are non-residents of the UK, or affecting the import or export of capital.

TAXATION General

The Company is incorporated in England and Wales and tax-resident in the Netherlands. As a tax resident of the Netherlands, it is generally required by Dutch law to withhold tax at a rate of 15% on dividends on its ordinary shares and ADSs, subject to the provisions of any applicable tax convention or domestic law. Depending on their particular circumstances, non-Dutch tax-resident holders may be entitled to a full or partial refund of Dutch withholding tax. The following sets forth the operation of other provisions on dividends on the Company's various ordinary shares and ADSs to UK and US holders, as well as certain other tax rules pertinent to holders. Holders should consult their own tax adviser if they are uncertain as to the tax treatment of any dividend.

Dividends paid on the dividend access shares

There is no Dutch withholding tax on dividends on B shares or B ADSs, provided that such dividends are paid on the dividend access shares pursuant to the dividend access mechanism (see "Dividend access mechanism for B shares" on page 278). Dividends paid on the dividend access shares are treated as UK-source for tax purposes and there is no UK withholding tax on them.

SHAREHOLDER INFORMATION continued

In 2019, all dividends with respect to B shares and B ADSs were paid on the dividend access shares pursuant to the dividend access mechanism.

Dutch withholding tax

When Dutch withholding tax applies on dividends paid to a US holder (that is, dividends on A shares or A ADSs, or on B shares or B ADSs that are not paid on the dividend access shares pursuant to the dividend access mechanism), the US holder will be subject to Dutch withholding tax at the rate of 15%. A US holder who is entitled to the benefits of the 1992 Double Taxation Convention (the Convention) between the USA and the Netherlands as amended by the protocol signed on March 8, 2004, will be entitled to a reduction in the Dutch withholding tax, either by way of a full or a partial exemption at source or by way of a partial refund or a credit as follows:

- if the US holder is an exempt pension trust as described in article 35 of the Convention, or an exempt organisation as described in article 36 thereof, the US holder will be exempt from Dutch withholding tax; or
- if the US holder is a company that holds directly at least 10% of the voting power in the Company, the US holder will be subject to Dutch withholding tax at a rate not exceeding 5%.

In general, the entire dividend (including any amount withheld) will be dividend income to the US holder and the withholding tax will be treated as a foreign income tax that is eligible for credit against the US holder's income tax liability or a deduction subject to certain limitations. A "US holder" includes, but is not limited to, a citizen or resident of the USA, or a corporation or other entity organised under the laws of the USA or any of its political subdivisions.

When Dutch withholding tax applies on dividends paid to UK tax-resident holders (that is, dividends on A shares or A ADSs, or on B shares or B ADSs that are not paid on the dividend access shares pursuant to the dividend access mechanism), the dividend will typically be subject to withholding tax at a rate of 15%. Such UK tax-resident holder may be entitled to a credit (not repayable) for withholding tax against their UK tax liability. However, certain corporate shareholders are, subject to conditions, exempt from UK tax on dividends. Withholding tax suffered cannot be offset against such exempt dividends. UK tax-resident holders should also be entitled to claim a refund of one-third of the Dutch withholding tax from the Dutch tax authorities in reliance on the tax convention between the Netherlands and the UK. Pension plans meeting certain defined criteria can, however, be entitled to claim a full refund or exemption at source of the dividend tax withheld. Also, UK tax-resident corporate shareholders holding at least a 5% shareholding and meeting other defined criteria are exempted at source from dividend tax.

CAPITAL GAINS TAX

For the purposes of UK capital gains tax, the market values [A] of the shares of the former public parent companies of the Royal Dutch/Shell Group at the relevant dates were:

	£	
	March 31, 1982	July 20, 2005
Royal Dutch Petroleum Company (N.V. Koninklijke Nederlandsche Petroleum Maatschappij) which ceased to exist on December 21, 2005	1.1349	17.6625
The "Shell" Transport and Trading Company, p.l.c. which delisted on July 19, 2005	1.4502	Not applicable

[A] Restated where applicable to reflect all capitalisation issues since the relevant date. This includes the change in the capital structure in 2005, when Royal Dutch Shell plc became the single parent company of Royal Dutch Petroleum Company and of The "Shell" Transport and Trading Company, p.l.c., now The Shell Transport and Trading Company Limited, and one share in Royal Dutch Petroleum Company was exchanged for two Royal Dutch Shell plc A shares and one share in The "Shell" Transport and Trading Company, p.l.c. was exchanged for 0.287333066 Royal Dutch Shell plc B shares.

For holders who are tax-resident in any other country, the availability of a whole or partial exemption or refund of Dutch withholding tax is governed by Dutch tax law and/or the tax convention, if any, between the Netherlands and the country of the holder's residence.

There may be other grounds on which holders who are tax-resident in the UK, the USA or any other country can obtain a full or partial refund of the Dutch withholding tax, depending on their particular circumstances; see "Taxation: General" above.

Dutch capital gains taxation

Capital gains on the sale of shares of a Dutch tax-resident company by a US holder are generally not subject to taxation by the Netherlands unless the US holder has a permanent establishment therein and the capital gain is derived from the sale of shares that are part of the business property of the permanent establishment.

Dutch succession duty and gift taxes

Shares of a Dutch tax-resident company held by an individual who is not a resident or a deemed resident of the Netherlands will generally not be subject to succession duty in the Netherlands on the individual's death.

A gift of shares of a Dutch tax-resident company by an individual who is not a resident or a deemed resident of the Netherlands is generally not subject to Dutch gift tax.

UK stamp duty and stamp duty reserve tax

Sales or transfers of the Company's ordinary shares within a clearance service (such as Euroclear Nederland) or of the Company's ADSs within the ADS depository receipts system will not give rise to a stamp duty reserve tax ("SDRT") liability and should not in practice require the payment of UK stamp duty.

The transfer of the Company's ordinary shares to a clearance service (such as Euroclear Nederland) or to an issuer of depository shares (such as ADSs) will generally give rise to a UK stamp duty or SDRT liability at the rate of 1.5% of consideration given or, if none, of the value of the shares. A sale of the Company's ordinary shares that are not held within a clearance service (for example, settled through the UK's CREST system of paperless transfers) will generally be subject to UK stamp duty or SDRT at the rate of 0.5% of the amount of the consideration, normally paid by the purchaser.

NON-GAAP MEASURES RECONCILIATIONS

These non-GAAP measures, also known as alternative performance measures, are financial measures other than those defined in International Financial Reporting Standards, which Shell considers provide useful information.

EARNINGS ON A CURRENT COST OF SUPPLIES BASIS

Segment earnings are presented on a current cost of supplies basis (CCS earnings), which is the earnings measure used by the Chief Executive Officer for the purposes of making decisions about allocating resources and assessing performance. On this basis, the purchase price of volumes sold during the period is based on the current cost of supplies during the same period after making allowance for the tax effect. CCS earnings therefore exclude the effect of changes in the oil price on inventory carrying amounts. The current cost of supplies adjustment does not impact Cash flow from operating activities in the "Consolidated Statement of Cash Flows".

Reconciliation of CCS earnings to income for the period

	\$ million		
	2019	2018	2017
Earnings on a current cost of supplies basis (CCS earnings)	15,827	24,364	12,471
Attributable to non-controlling interest	(557)	(531)	(390)
Earnings on a current cost of supplies basis attributable to Royal Dutch Shell plc shareholders	15,270	23,833	12,081
Current cost of supplies adjustment	605	(458)	964
Non-controlling interest	(33)	(23)	(68)
Income attributable to Royal Dutch Shell plc shareholders	15,842	23,352	12,977
Non-controlling interest	590	554	458
Income for the period	16,432	23,906	13,435

CASH CAPITAL EXPENDITURE AND CAPITAL INVESTMENT

Capital investment is a measure used to make decisions about allocating resources and assessing performance. It comprises Capital expenditure, Investments in joint ventures and associates and Investments in equity securities, exploration expense excluding well write-offs, leases recognised in the period and other adjustments.

The definition reflects two changes with effect from January 1, 2019, for simplicity reasons. Firstly, "Investments in equity securities" now includes investments under the Corporate segment and is aligned with the line introduced in the Consolidated Statement of Cash Flows from January 1, 2019. Secondly, the adjustments previously made to bring the Capital investment measure onto an accruals basis no longer apply. Comparative information has been revised.

Cash capital expenditure is introduced with effect from January 1, 2019, to monitor investing activities on a cash basis, excluding items such as lease additions which do not necessarily result in cash outflows in the period. The measure comprises the following lines from the Consolidated Statement of Cash flows: Capital expenditure, Investments in joint ventures and associates and Investments in equity securities. Information for prior periods are stated to enable comparison.

The reconciliation of "Capital expenditure" to "Cash capital expenditure" and "Capital investment" is as follows.

Cash capital expenditure and Capital investment reconciliation

	\$ million		
	2019	2018	2017
Capital expenditure [A]	22,971	23,011	20,845
Investments in joint ventures and associates [A]	743	880	595
Investments in equity securities [A]	205	187	93
Cash capital expenditure	23,919	24,078	21,533
Of which:			
Integrated Gas	4,299	3,819	3,616
Upstream	10,277	12,582	11,670
Downstream	8,926	7,408	6,090
Corporate	418	269	157
Exploration expense, excluding exploration wells written off	1,137	889	1,048
Leases recognised in the period	4,494	452	1,074
Other adjustments	(762)	(541)	-
Capital investment	28,788	24,878	23,655
Of which:			
Integrated Gas	6,706	4,259	3,921
Upstream	11,075	12,785	13,160
Downstream	10,542	7,565	6,418
Corporate	465	269	157

[A] Included within Cash flow from investing activities in the "Consolidated Statement of Cash Flows".

OPERATING EXPENSES

Operating expenses is a measure of Shell's cost management performance, comprising items from the "Consolidated Statement of Income" as follows.

Operating expenses

	\$ million		
	2019	2018	2017
Production and manufacturing expenses	26,438	26,970	26,652
Selling, distribution and administrative expenses	10,493	11,360	10,509
Research and development	962	986	922
Total	37,893	39,316	38,083
Of which			
Integrated Gas	6,667	6,014	5,471
Upstream	12,043	12,157	12,656
Downstream	18,697	20,743	19,583
Corporate	486	402	373

NON-GAAP MEASURES RECONCILIATIONS continued

RETURN ON AVERAGE CAPITAL EMPLOYED

Return on average capital employed (ROACE) measures the efficiency of our utilisation of the capital that we employ. In this calculation, ROACE is defined as income for the period, adjusted for after-tax interest expense, as a percentage of the average capital employed for the period. Capital employed consists of total equity, current debt and non-current debt.

Calculation of return on average capital employed

	\$ million		
	2019	2018	2017
Income for the period	16,432	23,906	13,435
Interest expense after tax	3,024	2,513	2,995
Income before interest expense	19,456	26,419	16,430
Capital employed – opening	295,398	283,477	280,988
Capital employed – closing	286,887	279,358	283,477
Capital employed – average	291,142	281,417	282,233
ROACE	6.7%	9.4%	5.8%

FREE CASH FLOW AND ORGANIC FREE CASH FLOW

Free cash flow is used to evaluate cash available for financing activities, including dividend payments, after investment in maintaining and growing our business.

Organic free cash flow is introduced in 2019, and it is defined as Free cash flow excluding the cash flows from acquisition and divestment activities. It is a measure used by management to evaluate generation of cash flow without these activities. Information for 2018 is stated to enable comparison.

Free cash flow and Organic free cash flow

	\$ million		
	2019	2018	2017
Cash flow from operating activities	42,178	53,085	35,650
Cash flow from investing activities	(15,779)	(13,659)	(8,029)
Free cash flow	26,399	39,426	27,621
Less: Cash inflows related to divestments [A]	7,871	10,465	
Add: Tax paid on divestments	187	482	
Add: Cash outflows related to inorganic capital expenditure [B]	1,400	1,740	
Organic free cash flow	20,116	31,183	

[A] Cash inflows related to divestments includes Proceeds from sale of property, plant and equipment and businesses, Proceeds from sale of joint ventures and associates, and Proceeds from sale of equity securities as reported in the "Consolidated Statement of Cash Flows".

[B] Cash outflows related to inorganic capital expenditure includes portfolio actions which expand Shell's activities through acquisitions and restructuring activities as reported in capital expenditure lines in the "Consolidated Statement of Cash Flows".

SHAREHOLDER DISTRIBUTION

Shareholder distribution is used to evaluate the level of cash distribution to shareholders. It is defined as the sum of Cash dividends paid to Royal Dutch Shell plc shareholders and Repurchases of shares, both of which are reported in the Consolidated Statement of Cash Flows.

Calculation of shareholder distribution

	\$ million		
	2019	2018	2017
Cash dividends paid to Royal Dutch Shell plc shareholders	15,198	15,675	10,877
Repurchases of shares	10,188	3,947	-
Shareholder distribution	25,386	19,622	10,877

DIVESTMENTS

Following the completion of the \$30 billion divestment programme for 2016-18, the Divestments measure was discontinued with effect from January 1, 2019.

APPENDICES

APPENDIX 1

SIGNIFICANT SUBSIDIARIES AND OTHER RELATED UNDERTAKINGS (AUDITED)

Significant subsidiaries and other related undertakings at December 31, 2019, are set out below. Shell's percentage of share capital is shown to the nearest whole number. All subsidiaries have been included in the "Consolidated Financial Statements" on pages 190-238, and those held directly by the Company are marked with the footnote [a]. A number of the entities listed are dormant or not yet operational. Entities that are proportionately consolidated are identified by the footnote [b]. Shell-owned shares are ordinary (voting) shares unless identified with one of the following annotations against the company name: [c] Membership interest; [d] Partnership capital; [e] Non-redeemable; [f] Ordinary, Membership interest; [g] Ordinary, Non-redeemable; [h] Ordinary, Partnership capital; [i] Ordinary, Redeemable; [j] Ordinary, Redeemable, Non-redeemable; and [k] Redeemable, Non-redeemable.

Company by country of incorporation	Address of registered office	%
ARGENTINA		
Shell Argentina S.A.	Avenida Pte. Roque Sáenz Peña 788, 5th floor, Buenos Aires, 1383	100
AUSTRALIA		
1st Energy Pty Ltd	Level 4, 459 Little Collins Street, Melbourne, VIC 3000	30
Alliance Automation Pty Ltd	c/o Alands Accountants, Level 1/293 Queen Street, Brisbane, QLD 4000	50
Arrow Energy Holdings Pty Ltd	Level 39, 111 Eagle Street, Brisbane, QLD 4000	50
Austen & Butta Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
BC 789 Holdings Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
BG CPS Pty Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
BNG (Surat) Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Braemar 3 Holdings Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
CCM Energy Solutions Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
Condamine 1 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Condamine 2 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Condamine 3 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Condamine 4 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Condamine Power Station Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
E.R.M. Oakey Power Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
Energy Locals Pty Ltd	132 Cremorne Street, Richmond, VIC 3121	33
ERM Braemar 3 Power Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Braemar 3 Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Employee Share Plan Administrator Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Energy Solutions Holdings Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Financial Services Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Gas Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Gas WA01 Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Holdings Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Innovation Labs Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Land Holdings Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Neerabup Power Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Neerabup Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Oakey Power Holdings Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Power Developments Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Power Engineering Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Power Generation Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Power International Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Power Investments Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Power Limited	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Power Projects Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Power Retail Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Power Services Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Power Utility Systems Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ERM Wellington 1 Holdings Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
ESCO Pacific Holdings Pty Ltd	Level 4, 13 Cremorne Street, Richmond, VIC 3121	49
Fuelink Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Greensense Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
Lumaed Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
New South Oil Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
NewGen Neerabup Pty Ltd [b]	Level 52, 111 Eagle Street, Brisbane, QLD 4000	50
NewGen Power Neerabup Pty Ltd [b]	Level 52, 111 Eagle Street, Brisbane, QLD 4000	50

Company by country of incorporation	Address of registered office	%
North West Shelf LNG Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Oakey Power Holdings Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
OME Resources Australia Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Out Performers Trading Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
Petroleum Resources (Thailand) Pty. Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
PowerMetric Metering Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
Provident & Pensions Holdings Proprietary Limited	Shell House, 562 Wellington Street, Perth, WA 6000	100
Pure Energy Resources Pty Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
QCLNG Operating Company Pty Ltd [i]	Level 30, 275 George Street, Brisbane, QLD 4000	75
QCLNG Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC (B7) Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC (Exploration) Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC (Infrastructure) Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Common Facilities Company Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 2 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 3 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 4 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 5 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 6 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 7 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 8 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Holdings 9 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Midstream Holdings Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Midstream Investments Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Midstream Land Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Midstream Limited Partnership	Level 42, Bourke Place, 600 Bourke Street, Melbourne, VIC 3000	100
QGC Midstream Services Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Northern Forestry Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Pty Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Sales Qld Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Train 1 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Train 1 Tolling Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Train 1 UJV Manager Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Train 2 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Train 2 Tolling No.2 Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Train 2 Tolling Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Train 2 UJV Manager Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Upstream Finance Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Upstream Holdings Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Upstream Investments Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
QGC Upstream Limited Partnership	Level 42, Bourke Place, 600 Bourke Street, Melbourne, VIC 3000	100
Queensland Electricity Investors Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
Queensland Gas Company Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Richmond Valley Solar Thermal Pty Ltd	Level 52, 111 Eagle Street, Brisbane, QLD 4000	100
Roma Petroleum Pty Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
SASF Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
SGA (Queensland) Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
SGAI Pty Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
Shell Australia FLNG Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Australia Lubricants Production Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Australia Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Australia Services Company Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Custodian Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Development (PSC19) Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Development (PSC20) Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Energy Australia Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Shell Energy Holdings Australia Limited	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell Energy Investments Australia Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100

APPENDIX 1 continued

Company by country of incorporation	Address of registered office	%
AUSTRALIA continued		
Shell Global Solutions Australia Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Shell New Energies Australia Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Shell QGC Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Shell Tankers Australia Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Solpod Pty Ltd	c/o Jeffrey Zivin, 140 Belmore Road, Balwyn, VIC 3103	24
Sonnen Australia Pty Limited	Lionsgate Business Park, Level 3, Main Administration Building, 180 Philip Highway, Elizabeth South, SA 5112	100
Starzap Pty Ltd	Level 30, 275 George Street, Brisbane, QLD 4000	100
Sunshine 685 Pty Limited	Level 30, 275 George Street, Brisbane, QLD 4000	100
Trident LNG Shipping Services Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Trident Shipping Services Pty Ltd	Shell House, 562 Wellington Street, Perth, WA 6000	100
Walloons Coal Seam Gas Company Pty Limited [i]	Level 30, 275 George Street, Brisbane, QLD 4000	75
AUSTRIA		
Salzburg Fuelling GmbH	Innsbrucker Bundesstrasse 95, Salzburg, 5020	33
Shell Austria Gesellschaft mbH	Tech Gate, Donau-City-Str. 1, Vienna, 1220	100
Shell Brazil Holding GmbH	Tech Gate, Donau-City-Str. 1, Vienna, 1220	100
Shell China Holding GmbH	Schulhof 6/1, Vienna, 1010	100
TBG Tanklager Betriebsgesellschaft m.b.H.	Rettenlackstrasse 3, Salzburg, 5020	50
Transalpine Ölleitung in Österreich GmbH	Kienburg 11, Matrei in Osttirol, 9971	19
BAHAMAS		
Shell E & P Ireland Offshore Inc.	P.O. Box N4805, St. Andrew's Court, Frederick Street Steps, Nassau	100
BARBADOS		
Shell Trinidad and Tobago Resources SRL	One Welches, Welches, St. Thomas, BB22025	100
Shell Western Supply and Trading Limited	GTC Corporate Services Limited, Sassoon House, Shirley Street & Victoria Avenue, Nassau	100
BELGIUM		
Belgian Shell S.A.	Cantersteen 47, Brussels, 1000	100
New Market Belgium S.A.	Cantersteen 47, Brussels, 1000	100
Shell Catalysts & Technologies Belgium N.V.	Pantserschipstraat 331, Gent, 9000	100
The New Motion Belgium BVBA	Regentlaan 37-40, Brussels, 1000	100
BERMUDA		
Egypt LNG Shipping Limited	Clarendon House, 2 Church Street, Hamilton, HM 11	25
Gas Investments & Services Company Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	85
Kuwait Shell Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Pecten Somalia Company Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Qatar Shell GTL Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Sakhalin Energy Investment Company Ltd	Clarendon House, 2 Church Street, Hamilton, HM 11	28
Shell Australia Natural Gas Shipping Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Bermuda (Overseas) Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Deepwater Borneo Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell EP International Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Holdings (Bermuda) Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell International Trading Middle East Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Markets (Middle East) Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Mexico Exploration and Production Investment Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Offshore Central Gabon Ltd	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Oman Trading Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Overseas Holdings (Oman) Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Petroleum (Malaysia) Ltd	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Saudi Arabia (Refining) Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell South Syria Exploration Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Trading (M.E.) Private Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Trust (Bermuda) Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Shell Trust (U.K. Property) Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Solen Insurance Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100
Solen Life Insurance Limited	3rd Floor Continental Building, 25 Church Street, Hamilton, HM 12	100

Company by country of incorporation	Address of registered office	%
BRAZIL		
BG Comercio e Importacao Ltda.	Avenida das Republica do Chile 330, 23° Andar, Torre 2, Centro, Rio de Janeiro, 20031-170	100
BG do Brasil Ltda.	Avenida das Republica do Chile 330, 23° Andar, Torre 2, Sala 2309, Centro, Rio de Janeiro, 20031-170	100
BG Petroleo & Gas Brasil Ltda.	Avenida das Republica do Chile 330, 23° Andar (parte) – Torre 2, Centro, Rio de Janeiro, 20031-170	100
Fusus Comércio e Participações Ltda.	Avenida das Republica do Chile nº 330, Bloco 2, Sala 2001 – Centro, Rio de Janeiro, 20031-170	100
Icolub – Industria de Lubrificantes S.A.	Praia Intendente Bittencourt, 2 (Parte), Ilha do Governador, Rio de Janeiro, 21930-030	100
Marlim Azul Energia S.A.	Avenida Paulista, 1274, 8° andar, Conjunto 23, Sala B, Bela Vista, São Paulo, 01310-100	30
Pecten do Brasil Servicos de Petroleo Ltda.	Av. República do Chile nº 330, Bloco 2, Sala 2301, Centro, Rio de Janeiro, 20031-170	100
Raizen Combustíveis S.A.	Avenida das Almirante Barroso, nº 81, 36° Andar, Sala 36A104, Rio de Janeiro, 20031-004	54
Raizen Energia S.A.	Avenida Brigadeiro Faria Lima, 4100, 11th floor, part V, Itaim Bibi, São Paulo, 04538-132	49
Seapros Ltda.	Av. República do Chile nº 330, Bloco 2, Sala 2401, Centro, Rio de Janeiro, 20031-170	100
Shell Brasil Participações Ltda.	Avenida Brigadeiro Faria Lima, 3311, Conj 81 Sala 02, Itaim Bibi, São Paulo, 04538-133	100
Shell Brasil Petroleo Ltda.	Av. República do Chile nº 330, Bloco 2, Salas 2001, 2301, 2401, 2501, 3101, 3201, 3301 e 3401, Centro, Rio de Janeiro, 20031-170	100
Shell Energy Brasil Comercializadora de Energia Ltda.	Avenida Brigadeiro Faria Lima nº 3.311, Conj 81, Sala 01, Itaim Bibi, São Paulo, 04538-133	100
Shell Energy do Brasil Ltda.	Avenida Brigadeiro Faria Lima nº 3.311, Conjunto 82, Itaim Bibi, São Paulo, 04538-133	100
BRUNEI		
Brunei LNG Sendirian Berhad	Lumut, Seria, KC2935	25
Brunei Shell Marketing Company Sendirian Berhad	Brunei Shell Petroleum Company, Sendirian Berhad, Seria, KB2933	50
Brunei Shell Petroleum Company Sendirian Berhad	Jalan Utara, Panaga, Seria, KB2933	50
Brunei Shell Tankers Sendirian Berhad	Jalan Utara, Panaga, Seria, KB2933	25
Shell Borneo Sendirian Berhad	c/o BSP Head Office, NDCO Block, Ground Floor, Jalan Utara, Panaga Seria, KB3534	100
BULGARIA		
Shell Bulgaria Ead	48, Sitnyakovo Blvd., Serdika Offices, 8th floor, Sofia, 1505	100
CAMBODIA		
Angkor Resources Company Limited	186C, Street No. 155, N/A – Tuol Tumpung Muoy, Chamkar Mon, Phnom Penh	49
CANADA		
10084751 Canada Limited	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
1745844 Alberta Ltd.	2100, 855 – 2nd Street S.W., Calgary, Alberta, T2P 4J8	50
7026609 Canada Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
7645929 Canada Limited	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Alberta Products Pipe Line Ltd.	5305 McCall Way N.E., Calgary, Alberta, T2E 7N7	20
Cansolv Technologies Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Coral Cibola Canada Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
FP Solutions Corporation	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	33
LNG Canada Development Inc. [b]	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	40
Sable Offshore Energy Inc.	1701 Hollis Street, Suite 1400, Halifax, Nova Scotia, B3J 3M8	33
SCL Pipeline Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
SFJ Inc.	199 Bay Street, Suite 5300, Commerce Court West, Toronto, Ontario, M5L 1B9	50
Shell Americas Funding (Canada) Limited	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Canada BROS Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Canada Energy [c]	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Canada Limited	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Canada OP Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Canada Products	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Canada Resources [c]	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Canada Services Limited	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Catalysts & Technologies Canada Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Chemicals Canada [c]	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Energy Merchants Canada Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Energy North America (Canada) Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Global Solutions Canada Inc.	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Quebec Limitée	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Trading Canada [c]	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Shell Treasury Centre Canada Inc	400 4th Avenue S.W., Calgary, Alberta, T2P 0J4	100
Sun-Canadian Pipe Line Company Limited	830 Highway No. 6 North, Flamborough, Ontario, L0R 2H0	45
Trans-Northern Pipelines Inc.	45 Vogel Road, Suite 310, Richmond Hill, Ontario, L4B 3P6	33
Zeco Systems (Canada) Inc.	295 Hagey Boulevard, Suite 300, Waterloo, Ontario, N2L 6R6	100

APPENDIX 1 continued

Company by country of incorporation	Address of registered office	%
CAYMAN ISLANDS		
Beryl North Sea Limited	Sterling Trust (Cayman) Limited, Whitehall House, 238 North Church Street, P.O. Box 1043, George Town, Grand Cayman, KY1-1102	100
BG Egypt S.A.	5th Floor, Bermuda House, Dr. Roy's Drive, George Town, Grand Cayman, KY1-1102	100
BG Exploration and Production India Limited	Campbells, Floor 4, Willow House, Cricket Square, George Town, Grand Cayman, KY1-9010	100
Gas Resources Limited	Zephyr House, 122 Mary Street, P.O. Box 2570, George Town, Grand Cayman, KY1-1103	100
Schiehallion Oil & Gas Limited	Caledonian Trust (Cayman) Limited, Caledonian House, 69 Dr Roy's Drive P.O. Box 1043, George Town, Grand Cayman, KY1-1102	100
Shell Bolivia Corporation	Zephyr House, 122 Mary Street, P.O. Box 2570, George Town, Grand Cayman, KY1-1103	100
Shell North Sea Holdings Limited	Maples Corporate Services Limited, Ugland House, P.O. Box 309, George Town, Grand Cayman, KY1-1104	100
CHILE		
Shell Chile S.A.	C/O Carey y Cia Abogados, Miraflores 222, Piso 28, Santiago	100
CHINA		
Anhui Shell Energy Company Limited	Room 2519-2522, 25/F, Greenland Center, Cross-area of Susong Rd and Changqin St, South Erhuan, Baohe District, Hefei, Anhui, 230000	100
Beijing Shell Petroleum Company Ltd.	Unit 1101-1104, level 11, Building 1, No. 19 Chaoyang Park Road, Chaoyang District, Beijing, 100125	49
Cansolv Technologies (Beijing) Company Limited	Unit 09, Level 31, No. 16 Building, No. 1 Jian Guo Men Wai Avenue, Chaoyang District, Beijing, 100004	100
Chongqing Doyen Shell Petroleum and Chemical Co. Ltd.	No. 196, Shuang Yuan Street, Beibei Zone, Chongqing, 400700	49
CNOOC and Shell Petrochemicals Company Limited	Dayawan Petrochemical Industrial Park, Huizhou, Guangdong, 516086	50
Fujian Xiangyu and Shell Petroleum Company Limited	Unit 604, 6/F, Building C, No. 3 Yunan Fourth Road, FTPZ Xiamen Sub-zone (Tariff-free Zone), Xiamen, 361000	49
Hangzhou Natural Gas Company Limited	10/F, Meiqi Mansion, No. 30 Tianmushan Road, Hangzhou, Zhejiang, 310007	25
Hubei Shell Energy Company Limited	No. 4, 5, 12/F, Unit A, Oceanwide International Center Office, 187 Yunxia Road, CBD, Jianhan District, Wuhan, 430000	100
Hunan Shell Energy Company Limited	Room 2407-2409, Building 15, Fangmaoyuan (Phase II), No. 1177 Huanhu Road, Yuelu District, Changsha, 410006	100
Infineum (China) Co. Ltd.	No. 1 Dongxin Road, Jiangsu Yangtze River International, Chemical Industry Park, Zhangjiagang, Jiangsu, 215600	50
Jiangsu Shell Energy Company Limited	Room 1001, 10/F, Unit 3, No. 198 Hexi Street, Jianye District, Nanjing, Jiangsu, 210019	100
Shell (Beijing) Real Estate Consulting Ltd.	Unit 01, 32/F, No. 16 Building, No. 1 Courtyard, Jian Guo Men Wai Avenue, Chaoyang District, Beijing, 100004	100
Shell (China) Limited	30/F Unit 01-02, No. 16 Building, No. 1 Courtyard, Jian Guo Men Wai Avenue, Chaoyang District, Beijing, 100004	100
Shell (China) Projects & Technology Limited	Unit 01-08, Level 31, No. 16 Building, No. 1 Jian Guo Men Wai Avenue, Chaoyang District, Beijing, 100004	100
Shell (Shanghai) Petroleum Company Limited	Room 522, The British Road No. 38, China (Shanghai) Pilot Free Trade Zone, Shanghai, 200131	100
Shell (Shanghai) Technology Limited	Building 4, Jin Chuang Building, No. 4560, Jin Ke Road, Pilot Free Trade Zone, Shanghai	100
Shell (Tianjin) Lubricants Company Limited	North to Gang Bei Road and East to Hai Gang Road, Nangang Industrial Zone, Tianjin Economic-Technological Development Area, Tianjin, 300280	100
Shell (Tianjin) Oil and Petrochemical Company Limited	No. 286 Nansan Road, Tianjin Harbour Nanjiang Dev. Zone, Tanggu, Binhai New District, Tianjin, 300452	100
Shell (Zhejiang) Petroleum Trading Limited	No. 1 Wangjiaba, Xinmiaozi Village, Puyuan Town, Tongxiang, Jiaxing, Zhejiang, 314502	100
Shell (Zhuhai) Lubricants Company Limited	Nanjin Wan, Gaolan Dao, Gaolan Harbour Economic Zone, Zhuhai, 519050	100
Shell Energy (China) Limited	Room 530, 5th Floor, Building 1, No. 239 Gang'ao Road, China (Shanghai) Free Trade Zone, Shanghai, 200137	100
Shell Management and Consulting Company Limited	8/F, Building 1, No. 818 Shenchang Road, Minhang District, Shanghai, 201106	100
Shell North China Petroleum Group Co., Ltd.	5th Floor, Administrative Commission Building, Wuqing Development Area, No. 18, Fuyuan Road, Wuqing District, Tianjin, 300203	49
Shell Road Solutions (Zhenjiang) Co. Ltd	No. 68 Xianjia, Dagang, Zhenjiang New District, Zhenjiang, 212132	100
Shell Road Solutions Xinyue (Foshan) Co. Ltd.	Baisha, Hekou, Sanshui District, Foshan, Guangdong, 528133	60
Sinopec and Shell (Jiangsu) Petroleum Marketing Company Limited	No. 100, Xingang Dadao, Nanjing Economic and Technological Development Zone, Nanjing, Jiangsu, 210000	40
Suzhou Liyuan Retail Site Management Co., Ltd.	No. 358 Zhuhui Road, Suzhou, 215000	50
Yanchang and Shell (Guangdong) Petroleum Co., Ltd.	39th Floor as Planning-designed (41st Floor as Self-designated), Leatop Plaza, No. 32 East Zhujiang Road, Zhujiang New Town, Tianhe District, Guangzhou, 510623	49
Yanchang and Shell (Sichuan) Petroleum Company Limited	23F, Yanlord Square, Section 2, Renmin South Road, Chengdu, Sichuan, 610016	45
Yanchang and Shell Petroleum Company Limited	18th Floor, Tower 1, Yongli International Finance Centre, Jinye No. 1 Road, High-tech District, Xi'an, 710075	45
Zhejiang Shell Fuels Company Limited	Room 2103, North Tower, Yefeng Modern Center, No. 161, Shaoxing Road, Xiacheng District, Hangzhou, Zhejiang, 310004	49
Zhejiang Shell Oil and Petrochemical Company Limited	The Port of Zhapu, Jiaxing Municipality, Zhejiang, 314201	100
Zhejiang Transar and Shell Energy Company Limited	Rm 1503, Building 2, Plaza of ZBA, No. 939 Minhe Road, Ningwei Street, Xiaoshan, Hangzhou, Zhejiang, 311215	49
COLOMBIA		
C.I. Shell Comercializadora Colombia, S.A.S	Calle 90 No. 19 - 41, Oficina 702- Edificio Quantum, Bogotá, 452	100
Shell Colombia S.A.	Calle 90 No. 19 - 41, Oficina 702- Edificio Quantum, Bogotá, 452	100
COOK ISLANDS		
Branstone (International) Limited [i]	Bermuda House, Tutakimoa Road, Rarotonga	100
CÔTE D'IVOIRE		
Cote d'Ivoire GNL	14, Blvd Carde, Imm. Les Heveas, Plateau, Abidjan, BP V 194	13
CYPRUS		
Rosneft-Shell Caspian Ventures Limited	Metochiou str, 37, Agios Andreas, Nicosia, CY-1101	49

Company by country of incorporation	Address of registered office	%
CZECH REPUBLIC		
Shell Czech Republic a.s.	Antala Staška 2027/77, Praha 4, 140 00	100
DENMARK		
A/S Dansk Shell	Egeskovvej 265, Fredericia, 7000	100
DCC & Shell Aviation Denmark A/S	Nærum Hovedgade 8, Nærum, 2850	49
Shell EP Holdingselskab Danmark ApS	Egeskovvej 265, Fredericia, 7000	100
TetraSpar Demonstrator ApS	Bredgade 30, København K, 1260	66
EGYPT		
Alam El Shawish Petroleum Company [b]	127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958	20
Badr Petroleum Company [b]	127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958	50
Burullus Gas Company S.A.E. [b]	28 Road 270, Maadi, Cairo	25
El Behera Natural Gas Liquefaction Company S.A.E.	City of Rashid, El Behera Governorate	36
IDKU Natural Gas Liquefaction Company S.A.E.	City of Rashid, El Behera Governorate	38
North Alam El-Shawish Petroleum Company [b]	127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958	50
North Um Baraka Petroleum Company [b]	127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958	50
Obaiyed Petroleum Company [b]	127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958	50
Rashid Petroleum Company S.A.E. [b]	38 Street No. 270, Maadi, Cairo	40
Shell Egypt Trading	Business View Building, No. 79, 90 Street (South), Fifth Settlement- New Cairo, Cairo, 11835	100
Shell Lubricants Egypt	Business View Building, No. 79, 90 Street (South), Fifth Settlement- New Cairo, Cairo, 11835	100
Sitra Petroleum Company [b]	127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958	50
The Egyptian LNG Company S.A.E.	City of Rashid, El Behera Governorate	36
The Egyptian Operating Company for Natural Gas Liquefaction Projects S.A.E.	City of Rashid, El Behera Governorate	36
Tiba Petroleum Company [b]	127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958	26
West Sitra Petroleum Company [b]	127 Abdel Aziz Fahmy St., Heliopolis, P.O. Box 5958, Cairo, 5958	50
FINLAND		
Shell Aviation Finland Oy	Teknobulevardi 3-5, Vantaa, 01530	100
FRANCE		
Accurasea	10 place de Catalogne, Paris, 75014	100
Airefsol Energies	10 place de Catalogne, Paris, 75014	67
Airefsol Energies 2	10 place de Catalogne, Paris, 75014	67
Airefsol Energies 6	10 place de Catalogne, Paris, 75014	67
Airefsol Energies 8	10 place de Catalogne, Paris, 75014	67
Airefsol Energies 9	10 place de Catalogne, Paris, 75014	67
Avitair SAS	Tour Pacific, 11/13 Cours Valmy - La Défense, Puteaux, 92800	100
Centrale Photovoltaïque Bouches-du-Rhône 1	10 place de Catalogne, Paris, 75014	100
Centrale Photovoltaïque Haute-Vienne	10 place de Catalogne, Paris, 75014	100
Centrale Photovoltaïque Landes 1	10 place de Catalogne, Paris, 75014	100
Centrale Photovoltaïque Var 1	10 place de Catalogne, Paris, 75014	100
Eolfi Offshore France	10 place de Catalogne, Paris, 75014	10
Eolfi SAS	10 place de Catalogne, Paris, 75014	100
Eoliennes du Gentilhomme	10 place de Catalogne, Paris, 75014	100
Ferme Eolienne Flottante de Groix & Belle-Ile	10 place de Catalogne, Paris, 75014	25
Ferme Eolienne Flottante Stenella Rhône	10 place de Catalogne, Paris, 75014	100
Groupeement Pétrolier Aviation SNC	Aéroport Roissy Charles de Gaulle, Zone de Frêt 1, 3 Rue des Vignes, Tremblay-en-France, 93290	20
Infineum France	Chemin départemental 54, Berre-L'Etang, 13130	50
Parc Eolien Aisne 1	10 place de Catalogne, Paris, 75014	100
Parc Eolien Charente 1	10 place de Catalogne, Paris, 75014	100
Parc Eolien Corrèze 1	10 place de Catalogne, Paris, 75014	100
Parc Eolien Côtes Armor 1	10 place de Catalogne, Paris, 75014	100
Parc Eolien de la Vrène	10 place de Catalogne, Paris, 75014	100
Parc Eolien Haute-Saône 1	10 place de Catalogne, Paris, 75014	100
Parc Eolien HMI	10 place de Catalogne, Paris, 75014	100
Parc Eolien Jura 1	10 place de Catalogne, Paris, 75014	100
Parc Eolien Marne 1	10 place de Catalogne, Paris, 75014	100
Parc Eolien Oise 1	10 place de Catalogne, Paris, 75014	100
Parc Eolien Oise 2	10 place de Catalogne, Paris, 75014	100
Parc Eolien Somme 1	10 place de Catalogne, Paris, 75014	100

APPENDIX 1 continued

Company by country of incorporation	Address of registered office	%
FRANCE continued		
Parc Eolien Somme 2	10 place de Catalogne, Paris, 75014	100
Parc Eolien Yonne 1	10 place de Catalogne, Paris, 75014	100
Service Aviation Paris SNC	Orly Sud No. 144 – Bat. 438, Orly Aerogares, 94541	33
Shell Retraites SAS	Tour Pacific, 11/13 Cours Valmy – La Défense, Puteaux, 92800	100
Société de Gestion Mobilière et Immobilière SAS	Tour Pacific, 11/13 Cours Valmy – La Défense, Puteaux, 92800	100
Société des Pétroles Shell SAS	Tour Pacific, 11/13 Cours Valmy – La Défense, Puteaux, 92800	100
Ste du Pipeline Sud Européen S.A.	7-9, Rue des Frères Morane, Paris, 75015	21
The New Motion France SAS	92 Avenue Charles de Gaulle, CS 30082, Neuilly sur Seine, 92522	100
GERMANY		
AGES Maut System GmbH & Co. KG	Berghausener Straße 96, Langenfeld, 40764	25
BEB Erdgas und Erdoel GmbH & Co. KG [b]	Riethorst 12, Hannover, 30659	50
BEB Holding GmbH [b]	Caffamacherreihe 5, Hamburg, 20355	50
Carissa Einzelhandel- und Tankstellenservice GmbH & Co. KG	Willinghusener Weg 5 D-E, Oststeinbek, 22113	100
Carissa Verwaltungsgesellschaft mbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
CRI Deutschland GmbH	Am Haupttor, Bau 8322, Leuna, 06237	100
Deutsche Infineum GmbH & Co. KG	Neusser Landstraße 16, Köln, 50735	50
Deutsche Shell GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Deutsche Shell Holding GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Deutsche Transalpine Oelleitung GmbH	Paul Wassermann Str. 3, Munich, 81829	19
Energeticum Energiesysteme GmbH	St.-Leonhard-Straße 26, Balzhausen, 86483	100
Enersol GmbH	Einsteinstr. 47, Vaihingen an der Enz, 71665	100
Erdoel-Raffinerie Deurag-Nerag GmbH	Riethorst 12, Hannover, 30659	50
euroShell Deutschland GmbH & Co. KG	Suhrenkamp 71 – 77, Hamburg, 22335	100
euroShell Deutschland Verwaltungsgesellschaft mbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
H2 Mobility Deutschland GmbH and Co. KG	EUREF-Campus 10-11, Berlin, 10829	28
HPRDS und SPNV Deutschland Oil GmbH & Co. KG	Suhrenkamp 71 – 77, Hamburg, 22335	100
HPRDS und SPNV Deutschland Verwaltungsges. mbH	Suhrenkamp 71 – 77, Hamburg, 22335	90
Infineum Deutschland Verwaltungsgesellschaft mbH	Neusser Landstraße 16, Köln, 50735	50
Mineraloelraffinerie Oberrhein Verwaltungs GmbH	DEA-Scholven-Str., Karlsruhe, 76187	32
Nord-West Oelleitung GmbH [b]	Zum Oelhafen 207, Wilhelmshaven, 26384	20
Oberrheinische Mineraloelwerke GmbH [b]	DEA-Scholven-Str., Karlsruhe, 76187	42
OLF Deutschland GmbH [b]	WeWork Europapassage, Hermannstraße 13, Hamburg, 20095	50
PCK Raffinerie GmbH [b]	Passower Chaussee 111, Schwedt/Oder, 16303	38
Rheinland Kraftstoff GmbH	Auf dem Schollbruch 24-26, Gelsenkirchen, 45899	100
Rhein-Main-Rohrleitungstransportgesellschaft mbH [b]	Godorfer Hauptstrasse 186, Köln, 50997	63
Shell Catalysts & Technologies Leuna GmbH	Am Haupttor, Bau 8322, Leuna, 06237	100
Shell Deutschland Additive GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell Deutschland Oil GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell Energy Deutschland GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell Erdgas Beteiligungsgesellschaft mbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell Erdgas Marketing GmbH & Co. KG	Suhrenkamp 71 – 77, Hamburg, 22335	75
Shell Erdoel und Erdgas Exploration GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell Exploration and Development Libya GmbH I	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell Exploration and Production Colombia GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell Exploration and Production Libya GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell Exploration et Production du Maroc GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell Exploration New Ventures One GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell Exploration und Produktion Deutschland GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell Global Solutions (Deutschland) GmbH	Hohe-Schaar-Straße 36, Hamburg, 21107	100
Shell Hydrogen Deutschland GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell Offshore Exploration und Produktion Deutschland GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell PrivatEnergie GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell Tunisia Offshore GmbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Shell Verwaltungsgesellschaft für Erdgasbeteiligungen mbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
Sonnen eServices Deutschland GmbH	Am Riedbach 1, Wildpoldsried, 87499	100
Sonnen eServices GmbH	Am Riedbach 1, Wildpoldsried, 87499	100

Company by country of incorporation	Address of registered office	%
Sonnen GmbH	Am Riedbach 1, Wildpoldsried, 87499	100
Sonnen Holding GmbH	Am Riedbach 1, Wildpoldsried, 87499	100
SPNV Deutschland Beteiligungsges. mbH	Suhrenkamp 71 – 77, Hamburg, 22335	100
The New Motion Deutschland GmbH	Wattstraße 11, Berlin, 13355	100
Tiramizoo GmbH	Prannerstr. 2-4, Munich, 80333	21
Toll4Europe GmbH	Französische Straße 33 a-c, Berlin, 10117	15
Wasserbeschaffungsverband Wesseling-Hersel	Bruehler Str. 95, Wesseling, 50389	35
GIBRALTAR		
Shell LNG Gibraltar Limited	57/63 Line Wall Road, P.O. Box 199, Gibraltar	51
GREECE		
Shell & MOH Aviation Fuels A.E.	151 Kifisias Ave., Marousi, Athens, 15124	51
GREENLAND		
Shell Greenland A/S	P.O. Box 510, Issortarfimmut 6, 102, Nuussuaq, 3905	100
GUAM		
Shell Guam Inc.	643 Chalan San Antonio, Suite 100, Tamuning, GU 96911	100
HONG KONG		
AFSC Operations Limited	3 Scenic Road, Chek Lap Kok, Lantau	11
AFSC Refuelling Limited	3 Scenic Road, Chek Lap Kok, Lantau	11
Fulmart Limited	35/F AIA Kowloon Tower, Landmark East, 100 How Ming Street, Kwun Tong, Kowloon	100
Hong Kong Response Limited	Esso Tsing Yi Terminal, Lot 46 Tsing Yi Road, Tsing Yi Island, New Territories	25
Ocean Century Tf Limited [i]	35/F AIA Kowloon Tower, Landmark East, 100 How Ming Street, Kwun Tong, Kowloon	100
Shell Developments (HK) Limited [i]	35/F AIA Kowloon Tower, Landmark East, 100 How Ming Street, Kwun Tong, Kowloon	100
Shell Hong Kong Limited	35/F AIA Kowloon Tower, Landmark East, 100 How Ming Street, Kwun Tong, Kowloon	100
Shell Korea Limited	35/F AIA Kowloon Tower, Landmark East, 100 How Ming Street, Kwun Tong, Kowloon	100
Shell Macau Limited	35/F AIA Kowloon Tower, Landmark East, 100 How Ming Street, Kwun Tong, Kowloon	100
HUNGARY		
Shell Hungary Trading close Company Limited by shares	Bocskai út 134-146., Budapest, 1113	100
INDIA		
BG India Energy Private Limited	3-C World Trade Tower, New Barakhamba Lane, New Delhi, 110001	100
BG India Energy Services Private Limited	3-C World Trade Tower, New Barakhamba Lane, New Delhi, 110001	100
BG India Energy Solutions Private Limited	3-C World Trade Tower, New Barakhamba Lane, New Delhi, 110001	100
BG LNG Regas India Private Limited	3-C World Trade Tower, New Barakhamba Lane, New Delhi, 110001	100
Greenlots Technology India LLP	Platina Tower MG Road, Near Sikandarpur Metro Station, Section, Haryana, Gurugram, 122001	100
Hazira Port Private Limited	101-103 Abhijeet-II, Mithakhali Circle, Ahmedabad 380 006, Gujarat, 380006	100
Pennzoil Quaker State India Limited	Plot No. T-5, MIDC, Talaja Industrial Area, Tal-Panvel, Raigad District, Mumbai, MH 410208	100
Shell Energy India Private Limited	101-103 Abhijeet-II, Mithakhali Circle, Ahmedabad 380 006, Gujarat, 380006	100
Shell Energy Marketing and Trading India Private Limited	2nd floor, Campus 4A, RMZ Millenia Business Park II, 143 Dr MGR Road, Kandhanchavady, Perungudi, Chennai, TN 600096	100
Shell India Markets Private Limited	2nd floor, Campus 4A, RMZ Millenia Business Park II, 143 Dr MGR Road, Kandhanchavady, Perungudi, Chennai, TN 600096	100
Shell MRPL Aviation Fuels and Services Limited	102, Prestige Sigma, Vittal Mallya Road, Bangalore, 560001	50
Shell Pahal Social Welfare Association	7, Bangalore Hardware Park, Devanahalli Industrial Park, Mahadeva-Kodigehalli, Bangalore, 562149	100
Tiki Tar and Shell India Private Limited	Tiki Tar Industries Village Road, Near Bhandup village, Bhandup West Mumbai, Mumbai, MH 400078	50
INDONESIA		
PT Shell LNG Indonesia	Talavera Office Park 22-26th Floor, Jl. Letjen. TB Simatupang Kav. 22-26, Jakarta Selatan, Jakarta, 12430	100
PT. Shell Indonesia	Talavera Office Park 22-26th Floor, Jl. Letjen. TB Simatupang Kav. 22-26, Jakarta Selatan, Jakarta, 12430	100
PT. Shell Manufacturing Indonesia	Talavera Office Park 22-26th Floor, Jl. Letjen. TB Simatupang Kav. 22-26, Jakarta Selatan, Jakarta, 12430	100
IRAQ		
Basrah Gas Company	Khor Al Zubair, Basrah	44
IRELAND		
Asiatic Petroleum Company (Dublin) Limited	1st Floor, Temple Hall, Temple Road, Blackrock, Co. Dublin, A94 K3K0	100
Irish Shell Trust Designated Activity Company	1st Floor, Temple Hall, Temple Road, Blackrock, Co. Dublin, A94 K3K0	100
Shell and Topaz Aviation Ireland Limited	Suite 7 Northwood House, Northwood Business Park, Santry, Dublin, 9	50
ISLE OF MAN		
Petrolon Europe Limited	First Names House, Victoria Road, Douglas, IM2 4DF	100
Petrolon International Limited	First Names House, Victoria Road, Douglas, IM2 4DF	100
Shell Marine Personnel (I.O.M.) Limited	Euromanx House, Freeport, Ballasalla, IM9 2AP	100
Shell Ship Management Limited	Euromanx House, Freeport, Ballasalla, IM9 2AP	100

APPENDIX 1 continued

Company by country of incorporation	Address of registered office	%
ISRAEL		
Ravin AI Ltd.	Derech Aba Hilel 16, Ramat Gan, 5250608	36
ITALY		
Alle S.R.L.	Via Vittor Pisani 16, Milano, 20124	100
Aquila S.p.A.	Via Vittor Pisani 16, Milano, 20124	100
BG Italia Power S.r.l	Via Tortona 25, Milano, 20144	100
Brindisi LNG S.r.l.	Via Tortona 25, Milano, 20144	100
Infineum Italia S.R.L.	Strada di Scorrimento 2, Vado Ligure, Savona, 17047	50
Shell Energy Italia S.R.L.	Via Vittor Pisani 16, Milano, 20124	100
Shell Fleet Solutions Consorzio	Via Susa 40, Torino, 10138	100
Shell International Exploration and Development Italia S.p.A.	Piazza dell'Indipendenza 11/B, Rome, 00185	100
Shell Italia E&P S.p.A.	Piazza dell'Indipendenza 11/B, Rome, 00185	100
Shell Italia Holding S.p.A.	Via Vittor Pisani 16, Milano, 20124	100
Shell Italia Oil Products S.R.L.	Via Vittor Pisani 16, Milano, 20124	100
Societa Italiana per l'Oleodotto Transalpino S.p.A.	Via Muggia #1, San Dorligo della Valle, Trieste, 34147	19
Societa' Oleodotti Meridionali S.p.A.	Via Emilia 1, San Donato Milanese, 20097	30
Sonnen eServices Italia S.R.L.	Via Autostrada 32, Bergamo, 24126	100
Sonnen S.R.L.	Via Autostrada 32, Bergamo, 24126	100
JAPAN		
Brunei Energy Services Company Ltd.	1-8-2 Marunouchi, Chiyoda-ku, Tokyo, 100-0005	25
CO2-free Hydrogen Energy Supply-chain TRA	7F Kokuryu Shiba Koen Building 2-6-15, Shiba Koen, Minato-ku, Tokyo, 105-0011	25
Sakhalin LNG Services Company Ltd.	2-3, Kanda, Awaji-cho, Chiyoda-ku, Tokyo, 101-0063	50
Shell Japan Limited	16F Pacific Century Place, 1-11-1, Marunouchi, Chiyoda-Ku, Tokyo, 100-6216	100
Sonnen Japan Kabushiki Kaisha	16F Pacific Century Place, 1-11-1, Marunouchi, Chiyoda-Ku, Tokyo, 100-6216	100
JERSEY		
Shell Service Station Properties Limited	Queensway House, Hilgrove Street, St. Helier, JE1 1ES	100
LUXEMBOURG		
Denham International Power SCSp [d]	412F, route d'Esch, Luxembourg, L-2086	32
Shell Finance Luxembourg Sarl	7, Rue de l'Industrie, Bertrange, Luxembourg, L-8069	100
Shell Luxembourgeoise Sarl	7, Rue de l'Industrie, Bertrange, Luxembourg, L-8005	100
Shell Treasury Luxembourg Sarl	7, Rue de l'Industrie, Bertrange, Luxembourg, L-8069	100
MACAU		
Shell Macau Petroleum Company Limited	876 Avenida da Amizade, Edificio Marina Gardens, Room 310, 3rd Floor	100
MALAYSIA		
Bonuskad Loyalty Sdn. Bhd. [i]	Level 8, Symphony House, Block D13, Pusat Dagangan Dana 1, Jalan PJU 1A/46, Petaling Jaya/Selangor Darul Ehsan, 47301	33
IOT Management Sdn. Bhd.	Lot 7689 and Lot 7690, Section 64, Kuching Town Land District, Jalan Pending, Kuching, Sarawak, 93450	7
Kebabangan Petroleum Operating Company Sdn. Bhd. [b]	Suite 13.03, 13 Floor, Menara Tan & Tan, 207 Tun Razak, Kuala Lumpur/Federal Territory, 50400	30
P S Pipeline Sendirian Berhad	Level 30, Tower 1, Petronas Twin Towers, KLCC, Kuala Lumpur/Federal Territory, 50088	50
P S Terminal Sendirian Berhad	12th Floor, Menara Symphony, No. 5, Jalan Prof. Khoo Kay Kim, Seksyen 13, Petaling Jaya/Selangor Darul Ehsan, 46200	35
Pertini Vista Sdn. Bhd.	12th Floor, Menara Symphony, No. 5, Jalan Prof. Khoo Kay Kim, Seksyen 13, Petaling Jaya/Selangor Darul Ehsan, 46200	100
Provista Ventures Sdn. Bhd.	12th Floor, Menara Symphony, No. 5, Jalan Prof. Khoo Kay Kim, Seksyen 13, Petaling Jaya/Selangor Darul Ehsan, 46200	100
Sarawak Shell Berhad	12th Floor, Menara Symphony, No. 5, Jalan Prof. Khoo Kay Kim, Seksyen 13, Petaling Jaya/Selangor Darul Ehsan, 46200	100
Shell Business Service Centre Sdn. Bhd.	12th Floor, Menara Symphony, No. 5, Jalan Prof. Khoo Kay Kim, Seksyen 13, Petaling Jaya/Selangor Darul Ehsan, 46200	100
Shell Global Solutions (Malaysia) Sdn. Bhd.	12th Floor, Menara Symphony, No. 5, Jalan Prof. Khoo Kay Kim, Seksyen 13, Petaling Jaya/Selangor Darul Ehsan, 46200	100
Shell Malaysia Trading Sendirian Berhad	12th Floor, Menara Symphony, No. 5, Jalan Prof. Khoo Kay Kim, Seksyen 13, Petaling Jaya/Selangor Darul Ehsan, 46200	100
Shell MDS (Malaysia) Sendirian Berhad	12th Floor, Menara Symphony, No. 5, Jalan Prof. Khoo Kay Kim, Seksyen 13, Petaling Jaya/Selangor Darul Ehsan, 46200	72
Shell New Ventures Malaysia Sdn. Bhd. [i]	12th Floor, Menara Symphony, No. 5, Jalan Prof. Khoo Kay Kim, Seksyen 13, Petaling Jaya/Selangor Darul Ehsan, 46200	100
Shell People Services Asia Sdn. Bhd.	12th Floor, Menara Symphony, No. 5, Jalan Prof. Khoo Kay Kim, Seksyen 13, Petaling Jaya/Selangor Darul Ehsan, 46200	100
Shell Sabah Selatan Sendirian Berhad	12th Floor, Menara Symphony, No. 5, Jalan Prof. Khoo Kay Kim, Seksyen 13, Petaling Jaya/Selangor Darul Ehsan, 46200	100
Shell Timur Sdn. Bhd.	12th Floor, Menara Symphony, No. 5, Jalan Prof. Khoo Kay Kim, Seksyen 13, Petaling Jaya/Selangor Darul Ehsan, 46200	70
Shell Treasury Malaysia (L) Limited	Kensington Gardens, No. U1317, Lot 7616, Jalan Jumidar Buyong, Labuan F.T., 87000	100
Tanjung Manis Oil Terminal Management Sdn. Bhd.	Lot 7689 and Lot 7690, Section 64, Kuching Town Land District, Jalan Pending, Kuching, Sarawak, 93450	14
MAURITIUS		
BG Mauritius LNG Holdings Ltd	6th Floor, Tower A, 1 Cybercity, Ebene, 72201	100
BG Mumbai Holdings Limited	6th Floor, Tower A, 1 Cybercity, Ebene, 72201	100
Pennzoil Products International Company	33 Edith Cavell Street, Port Louis, 11324	100

Company by country of incorporation	Address of registered office	%
MEXICO		
Comercial Importadora S.A. De C.V.	Guillermo González Camarena No. 400, Santa Fe, Ivaro Obregón, Ciudad de México, 1210	50
Concilia Asesores y Servicios, S.A. de C.V.	Guillermo González Camarena No. 400, Santa Fe, Ivaro Obregón, Ciudad de México, 1210	50
Gas Del Litoral, S. de R.L. de C.V.	Avenida Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
Mega Gasolinerías SA de CV	Avenida Cerro Gordo del Campestre 201 int 202, Las Quintas, León, Guanajuato, 37125	50
Shell Energy Mexico, S.A. de C.V.	Avenida Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
Shell Exploración y Extracción de México, S.A. de C.V.	Avenida Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
Shell México Gas Natural, S. de R.L. de C.V.	Avenida Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
Shell México, S.A. de C.V.	Avenida Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
Shell Servicios México, S.A. de C.V.	Avenida Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
Shell Solutions Mexico S.A. de C.V.	Avenida Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
Shell Trading México, S. de R.L. de C.V.	Avenida Paseo de las Palmas 340, 1st floor, Colonia Lomas de Chapultepec, Delegación Miguel Hidalgo, Ciudad de México, 11000	100
NETHERLANDS		
Amsterdam Schiphol Pijpleiding Beheer B.V.	Amsterdamseweg 55, 1182 GP Amstelveen, P.O. Box 75650, Luchthaven Schiphol, 1118 ZS	40
Attiki Gas B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
B.R.E. B.V.	Lelystad, Deventer, 7425 SB	100
B.V. Dordtsche Petroleum Maatschappij	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
B.V. Petroleum Assurantie Maatschappij	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas Atlantic Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas Brazil E&P 12 B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas Brazil Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas Global Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas International B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas International Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas Netherlands Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BG Gas Sao Paulo Investments B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
BJS Oil Operations B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	80
BJSA Exploration and Production B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Blauwwind II C.V. [d]	Weena 70, Rotterdam, 3012 CM	20
Blauwwind Management II B.V.	Weena 70, Rotterdam, 3012 CM	20
Caspi Meruerty Operating Company B.V. [b]	Muiderstraat 1, Amsterdam, 1011 PZ	40
Chosun Shell B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Cicerone Holding B.V.	Herikerbergweg 238, Amsterdam, 1101 CM	51
Ellba B.V. [b]	Vondelingenweg 601, Vondelingenplaat, Rotterdam, 3196 KK	50
Ellba C.V. [b] [d]	Vondelingenweg 601, Vondelingenplaat, Rotterdam, 3196 KK	50
Euroshell Cards B.V.	Weena 70, Rotterdam, 3012 CM	100
Fitzroy C.V. [d]	Stationsplein 45, Rotterdam, 3013 AK	20
Gasterra B.V.	P.O. Box 477, Groningen, 9700 AL	25
Guara B.V.	Weena 722, Rotterdam, 3014 DA	30
Hkz Lp 18 B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Hkz Lp 19 B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Hkz Lp 20 B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Hkz Lp 21 B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Hkz Lp 22 B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Iara B.V.	Weena 762, 9e verdieping, kamer A, Rotterdam, 3014 DA	25
Infineum Holdings B.V.	Herikerbergweg 238, Amsterdam, 1101 CM	50
Integral Investments B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Jordan Oil Shale Company B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Karachaganak Petroleum Operating B.V. [b]	Strawinskylaan 1345, Amsterdam, 1077 XX	29
Lapa Oil & Gas B.V.	Weena 762, 9e verdieping, kamer A, Rotterdam, 3014 DA	30
Libra Oil & Gas B.V.	Weena 762, Rotterdam, 3014 DA	20
LNG Shipping Operation Services Netherlands B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Loyalty Management Netherlands B.V.	Polaris Avenue 81, P.O. Box 2047, 2130 GE, Hoofddorp, 2132 JH	40

APPENDIX 1 continued

Company by country of incorporation	Address of registered office	%
NETHERLANDS continued		
Maasvlakte Olie Terminal C.V. [d]	Europaweg 975, Maasvlakte, Rotterdam, 3199 LC	16
Multi Tank Card B.V.	Antareslaan 39, P.O. Box 3068, 2130 KB, Hoofddorp, 2132 JE	30
N.V. Rotterdam-Rijn Pijpleiding Maatschappij [b]	Butaanweg 215, Vondelingplaat, Rotterdam, 3196 KC	56
Nederlandse Aardolie Maatschappij B.V.	Schepersmaat 2, Assen, 9405 TA	50
Netherlands Aing Holding Company B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Noordzeewind B.V.	2e Havenstraat 5b, Ijmuiden, 1976 CE	50
Noordzeewind C.V. [d]	2e Havenstraat 5b, Ijmuiden, 1976 CE	50
North Caspian Operating Company N.V. [b]	Oostduinlaan 2, The Hague, 2596 JM	17
Paqell B.V.	Reactorweg 301, unit 1.3, Utrecht, 3542 AD	50
Raffinaderij Shell Mersin N.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
RESCO B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Salym Petroleum Development N.V. [b]	Carel van Bylandtlaan 30, The Hague, 2596 HR	50
Shell Abu Dhabi B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Additives Holdings (I) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Additives Holdings (II) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Albania Block 4 B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell and Vivo Lubricants B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	50
Shell Asset Management Company B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Brazil Holding B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Business Development Central Asia B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Caspian B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Caspian Pipeline Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Chemicals Europe B.V.	Weena 70, Rotterdam, 3012 CM	100
Shell Chemicals Ventures B.V. [k]	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell China B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell China Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Deepwater Tanzania B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Development Iran B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Downstream Services International B.V.	Weena 70, Rotterdam, 3012 CM	100
Shell E and P Offshore Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Egypt N.V. [e]	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Energy Europe B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell EP Holdings (EE&ME) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell EP Middle East Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell EP Oman B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell EP Russia Investments (III) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell EP Russia Investments (V) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell EP Somalia B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell EP Wells Equipment Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Europe New Energies Holding B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration & Production Brunei B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (100) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (101) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (102) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (103) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (104) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (105) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (106) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (107) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (79) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (82) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (84) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (89) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (90) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (91) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (92) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (93) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100

Company by country of incorporation	Address of registered office	%
Shell Exploration and Production (94) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (96) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (99) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LI) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LXI) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LXII) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LXV) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LXVI) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LXXI) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (LXXV) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production (XLI) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Investments B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Mauritania (C10) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Mauritania (C19) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Services (RF) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production South Africa B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Ukraine I B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Ukraine Investments (I) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production Ukraine Investments (II) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration and Production West-Siberia B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration Company (RF) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration Company (West) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration Company B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Exploration Venture Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Finance (Netherlands) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Gas & Power Developments B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Gas (LPG) Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Gas B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Gas Iraq B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Gas Nigeria B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Gas Venezuela B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Generating (Holding) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Geothermal B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Global Solutions (Eastern Europe) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Global Solutions International B.V.	Lange Kleiweg 40, Rijswijk, 2288 GK	100
Shell Global Solutions Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Information Technology International B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Integrated Gas Oman B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell International B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell International Exploration and Production B.V.	Carel van Bylandtlaan 16, The Hague, 2596 HR	100
Shell International Finance B.V. [a]	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Internationale Research Maatschappij B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Internet Ventures B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Iraq Petroleum Development B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Iraq Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Kazakhstan B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Kazakhstan Development B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Kuwait Exploration and Production B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell LNG Bunkering B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell LNG Port Spain B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Lubricants Supply Company B.V.	Weena 70, Rotterdam, 3012 CM	100
Shell Manufacturing Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Mozambique B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell MSPO 2 Holding B.V.	Vondelingenweg 601, Vondelingenplaat, Rotterdam, 3196 KK	100
Shell Namibia Upstream B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Nanhai B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100

APPENDIX 1 continued

Company by country of incorporation	Address of registered office	%
NETHERLANDS continued		
Shell Nederland B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Nederland Chemie B.V. [i]	Chemieweg 25, P.O. Box 6060, Moerdijk, 4780 LN	100
Shell Nederland Raffinaderij B.V.	Vondelingenweg 601, Vondelingenplaat, Rotterdam, 3196 KK	100
Shell Nederland Verkoopmaatschappij B.V.	Weena 70, Rotterdam, 3012 CM	100
Shell Netherlands Canada Financing B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell New Energies NL B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Offshore (Personnel) Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Offshore Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell OKLNG Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Olie OG Gas Holding B.V. [k]	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Oman Exploration and Production B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Overseas Investments B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Pensioenbureau Nederland B.V.	Postbus 157, The Hague, 2501 CD	100
Shell Petroleum N.V. [a]	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Philippines Exploration B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Project Development (VIII) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell RDS Holding B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Sakhalin Holdings B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Sakhalin Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Salym Development B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Sao Tome and Principe B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Services Oman B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Shared Services (Asia) B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell TapUp B.V.	Hofplein 20, Rotterdam, 3032 AC	100
Shell Technology Ventures Fund 1 B.V.	Strawinskylaan 3127 8e etage, Amsterdam, 1077 ZX	52
Shell Trademark Management B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Trading Rotterdam B.V.	Weena 70, Rotterdam, 3012 CM	100
Shell Trading Russia B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Upstream Albania B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Upstream Development B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Upstream Indonesia Services B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Upstream Spain B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Upstream Turkey B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Ventures B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Ventures Investments B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Western LNG B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Windenergy Netherlands B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Shell Windenergy NZW I B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
Snijders Olie B.V.	Weena 70, Rotterdam, 3012 CM	100
SolarNow B.V.	Zeelandsestraat 1, Millingen aan de Rijn, 6566 DE	23
Syria Shell Petroleum Development B.V. [j]	Carel van Bylandtlaan 30, The Hague, 2596 HR	65
Tamba B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	50
Tankstation Exploitatie Maatschappij Holding B.V.	Weena 70, Rotterdam, 3012 CM	100
The Green Near Future 5 B.V.	Carel van Bylandtlaan 30, The Hague, 2596 HR	100
The New Motion B.V.	Rigakade 20, Amsterdam, 1013 BC	100
Travis Road Services International B.V.	Dr. Hub van Doorneweg 183, Tilburg, 5026 RD	34
Tupi B.V.	Wilhelminatoren, Wilhelminaplein 14, Rotterdam, 3072	25
W2C GP B.V.	Stationsplein 45, Rotterdam, 3013 AK	20
Waalbrug Exploitatie Maatschappij B.V.	Henri Berssenbruggestraat 9, Deventer, 7425 SB	100
Zeolyst C.V.	Oosterhorn 36, Farmsum, 9936 HD	50
NEW ZEALAND		
Energy Finance NZ Limited	c/o Baker Tilly Staples Rodway Taranaki Limited, 109-113 Powderham Street, P.O. Box 146, New Plymouth, Taranaki, 4340	100
Energy Holdings Offshore Limited	c/o Baker Tilly Staples Rodway Taranaki Limited, 109-113 Powderham Street, P.O. Box 146, New Plymouth, Taranaki, 4340	100
Shell (Petroleum Mining) Company Limited	c/o Baker Tilly Staples Rodway Taranaki Limited, 109-113 Powderham Street, P.O. Box 146, New Plymouth, Taranaki, 4340	100
Shell Energy Asia Limited	c/o Baker Tilly Staples Rodway Taranaki Limited, 109-113 Powderham Street, P.O. Box 146, New Plymouth, Taranaki, 4340	100
Shell Investments NZ Limited	c/o Baker Tilly Staples Rodway Taranaki Limited, 109-113 Powderham Street, P.O. Box 146, New Plymouth, Taranaki, 4340	100
Southern Petroleum No Liability	c/o Baker Tilly Staples Rodway Taranaki Limited, 109-113 Powderham Street, P.O. Box 146, New Plymouth, Taranaki, 4340	100

Company by country of incorporation	Address of registered office	%
NIGERIA		
All on Partnerships for Energy Access Limited by Guarantee	44 Bourdillon Road, Ikoyi, Lagos	100
BG Exploration and Production Nigeria Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
BG Upstream A Nigeria Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Delta Business Development Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Nigeria LNG Limited	Corporate Office, Intels Aba Road Estate, Km16 Aba Expressway, Port Harcourt, 500211	26
NLNG Shipping Management Limited	Corporate Office, Intels Aba Road Estate, Km16 Aba Expressway, Port Harcourt, 500211	20
Shell Exploration and Production Africa Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Business Operations Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Closed Pension Fund Administrator Ltd	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Exploration and Production Company Ltd	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Exploration and Production Echo Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Exploration Properties Alpha Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Exploration Properties Beta Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Exploration Properties Charlie Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Gas Ltd (SNG)	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Infrastructure Development Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Offshore Prospecting Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Oil Products Limited (SNOP)	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Ultra Deep Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Nigeria Upstream Ventures Limited	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	100
Shell Thrift & Loan Fund Trustees Nig Ltd	Freeman House, 21/22 Marina, P.M.B. 2418, Lagos	99
The Shell Petroleum Development Company of Nigeria Limited	Shell Industrial Area, P.O. Box 263, Rivers State, Port Harcourt, 500272	100
NORWAY		
A/S Norske Shell	Tankvegen 1, Tananger, 4056	100
Aviation Fuelling Services Norway AS	Bygg 6, Drammensveien 134, Oslo, 0277	50
Enhanced Well Technologies Group AS	Kongsgårdbakken 1, Stavanger, 4005	35
Gasnor AS	Helganesvegen 59, Avaldsnes, Karmøy, 4262	100
Ormen Lange Eiendom DA	Nyhamna, Aukra, 6480	18
Shell New Energies AS	Karenslyst Allé 2, Oslo, 0278	100
Technology Centre Mongstad DA	Mongstad 71A, Mongstad, 5954	8
Vestprosess DA	Forusbeen 50, Stavanger, 4035	8
OMAN		
Oman LNG LLC	P.O. Box 560, Mina Al Fahal, Muscat, 116	30
Petroleum Development Oman LLC	P.O. Box 81, Mina Al Fahal, Muscat, 113	34
Shell Development Oman LLC	P.O. Box 74, Mina Al Fahal, Muscat, 116	100
Shell Oman Marketing Company SAOG	P.O. Box 38, Mina Al Fahal, Muscat, 116	49
Sohar Solar Qabas (FZC) LLC	P.O. Box 398, Sohar Free Zone, North Al Batinah Governorate, Sohar, 322	100
PAKISTAN		
Pak Arab Pipeline Company Limited	House No. 2-B, Nazimuddin Road, F-8/1, Islamabad, 75400	20
Pakistan Energy Gateway Limited	E110, Khayaban e Jinnah, Lahore Cantonement, Punjab, Cantonement, 54810	33
Shell Energy Pakistan (smc-private) Limited	Shell House, 6 Ch. Khaliqzaman Road, Karachi, 75530	100
Shell Pakistan Limited	Shell House, 6 Ch. Khaliqzaman Road, Karachi, 75530	76
PERU		
Shell GNL Peru S.A.C.	Calle Dean Valdivia 111, Oficina 802, San Isidro, Lima, Lima 27	100
Shell Operaciones Peru S.A.C.	Calle Dean Valdivia 111, Oficina 802, San Isidro, Lima, Lima 27	100
PHILIPPINES		
Bonifacio Gas Corporation	2nd Floor, Bonifacio Technology Center, 31st Street corner 2nd Avenue, Bonifacio Global City, Taguig, Metro Manila, 1635	24
Connected Freight Solutions Philippines, Inc.	41st Floor, The Finance Center, 26th Street corner 9th Avenue, Bonifacio Global City, Taguig, Metro Manila, 1635	84
Kamayan Realty Corporation	NDC Bldg., 116 Tordesillas St., Salcedo Village, Makati City, Metro Manila, 1227	22
Manta Energy Inc	1004 East Tower, PSE Centre, Exchange Road, Ortigas Center, Pasig City, 1605	100
Pilipinas Shell Petroleum Corporation	41st Floor, The Finance Center, 26th Street corner 9th Avenue, Bonifacio Global City, Taguig, Metro Manila, 1635	55
Shell Chemicals Philippines, Inc.	41st Floor, The Finance Center, 26th Street corner 9th Avenue, Bonifacio Global City, Taguig, Metro Manila, 1635	100
Shell Gas and Energy Philippines Corporation	41st Floor, The Finance Center, 26th Street corner 9th Avenue, Bonifacio Global City, Taguig, Metro Manila, 1635	100
Shell Gas Trading (Asia Pacific), Inc.	Subic Bay Free Port Zone, Olongapo City, 2200	100
Shell Solar Philippines Corporation	41st Floor, The Finance Center, 26th Street corner 9th Avenue, Bonifacio Global City, Taguig, Metro Manila, 1635	100
Tabangao Realty, Inc.	Unit D 9th Floor Inoza Tower, 40th Street, North Bonifacio, Bonifacio Global City, Taguig, Metro Manila, 1634	40

APPENDIX 1 continued

Company by country of incorporation	Address of registered office	%
POLAND		
Shell Energy Retail Poland Sp. z o.o.	Al. Pokoju 5, Krakow, 31-548	100
Shell Polska Sp. z o.o.	ul. Bitwy Warszawskiej 1920 r. nr 7A, Warsaw, 02-366	100
PORTUGAL		
Shell Madeira Praia Formosa – Instalações, Comércio e Distribuição de Combustíveis S.A	Avenida dos Combatentes da Grande Guerra nº 17, Freguesia de S. Juliao, Setúbal, 2900-329	100
PUERTO RICO		
Station Managers of Puerto Rico, Inc.	P.O. Box 186, Yabucoa, PR 00767-0186	100
QATAR		
Qatar Liquefied Gas Company Limited (4)	P.O. Box 22666, Doha	30
Qatar Shell Research & Technology Centre QSTP-LLC	Qatar Science & Technology Park Tech1, Office 101, P.O. Box 3747, Doha	100
Qatar Shell Service Company W.L.L.	Al Mirqab Tower, West Bay, P.O. Box 3747, Doha	100
RUSSIA		
Khanty-Mansiysk Petroleum Alliance Closed Joint Stock Company [b]	24 A Yakubovicha ul., Saint Petersburg, 190000	50
Limited Liability Company "Shell Neft"	24 Bld D Smolnaya street, Moscow, 125445	100
Limited Liability Company "Shell Neftegaz Development (V)"	Novinsky blvd, 31, Moscow, 123242	100
LLC Shell NefteGaz Development	Novinsky blvd, 31, Moscow, 123242	100
Meretoyahaneftgaz LLC [b] [c]	16 Komsomolskaya street, Apartment 36, Yamalo-Nenetsky Autonomous Region, Nadyem, 629733	50
Syriaga Neftegaz Development LLC	Novinsky blvd, 31, Moscow, 123242	100
SAINT KITTS AND NEVIS		
Shell Oil & Gas (Malaysia) LLC	Morning Star Holdings Limited, Main Street, Suite 556, Charlestown, Nevis, West Indies	90
SAINT LUCIA		
BG Atlantic 1 Holdings Limited	Mercury Court, Choc Estate, Castries	100
BG Atlantic 2/3 Holdings Limited	Mercury Court, Choc Estate, Castries	100
BG Atlantic 4 Holdings Limited	Mercury Court, Choc Estate, Castries	100
BG Central Holdings Ltd.	Mercury Court, Choc Estate, Castries	100
BG West Indies No. 2 Limited	Mercury Court, Choc Estate, Castries	100
SAUDI ARABIA		
Al Jomaih and Shell Lubricating Oil Co.Ltd.	P.O. Box 41467, Riyadh, 11521	50
Peninsular Aviation Services Company Limited	P.O. Box 6369, Jeddah, 21442	25
SINGAPORE		
BG Asia Pacific Holdings Pte. Limited	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
BG Asia Pacific Services Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
BG Exploration & Production Myanmar Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
BG Insurance Company (Singapore) Pte Ltd	10 Collyer Quay, #10-01 Ocean Financial Centre, Singapore, 049315	100
BG Myanmar Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
BG Oil Marketing Pte Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Cleantech Renewable Assets Pte Ltd	25 Church Street, 03-04 Capital Square three, Singapore, 049482	49
Connected Freight Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	84
Ellba Eastern (Pte) Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Fueling Pte. Ltd	50 Gul Road, Singapore, 629351	50
Infineum Singapore LLP	31 International Business Park, #04-08, Creative Resource, Singapore, 609921	50
QPI and Shell Petrochemicals (Singapore) Pte Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	51
Shell Catalysts & Technologies Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Chemicals Seraya Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Eastern Petroleum (Pte) Ltd [i]	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Eastern Trading (Pte) Ltd [i]	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Gas Marketing Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell India Ventures Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Integrated Gas Thailand Pte.Limited	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell International Shipping Services (Pte) Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Myanmar Energy Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Myanmar Petroleum Pte. Ltd.	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Pulau Moa Pte Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Seraya Pioneer (Pte) Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Singapore Trustees (Pte) Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Shell Tankers (Singapore) Private Limited	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100

Company by country of incorporation	Address of registered office	%
Shell Treasury Centre East (Pte) Ltd	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	100
Singapore Lube Park Pte. Ltd. [b]	160 Tuas South Avenue 5, Singapore, 637364	44
Sirius Well Manufacturing Services Pte. Ltd. [b]	The Metropolis Tower 1, 9 North Buona Vista Drive, #07-01, Singapore, 138588	50
Zeco Systems Pte. Ltd.	1 Commonwealth Lane, #09-30, One Commonwealth, Singapore, 149544	99
SLOVAKIA		
SHELL Slovakia s.r.o.	Einsteinova 23, Bratislava, 851 01	100
SLOVENIA		
Shell Adria d.o.o.	Bravnicarjeva ulica 13, Ljubljana, 1000	100
SOUTH AFRICA		
Bitugard Southern Africa (Pty) Ltd	Twickenham, The Campus, 57 Sloan Street, Epsom Downs, Bryanston, 2021	36
Blendcor (Pty) Ltd. [b]	Honshu Road, Durban, 4001	36
Sekelo Oil Trading (Pty) Limited	1st Floor Oxford Parks, 199 Oxford Road, Dunkeld, Gauteng, 2196	43
Shell & BP South African Petroleum Refineries (Pty) Limited [b]	Reunion, Durban, 4001	36
Shell Downstream South Africa (Pty) Ltd	Twickenham, The Campus, 57 Sloan Street, Epsom Downs, Bryanston, 2021	72
Shell Global Customer Services Centre Cape Town (Pty) Ltd	10 Rua Vasco de Gama, Foreshore, Cape Town, 8000	100
Shell South Africa Energy (Pty) Ltd	Twickenham, The Campus, 57 Sloan Street, Epsom Downs, Bryanston, 2021	100
Shell South Africa Exploration (Pty) Limited	Twickenham, The Campus, 57 Sloan Street, Epsom Downs, Bryanston, 2021	100
Shell South Africa Holdings (Pty) Ltd	Twickenham, The Campus, 57 Sloan Street, Epsom Downs, Bryanston, 2021	100
STISA (Pty) Limited	Suite OE/2, The Nautica, The Waterclub, Beach Road, Granger Bay, Cape Town, 8001	72
SOUTH KOREA		
Hankook Shell Oil Company	No. 250, Sinsun-ro, Nam-gu, Busan, 48561	54
Hyundai and Shell Base Oil Co., Ltd	640-6, Daejuk-ri, Daesan-eup, Seosan-shi, Chungchongnam-do, 356-713	40
SPAIN		
BG Energy Iberian Holdings, S.L.	Paseo de la Castellana, 257-6°, Madrid, 28046	100
Shell & Disa Aviation España, S.L.	Rio Bullaque, 2, Madrid, 28034	50
Shell España, S.A.	Paseo de la Castellana, 257-6°, Madrid, 28046	100
Shell Spain LNG, S.A.U.	Paseo de la Castellana, 257-6°, Madrid, 28046	100
SUDAN		
Shell (Sudan) Petroleum Development Company Limited	Shell House, P.O. Box 320, Khartoum	100
SWEDEN		
A Flygbränslehantering Aktieföretag	P.O. Box 135, Stockholm-Arlanda, 190 46	25
BG International Services AB	Deloitte, P.O. Box 450, Östersund, 831 26	100
Gothenburg Fuelling Company AB	P.O. Box 2154, Gothenburg, 438 14	33
Malmö Fuelling Services AB	Sturup Flygplats, P.O. Box 22, Malmö, 230 32	33
Shell Aviation Sweden AB	Gustavslundsvägen 22, Bromma, 16751	100
Stockholm Fuelling Services AB	P.O. Box 85, Stockholm-Arlanda, 190 45	25
SWITZERLAND		
Saraco SA	Route de Pré-Bois 17, Cointrin, 1216	20
Shell (Switzerland) AG	Baarermatte, Baar, 6340	100
Shell Brands International AG	Baarermatte, Baar, 6340	100
Shell Corporate Services Switzerland AG	Baarermatte, Baar, 6340	100
Shell Finance Switzerland AG	Baarermatte, Baar, 6340	100
Shell Holdings Switzerland AG	Baarermatte, Baar, 6340	100
Shell Lubricants Switzerland AG	Steigerhubelstrasse 8, Bern, 3008	100
Shell Trading Switzerland AG	Baarermatte, Baar, 6340	100
Shell Treasury Company Switzerland AG	Baarermatte, Baar, 6340	100
SOGEP Société Genevoise des Pétroles SA	Route de Vernier 132, Vernier, 1214	34
Solen Versicherungen AG	Baarermatte, Baar, 6340	100
Stazioni Autostradali Bellinzona SA	Autostrada A2 (direzione Gottardo), Hotel Bellinzona Sud, Monte Carasso, 6513	50
UBAG – Unterflurbetankungsanlage Flughafen Zürich AG	Zwüschemteich, Rümlang, 8153	20
SYRIA		
Al Badiya Petroleum Company	Damascus New Sham Western Dummar, Island No. 1 – Property 2299, P.O. Box 7660, Damascus	22
Al Furat Petroleum Company	Damascus New Sham Western Dummar, Island No. 1 – Property 2299, P.O. Box 7660, Damascus	20
TAIWAN		
CPC Shell Lubricants Co. Ltd	No. 2, Tso-Nan Road, Nan-Tze District, P.O. Box 25-30, Kaohsiung, 811	51
Shell Taiwan Limited	International Trade Building, Room 2001, 20th Floor, 333, Keelung Road Section 1, Taipei, 110	100

APPENDIX 1 continued

Company by country of incorporation	Address of registered office	%
TANZANIA		
Fahari Gas Marketing Company Limited	1st Floor Kilwa House, Plot 369, Toure Drive, Oyster Bay, P.O. Box 105833, Dar es Salaam	53
Mzalendo Gas Processing Company Limited	1st Floor Kilwa House, Plot 369, Toure Drive, Oyster Bay, P.O. Box 105833, Dar es Salaam	53
Ruvuma Pipeline Company Limited	1st Floor Kilwa House, Plot 369, Toure Drive, Oyster Bay, P.O. Box 105833, Dar es Salaam	53
Tanzania LNG Limited	1st Floor Kilwa House, Plot 369, Toure Drive, Oyster Bay, P.O. Box 105833, Dar es Salaam	100
THAILAND		
Pattanaadhorn Company Limited	10 Soonthornkosa Road, Klongtoey, Bangkok, 10110	42
Sahapanichkijphun Company Limited	10 Soonthornkosa Road, Klongtoey, Bangkok, 10110	42
Shell Global Solutions (Thailand) Limited	10 Soonthornkosa Road, Klongtoey, Bangkok, 10110	48
Shell Global Solutions Holdings (Thailand) Limited	10 Soonthornkosa Road, Klongtoey, Bangkok, 10110	49
Shell Global Solutions Service (Thailand) Company Limited	10 Soonthornkosa Road, Klongtoey, Bangkok, 10110	100
Thai Energy Company Limited	10 Soonthornkosa Road, Klongtoey, Bangkok, 10110	100
Unitas Company Limited	10 Soonthornkosa Road, Klongtoey, Bangkok, 10110	42
TRINIDAD AND TOBAGO		
BG 2/3 Investments Limited	5 Saint Clair Avenue, Saint Clair, Port of Spain	100
Point Fortin LNG Exports Limited	5 Saint Clair Avenue, Saint Clair, Port of Spain	81
Shell Gas Supply Trinidad Limited	5 Saint Clair Avenue, Saint Clair, Port of Spain	100
Shell LNG T&T Ltd	5 Saint Clair Avenue, Saint Clair, Port of Spain	100
Shell Manatee Limited	5 Saint Clair Avenue, Saint Clair, Port of Spain	100
Shell Trinidad Central Block Limited	5 Saint Clair Avenue, Saint Clair, Port of Spain	100
Shell Trinidad Ltd	Shell Energy House, 5 St. Clair Avenue, Port of Spain	100
Shell Trinidad North Coast Limited	5 Saint Clair Avenue, Saint Clair, Port of Spain	100
The International School of Port of Spain Limited	1 International Drive, Westmoorings	25
TRINLING Limited	5 Saint Clair Avenue, Saint Clair, Port of Spain	100
TUNISIA		
Amilcar Petroleum Operations S.A.	Immeuble Mezghenni, Rue du Lac Windermere BP36, Les Berges du Lac, Tunis, 1053	50
Shell Tunisia LPG S.A.	Immeuble Rue du Lac Windermere, Les Berges du Lac, Tunis, 1053	100
Tunisian Processing S.A.	Immeuble Rue du Lac Windermere, Les Berges du Lac, Tunis, 1053	100
TURKEY		
Ambarli Depolama Hizmetleri Ltd. Sti.	Yakuplu Mah. Gencosman Cad. No:7, Beylikduzu, Istanbul, 34524	35
Cekisan Depolama Hizmetleri Ltd. Sti.	Yakuplu Mah. Gencosman Cad. No:3, Beylikduzu, Istanbul, 34524	35
Marmara Depoculuk Hizmetleri A.S.	Sultankoy Mahallesi Maltepe Sokak No:66, Marmara Ereglisi, Tekirdag, 59750	32
Samsun Akaryakit VE Depolama A.S.	Dilovasi Organize Sanayi Bolgesi I.Kisim, 1004 Sokak No:10, Dilovasi, Kocaeli	35
Shell & Turcas Petrol A.S.	Gulbahar Mah.Salih Tozan Sok., Karamancilar Is Merkezi B Blok No:18, Esentepe, Sisli, Istanbul, 34394	70
Shell Enerji A.S.	Gulbahar Mah.Salih Tozan Sok., Karamancilar Is Merkezi B Blok No:18, Esentepe, Sisli, Istanbul, 34394	100
Shell Petrol A.S.	Gulbahar Mah.Salih Tozan Sok., Karamancilar Is Merkezi B Blok No:18, Esentepe, Sisli, Istanbul, 34394	70
UK		
Alie Investments Limited	Shell Centre, London, SE1 7NA	100
Angkor Shell Limited	Shell Centre, London, SE1 7NA	100
Applied Blockchain Ltd	Level 39, One Canada Square, London, E14 5AB	21
Autogas Limited	Athena House, Athena Drive, Tachbrook Park, Warwick, CV34 6RL	50
BG Central Holdings Limited	Shell Centre, London, SE1 7NA	100
BG Cyprus Limited	Shell Centre, London, SE1 7NA	100
BG Delta Limited	Shell Centre, London, SE1 7NA	100
BG Employee Shares Trustees Limited	Shell Centre, London, SE1 7NA	100
BG Energy Capital Plc	Shell Centre, London, SE1 7NA	100
BG Energy Holdings Limited	Shell Centre, London, SE1 7NA	100
BG Energy Marketing Limited	Shell Centre, London, SE1 7NA	100
BG Equatorial Guinea Limited	Shell Centre, London, SE1 7NA	100
BG Exploration and Production Limited	Shell Centre, London, SE1 7NA	100
BG Gas Services Limited	Shell Centre, London, SE1 7NA	100
BG Gas Supply (UK) Limited	Shell Centre, London, SE1 7NA	100
BG General Holdings Limited	Shell Centre, London, SE1 7NA	100
BG General Partner Limited	50 Lothian Road, Festival Square, Edinburgh, EH3 9WJ	100
BG Global Employee Resources Limited	Shell Centre, London, SE1 7NA	100
BG Great Britain Limited	Shell Centre, London, SE1 7NA	100
BG Group Company Secretaries Limited	Shell Centre, London, SE1 7NA	100
BG Group Employee Benefit Trust Limited	Shell Centre, London, SE1 7NA	100

Company by country of incorporation	Address of registered office	%
BG Group Employee Shares Trustees Limited	Shell Centre, London, SE1 7NA	100
BG Group Limited	Shell Centre, London, SE1 7NA	100
BG Group Pension Trustees Limited	Shell Centre, London, SE1 7NA	100
BG Group Trustees Limited	Shell Centre, London, SE1 7NA	100
BG Intellectual Property Limited	Shell Centre, London, SE1 7NA	100
BG International Limited	Shell Centre, London, SE1 7NA	100
BG Iran Limited	Shell Centre, London, SE1 7NA	100
BG Karachaganak Limited	Shell Centre, London, SE1 7NA	100
BG Karachaganak Trading Limited	Shell Centre, London, SE1 7NA	100
BG Kenya L10A Limited	Shell Centre, London, SE1 7NA	100
BG Kenya L10B Limited	Shell Centre, London, SE1 7NA	100
BG LNG Investments Limited	Shell Centre, London, SE1 7NA	100
BG Mongolia Holdings Limited	Shell Centre, London, SE1 7NA	100
BG Netherlands	Shell Centre, London, SE1 7NA	100
BG Netherlands Financing Unlimited	Shell Centre, London, SE1 7NA	100
BG Norge Exploration Limited	Shell Centre, London, SE1 7NA	100
BG Norge Limited	Shell Centre, London, SE1 7NA	100
BG North Sea Holdings Limited	Shell Centre, London, SE1 7NA	100
BG OKLNG Limited	Shell Centre, London, SE1 7NA	100
BG Overseas Holdings Limited	Shell Centre, London, SE1 7NA	100
BG Overseas Investments Limited	Shell Centre, London, SE1 7NA	100
BG Overseas Limited	Shell Centre, London, SE1 7NA	100
BG Pension Funding Scottish Limited Partnership [I]	50 Lothian Road, Festival Square, Edinburgh, EH3 9WJ	100
BG Rosetta Limited	Shell Centre, London, SE1 7NA	100
BG South East Asia Limited	Shell Centre, London, SE1 7NA	100
BG Subsea Well Project Limited	Shell Centre, London, SE1 7NA	100
BG Tanzania Holdings Limited	Shell Centre, London, SE1 7NA	100
BG Trinidad LNG Limited	Shell Centre, London, SE1 7NA	100
BG UK Holdings Limited	Shell Centre, London, SE1 7NA	100
Brazil Shipping I Limited	Shell Centre, London, SE1 7NA	100
Brazil Shipping II Limited	Shell Centre, London, SE1 7NA	100
British Pipeline Agency Limited	5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS	50
B-Snug Limited	Shell Centre, London, SE1 7NA	100
CRI Catalyst Company Europe Limited	Shell Centre, London, SE1 7NA	100
Derivatives Trading Americas Limited	Shell Centre, London, SE1 7NA	100
Dragon LNG Group Limited [b]	Main Road, Waterston, Milford Haven, Pembrokeshire, SA73 1DR	50
Eastham Refinery Limited [b]	Shell Centre, London, SE1 7NA	50
Enterprise Oil Limited	Shell Centre, London, SE1 7NA	100
Enterprise Oil Middle East Limited	Shell Centre, London, SE1 7NA	100
Enterprise Oil Norge Limited	Shell Centre, London, SE1 7NA	100
Enterprise Oil Operations Limited	Shell Centre, London, SE1 7NA	100
Enterprise Oil U.K. Limited	Shell Centre, London, SE1 7NA	100
Farepilot Limited	Shell Centre, London, SE1 7NA	100
First Telecommunications Limited	Shell Energy House, Westwood Business Park, Westwood Way, Coventry, CV4 8HS	100
First Utility Limited	Shell Energy House, Westwood Business Park, Westwood Way, Coventry, CV4 8HS	100
Gainrace Limited	Shell Centre, London, SE1 7NA	100
Gatwick Airport Storage and Hydrant Company Limited	Shell Centre, London, SE1 7NA	13
Glossop Limited	Shell Centre, London, SE1 7NA	100
GGOB Limited	Shell Centre, London, SE1 7NA	100
Heathrow Airport Fuel Company Limited	Building 1204, Sandringham Road, Heathrow Airport, Hounslow, Middlesex, TW6 3SH	14
Heathrow Hydrant Operating Company Limited	Building 1204, Sandringham Road, Heathrow Airport, Hounslow, Middlesex, TW6 3SH	10
Hudson Energy Supply UK Limited	3/F Elder House, 586-592 Elder Gate, Milton Keynes, MK9 1LR	100
Impello Limited	Shell Energy House, Westwood Business Park, Westwood Way, Coventry, CV4 8HS	100
International Inland Waterways, Limited	Shell Centre, London, SE1 7NA	100
Karachaganak Project Development Limited [b]	Shell Centre, London, SE1 7NA	38

[I] Established by BG Group plc and the BG Trustee in 2013 as part of funding agreements associated with the BG pension scheme. Under the exemption conferred by Regulation 7 of the Partnerships (Accounts) Regulations 2008, the accounts of this partnership have not been appended to Shell's Consolidated Financial Statements and have not been filed at the Companies House.

APPENDIX 1 continued

Company by country of incorporation	Address of registered office	%
UK continued		
Khmer Shell Limited	Shell Centre, London, SE1 7NA	100
Kite Power Systems Limited	146 New London Road, Chelmsford, Essex, CM2 0AW	34
Limejump Energy Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Intermediate 1 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Ltd	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 1 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 10 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 11 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 12 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 13 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 14 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 15 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 2 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 3 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 4 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 5 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 6 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 7 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 8 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Limejump Virtual 9 Limited	Canterbury Court, Kennington Park, 1-3 Brixton Road, London, SW9 6DE	100
Machine Max Limited	Shell Centre, London, SE1 7NA	56
Manchester Airport Storage and Hydrant Company Limited	50 Broadway, London, SW1H 0BL	25
Maritime Association for Risk Mitigation & Safety Limited	Shell Centre, London, SE1 7NA	100
Methane Services Limited	Shell Centre, London, SE1 7NA	100
Murphy Schiehallion Limited	Shell Centre, London, SE1 7NA	100
Octane Properties Limited	Shell Centre, London, SE1 7NA	100
Private Oil Holdings Oman Limited	Shell Centre, London, SE1 7NA	85
Sabah Shell Petroleum Company Limited	Shell Centre, London, SE1 7NA	100
Saxon Oil Limited	Shell Centre, London, SE1 7NA	100
Saxon Oil Miller Limited	Shell Centre, London, SE1 7NA	100
Schooner Trustees Limited	Shell Centre, London, SE1 7NA	100
SELAP Limited	Shell Centre, London, SE1 7NA	100
SF Investment Management Limited	Shell Centre, London, SE1 7NA	100
Shell Aircraft Limited	Shell Centre, London, SE1 7NA	100
Shell Arabia Car Service Limited	Shell Centre, London, SE1 7NA	100
Shell Aviation Limited	Shell Centre, London, SE1 7NA	100
Shell Business Development Middle East Limited	Shell Centre, London, SE1 7NA	100
Shell Caribbean Investments Limited	Shell Centre, London, SE1 7NA	100
Shell Catalysts & Technologies Limited	Shell Centre, London, SE1 7NA	100
Shell Chemical Company of Eastern Africa Limited	Shell Centre, London, SE1 7NA	100
Shell Chemicals (Hellas) Limited	Shell Centre, London, SE1 7NA	100
Shell Chemicals Limited	Shell Centre, London, SE1 7NA	100
Shell Chemicals Support Services Asia Limited	Shell Centre, London, SE1 7NA	100
Shell Chemicals U.K. Limited	Shell Centre, London, SE1 7NA	100
Shell China Exploration and Production Company Limited	Shell Centre, London, SE1 7NA	100
Shell Clair UK Limited	Shell Centre, London, SE1 7NA	100
Shell Club Corringham Limited	Shell Centre, London, SE1 7NA	100
Shell Company (Hellas) Limited	Shell Centre, London, SE1 7NA	100
Shell Company (Pacific Islands) Limited	Shell Centre, London, SE1 7NA	100
Shell Corporate Director Limited	Shell Centre, London, SE1 7NA	100
Shell Corporate Secretary Limited	Shell Centre, London, SE1 7NA	100
Shell Direct (U.K.) Limited	Shell Centre, London, SE1 7NA	100
Shell Distributor (Holdings) Limited	Shell Centre, London, SE1 7NA	100
Shell Employee Benefits Trustee Limited	Shell Centre, London, SE1 7NA	100
Shell Energy Europe Limited	Shell Centre, London, SE1 7NA	100

Company by country of incorporation	Address of registered office	%
Shell Energy Investments Limited	Shell Centre, London, SE1 7NA	100
Shell Energy Retail Limited	Shell Energy House, Westwood Business Park, Westwood Way, Coventry, CV4 8HS	100
Shell Energy Supply UK LTD.	Shell Centre, London, SE1 7NA	100
Shell EP Offshore Ventures Limited	Shell Centre, London, SE1 7NA	100
Shell Exploration and Production Tanzania Limited	Shell Centre, London, SE1 7NA	100
Shell Finance GB Limited	Shell Centre, London, SE1 7NA	100
Shell Gas Holdings (Malaysia) Limited	Shell Centre, London, SE1 7NA	100
Shell Gas Marketing U.K Limited	Shell Centre, London, SE1 7NA	100
Shell Global LNG Limited	Shell Centre, London, SE1 7NA	100
Shell Hasdrubal Limited	Shell Centre, London, SE1 7NA	100
Shell Holdings (U.K.) Limited	Shell Centre, London, SE1 7NA	100
Shell Information Technology International Limited	Shell Centre, London, SE1 7NA	100
Shell International Gas Limited	Shell Centre, London, SE1 7NA	100
Shell International Limited	Shell Centre, London, SE1 7NA	100
Shell International Petroleum Company Limited	Shell Centre, London, SE1 7NA	100
Shell International Trading and Shipping Company Limited	Shell Centre, London, SE1 7NA	100
Shell Malaysia Limited	Shell Centre, London, SE1 7NA	100
Shell Marine Products Limited	Shell Centre, London, SE1 7NA	100
Shell New Energies UK Ltd	Shell Centre, London, SE1 7NA	100
Shell Overseas Holdings Limited	Shell Centre, London, SE1 7NA	100
Shell Overseas Services Limited	Shell Centre, London, SE1 7NA	100
Shell Pension Reserve Company (SIPF) Limited	Shell Centre, London, SE1 7NA	100
Shell Pension Reserve Company (SOCPF) Limited	Shell Centre, London, SE1 7NA	100
Shell Pension Reserve Company (UK) Limited	Shell Centre, London, SE1 7NA	100
Shell Pensions Trust Limited	Shell Centre, London, SE1 7NA	100
Shell Property Company Limited	Shell Centre, London, SE1 7NA	100
Shell QGC Holdings Limited [i]	Shell Centre, London, SE1 7NA	100
Shell QGC Midstream 1 Limited [i]	Shell Centre, London, SE1 7NA	100
Shell QGC Midstream 2 Limited	Shell Centre, London, SE1 7NA	100
Shell QGC Upstream 1 Limited	Shell Centre, London, SE1 7NA	100
Shell QGC Upstream 2 Limited	Shell Centre, London, SE1 7NA	100
Shell Research Limited	Shell Centre, London, SE1 7NA	100
Shell Response Limited	Shell Centre, London, SE1 7NA	100
Shell Shared Service Centre – Glasgow Limited	Shell Centre, London, SE1 7NA	100
Shell South Asia LNG Limited	Shell Centre, London, SE1 7NA	100
Shell Supplementary Pension Plan Trustees Limited	Shell Centre, London, SE1 7NA	100
Shell Tankers (U.K.) Limited	Shell Centre, London, SE1 7NA	100
Shell Trading International Limited	Shell Centre, London, SE1 7NA	100
Shell Treasury Centre Limited	Shell Centre, London, SE1 7NA	100
Shell Treasury Dollar Company Limited	Shell Centre, London, SE1 7NA	100
Shell Treasury Euro Company Limited	Shell Centre, London, SE1 7NA	100
Shell Treasury UK Limited	Shell Centre, London, SE1 7NA	100
Shell Trinidad 5(A) Limited	Shell Centre, London, SE1 7NA	100
Shell Trinidad and Tobago Limited	Shell Centre, London, SE1 7NA	100
Shell Trinidad Block E Limited	Shell Centre, London, SE1 7NA	100
Shell Trustee Solutions Limited	1 Altens Farm Road, Nigg, Aberdeen, AB12 3FY	100
Shell Tunisia Upstream Limited	Shell Centre, London, SE1 7NA	100
Shell U.K. Limited	Shell Centre, London, SE1 7NA	100
Shell U.K. North Atlantic Limited	Shell Centre, London, SE1 7NA	100
Shell U.K. Oil Products Limited	Shell Centre, London, SE1 7NA	100
Shell Upstream Overseas Services (I) Limited	Shell Centre, London, SE1 7NA	100
Shell Ventures New Zealand Limited	Shell Centre, London, SE1 7NA	100
Shell Ventures U.K. Limited	Shell Centre, London, SE1 7NA	100
Shell-Mex and B.P. Limited	Shell Centre, London, SE1 7NA	60
Stansted Fuelling Company Limited	Exxonmobil House, Ermyn Way, Leatherhead, KT22 8UX	14
Steam Company Limited	Pannone Corporate Llp, 378-380 Deansgate, Castlefield, Manchester, M3 4LY	35

APPENDIX 1 continued

Company by country of incorporation	Address of registered office	%
UK continued		
STT (Das Beneficiary) Limited [a]	Shell Centre, London, SE1 7NA	100
Synthetic Chemicals (Northern) Limited	Shell Centre, London, SE1 7NA	100
Telegraph Service Stations Limited	Shell Centre, London, SE1 7NA	100
The Anglo-Saxon Petroleum Company Limited	Shell Centre, London, SE1 7NA	100
The Asiatic Petroleum Company Limited	Shell Centre, London, SE1 7NA	100
The Consolidated Petroleum Company Limited	Shell Centre, London, SE1 7NA	50
The Mexican Eagle Oil Company Limited	Shell Centre, London, SE1 7NA	100
The New Motion EVSE Limited	4th Floor, Davidson Building, 5 Southampton Street, London, WC2E 7HA	100
The Shell Company (W.I.) Limited	Shell Centre, London, SE1 7NA	100
The Shell Company of Hong Kong Limited	Shell Centre, London, SE1 7NA	100
The Shell Company of India Limited	Shell Centre, London, SE1 7NA	100
The Shell Company of Nigeria Limited	Shell Centre, London, SE1 7NA	100
The Shell Company of Thailand Limited	Shell Centre, London, SE1 7NA	100
The Shell Company of The Philippines Limited	Shell Centre, London, SE1 7NA	75
The Shell Company of Turkey Limited	Shell Centre, London, SE1 7NA	100
The Shell Company of West Africa Limited	Shell Centre, London, SE1 7NA	100
The Shell Marketing Company of Borneo Limited	Shell Centre, London, SE1 7NA	100
The Shell Petroleum Company Limited	Shell Centre, London, SE1 7NA	100
The Shell Transport and Trading Company Limited	Shell Centre, London, SE1 7NA	100
Thermocomfort Limited	Shell Centre, London, SE1 7NA	100
UK Shell Pension Plan Trust Limited	Shell Centre, London, SE1 7NA	100
United Kingdom Oil Pipelines Limited [b]	5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS	48
Walton-Gatwick Pipeline Company Limited [b]	5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS	52
West London Pipeline and Storage Limited [b]	5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS	38
Wonderbill Limited	Shell Centre, London, SE1 7NA	100
Woodlea Limited	Shell Centre, London, SE1 7NA	100
UKRAINE		
Shell Ukraine Exploration and Production I LLC	4 Mykolya Grinchenka street, Kiev, 03038	100
UNITED ARAB EMIRATES		
Abu Dhabi Gas Industries Limited (GASCO)	P.O. Box 665, Abu Dhabi	15
Emdad Aviation Fuel Storage FZCO	Emdad Aviation Fuel Storage FZCO, P.O. Box 261781, Jebel Ali, Dubai	33
Sharjah Fuelling Services Company Ltd.	P.O. Box 4225, Sharjah, 4225	49
URUGUAY		
BG (Uruguay) S.A.	La Cumparsita, 1373 4th Floor, Montevideo, 11200	100
Dinaref S.A.	La Cumparsita, 1373 4th Floor, Montevideo, 11200	50
Gasoducto Cruz del Sur S.A.	La Cumparsita, 1373 4th Floor, Montevideo, 11200	40
USA		
Aera Energy LLC [b]	10000 Ming Avenue, Bakersfield, CA 93311	52
Aera Energy Services Company	10000 Ming Avenue, Bakersfield, CA 93311	50
Airbiquity Inc.	1191 2nd Avenue, Suite 1900, Seattle, WA 98101	26
Amberjack Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	30
Asset Management and Power Services LLC	2441 High Timbers Drive, Suite 220, The Woodlands, TX 77380	50
Atlantic 1 Holdings LLC [c]	RL & F Service Corp, 920 N King St Floor 2, New Castle, Wilmington, DE 19801	46
Atlantic 2/3 Holdings LLC [c]	RL & F Service Corp, 920 N King St Floor 2, New Castle, Wilmington, DE 19801	58
Atlantic 4 Holdings LLC [c]	RL & F Service Corp, 920 N King St Floor 2, New Castle, Wilmington, DE 19801	1
Atlantic Shores Offshore Wind, LLC [c]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808	50
Au Energy, LLC	41805 Albrae Street, Fremont, CA 94538	50
Bacanton Power LLC [c]	1499 38th Boulevard N.W., Cairo, GA 31728	35
Bengal Pipeline Company LLC	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808	28
BG Brasilia, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG Energy Finance, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG Energy Merchants, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG Gulf Coast LNG, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG LNG Services, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG LNG Trading, LLC	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG North America, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100

Company by country of incorporation	Address of registered office	%
BG US Production Company, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
BG US Services, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Bluware Headwave Ventures Inc.	16285 Park Ten Place, Suit 300, Houston, TX 77084	20
Brazil Crude Services, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Brazos Wind Ventures, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Caesar Oil Pipeline Company, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	15
Colbea Enterprises, LLC	2050 Plainfield Pike, Cranston, RI 02921	50
Colonial Pipeline Company	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808	8
Concha Chemical Pipeline LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Crestwood Permian Basin LLC	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	24
CRI Sales and Services Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
CRI Zeolites Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Cumulus Digital Systems, Inc.	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808	44
Deer Park Refining Limited Partnership [b] [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	50
Distributed Generation Solutions LLC	2441 High Timbers Drive, Suite 220, The Woodlands, TX 77380	33
EcoSmart Solution LLC	Corporation Service Company, 215 Little Falls Drive, Wilmington, DE 19808	35
Ellwood Land Holdings, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Endymion Oil Pipeline Company, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	5
Enterprise Oil North America Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
EPP LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
Equilon Enterprises LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Explorer Pipeline Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	19
Gaviota Terminal Company [d]	150 N. Dairy Ashford, Houston, TX 77079	20
GI Endurant LLC [b]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	58
GI Energy Storage LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
GlassPoint Solar Inc.	47669 Fremont Blvd., Fremont, CA 94538	39
Husk Power Systems, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	30
Infineum USA Inc.	1900 East Linden Avenue, Linden, NJ 07036	50
Infineum USA L.P. [h]	Corporation Service Company, 2711 Centerville Road, Suite 400, Wilmington, DE 19808	50
J & J Lubrication, LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
Jiffy Lube International, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Lake Charles Exports, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	80
Laurentide E&P, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Lazlyng Real Estate Company, LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
LOCAP LLC	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	20
LOOP LLC	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	46
Maple Power Holdings LLC	Bechtel Enterprises, 12011 Sunset Hills Road, Reston, VA 20190	68
Mars Oil Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	34
Mattox Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	79
Mayflower Wind Energy LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	50
MP2 Energy LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
MP2 Energy NE LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
MP2 Energy NY LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
MP2 Energy Retail Holdings LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
MP2 Energy Texas LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
MP2 Generation LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
MP2 Mesquite Creek Wind LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
Mpower2 LLC [c]	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
Noble Assurance Company	C T Corporation System, 1999 Bryan Street, Suite 900, Dallas, TX 75201	100
Odyssey Pipeline L.L.C. [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	34
Oryx Caspian Pipeline, L.L.C. [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pacwest Energy, LLC.	3450 E. Commercial Ct., Meridian, ID 83642	50
Pecten Arabian Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pecten Brazil Exploration Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pecten Midstream LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	48
Pecten Orient Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pecten Orient Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100

APPENDIX 1 continued

Company by country of incorporation	Address of registered office	%
USA continued		
Pecten Producing Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pecten Trading Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pecten Victoria Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pecten Yemen Masila Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pennzoil-Quaker State Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pennzoil-Quaker State International Corporation	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Pennzoil-Quaker State Nominee Company	The Corporation Trust Company of Nevada, 311 South Division Street, Carson City, NV 89703	100
Peru LNG Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	20
Poseidon Oil Pipeline Company, LLC	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	17
Power Limited Partnership [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Premium Velocity Auto LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Proteus Oil Pipeline Company, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	5
Quaker State Investment Corporation	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
RDK Ventures, LLC	4080 West Jonathan Moore Pike, Columbus, IN 47201	50
RK Caspian Shipping Company, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
S T Exchange, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Salamander Solutions Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	28
San Pablo Bay Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Sand Dollar Pipeline LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	48
SCOGI GP [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell (US) Gas & Power M&T Holdings, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell California Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Catalysts & Technologies Americas LP [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Catalysts & Technologies Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Catalysts & Technologies Holdings Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Catalysts & Technologies LP [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Catalysts & Technologies US LP [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Catalysts Ventures Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Chemical Appalachia LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Chemical LP [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Chemicals Arabia L.L.C. [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Communications, Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Deepwater Royalties Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Downstream Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Energy Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Energy Holding GP LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Energy North America (US), L.P. [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Energy Resources Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell EP Holdings Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Expatriate Employment US Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Exploration & Production Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Exploration Company Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Frontier Oil & Gas Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Gas Gathering Corp. #2	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Global Solutions (US) Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell GOM Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Gulf of Mexico Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Information Technology International Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell International Exploration and Production Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Lake Charles Operations, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Leasing Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Marine Products (US) Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Midstream LP Holdings LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Midstream Operating LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	48
Shell Midstream Partners GP LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100

Company by country of incorporation	Address of registered office	%
Shell Midstream Partners, L.P. [h]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	48
Shell NA Gas & Power Holding Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell NA LNG LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell New Energies US LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell North America Gas & Power Services Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Offshore and Chemical Investments Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Offshore Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Offshore Response Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Oil Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Oil Company Investments Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Oil Products Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Onshore Ventures Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Petroleum Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Pipeline Company LP [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Pipeline GP LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Rail Operations Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Retail and Convenience Operations LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell RSC Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Thailand E&P Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Trademark Management Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Trading (US) Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Trading North America Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Trading Risk Management, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Trading Services Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Transportation Holdings LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Treasury Center (West) Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell US E&P Investments LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell US Gas & Power LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell US Hosting Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell US LNG, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell Ventures LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell WindEnergy Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Shell WindEnergy Services Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Ship Shoal Pipeline Company [d]	150 N. Dairy Ashford, Houston, TX 77079	43
Silicon Ranch Corporation	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	43
SOI Finance Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Sonnen Inc.	2711 Centerville Road, Suite 400, New Castle County, Wilmington, DE 19808	100
SOPC Holdings East LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
SOPC Holdings West LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
SOPC Southeast Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
SWPEI LP [d]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Tejas Coral GP, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Tejas Coral Holding, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Tejas Power Generation, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Texas Petroleum Group LLC	11111 Wilcrest Green, Suite 100, Houston, TX 77042	50
Texas-New Mexico Pipe Line Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
The Valley Camp Coal Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Three Wind Holdings, LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	50
TMR Company	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Tri Star Energy LLC	1740 Ed Temple Blvd, Nashville, TN 37208	33
Triton Diagnostics Inc.	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Triton Terminals LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	100
Triton West LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	48
True North Energy LLC	10346 Brecksville Rd, Brecksville, OH 44141	50
URSA Oil Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	45

APPENDIX 1 continued

Company by country of incorporation	Address of registered office	%
USA continued		
West Shore Pipe Line Company	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808	19
Zeco Holdings, Inc.	1013 Centre Road, County of New Castle, Delaware, Wilmington, DE 19805	100
Zeco Systems, Inc.	1013 Centre Road, County of New Castle, Delaware, Wilmington, DE 19805	100
Zeolyst International	3333 Hwy 6 South, Houston, TX 77082	50
Zydeco Pipeline Company LLC [c]	The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, DE 19801	52
VENEZUELA		
Shell Venezuela Productos, C.A.	Av. Orinoco, Edificio Centro Empresarial Premium, Piso 2, Oficina 2-B, Urbanización Las Mercedes, Caracas, Distrito Capital, 1060	100
Shell Venezuela, S.A.	Av. Orinoco, Edificio Centro Empresarial Premium, Piso 2, Oficinas 2-A y 2-B, Urbanización Las Mercedes, Caracas, Distrito Capital, 1060	100
Sucre Gas, S.A.	Avenida Leonardo Da Vinci, Edificio PDV Servicios, Caracas, Distrito Capital	30
VIETNAM		
Shell Vietnam Ltd	Go Dau Industrial Zone, Phuoc Thai Commune, Long Thanh District, Dong Nai Province	100
ZIMBABWE		
Central African Petroleum Refineries (Private) Limited	Block 1, Tendeseka Office Park, CNR Samora Machel Avenue, Renfrew Road, Harare	21

NOTES

NOTES

FINANCIAL CALENDAR IN 2020

The Annual General Meeting will be held on May 19, 2020.

	2019 Fourth quarter [A]	2020 First quarter [B]	2020 Second quarter [B]	2020 Third quarter [B]
Results announcements	January 30	April 30	July 30	October 29
Interim dividend timetable				
Announcement date	January 30 [C]	April 30	July 30	October 29
Ex-dividend date [D]	February 13	May 14	August 13	November 12
Record date	February 14	May 15	August 14	November 13
Closing of currency election date [E]	February 28	June 2	August 28	November 27
Pounds sterling and euro equivalents announcement date	March 9	June 8	September 8	December 3
Payment date	March 23	June 22	September 21	December 16

[A] In respect of the financial year ended December 31, 2019.

[B] In respect of the financial year ended December 31, 2020.

[C] The Directors do not propose to recommend any further distribution in respect of 2019.

[D] The New York Stock Exchange (NYSE), with effect from September 5, 2017, reduced the standard settlement cycle in accordance with the SEC amendments to Exchange Act Rule 15c6-1(a). Under these rules, regular settlement will occur on a T+2 basis for trades occurring on or after the SEC's implementation date of September 5, 2017. As a result RDS A ADSs and RDS B ADSs traded on the NYSE markets will now settle in line with RDS A shares and RDS B shares traded on European markets, who moved to a T+2 settlement basis for trades in 2014, resulting in the same ex-dividend date for RDS A shares, RDS B shares, RDS A ADSs and RDS B ADSs. Record dates will not change. The timings of these are detailed above.

[E] A different currency election date may apply to shareholders holding shares in a securities account with a bank or financial institution ultimately through Euroclear Nederland. This may also apply to other shareholders who do not hold their shares either directly on the Register of Members or in the corporate sponsored nominee arrangement. Shareholders can contact their broker, financial intermediary, bank or financial institution for the election deadline that applies.

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Company number 4366849
Registered with the Dutch Trade Register
under number 34179503

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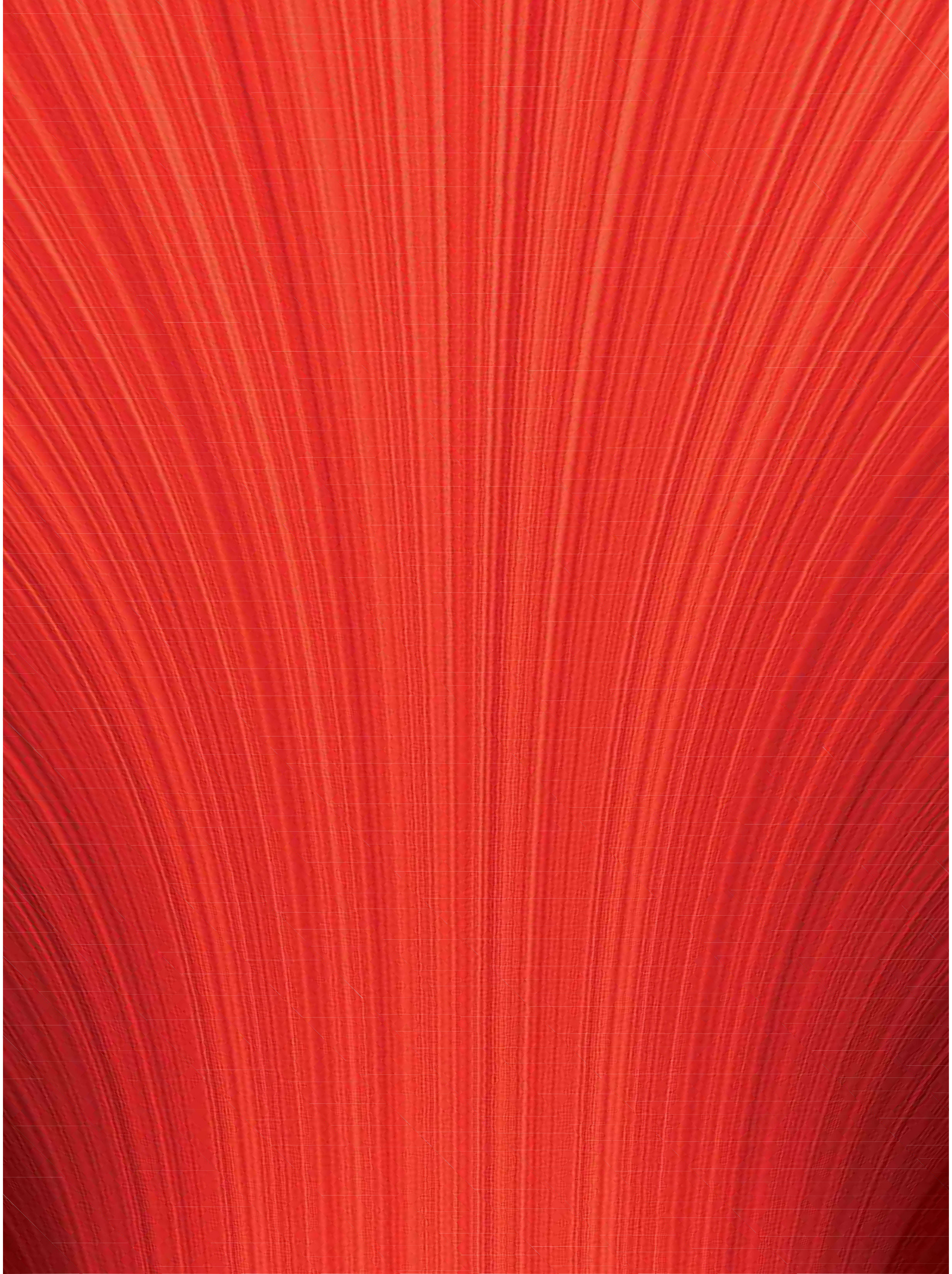
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- Comprehensive financial information on our activities throughout 2019
- Detailed operational information including maps
- Report on our progress in contributing to sustainable development



POWERING PROGRESS

ANNUAL REPORT AND ACCOUNTS
FOR THE YEAR ENDED DECEMBER 31, 2020
ROYAL DUTCH SHELL PLC



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ABOUT THIS REPORT

The Royal Dutch Shell plc Annual Report (this Report) serves as the Annual Report and Accounts in accordance with UK requirements for the year ended December 31, 2020, for Royal Dutch Shell plc (the Company) and its subsidiaries (collectively referred to as Shell). This Report presents the Consolidated Financial Statements of Shell (pages 216-264), the Parent Company Financial Statements of Shell (pages 283-291) and the Financial Statements of the Royal Dutch Shell Dividend Access Trust (pages 294-297). Except for these Financial Statements, the numbers presented throughout this Report may not sum precisely to the totals provided and percentages may not precisely reflect the absolute figures due to rounding.

The financial statements contained in this Report have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the IASB. IFRS as defined above includes interpretations issued by the IFRS Interpretations Committee. Financial reporting terms used in this Report are in accordance with IFRS.

This Report contains certain following forward-looking non-GAAP measures such as cash capital expenditure and divestments. We are unable to provide a reconciliation of these forward-looking Non-GAAP measures to the most comparable GAAP financial measures because certain information needed to reconcile those Non-GAAP measures to the most comparable GAAP financial measures is dependent on future events some of which are outside the control of the company, such as oil and gas prices, interest rates and exchange rates. Moreover, estimating such GAAP measures with the required precision necessary to provide a meaningful reconciliation is extremely difficult and could not be accomplished without unreasonable effort. Non-GAAP measures in respect of future periods which cannot be reconciled to the most comparable GAAP financial measure are calculated in a manner which is consistent with the accounting policies applied in Royal Dutch Shell plc's consolidated financial statements.

The companies in which Royal Dutch Shell plc directly or indirectly owns investments are separate legal entities. In addition to the term "Shell", in this Report "Shell Group", "we", "us" and "our" are also used to refer to the Company and its subsidiaries in general or to those who work for them. These terms are also used where no useful purpose is served by identifying the particular entity or entities. "Subsidiaries" and "Shell subsidiaries" refer to those entities over which the Company has control, either directly or indirectly. Entities and unincorporated arrangements over which Shell has joint control are generally referred to as "joint ventures" and "joint operations", respectively. "Joint ventures" and "joint operations" are collectively referred to as "joint arrangements". Entities over which Shell has significant influence but neither control nor joint control are referred to as "associates". The term "Shell interest" is used for convenience to indicate the direct and/or indirect ownership interest held by Shell in an entity or unincorporated joint arrangement, after exclusion of all third-party interest. Shell subsidiaries' data include their interests in joint operations.

As used in this Report, "Accountable" is intended to mean: required or expected to justify actions or decisions. The Accountable person does not necessarily implement the action or decision (implementation is usually carried out by the person who is Responsible) but must organise the implementation and verify that the action has been carried out as required. This includes obtaining requisite assurance from Shell companies that the framework is operating effectively. "Responsible" is intended to mean: required or expected to implement actions or decisions. Each Shell company and Shell operated venture is responsible for its operational performance and compliance with the Shell General Business Principles, Code of Conduct, Statement on Risk Management and Risk Manual, and Standards and Manuals. This includes responsibility for the operationalisation and implementation of Shell Group strategies and policies.

This Report references Shell's Sky and new Sky 1.5 scenarios, specifically within the Climate change and energy transition section (pages 94-107). Unlike Shell's previously published Mountains and Oceans exploratory scenarios, the Sky scenario is based on the assumption that society reaches the Paris Agreement's goal of holding the rise in global average temperatures this century to well below two degrees Celsius (2°C) above pre-industrial levels. Unlike Shell's Mountains and Oceans scenarios which unfolded in an open-ended way based upon plausible assumptions and quantifications, the Sky scenario was specifically designed to reach the Paris Agreement's goal in a technically possible manner.

Sky 1.5 scenario starts with data from Shell's Sky scenario but is more aggressive and challenging in its assumptions about energy transitions as the pace of change is accelerated. As in Sky, this scenario is normative, meaning we assumed that society achieves the 1.5 degrees Celsius stretch goal of the Paris Agreement, and we worked back in designing how this could occur. Of course, there are many possible paths that society could take to achieve this goal. This will be extremely challenging, but as of today, we believe there is still a technically possible path while maintaining a growing global economy. However, we believe the window for success is quickly closing.

These scenarios are a part of an ongoing process used in Shell for over 40 years to challenge executives' perspectives on the future business environment. They are designed to stretch management to consider even events that may only be remotely possible. Scenarios, therefore, are not intended to be predictions of likely future events or outcomes. Shell's scenarios also are not intended to be projections or forecasts of the future. Shell's scenarios, including the scenarios referenced in this Report, are not Shell's strategy or business plan. When developing Shell's strategy, our scenarios are one of many variables that we consider. Ultimately, whether society meets its goals to decarbonise is not within Shell's control. While we intend to travel this journey in step with society, only governments can create the framework for success.

Shell's operating plan, outlook and budgets are forecasted for a ten-year period and are updated every year. They reflect the current economic environment and what we can reasonably expect to see over the next ten years. Accordingly, Shell's operating plans, outlooks, budgets and pricing assumptions do not reflect our net-zero emissions target. In the future, as society moves towards net-zero emissions, we expect Shell's operating plans, outlooks, budgets and pricing assumptions to reflect this movement.

Shell's "Net Carbon Footprint" referred to in this Report includes Shell's carbon emissions from the production of our energy products, our suppliers' carbon emissions in supplying energy for that production, and our customers' carbon emissions associated with their use of the energy products we sell. Shell only controls its own emissions. The use of the term "Net Carbon Footprint" is for convenience only and not intended to suggest these emissions are those of Shell or its subsidiaries.

Except where indicated, the figures shown in the tables in this Report are in respect of subsidiaries only, without deduction of any non-controlling interest. However, the term "Shell share" is used for convenience to refer to the volumes of hydrocarbons that are produced, processed or sold through subsidiaries, joint ventures and associates. All of a subsidiary's production, processing or sales volumes (including the share of joint operations) are included in the Shell share, even if Shell owns less than 100% of the subsidiary. In the case of joint ventures and associates, however, Shell-share figures are limited only to Shell's entitlement. In all cases, royalty payments in kind are deducted from the Shell share.

Except where indicated, the figures shown in this Report are stated in US dollars. As used herein all references to “dollars” or “\$” are to the US currency.

This Report contains forward-looking statements concerning the financial condition, results of operations and businesses of Shell. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. Forward-looking statements are statements of future expectations that are based on management’s current expectations and assumptions and involve known and unknown risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied in these statements. Forward-looking statements include, among other things, statements concerning the potential exposure of Shell to market risks and statements expressing management’s expectations, beliefs, estimates, forecasts, projections and assumptions. These forward-looking statements are identified by their use of terms and phrases such as “aim”, “ambition”, “anticipate”, “believe”, “could”, “estimate”, “expect”, “goals”, “intend”, “may”, “objectives”, “outlook”, “plan”, “probably”, “project”, “risks”, “schedule”, “seek”, “should”, “target”, “will” and similar terms and phrases. There are a number of factors that could affect the future operations of Shell and could cause those results to differ materially from those expressed in the forward-looking statements included in this Report, including (without limitation): (a) price fluctuations in crude oil and natural gas; (b) changes in demand for Shell’s products; (c) currency fluctuations; (d) drilling and production results; (e) reserves estimates; (f) loss of market share and industry competition; (g) environmental and physical risks; (h) risks associated with the identification of suitable potential acquisition properties and targets, and successful negotiation and completion of such transactions; (i) the risk of doing business in developing countries and countries subject to international sanctions; (j) legislative, fiscal and regulatory developments including regulatory measures addressing climate change; (k) economic and financial market conditions in various countries and regions; (l) political risks, including the risks of expropriation and renegotiation of the terms of contracts with governmental entities, delays or advancements in the approval of projects and delays in the reimbursement for shared costs; (m) risks associated with the impact of pandemics, such as the COVID-19 (coronavirus) outbreak; and (n) changes in trading conditions. Also see “Risk factors” on pages 28-37 for additional risks and further discussion. No assurance is provided that future dividend payments will match or exceed previous dividend payments. All forward-looking statements contained in this Report are expressly qualified in their entirety by the cautionary statements contained or referred to in this section. Readers should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of this Report. Neither the Company nor any of its subsidiaries undertake any obligation to publicly update or revise any forward-looking statement as a result of new information, future events or other information. In light of these risks, results could differ materially from those stated, implied or inferred from the forward-looking statements contained in this Report.

This Report contains references to Shell’s website, the Shell Sustainability Report, Tax Contribution Report, Industry Associations Climate Review and our report on Payments to Governments. These references are for the readers’ convenience only. Shell is not incorporating by reference into this report any information posted on www.shell.com or in the Shell Sustainability Report, Tax Contribution Report, Industry Associations Climate Review or our report on Payments to Governments.

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DOCUMENTS ON DISPLAY

This Report is also available, free of charge, at www.shell.com/annualreport or at the offices of Shell in The Hague, the Netherlands and London, United Kingdom. Copies of this Report also may be obtained, free of charge, by mail.

TERMS AND ABBREVIATIONS

Currencies

\$	US dollar
€	euro
£	sterling

Units of measurement

acre	approximately 0.004 square kilometres
b(/d)	barrels (per day)
boe(/d)	barrels of oil equivalent (per day); natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel
kboe(/d)	thousand barrels of oil equivalent (per day); natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel
MMBtu	million British thermal units
megajoule	a unit of energy equal to one million joules
mtpa	million tonnes per annum
per day	volumes are converted into a daily basis using a calendar year
scf(/d)	standard cubic feet (per day)

Products

GTL	gas-to-liquids
LNG	liquefied natural gas
LPG	liquefied petroleum gas
NGL	natural gas liquids

Miscellaneous

ADS	American Depositary Share
AGM	Annual General Meeting
API	American Petroleum Institute
CCS	carbon capture and storage
CCS earnings	earnings on a current cost of supplies basis
CO ₂	carbon dioxide
EMTN	Euro medium-term note
EPS	earnings per share
FCF	free cash flow
FID	final investment decision
GAAP	generally accepted accounting principles
GHG	greenhouse gas
HSSE	health, safety, security and environment
IAS	International Accounting Standard
IEA	International Energy Agency
IFRS	International Financial Reporting Standard(s)
IOGP	International Association of Oil & Gas Producers
IPIECA	International Petroleum Industry Environmental Conservation Association (global oil and gas industry association for environmental and social issues)
LTIP	Long-term Incentive Plan
OECD	Organisation for Economic Co-operation and Development
OML	oil mining lease
OPEC	Organization of the Petroleum Exporting Countries
OPL	oil prospecting licence
PSC	production-sharing contract
PSP	Performance Share Plan
REMCO	Remuneration Committee
SEC	US Securities and Exchange Commission
TRCF	total recordable case frequency
TSR	total shareholder return
WTI	West Texas Intermediate

POWERING PROGRESS

Our strategy to accelerate the transition to net-zero emissions, purposefully and profitably



COVER IMAGES

The images on the front cover represent the four goals of Shell's Powering Progress strategy, (clockwise from top): generating shareholder value; achieving net-zero emissions; respecting nature; and powering lives.

Powering Progress is designed to create value for shareholders, customers and wider society. The strategy seeks to accelerate Shell's transformation into a provider of net-zero emissions energy products and services, powered by growth in its customer-facing businesses.

STRATEGIC REPORT

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ACHIEVING **NET-ZERO EMISSIONS**

CHAIR'S MESSAGE

COURAGE AND COVID-19: HOW OUR PEOPLE STEPPED UP



CHAD HOLLIDAY
Chair

In 2020, the world faced exceptional adversity in the form of the COVID-19 pandemic. Adversity reveals character. It forces us to find strength we never knew we had.

For the good of all, many people volunteered for medical trials. Scientists and doctors from around the world shared knowledge. Vaccines were developed at a speed no one thought possible. Just imagine what humanity might achieve if it could direct such public-spirited co-operation towards other challenges, like poverty, or climate change.

PEOPLE AND PRODUCTIVITY

If the pandemic revealed humanity's collective strength, it also showed the resilience of Shell. As I prepare to stand down as Chair of the Royal Dutch Shell plc Board in 2021, I am convinced Shell has a bright future. I am also convinced we have a compelling investment case.

The strength and clarity of our strategy will enable us to succeed as a business in the energy transition. We will continue to power progress by generating value for shareholders and investing in energy projects to help meet demand. In turn, this will support supply chains and boost local economies.

My confidence in Shell is made even stronger by the quality of our people. During my 10 years on the Board, I have seen so many colleagues who inspired me as they helped Shell to succeed. When COVID-19 struck, and lockdowns spread, our people rose to the challenge. They continued to produce and deliver vital energy supplies. They helped to power hospitals and fuel ambulances, to keep homes lit and to maintain essential businesses. They showed ingenuity as well as resilience. They put technology to work. For instance, using crawler robots on the roofs of refinery tanks freed our inspectors from having to work at height. The

inspectors could stay in the safety of their homes, focus on analysing the data gathered by the robots, and offer expert opinion. By innovating in such challenging times, we also improved safety and productivity.

And I was struck by the courage and dedication that so many of our people showed in the face of the virus. I heard remarkable personal stories. In Iraq, Niki Jackson and his colleagues at the Basrah Gas Company (BGC) sweated through a summer where temperatures rose to 50 degrees Celsius and COVID-19 spread through the surrounding area. Niki knew he risked catching the virus, despite all the precautions taken by BGC, a joint venture between Shell, the Iraqi government and Mitsubishi. But Niki, from Aberdeen, Scotland, wanted to be on the ground with his colleagues. How else could he be effective in his job as asset services director, responsible for maintenance and engineering operations? His words are worth repeating: "I saw the pride of my Iraqi colleagues, a pride that comes from being able to tell your family: 'I am helping to ensure that everyone around us has electricity, and gas for cooking.'

"I made my decision: 'Am I still happy doing this? Too right I am. Let's get on with it.'"

Krishna Gupta, a shift superintendent, went out during lockdown to Shell Energy India's regasification facility in Hazira, Gujarat. How did he explain this to his 11-year-old son? He told him: "If I don't go to the facility, our gas can't get to those who need it."

ADAPTING TO THE ENERGY TRANSITION

People like Krishna and Niki give me confidence about Shell's future. So too does our strategy. I have seen the progress we have made, and continue to make, towards becoming fully able to play a role in the transition to a low-carbon future.

We are helped by long experience of serving the needs of our customers. Our global network of around 46,000 service stations, for example, gives us insights into the nature of consumer demand for everything from groceries to electric vehicle charging points. It helps us to understand what we must do to be in step with society in the energy transition.

As our business customers work to reduce carbon dioxide emissions, Shell will increasingly provide the low-carbon energy and products to help. We already have the kind of portfolio that other companies are trying to build. We can invest where we will be competitive, for example, in integrated power, hydrogen and low-carbon biofuels. We will also continue to supply oil and gas because the world will need both for years to come. Our Upstream business will help give us the financial strength to invest in low-carbon sources of energy.

OUR MOST DIFFICULT DECISION

This year has shown how Shell must expect the unexpected and be resilient enough to cope with it. The recession of 2020 was unprecedented. US oil prices briefly turned negative for the first time in history.

In April, we faced a perfect storm. With vaccines not yet on the horizon, no one could predict how bad things might get. That was the backdrop to the most difficult decision I have experienced on a company board: the vote to rebase the dividend. It was historic for Shell. More importantly, it was human. This was about the people who invest in us, whose belief in Shell is partly rewarded by the dividend. The grim reality was there was only one thing worse than rebasing the dividend: not rebasing the dividend.

We could have borrowed to keep the dividend at the same level. But in our view that would have been a mistake. By taking the decisive action to rebase the dividend significantly as we did, I believe we ensured that Shell could emerge from the impact of COVID-19 in strong shape.

In October, we were able to raise the dividend by a modest amount, and signal our intention to have annual dividend increases, subject to Board approval. The fundamentals remain intact. Despite the global economic havoc wreaked by the pandemic, Shell continues to make strategic progress.

FINDING A WAY

Ben van Beurden, the Chief Executive Officer of Royal Dutch Shell, deserves credit for this progress. Over the years, he has listened to those urging Shell to do more to help tackle climate change. He saw we could create new businesses serving new customers and new markets for low-carbon energy products. And the more governments act on climate change, the more successful these businesses can become, and the better it will be for the planet.

We are also making progress in other ways. We hope that in May, shareholders will agree to appoint a Board which, for the first time in Shell's history, will consist equally of men and women. Greater diversity brings greater understanding of people, and better decision-making.

Shell has set challenging emissions targets. In 2020, we announced our target to become a net-zero emissions energy business by 2050 in step with society. We intend to meet our customers' demand for cleaner energy, keeping pace with society's progress towards tackling climate change. As this suggests, we cannot stand still. When necessary, we must be as fast-moving as we were when the pandemic hit. We must also strive constantly to increase productivity, to continue to build financial strength.

In the worst of times, you often see the best of people. In 2020, our people showed great character in adversity. I thank every one of them. I firmly believe their efforts mean Shell will continue to succeed, to deliver energy and to power progress.

CHAD HOLLIDAY

Chair

Adapting to the energy transition

Shell can invest in areas where we will be competitive, such as hydrogen.



Working together across Shell during the COVID-19 global pandemic

Below (clockwise from top left): Shell made innovative use of robots during lockdowns; our people kept service stations open; Krishna Gupta; Niki Jackson.



CHIEF EXECUTIVE OFFICER'S REVIEW

POWERING PROGRESS AND FACING A PANDEMIC



BEN VAN BEURDEN
Chief Executive Officer

In 2020, the COVID-19 pandemic affected us all. Sadly, it claimed the lives of 20 of our Shell colleagues. I heard the stories behind these tragedies, and the cruelty of the pandemic really hit home.

The virus also wreaked havoc with the global economy, dramatically suppressing energy demand. Our income went from \$16.4 billion in 2019 to a loss of \$21.5 billion in 2020, which included non-cash impairments of \$28.1 billion. In April, with oil prices falling rapidly, Shell took swift, decisive action to preserve cash and stay resilient. We rebased the dividend, lowering it by 66%.

It was a very difficult decision to make, but the right thing to do.

Our dividend payments went from \$15.2 billion in 2019 to \$7.4 billion in 2020. We combined rebasing the dividend with the discipline to reduce cash capital expenditure from \$23.9 billion in 2019 to \$17.8 billion in 2020. We reduced net debt from \$79.1 billion in 2019 to \$75.4 billion at the end of 2020.

In October, with global energy demand looking more robust, we raised the dividend by 4% and signalled our intention to have annual dividend increases, subject to Board approval.

Our industry-leading cash flows from operations confirm Shell's underlying strength. Despite the unprecedented challenges, we delivered cash flow from operating activities of \$34.1 billion in 2020, compared with \$42.2 billion in 2019.

Once we have reduced net debt to \$65 billion, we will target total shareholder distributions of 20-30% of cash flow from operations.

In 2020 we began implementing our new safety approach, which places greater emphasis on increasing the chances of people emerging unharmed even if there is an incident. For the first year in our history, there were zero fatal accidents in Shell-operated facilities. I want this achievement to spur us on so that we keep working hard on safety.

THE GOALS OF POWERING PROGRESS

We worked towards refreshing our strategy in 2020, and in February 2021, we announced Powering Progress. It is what I believe Shell does. It is what I believe Shell should continue to do.

Our Powering Progress strategy combines our ambitions under four goals: generating shareholder value, achieving net-zero emissions, powering lives and respecting nature. This will help us accelerate our progress towards becoming a net-zero emissions energy business by 2050, in step with society.

We will lower emissions from our operations, including the energy consumed in running them, and help our customers to reduce their emissions from using our products. Importantly, this will include emissions from oil and gas that others produce and we then sell in our products – an industry-leading approach.

Shell will deal with any of its remaining emissions using carbon capture and storage (CCS) technology, or offsets where plants absorb carbon dioxide.

We expect our total oil production to reduce by 1-2% a year until 2030, taking into account divestments and natural decline. But we expect Upstream oil and gas production to deliver strong cash flows into the 2030s, underpinning our returns to shareholders and helping to fund the low-carbon investments that will transform Shell's energy mix. In all these ways, Shell will change as the world adopts the low-carbon energy system needed to tackle climate change.

WINNING IN A TRANSFORMED ENERGY SYSTEM

Customers and the choices they make will define the nature of the future energy system.

I think the winning energy companies will be those, like Shell, who are best placed to serve customers.

We serve more than 1 million commercial and industrial customers, and 30 million customers at 46,000 retail service stations every day.

We have the leading market positions. We have strong starting positions in products and services that customers are going to want more and more: biofuels, electric-vehicle charging networks, and hydrogen.

Powering Progress

The Powering Progress strategy combines our ambitions under four goals (from top): generating shareholder value; achieving net-zero emissions; powering lives; and respecting nature.



We can work with our customers to develop the low-carbon markets of the future. In this way, Shell would generate value for shareholders while working towards its net-zero carbon emissions target. Society would benefit from reduced emissions.

Take the CrossWind consortium, a joint venture between Shell and Eneco that in 2020 won the tender for the Hollandse Kust (noord) wind farm off the Dutch coast. Shell's plan is to use the wind farm's renewable electricity for powering the industrial-scale production of low-carbon hydrogen by electrolysis, a process that splits water into oxygen and hydrogen.

We will then work with hauliers and truck manufacturers to develop a market for hydrogen as a low-carbon fuel for heavy goods transport.

THE VALUE OF STRATEGIC RELATIONSHIPS

Hollandse Kust (noord) is helping Shell to form other important strategic relationships. In February 2021, Amazon signed an agreement to buy renewable electricity from the wind farm.

Through its air cargo fleet, Amazon also has a growing interest in aviation, one of those sectors that will be hard to decarbonise. Shell has one of the world's most extensive aircraft refuelling networks. We can work with customers, suppliers and regulators to develop a commercially viable and profitable market for sustainable aviation fuel (SAF). We have agreed to supply Amazon with up to six million gallons of blended SAF for its cargo aircraft. This biofuel, produced by the company World Energy using agricultural waste fats and oils, has lower life-cycle carbon emissions than conventional jet fuel.

We also formed a strategic alliance with Microsoft in 2020. Shell is supplying Microsoft with renewable energy, supporting it towards its goal of using 100% renewable energy by 2025. Both businesses will develop digital tools to help Shell's customers decarbonise.

We are working on more of these strategic relationships, generating value while helping sectors to reduce their carbon emissions.

In 2020 we announced a major reorganisation which will take effect from August 2021. We believe this will make us more responsive to customers, as a nimbler organisation with lower costs.

We expect to reduce between 7,000 and 9,000 jobs as we make these changes. It will mean saying goodbye to many people who have shown us great loyalty. We will do this in the spirit of our core values of honesty, integrity and respect for people.

As we prepare for the years ahead, we can draw confidence from how we rose to the challenges of 2020.

What struck me was how our people combined ingenuity with determination to do the right thing: in applying financial discipline, in supplying energy during lockdowns, in making donations to help their communities fight COVID-19. In such hard times, our people generated value for society, and Shell.

They fill me with confidence for the future. With a strong strategy and good people, Shell will power progress for decades to come.

BEN VAN BEURDEN

Chief Executive Officer

SELECTED FINANCIAL DATA

The selected financial data set out below are derived, in part, from the “Consolidated Financial Statements”. These data should be read in conjunction with the “Consolidated Financial Statements” and related Notes, as well as with this Strategic Report.

Consolidated Statement of Income and Statement of Comprehensive Income data

180,543

Revenue (\$ million)

(21,534)

(Loss)/income for the period (\$ million)

146

Income attributable to non-controlling interest (\$ million)

(21,680)

(Loss)/income attributable to Royal Dutch Shell plc shareholders (\$ million)

(23,512)

Comprehensive (loss)/income attributable to Royal Dutch Shell plc shareholders (\$ million)

\$ million	2020	2019	2018	2017	2016
Revenue	180,543	344,877	388,379	305,179	233,591
(Loss)/income for the period	(21,534)	16,432	23,906	13,435	4,777
Income attributable to non-controlling interest	146	590	554	458	202
(Loss)/income attributable to Royal Dutch Shell plc shareholders	(21,680)	15,842	23,352	12,977	4,575
Comprehensive (loss)/income attributable to Royal Dutch Shell plc shareholders	(23,512)	13,773	24,475	18,828	(1,374)

Consolidated Balance Sheet data

379,268

Total assets (\$ million)

108,014

Total debt (\$ million)

651

Share capital (\$ million)

155,310

Equity attributable to Royal Dutch Shell plc shareholders (\$ million)

75,386

Net debt (\$ million)

3,227

Non-controlling interest (\$ million)

\$ million	2020	2019	2018	2017	2016
Total assets	379,268	404,336	399,194	407,097	411,275
Total debt [A]	108,014	96,424	76,824	85,665	92,476
Net debt [A]	75,386	79,093	51,428	65,944	73,346
Share capital	651	657	685	696	683
Equity attributable to Royal Dutch Shell plc shareholders	155,310	186,476	198,646	194,356	186,646
Non-controlling interest	3,227	3,987	3,888	3,456	1,865

[A] Total debt and net debt figures for 2018 and earlier periods are on an IAS 17 basis.

Consolidated Statement of Cash Flows data [A]

34,105

Cash flow from operating activities (\$ million)

16,585

Capital expenditure (\$ million)

13,278

Cash flow from investing activities (\$ million)

7,424

Cash dividends paid to Royal Dutch Shell plc shareholders (\$ million)

1,702

Repurchases of shares (\$ million)

\$ million	2020	2019	2018	2017	2016
Cash flow from operating activities	34,105	42,178	53,085	35,650	20,615
Capital expenditure	16,585	22,971	23,011	20,845	22,116
Cash flow from investing activities	13,278	15,779	13,659	8,029	30,963
Cash dividends paid to Royal Dutch Shell plc shareholders	7,424	15,198	15,675	10,877	9,677
Repurchases of shares	1,702	10,188	3,947	—	—

[A] With the exception of Cash flow from operating activities, which are cash inflows, all other items are cash outflows.

Earnings per share

(2.78)

Basic earnings per €0.07 ordinary share (\$)

(2.78)

Diluted earnings per €0.07 ordinary share (\$)

\$	2020	2019	2018	2017	2016
Basic earnings per €0.07 ordinary share	(2.78)	1.97	2.82	1.58	0.58
Diluted earnings per €0.07 ordinary share	(2.78)	1.95	2.80	1.56	0.58

Dividend per share

0.65

Dividend per share (\$)

\$	2020	2019	2018	2017	2016
Dividend per share	0.65	1.88	1.88	1.88	1.88

Shares

7,795.6

Basic weighted average number of A and B shares (million)

7,795.6

Diluted weighted average number of A and B shares (million)

Million	2020	2019	2018	2017	2016
Basic weighted average number of A and B shares	7,795.6	8,058.3	8,282.8	8,223.4	7,833.7
Diluted weighted average number of A and B shares	7,795.6	8,112.5	8,348.7	8,299.0	7,891.7

SHELL STORY: WHO WE ARE

Shell is a global group of energy and petrochemical companies with 87,000 employees in more than 70 countries.

We have expertise in the exploration, production, refining, marketing and trading of oil and natural gas, and the manufacturing and marketing of chemicals.

We use advanced technologies and take an innovative approach to help build a sustainable energy future. We also invest in power, including from renewable sources such as wind and solar, and new fuels for transport, such as advanced biofuels and hydrogen.

We serve more than 30 million customers at almost 46,000 retail service stations every day.

Our strategy is to accelerate the transition of our business to net-zero emissions, purposefully and profitably.

OUR CONTEXT

The rising standard of living of a growing global population is likely to continue to drive demand for energy, including oil and gas, for years to come. At the same time, technological changes and the need to tackle climate change mean there is a transition under way to a lower-carbon, multi-source energy system with increasing customer choice.

OUR STAKEHOLDERS INCLUDE:

Our investor community
Our customers
Our employees/workforce/pensioners
Our strategic partners/suppliers
Communities
NGOs/civil society stakeholders/
academia/think-tanks
Governments/regulators

See "Section 172(1) statement" on pages 22-27, "Environment and society" on pages 85-93, "Our people" on pages 108-111 and "Governance" on pages 112-189 for more detailed discussions around our context and stakeholders.

OUR PURPOSE

We power progress together by providing more and cleaner energy solutions.

See "Strategy and outlook" on page 18 for more detailed discussion around our purpose.

OUR CORE VALUES

Honesty
Integrity
Respect for people

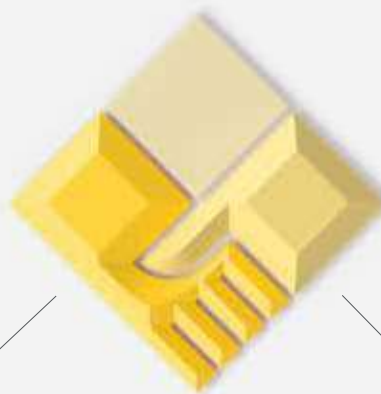
The Shell General Business Principles, Code of Conduct, and Code of Ethics help everyone at Shell to act in line with these values and comply with relevant laws and regulations. We also strive to build and maintain a diverse and inclusive culture within our company.

See "Our people" on pages 108-111 for more detailed discussion around our core values.

THE SHELL INVESTMENT CASE

POWERING PROGRESS

Our strategy to accelerate the transition to net-zero emissions, purposefully and profitably



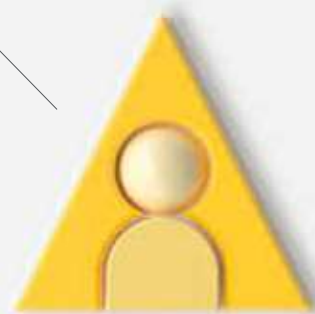
GENERATING SHAREHOLDER VALUE

Growing value through a dynamic portfolio and disciplined capital allocation



RESPECTING NATURE

Protecting the environment, reducing waste and making a positive contribution to biodiversity



POWERING LIVES

Powering lives through our products and activities, and supporting an inclusive society



ACHIEVING NET-ZERO EMISSIONS

Working with our customers and sectors to accelerate the energy transition to net-zero emissions

UNDERPINNED BY
OUR **CORE VALUES**
AND OUR FOCUS
ON **SAFETY**

SHELL STORY: WHAT WE DO

We aim to meet the world's growing need for more and cleaner energy solutions in ways that are economically, environmentally and socially responsible.

OUR INPUTS [A]

FINANCIAL

276,719 2019: 291,142
Average capital employed (\$ million)

17,827 2019: 23,919
Cash capital expenditure (\$ million)

Read more in "Performance indicators" on pages 43-45 and "Non-GAAP measures reconciliations" on pages 305-306.

OPERATIONS

95.5% 2019: 90.8%
Refinery and chemical plant availability

48% 2019: 90%
Project delivery on schedule

104% 2019: 99%
Project delivery on budget

Read more in "Performance indicators" on pages 43-45.

INNOVATION

907 2019: 962
Investments in research and development (\$ million)

8,480 2019: 9,449
Patents [B]

Read more in "Technology and Innovation" on page 17.

HUMAN CAPITAL

87,000 2019: 87,000
Employees [B]

234,000 2019: 373,000
Training days

Read more in "Our people" on pages 108-111.

RELATIONSHIPS

Customers
Joint arrangements
Government relations
Suppliers

>70 2019: >70
Operating countries [B]

Read more in "Section 172(1) statement" on pages 22-27, "Environment and society" on pages 85-93 and "Governance" on pages 112-189.

NATURAL RESOURCES

9,124 2019: 11,096
Proved oil and gas reserves (million boe) [B]

1,239 2019: 1,338
Oil and gas production available for sale (million boe)

171 2019: 192
Fresh water withdrawn (million cubic metres)

Read more in "Oil and gas information" on pages 61-69 and "Environment and society" on pages 85-93.

OUR BUSINESS MODEL

We seek to create shareholder value by:

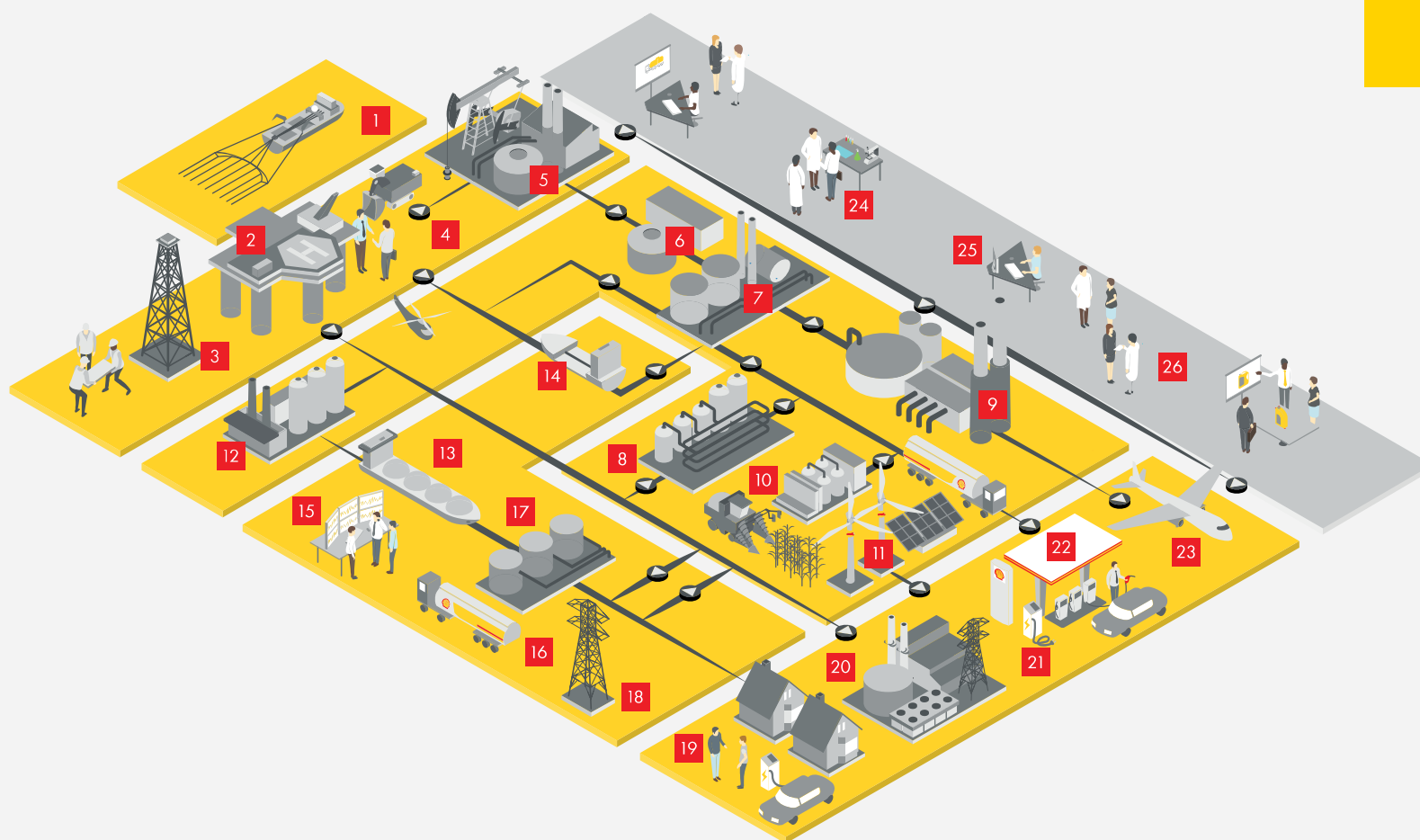
- exploring for crude oil and natural gas worldwide;
- developing new crude oil and natural gas supplies from major fields and extracting bitumen from oil sands;
- cooling natural gas to produce liquefied natural gas (LNG) and converting gas to liquids (GTL);
- supplying, marketing and trading oil, gas and other energy-related products, such as electricity and carbon-emission rights as part of our integrated business model;
- having a portfolio of refineries and chemical plants producing a wide range of products including gasoline, diesel, aviation and marine fuel, lubricants and petrochemicals;
- marketing lubricants, aviation fuels, bitumen, sulphur, retail mobility fuels and convenience products and services, as well as low-carbon fuels to customers;
- capturing carbon dioxide using carbon capture and storage (CCS) technology; and
- investing in nature-based solutions that avoid or reduce carbon dioxide emissions.

The integration of our businesses is one of our competitive advantages, allowing optimisations across our global portfolio.

[A] In 2020 unless stated otherwise.
[B] At 31.12.2020.

OUR BUSINESS MODEL EXPLAINED

BUSINESS ACTIVITIES



EXPLORATION

1. Exploring for oil and gas onshore and offshore

DEVELOPMENT AND EXTRACTION

2. Developing onshore and offshore fields
3. Producing conventional, deep-water and shale oil and gas
4. Capturing carbon dioxide and storing it safely underground
5. Extracting bitumen

MANUFACTURING AND ENERGY PRODUCTION

6. Upgrading bitumen
7. Refining oil into fuels and lubricants
8. Producing gas-to-liquids (GTL) products
9. Producing petrochemicals
10. Producing biofuels
11. Generating renewable power
12. Producing liquefied natural gas (LNG)

TRANSPORT AND TRADING

13. Shipping gas to where it is needed
14. Shipping oil to where it is needed
15. Trading oil and gas
16. Supply and distribution of LNG for transport applications
17. Regasifying LNG
18. Trading power

SALES AND MARKETING

19. Supplying domestic electricity
20. Supplying products to businesses, including gas for cooking, heating and electrical power
21. Progressing electric vehicle and hydrogen refuelling infrastructure
22. Providing mobility solutions for customers, including fuels and lubricants
23. Supplying aviation fuel

TECHNICAL AND BUSINESS SERVICES

24. Researching and developing new technology solutions
25. Managing the delivery of major projects
26. Providing technical and supporting services

Our Powering Progress strategy is designed to create value for our shareholders, customers and wider society.

OUR OUTCOME AND IMPACT [A]


ENERGY TRANSITION AND CLIMATE CHANGE

75 2019: 78

Net Carbon Footprint
(grams of CO₂ equivalent
per megajoule)

63 2019: 70

Direct greenhouse gas (GHG)
emissions (million tonnes of
CO₂ equivalent)

 Read more in "Climate change and energy transition" on pages 94-107.


ENVIRONMENTAL IMPACTS

68 2019: 67

Operational spills of more
than 100 kg

0.4 2019: 0.2

Weight of operational spills
(in '000 tonnes)

 Read more in "Environment and society" on pages 85-93.

[A] In 2020 unless stated otherwise.

FINANCIAL PERFORMANCE

(6.8)% 2019: 6.7%
Return on average capital employed (ROACE)

9,126 2019: 25,386
Shareholder distributions (\$ million)

Read more in "Performance indicators" on pages 43-45 and "Non-GAAP measures reconciliations" on pages 305-306.

RESILIENCE OF BUSINESS MODEL

20,828 2019: 26,399
Free cash flow (\$ million)

75,386 2019: 79,093
Net debt (\$ million)

Read more in "Performance indicators" on pages 43-45 and "Liquidity and capital resources" on pages 81-84.

TRUST AND TRANSPARENCY

42.2 2019: 47.5
Brand value (\$ billion) [C]

1,425 2019: 1,686
Shell Global Helpline (reports to the helpline)

Publication of the second Shell Tax Contribution Report

Read more in "Corporate" on page 80 and "Our people" on pages 108-111.

HEALTH, SAFETY AND SECURITY

0.7 2019: 0.9
Total recordable case frequency (injuries per million working hours)

103 2019: 130
Operational Tier 1 and 2 process safety events

Read more in "Environment and society" on pages 85-93.

CONTRIBUTION TO COUNTRIES OF OPERATION

47.3 2019: 61.3
Taxes paid and collected (\$ billion)

39.3 2019: 44.9
Total spend on goods and services (\$ billion)

Read more in "Environment and society" on pages 85-93.

OUR PEOPLE

27.8% 2019: 26.4%
Women in senior leadership positions [B]

78 2019: 78
Average employee engagement score (points)

Read more in "Our people" on pages 108-111.

[B] At 31.12.2020.

[C] Source: Brand Finance Global 500 2021 Report.

OUR ORGANISATION

We describe below how our activities are organised. Integrated Gas, Upstream and Downstream focus on our three business pillars (see “Strategy and outlook” on page 18). Our Projects & Technology organisation manages the delivery of Shell’s major projects and drives research and innovation to develop new technology solutions.

INTEGRATED GAS (INCLUDING NEW ENERGIES)

Integrated Gas manages LNG activities and the conversion of natural gas into GTL fuels and other products. It includes natural gas exploration and extraction, and the operation of upstream and midstream infrastructure necessary to deliver gas to market. It markets and trades natural gas, LNG, electricity and carbon-emission rights and also markets and sells LNG as a fuel for heavy-duty vehicles and marine vessels.

In New Energies, which was rebranded to Renewables and Energy Solutions in 2021, we are exploring emerging opportunities and investing in those where we believe sufficient commercial value is available. We focus on new fuels for transport, such as advanced biofuels, hydrogen and charging for battery-electric vehicles; and power, including from natural gas and low-carbon sources such as wind and solar.

UPSTREAM

Upstream manages the exploration for and extraction of crude oil, natural gas and natural gas liquids. It also markets and transports oil and gas, and operates infrastructure necessary to deliver them to market.

DOWNSTREAM

Downstream manages different Oil Products and Chemicals activities as part of an integrated value chain that trades and refines crude oil and other feedstocks into a range of products which are moved and marketed around the world for domestic, industrial and transport use. The products we sell include gasoline, diesel, heating oil, aviation fuel, marine fuel, biofuel, lubricants, bitumen and sulphur. We also produce and sell petrochemicals for industrial use worldwide. Our Downstream organisation also manages Oil Sands activities (the extraction of bitumen from mined oil sands and its conversion into synthetic crude oil).

PROJECTS & TECHNOLOGY

Our Projects & Technology organisation manages the delivery of our major projects and drives research and innovation to develop new technology solutions. It provides technical services and technology capability for our Integrated Gas, Upstream and Downstream activities. It is also responsible for providing functional leadership across Shell in the areas of safety and environment, contracting and procurement, wells activities and greenhouse gas management.

Our future hydrocarbon production depends on the delivery of large and integrated projects (see “Risk factors” on pages 28-37). Systematic management of life-cycle technical and non-technical risks is in place for each opportunity, with assurance and control activities embedded throughout the project life cycle. We focus on the cost-effective delivery of projects through commercial agreements, supply-chain management, and construction and engineering productivity through effective planning and simplification of delivery processes. Development of our employees’ project management competencies is underpinned by project principles, standards and processes. A dedicated competence framework, training, standards and processes exist for various technical disciplines. We also provide governance support for our non-Shell-operated ventures or projects.

SEGMENTAL REPORTING

Our reporting segments are Integrated Gas, Upstream, Oil Products, Chemicals and Corporate. Integrated Gas, Upstream, Oil Products and Chemicals include their respective elements of our Projects & Technology organisation. The Corporate segment comprises our holdings and treasury organisation, self-insurance activities, and headquarters and central functions. See Note 4 to the “Consolidated Financial Statements” on pages 230-232.

With effect from January 1, 2020, additional contracts were classified as held for trading purposes and consequently revenue is reported on a net rather than gross basis.

Revenue by business segment (including inter-segment sales) [A]

	\$ million		
	2020	2019	2018
Integrated Gas			
Third parties	33,287	41,322	43,764
Inter-segment	3,410	4,280	5,031
Total	36,697	45,602	48,795
Upstream			
Third parties	6,767	9,482	9,459
Inter-segment	21,564	35,735	37,125
Total	28,330	45,217	46,584
Oil Products			
Third parties	128,717	280,460	316,409
Inter-segment	6,213	7,819	10,613
Total	134,930	288,279	327,022
Chemicals			
Third parties	11,721	13,568	18,704
Inter-segment	2,850	3,917	4,864
Total	14,571	17,485	23,568
Corporate			
Third parties	51	45	43
Total	51	45	43

[A] Historical comparatives are based on prevailing foreign exchange rates for respective years.

Revenue by geographical area (excluding inter-segment sales) [A]

	\$ million		
	2020	2019	2018
Europe	50,138	98,455	118,960
Asia, Oceania, Africa	65,139	139,916	153,716
USA	50,856	83,212	89,876
Other Americas	14,410	23,294	25,827
Total	180,543	344,877	388,379

[A] Historical comparatives are based on prevailing foreign exchange rates for respective years.

TECHNOLOGY AND INNOVATION

Technology and innovation are essential to our efforts to meet the world's energy needs in a competitive way. If we do not develop the right technology, do not have access to it or do not deploy it effectively, this could have a material adverse effect on the delivery of our strategy and our licence to operate (see “Risk factors” on pages 28-37). We continually look for technologies and innovations of potential relevance to our business. Our Chief Technology Officer oversees the development and deployment of new and differentiating technologies and innovations across Shell, seeking to align business and technology requirements throughout our technology maturation process.

In 2020, research and development expenses were \$907 million, compared with \$962 million in 2019, and \$986 million in 2018. Our main technology centres are in India, the Netherlands and the USA, with other centres in Brazil, China, Germany, Oman, and Qatar. A strong patent portfolio underlies the technology that we employ in our various businesses. In total, we have around 8,480 granted patents and pending patent applications.

OUR STRATEGY

In February 2021, Shell launched Powering Progress which sets out our strategy to accelerate the transition of our business to net-zero emissions, in step with society, purposefully and profitably.

CONTEXT

Our strategy is founded on our outlook for the energy sector and the chance to grasp opportunities arising from the substantial changes in the world around us. We believe the rising standard of living of a growing global population will continue to drive demand for energy for years to come. The world will need to find a way to meet this growing demand, while transitioning to a net-zero emissions energy system to counter climate change.

POWERING PROGRESS

In February 2021, Shell launched Powering Progress, which sets out our strategy to accelerate the transition of our business to net-zero emissions, in step with society, purposefully and profitably.

We will build a strong and resilient business by putting customers at the centre of our strategy, innovating the products and solutions customers need on their journey to net zero. This includes partnering with others to reduce carbon emissions, especially in sectors that are hard to decarbonise. We aim to deliver value through our integrated assets and supply chains, optimising value and managing risk for Shell and our customers as we produce, buy, trade, transport and sell energy products across the world. This is a strategy that combines our financial strength and discipline with a dynamic approach to our portfolio of assets and products, so that we are ready to seize the significant opportunities that exist for us in the energy transition.

POWERING PROGRESS

GENERATING SHAREHOLDER VALUE

Growing value through a dynamic portfolio and disciplined capital allocation

ACHIEVING NET-ZERO EMISSIONS

Working with our customers and across sectors to accelerate the transition to net-zero emissions



Powering Progress generates value for our shareholders, customers and wider society. It has four main goals which integrate sustainability with our business strategy. These goals support Shell's purpose, to power progress together by providing more and cleaner energy solutions. They are underpinned by our core values of honesty, integrity and respect for people, and our focus on safety.

Generating shareholder value: We aim to create the conditions for share price appreciation by preparing our business for the future and accessing the opportunities that the future of energy holds. We will do this while providing sustainable distributions today through our progressive dividend policy. The changing energy landscape means that Shell must take a dynamic approach to its portfolio of assets and products. That means continuing to provide the energy the world needs today, and increasing our investments in cleaner energy. We will keep a disciplined approach to capital investment, and a strong balance sheet, so that our organisation remains strong and resilient. In this way, we will achieve our aim of being a compelling investment case for our shareholders.

Achieving net-zero emissions: Tackling climate change is an urgent challenge. That is why we have set a target to become a net-zero emissions energy business by 2050, in step with society. We are transforming our business and finding new opportunities – selling more low-carbon products such as biofuels, electricity generated by solar and wind power, hydrogen and charging for electric vehicles. We are partnering with customers, businesses and governments to address the energy transition and reduce emissions sector by sector. This includes in sectors that are harder to decarbonise, such as aviation, shipping,

commercial road freight, power, heating and certain parts of industry. We also support government policies to reduce carbon emissions in the economy, sector by sector.

Powering lives: Shell helps to power lives and livelihoods by providing vital energy for homes, businesses and transport. The supply of affordable, reliable and sustainable energy is also crucial for addressing global challenges, including those related to poverty and inequality. Our operations support livelihoods by providing employment and training in the communities where we operate. We are working to become one of the most diverse and inclusive companies in the world, a place where everyone feels valued and respected. We are focusing on four areas: gender, race and ethnicity, LGBT+ and disability. We respect human rights in all parts of our business.

Respecting nature: We are stepping up our environmental ambitions, shaping them to reflect the UN Sustainable Development Goals. Our environmental ambitions include protecting and enhancing biodiversity. We are also focusing on using water and other resources more efficiently across all our activities, reusing as much of them as we can. We are reducing waste from our operations and increasing recycling of plastics. We are helping to improve air quality by reducing emissions from our operations and providing cleaner ways to power transport and industry.

Working with our partners and suppliers and developing new collaborations is key. We will join with others across industry, governments, our customers and supply chains to protect nature.

POWERING LIVES

Powering lives through our products and activities, and by supporting an inclusive society

RESPECTING NATURE

Protecting the environment, reducing waste and making a positive contribution to biodiversity



STRATEGY AND OUTLOOK continued

BUSINESS PILLARS

Powering Progress is a strategy that combines our financial strength and discipline with a dynamic approach to our portfolio of assets and products, so that we are ready to seize the significant opportunities that exist for us in the energy transition. Shell will reshape its portfolio of assets and products to meet the cleaner energy needs of its customers in the coming decades. We will deliver our strategy through three business pillars: Growth, Transition, and Upstream.

Through these three areas, we are creating flexibility in investment opportunities while enabling growth in our customer-facing businesses. Our strategy delivers additional value through trading and optimisation.

Achieving our strategy depends on how we respond to competitive forces. We continually assess the external environment – the markets and the underlying economic, political, social and environmental drivers that shape them – to evaluate changes in competitive forces and business models. We use multiple future scenarios to assess the resilience of our strategy. We regularly review the markets where we operate, assessing our competitive position by analysing trends, uncertainties, and the strengths and weaknesses of our traditional and non-traditional competitors.

To support the delivery of our strategy, we are redesigning Shell to put customers at the centre. That means organising ourselves to help economic sectors to decarbonise, by providing integrated, lower-carbon energy solutions, sector by sector.

We maintain business strategies and plans that focus on actions and capabilities to create and sustain competitive advantage. We maintain a risk management framework that regularly assesses our response to, and risk appetite for, identified risks.

See "Risk factors" on page 28 and "Governance" on page 112.

Our Executive Directors' remuneration is linked to the successful delivery of our strategy, based on performance indicators that are aligned with shareholder interests. Long-term incentives form the majority of the Executive Directors' remuneration for above-target performance. In 2020, the Long-term Incentive Plan (LTIP) included cash generation, capital discipline, value created for shareholders, and an energy transition condition. For 2021, the weighting of the energy transition condition in the LTIP has been increased to 20%.

See the "Directors' Remuneration Report" on page 153.

For more details on how the strategic pillars are embedded into our businesses, see "Shell story" on pages 10-17.

DELIVERING THE STRATEGY: OUR VISION FOR THE FUTURE OF ENERGY

GROWTH PILLAR: THE FUTURE OF ENERGY

MARKETS



TRANSITION PILLAR: ENABLING OUR STRATEGY

ASSETS



UPSTREAM PILLAR: FUNDING OUR STRATEGY

RESOURCES



Enhanced value delivery through trading and optimisation

OUTLOOK FOR 2021 AND BEYOND

We believe that our integrated business model is key to driving our strategy. It means that our portfolio is greater than the sum of its parts. This competitive portfolio has a solid track record on cash generation, where Shell is leading its peer group. We intend to evolve our portfolio of assets and the mix of energy that we sell to meet the cleaner energy needs of our customers in the coming decades, while delivering value for our shareholders.

Delivering our strategy will require clear and deliberate capital allocation choices. We approach capital allocation at three levels: enterprise, portfolio and project. The enterprise level is about how we make choices between increasing distributions to our shareholders, investing in our business and/or strengthening our balance sheet. The portfolio level is about how we allocate capital between our three business pillars – Growth, Transition and Upstream. The project level is about how we evaluate and prioritise investment opportunities.

At the enterprise level, we look to achieve the right balance between shareholder distributions today and investing for value-enhancing growth.

For cash capital expenditure, we plan to spend between \$19 and 22 billion per annum in the near term. In addition, we expect operating costs to be no higher than \$35 billion and to deliver a divestment programme totalling around \$4 billion a year in this period. We remain committed to our progressive dividend policy and focused on targeting AA-equivalent credit metrics through the cycle.

Subject to Board approval, we aim to grow the dividend per share by around 4 percent every year. Once our net debt level has reached \$65 billion, we will target the distribution of 20-30% of cash flow from operations to shareholders, and may choose to return cash to shareholders through a combination of dividends and share buybacks.

Once we have achieved this level of shareholder distributions, additional surplus cash will be allocated between further disciplined capital investments to deliver our strategy and further debt reduction to strengthen the balance sheet.

We fully support the Paris Agreement's goal to keep the rise in global average temperature this century to well below two degrees Celsius above pre-industrial levels and to pursue efforts to limit temperature increase even further to 1.5 degrees Celsius. We announced a long-term target to become a net-zero emissions energy business by 2050, in step with society. This includes a target to be net zero on all emissions from the manufacture of all our products – (our Scope 1 and 2 emissions) – by 2050, and also net zero from the end use of all the energy products we sell (Scope 3 emissions). We aim to reduce the net carbon intensity of energy sold by 6-8% by 2023, 20% by 2030, 45% by 2035 and 100% by 2050, in comparison with 2016. We expect that our total carbon emissions from energy sold will stay below 2018 levels. Further details are in the "Climate change and energy transition" section on page 94.

As a result of COVID-19, there continues to be significant uncertainty in the macroeconomic conditions with an expected negative impact on demand for oil, gas and related products. Demand or regulatory requirements and/or constraints in infrastructure may cause Shell to take measures to curtail or reduce oil and/or gas production, LNG liquefaction and utilisation of refining and chemicals plants. Sales volumes could be similarly affected. Such measures could impact our earnings, cash flow and financial condition.

The statements in this "Strategy and outlook" section, including those related to our growth strategies and our expected or potential future cash flow from operations, organic free cash flow, share buybacks, capital investment, divestments, production and Net Carbon Footprint, are based on management's current expectations and certain material assumptions and, accordingly, involve risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied herein. See "About this Report" on page iii and "Risk factors" on pages 28-37.

CAPITAL ALLOCATION: TARGET SHAREHOLDER DISTRIBUTIONS OF 20-30% OF CFFO

	Clear capital allocation framework	Operationalising the framework
1st PRIORITY	Near-term cash capex Ordinary progressive dividend	<ul style="list-style-type: none"> Apportion near-term \$19-22 billion cash capital expenditure: <ul style="list-style-type: none"> Marketing ~\$3 billion; Renewables and Energy Solutions \$2-3 billion; Integrated Gas ~\$4 billion; Chemicals and Products \$4-5 billion; Upstream ~\$8 billion Inorganic capex included in range ~4% dividend per share growth annually, subject to Board approval
2nd PRIORITY	AA credit metrics through the cycle	<ul style="list-style-type: none"> Reduce net debt to \$65 billion <ul style="list-style-type: none"> Milestone for AA credit metrics threshold in the near term
3rd PRIORITY	Additional shareholder distributions	<ul style="list-style-type: none"> Total shareholder distributions of 20-30% of CFFO (on reaching net debt of \$65 billion) <ul style="list-style-type: none"> Distributions include dividends and share buybacks
4th PRIORITY	Capex growth Continued balance sheet strengthening	<ul style="list-style-type: none"> Measured, disciplined capex growth to enable strategy Further reduce net debt to achieve firm long-term AA credit metrics

First cash priority also includes interest paid (CFFF).

Near-term cash capex numbers split by business are rounded and total will be managed within the near-term range of \$19-22 billion.

SECTION 172(1) STATEMENT

The Companies (Miscellaneous Reporting) Regulations 2018 (2018 MRR) require Directors to explain how they considered the interests of key stakeholders and the broader matters set out in Section 172(1) (a) to (f) of the Companies Act 2006 (S172) when performing their duty to promote the success of the Company under S172. This includes considering the interests of other stakeholders which may affect the long-term success of the company. This S172 statement explains how Shell Directors:

- have engaged with employees, suppliers, customers and others; and
- have considered employee interests, the need to foster business relationships with suppliers, customers and others, and the effects of those considerations, including on the principal decisions taken during the financial year.

The S172 statement focuses on matters of strategic importance to Shell, and the level of information disclosed is consistent with the size and the complexity of Shell's businesses.

GENERAL CONFIRMATION OF DIRECTORS' DUTIES

Shell's Board has a clear framework for determining the matters within its remit and has approved Terms of Reference for the matters delegated to its Committees. Certain financial and strategic thresholds have been set, in order to identify matters requiring Board consideration and approval. The Manual of Authority sets out the delegation and approval process across the broader business. More information on Shell's controls and procedures can be found in "Other regulatory and statutory information" on page 182.

When making decisions, each Director ensures that (s)he acts in the way he or she considers, in good faith, would most likely promote Shell's success for the benefit of its members as a whole, and in doing so has regard (among other matters) to the issues set out below.

S172(1) (a) "THE LIKELY CONSEQUENCES OF ANY DECISION IN THE LONG TERM"

The Directors understand the business and the evolving environment in which we operate, including the challenges of navigating through the energy transition. Based on Shell's purpose to power progress together by providing more and cleaner energy solutions, the strategy set by the Board is intended to strengthen our position as a leading energy company by providing oil, gas and low-carbon energy products and services that meet our customers' cleaner energy needs as the global energy system transforms, while keeping safety and social responsibility fundamental to our business approach.

As outlined in "Our context" in the "Shell story" section on pages 10-17, the rising standard of living of a growing global population is likely to continue to drive demand for energy, including oil and gas, for years to come. At the same time, tackling climate change requires an orderly transition to a lower-carbon, multi-source energy system that is enabled by technological changes and facilitates increasing customer choice. Shell's strategic ambitions have been set in that context. We want to increase long-term value for shareholders, recognising that the long-term success of our business depends on our stakeholders and the effects of our business activities on wider society.

In 2020, we had to operate in the unprecedented context created by the COVID-19 pandemic, the resulting macroeconomic conditions and the imbalance between supply and demand in the oil and gas market.

To retain focus on achieving the strategic ambitions, in 2020 the Board determined a cash allocation framework designed to enable debt reduction, increase shareholder distributions, and facilitate disciplined growth as Shell reshapes its business for the future of energy. Shell also announced the reshaping of its portfolio of assets and products to meet its customers' cleaner energy needs in the coming decades. The key elements of Shell's strategic direction include:

- setting a target to be a net-zero emissions energy business by 2050, in step with society.
- growing its leading marketing business, further developing the integrated power business and commercialising hydrogen and biofuels to support customers' efforts to achieve net-zero emissions;
- transforming its refining portfolio from the current 13 sites into six high-value energy and chemicals parks, integrated with Chemicals. Growth in Chemicals will shift to more performance chemicals and recycled feedstocks;
- extending leadership in liquefied natural gas (LNG) to enable decarbonisation of key markets and sectors;
- focusing on value over volume by simplifying Upstream to nine significant core positions, which will generate more than 80% of Upstream's cash flow from operations; and
- enhancing value delivery through trading and optimisation.

The Directors recognise that there are differing societal views about our operations and that some Board decisions taken today may not align with all stakeholder interests. Given the complexity of the evolving energy transition, the Directors have taken the decisions they believe best support Shell's strategic ambitions.

S172(1) (b) "THE INTERESTS OF THE COMPANY'S EMPLOYEES"

The Directors recognise that Shell employees are fundamental and core to our business and the delivery of our strategic ambitions. The success of our business depends on attracting, retaining and motivating talented employees. The Directors consider and assess the implications of decisions on employees and the wider workforce, where relevant and feasible. The Directors seek to ensure that Shell remains a responsible employer, including with respect to pay and benefits, health and safety issues, and the workplace environment. The Directors recognise that our pensioners, though no longer employees, also remain important stakeholders.

More information on this can be found in "Workforce engagement" on page 138.

S172(1) (c) "THE NEED TO FOSTER THE COMPANY'S BUSINESS RELATIONSHIPS WITH SUPPLIERS, CUSTOMERS AND OTHERS"

Delivering our strategy requires strong mutually beneficial relationships with suppliers, customers, governments, national oil companies and joint-venture partners. Shell seeks to promote and apply certain general principles in such relationships. The ability to promote these principles effectively is an important factor in the decision to enter into or remain in such relationships. This standard and others are described in the Shell General Business Principles, which are based upon our core values of honesty, integrity and respect for people (i.e. our stakeholders). The Board periodically reviews and approves the Shell General Business Principles. The Directors take account of the General Business Principles and core values when exercising their duties and making Board decisions. "Core Value Moments" are built into Board agendas and provide the Board with opportunities to reflect on the importance of the General Business

Principles and Core Values. The Board also reviews and approves Shell's approach to suppliers, which is set out in the Shell Supplier Principles. The businesses continually assess the priorities related to customers and those with whom we do business. The Board engages with the businesses on these topics, for example, within the context of business strategy updates and investment proposals.

The Directors also receive updates on a variety of topics that indicate how these stakeholders have been engaged.

These updates include information provided by the Projects & Technology function on suppliers and joint-venture partners, with respect to items such as project updates and supplier contract management. Businesses also provide information on customers and joint-venture partners in relation to business strategies, projects, and investment or divestment proposals.

S172(1) (d) "THE IMPACT OF THE COMPANY'S OPERATIONS ON THE COMMUNITY AND THE ENVIRONMENT"

This aspect is inherent in our strategic ambitions. The Board receives information on various topics to help it make decisions relating, for example, to issues such as the Net Carbon Footprint target, the COVID-19 pandemic's impact on Shell, country-entry considerations, proposals to invest or divest, and business strategy reviews. The information also goes into Group-level overviews, such as updates on safety and environment performance, reports from the Chief Ethics & Compliance Officer, and reports from the Chief Internal Auditor. In 2020, certain Board committees and Non-executive Directors conducted site visits of various Shell operations and overseas offices and held external stakeholder engagements, where feasible. The physical site visits were not as extensive as in past years because of travel and other restrictions imposed by governments in response to COVID-19. Despite the challenges presented by COVID-19 in terms of international travel and face-to-face meetings, the Board maintained a strong interface with businesses and staff through virtual engagements, making best use of the technology available.

More information on this, including details of face-to-face visits held pre-COVID-19, can be found in "Understanding and engaging with our stakeholders" on page 134, or in the reports of each Board committee.

S172(1) (e) "THE DESIRABILITY OF THE COMPANY MAINTAINING A REPUTATION FOR HIGH STANDARDS OF BUSINESS CONDUCT"

Shell aims to meet the world's growing need for more and cleaner energy solutions in economically, environmentally and socially responsible ways. The Board periodically reviews and approves clear frameworks, such as The Shell General Business Principles, Shell's Code of Conduct, specific Ethics and Compliance manuals, the Ethical Decision-Making Framework, and its Modern Slavery Statements, to ensure that its high standards are maintained in Shell businesses and in Shell's business relationships. This, complemented by the ways the Board is informed and monitors compliance with relevant governance standards, helps to ensure that Board decisions and the actions of Shell companies promote high standards of business conduct.

S172(1) (f) "THE NEED TO ACT FAIRLY AS BETWEEN MEMBERS OF THE COMPANY"

After weighing up all relevant factors, the Directors consider which course of action best enables delivery of our strategy through the long term, taking into consideration the effect on stakeholders. In doing so, our Directors act fairly as between the Company's members but are not required to balance the Company's interest with those of other stakeholders. This can sometimes mean that certain stakeholder interests may not be fully aligned.

CULTURE

The Board recognises that it plays an important role in assessing and monitoring that our desired culture is embedded in our values, attitudes and behaviours, including in our activities and stakeholder relationships. The Board has established honesty, integrity and respect for people as Shell's core values. The General Business Principles, Code of Conduct, and Code of Ethics help everyone at Shell to act in line with these values and comply with relevant laws and regulations. The Shell Commitment and Policy on Health, Safety, Security, Environment & Social Performance applies across Shell and is designed to help protect people and the environment. In 2020, we refreshed our approach to safety to avoid fatalities and life-changing injuries by building on existing strong foundations, with an increased and deliberate focus on "human performance". "Human performance" is the way people, culture, equipment, work systems and processes interact as a system. It remains our ambition to achieve Goal Zero, no harm and no leaks across all our operations.

Shell has an ambitious strategy to achieve net-zero emissions by 2050 in step with society, while generating shareholder value. This also includes medium- and long-term targets of 20% by 2030, 45% by 2035, and 100% by 2050 (compared with 2016). To achieve our strategic goals, we need to adapt our mindset and behaviours as we navigate the increasing complexity in the world around us. "Who we are" captures the mindset and behaviours needed to succeed in the coming years, including:

- applying a learner mindset: everyone has the ability to grow, learn from mistakes and successes, and speak up openly in a safe environment. We encourage curiosity, humility, openness, helping each other to make better decisions and create more value;
- maximising our performance: we collaborate across boundaries and speak up when we see things that can be improved. We enable people to deliver, and we work in an integrated way with discipline, clear focus on priorities, and tangible outcomes in order to reach our full potential;
- increasing trust in Shell: we aim to be a valued member of the communities in which we operate, and to make a positive contribution to society. We seek to listen carefully and with humility and we have a strong desire to understand, and, where possible, adapt to the changing needs and expectations of society, especially as they relate to the environment. We build strong and trusted relationships with customers and partners which are fundamental to our collective success;
- living by our values and Goal Zero: we live by our values and do the right things in respect to ethics, safety and the environment; and
- inspiring and engaging: we aspire to a situation where everyone feels connected to what we stand for. We build trusting and effective teams where everyone feels ownership and has a voice in how work gets done. We strive to maintain a diverse and inclusive culture.

The Board considers the Shell People Survey to be an important tool for measuring employee engagement, motivation, affiliation and commitment to Shell. It provides insights into employee views and has a consistently high response rate. It also helps the Board to understand how the survey's outcomes are being used to strengthen Shell culture and values. The Board has noted that although staff surveys offer insight, limitations exist. The surveys may lack sufficient detail on how culture is embedded. As a result, a more rigorous approach to Board oversight of culture will be adopted in the year ahead to establish more effective ways of monitoring and assessing culture and how it aligns with purpose, values and strategy.

SECTION 172(1) STATEMENT continued

The Board recognises the important role Shell has in society and is deeply committed to public collaboration and stakeholder engagement. This commitment is at the heart of Shell's strategic ambitions. The Board strongly believes that Shell will only succeed by working together with customers, governments, business partners, investors and other stakeholders.

Working together is critical, particularly at a time when society, including businesses, governments and consumers, faces issues as complex and challenging as climate change.

We continue to build on our long track record of working with others, such as investors, industry and trade groups, universities, governments, non-governmental organisations (NGOs) and, in some appropriate instances, our competitors through our joint-venture operations or industry bodies. We believe that working together and sharing knowledge and experience with others offers us greater insight into our business. We also appreciate our long-term relationships with our investors and acknowledge the positive impact of ongoing engagement and dialogue.

STAKEHOLDER ENGAGEMENT (INCLUDING EMPLOYEE ENGAGEMENT)

The guidance on preparing information, proposals or discussion items for the Board asks for these materials to include considerations of the views, interests and concerns of stakeholders and how management addressed them. This helps to strengthen the Board's knowledge of how the broader business undertakes significant levels of stakeholder engagement. Board minutes have also reflected key points on stakeholder considerations, where appropriate. The Terms of Reference for our Safety, Environment and Sustainability Committee also include, within the Committee's remit, the review and consideration of external stakeholder perspectives and how major issues of public concern that could affect Shell's reputation and licence to operate were, or are being addressed.

The Board also engaged with certain stakeholders directly, to understand their views. The Board also leverages its very substantial in-house expertise by receiving input from economics and policy experts on key political and economic themes periodically, with some updates being presented to the Board each quarter. More on this engagement is provided in "Understanding and engaging with our stakeholders" on page 134.

Information on how the Directors have engaged with employees can be found on page 138 and in the "Our people" section on pages 108. The tables below include examples of how Directors have considered the interests of Shell employees and the resulting outcomes.

PRINCIPAL DECISIONS

In the table below, we outline some of the principal decisions made by the Board over the year, explain how the Directors have engaged with, or in relation to, the different key stakeholder groups and how stakeholder interests were considered in decision-making.

To remain concise, we have categorised our key stakeholders into seven groups. Where appropriate, each group is considered to include both current and potential stakeholders. The groups are:

- A investor community;
- B employees/workforce/pensioners;
- C regulators/governments;
- D NGOs/civil society stakeholders/academia/think-tanks;
- E communities;
- F customers; and
- G suppliers/strategic partners.

Principal decisions

We define principal decisions taken by the Board as decisions taken in 2020 that are of a strategic nature and significant to any of our key stakeholder groups. As outlined in the UK Financial Reporting Council (FRC) Guidance on the Strategic Report, we include decisions related to capital allocation and dividend policy.

How were stakeholders considered

We describe how regard was given to likely long-term consequences of the decision including how stakeholders were considered during the decision-making process.

What was the outcome

We describe which accommodations or mitigations were made, if any, and how Directors have considered different interests, and the factors taken into account.

Strategic updates

Over the course of the year, the Board considered strategic options and areas of emerging strategic focus, including in relation to the Net Carbon Footprint target. Principal decisions included: Shell's plans to become a net-zero emissions (NZE) energy business by 2050, in step with society, covering Scope 1, 2 and 3 emissions (the NZE energy business target as announced on April 16, 2020); and the update on strategic direction that clarified the investment proposition and how the value that Shell generates is translated into shareholder distributions (announced on October 29, 2020).

How stakeholders were considered

Given the significance of the strategic topics, the Board had multiple stakeholder engagements. These involved shareholders, employees and our internal climate experts throughout the year, and in earlier years where we also engaged external climate scientists, to help inform the key choices and parameters in the months leading up to the decisions, which included a three-day annual strategy meeting. These engagements included an update and discussion on: the strategic agenda; the proposed strategic pathway and underlying premises; the energy transition strategy; choices for traditional businesses and preparing for alternative strategies; and the financial framework required. These discussions were informed by research undertaken for the Executive Committee to better understand the requirements and expectations of Shell's external stakeholders. This research focused on: investors; environmental, social, and governance (ESG) and sustainability benchmarks; customers; business partners; international organisations; NGOs; civil society stakeholders; think-tanks; academia and schools; and general public audiences. This included qualitative and quantitative interview-based analysis. The Board considered: implications for customer sectors to drive the approach to decarbonising; business opportunities in new areas to develop the energy system; changes to be made to current business to drive competitive performance, delivery and funds for future investments and shareholders; and Shell's Net Carbon Footprint. In later meetings, the strategy was subsequently refined. In these discussions, the Board considered, among other things, shifting societal expectations of the extent and pace of the energy transition; government and regulatory expectations; ways to meet existing investors' expectations and what would be needed to attract new investors in future; and strategic partnerships.

The Board participated in virtual staff engagement sessions that enabled the Board members to speak directly with staff from various locations on themes including leadership styles, safety and controls, the Reshape reorganisation and the future of Shell.

What was the outcome

In relation to Shell's target to become a net-zero emissions energy business by 2050, in step with society, the Board considered whether the NZE energy business target would meet investors' expectations, how Shell can help customers find ways to decarbonise, and how to ensure Shell's credible leadership in informing and driving a societal energy transition. The outcome of those deliberations was the view that we should work with our customers to address the emissions that are produced when they use products they buy from Shell. This is in addition to the other elements of the NZE energy business target.

The direction of the strategic discussion fed through into the discussions on cash allocation, shareholder returns and to the development of Shell's Powering Progress strategy. After feedback from investors seeking an update on our strategic discussions, in October 2020, stakeholders were informed about Shell's response to the COVID-19 pandemic and provided with an explanation of the driver behind the enhanced target to be a NZE energy business. The direction of the ongoing restructuring of Shell's ways of working and organisation was also outlined in order to provide stakeholders with continued updates in the lead-up to Shell's Strategy Day in February 2021.

As part of the Shell Strategy Day 2021, we announced Powering Progress, our strategy to accelerate the transition of our business to cleaner energy while delivering value for our shareholders, our customers and wider society. The strategy includes how we are working towards our target to become a net-zero emissions energy business by 2050, in step with society. We are increasing our investments in the cleaner products and solutions that our customers need, from biofuels to hydrogen and renewable power, so that we can build a low-carbon business of significant scale by the beginning of the 2030s. We will fund these investments, and our returns to shareholders, with the strong returns we expect from our oil and gas production over the rest of this decade. The Board has been involved in formulating the strategy and ensuring that the Company maintains financial resilience while being able to seize the opportunities that transition will bring as part of our journey to net zero. We are the first energy company to offer shareholders an advisory vote on our energy transition strategy at our Annual General Meeting. We will do this every three years, starting in 2021. We will also on an annual basis offer an advisory vote on our progress against the targets we set for ourselves in the energy transition strategy. The Board believe this is a time of tremendous opportunity for Shell. By transforming our business, we will contribute to achieving a net-zero world, help society reach its climate goals and create a compelling investment case for our shareholders, today and in the future. That is the essence of Powering Progress and it has been fully endorsed by the Board through multiple engagements with management over a 12-month period.

SECTION 172(1) STATEMENT continued

Financial strength, cash allocation including shareholder distributions

The year 2020 involved unprecedented conditions for Shell, the industry and society generally. The challenges caused by COVID-19 resulted in material responses by Shell to successfully maintain its financial strength and resilience. The Board considered Shell's financial policies on several occasions and made decisions accordingly (see above, regarding the relationship and direction of the strategic and cash allocation discussions). The long-term financial health of Shell is crucial for staff, customers, the communities in which Shell operates, and for debt holders and shareholders. In early 2020, a key focus area for the Board was cash preservation, which included cost and capital spend reduction, pausing of the share buyback programme and the reduction of the dividend. In the later part of the year, Directors approved the cash allocation framework, which was announced as part of the third quarter 2020 results. For each quarter, the Board assessed the continuation of the share buyback programme and the ongoing payment and rate of dividend per share payable to shareholders.

How stakeholders were considered

A number of metrics and factors underpinned each decision, including the BG intention statement regarding equity issued in connection with the combination with the BG Group.

When making decisions relating to Shell's financial policies, including the cash allocation framework, the Board asked for further information on specific yet broad topics that impacted various stakeholders, such as: information on the proposed operating and capital expenditure reductions; the potential impact of a reduced dividend on strategic options; the articulation of cash allocation plans to investors and other stakeholders; and potential asset and project risks associated with counterparty financial viability risks. These considerations were balanced against prior intention statements.

To support these discussions, the Board was provided with information from an investor survey. This was discussed extensively in order to understand the perceptions of the market in relation to Shell's direction, strategy and financial strength. Having equity advisors and banks present directly to the Board helped build the Board's knowledge of what the markets were looking for. This helped guide the content of the third quarter 2020 communications.

An annual investor perception study was commissioned and considered by the Board. The Board was also provided with periodic reports from the Executive Vice President, Investor Relations which summarised feedback from various brokers and provided detailed analysis of how Shell's messages had been received by investors.

The Board was regularly updated on, and discussed, the management and impact of COVID-19 on Shell's activities and workforce.

Approval of Shell's detailed Operating Plan 2021-2023 (OP20)

The approval of OP20 followed an in-depth review by the Board of proposals on capital allocation, capital investment outlook, competitive outlook, operating expenses, return on average capital employed and shareholder distributions. This included reviews in the latter part of 2020 as an advance engagement on OP20 while it was under preparation, and in December 2020 for final approval.

How stakeholders were considered

OP20 discussions included a full review against Shell's strategic ambitions. The Directors and Executive Committee balanced the priorities in the operating plan versus the strategy by using feedback received as part of continual engagement with investors, discussions with equity and debt market analysts, and commitments made regarding share buybacks, gearing and organic free cash flow. The plan was discussed extensively and reviewed thoroughly.

In the assessment, the interests of investors and capital markets received particular attention and featured heavily in many discussions. Potential differences of interests between debt and equity investors were observed. This was balanced against the importance of the value that societies – (including communities, employees, customers, suppliers) – place on Shell because of the services it provides and the way it conducts business.

Information on employees and our organisational structure featured as part of OP20. The plan maintained the approach to salaries, benefits, health, worker welfare, focus on employee experience and training.

Metrics agreed within OP20 underpin the 2021 organisational scorecard, against which the majority of employee bonuses are calculated. Both the Board and the Remuneration Committee discussed these metrics at length to ensure they are suitably stretching and motivating, support the right culture within the business, and align to the strategic ambitions.

OP20 reflects the refreshing of the strategy with the growth of low-carbon, customer-facing businesses. It considered the economic and social effects of the pandemic in developing the plan and sought appropriate balance between key priorities, including sustaining cash flows, pivoting the portfolio to deliver the strategy (including reductions in carbon emissions), reducing debt and increasing shareholder distributions.

What was the outcome

The Board and management carefully considered various stakeholders in their decisions to reinforce the financial strength and resilience of Shell's business. They also took action to protect staff and customers. Their considerations focused on three key areas: care for staff, customers, and communities; business continuity and the need to continue to serve customers in every way we can, including providing them with certainty; and generating and preserving cash to protect the future financial health of Shell.

For example, in relation to staff and the wider workforce, the Board considered with management the appropriate timing of any large-scale redundancies, given the stress involved and the potential vulnerability of staff and their families to issues associated with COVID-19; how management was engaging with staff while most people were working from home; and how work sites were being equipped and return-to-work plans were being formulated to ensure people could return to work safely.

In relation to the decision to lower the dividend level, the Board and Management considered employees, Shell pensioners, lenders, debt holders, credit-rating agencies, suppliers, customers, governments, partners and communities. As a reduced dividend meant greater retention of cash to use for increasing financial resilience, the outcome of the consideration of stakeholders was that the decision would be largely positive for all stakeholders in the longer term.

Investor feedback received towards the middle of 2020 led to the decision to more clearly communicate the cash allocation framework to investors and the prioritisation of allocation between balance sheet strength, shareholder distributions and investments. More information on this can be found in "Dividend policy" on 183.

What was the outcome

Following the review of the draft operating plan, the Board requested further information on a number of specific matters. Responses were provided on these items and changes were incorporated into the plan where appropriate.

The overall outcome of this decision is an operating plan that the Board believes underpins Shell's strategic ambitions and has taken into account different stakeholder views, realising that not all stakeholder views can or will completely align with OP20.

While stakeholder opinion may differ on Shell's approach, OP20 is based on society's demand for products and services. OP20 supports Shell in maintaining a reputation for high standards on business conduct and health, safety, security and environment issues. It maintained the approach to employee remuneration and benefits to pensioners. OP20 seeks to reward our investors with returns and maintain long-term financial strength to invest in more and cleaner forms of energy and meet the current and future needs of society.

Investing in new business, acquisitions and divestments, and closures	What was the outcome
<p>Over the course of the year, the Board discussed and approved new opportunities, new projects and proposed divestments or closures across the different segments. This was in order to continually high-grade the portfolio, to deliver the best from our traditional businesses, to grow our customer-centric business and to rapidly and purposefully innovate for our future business models.</p> <p>How stakeholders were considered The Board obtained a clearer perspective on the role of Shell's Trading and Supply organisation in the energy transition (for example, in biofuels and renewable energy). This assisted the Board in assessing the possible impact on stakeholders and risks to its reputation in relation to certain stakeholder groups. These considerations included assessing the impact on cash allocation and shareholder distributions.</p> <p>Investors shared their opinions on significant acquisitions in the New Energies sector compared with organic growth/investment.</p> <p>Oil and gas – During the year Shell secured new opportunities in a number of regions, some of which were considered and approved by the Board. The Directors carefully reviewed new significant entries and risk and rewards of new projects. During these discussions, the Board was aware that some stakeholders may disagree with Shell's strategy to continue to invest in oil and gas during the energy transition.</p> <p>Offshore wind farm Hollandse Kust (noord) – The CrossWind Consortium, a joint venture between Shell and Eneco, was awarded the tender for this wind farm. The consortium plans to have Hollandse Kust (noord) operational in 2023 with an installed capacity of 759 MW, generating at least 3.3 TWh per year. This is enough renewable power to supply more than 1 million Dutch households with green electricity. The Board was informed of stakeholder engagements, including with the Rijksdienst voor Ondernemend Nederland (the ministerial entity responsible for the tender).</p>	<p>As a result of discussion and decisions in this area, the Board obtained insights on renewables growth, customers' priorities (around price and interest in clean power), and information on anticipated market direction and regulatory frameworks.</p> <p>Oil and gas – The Board recognises that societal views vary widely in this area. It must also bear in mind that global demand for energy is still growing. Although renewable resources will meet a growing share of the rising energy demand, Shell and other experts believe there continues to be a need for oil and gas for many years to come through the energy transition. The Directors also appreciate that it is this business that provides the capital to invest in the energy transition.</p> <p>Offshore wind farm Hollandse Kust (noord) – Throughout 2019, the Board obtained a clearer understanding of New Energies' investments and their alignment with the Power strategy. In 2020, the Board continued to receive updates on strategic priorities for New Energies/Power investments. The Board also received a summary of potential opportunities being considered in order for Shell to deliver upon the overarching goal of creating a profitable, cohesive and integrated business in the Power strategy's core markets. North-west Europe is a priority region for implementing Shell's Power Strategy. The Board reflected on Shell's differentiators to be successful in the tender, including technology and innovation. During the Board's discussion, particular attention was paid to where this proposal fits in the capital programme and the role of this proposal in customer offerings for decarbonised power.</p>

RISK FACTORS

The risks discussed below could have a material adverse effect separately, or in combination, on our earnings, cash flows and financial condition. Accordingly, investors should carefully consider these risks.

Further background on each risk is set out in the relevant sections of this Report indicated by way of cross-references under each risk factor.

The Board's responsibility for identifying, evaluating and managing our significant and emerging risks is discussed in "Other Regulatory and Statutory Information" on pages 182-189.

STRATEGIC RISKS

Risk description	How this risk is managed
<p>We are exposed to macroeconomic risks including fluctuating prices of crude oil, natural gas, oil products and chemicals.</p> <p>The prices of crude oil, natural gas, oil products and chemicals are affected by supply and demand, both globally and regionally. Macroeconomic, geopolitical and technological uncertainties can also affect production costs and demand for our products. Government actions may also affect the prices of crude oil, natural gas, oil products and chemicals. This could happen, for example, if governments promote the sale of lower-carbon electric vehicles or even prohibit future sales of new diesel or gasoline vehicles, such as the prohibition in the United Kingdom (UK) that is expected to come into force in 2030. Oil and gas prices can also move independently of each other. Factors that influence supply and demand include operational issues, natural disasters, weather, pandemics such as COVID-19, political instability, conflicts, economic conditions and actions by major oil and gas producing countries. In a low oil and gas price environment, we would generate less revenue from our Upstream and Integrated Gas businesses, and parts of those businesses could become less profitable or incur losses. Low oil and gas prices have also resulted and could continue to result in the debooking of proved oil or gas reserves, if they become uneconomic in this type of price environment. Prolonged periods of low oil and gas prices, or rising costs, have resulted and could continue to result in projects being delayed or cancelled. Assets have been impaired in the past, (including in 2020), and there could be impairments in the future. Low oil and gas prices could also affect our ability to maintain our long-term capital investment programme and dividend payments. Prolonged periods of low oil and gas prices could adversely affect the financial, fiscal, legal, political and social stability of countries that rely significantly on oil and gas revenue. In a high oil and gas price environment, we could experience sharp increases in costs, and, under some production-sharing contracts, our entitlement to proved reserves would be reduced. Higher prices could also reduce demand for our products, which could result in lower profitability, particularly in our Oil Products and Chemicals business. Higher prices can also lead to more capacity being built, potentially resulting in an oversupply of products that can negatively affect our LNG and Chemicals businesses.</p> <p>Accordingly, price fluctuations could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See "Market overview" on page 38.</p>	<p>We maintain a diversified portfolio to mitigate the impact of price volatility. We test the resilience of our projects and other opportunities against a range of prices and costs for crude oil, natural gas, oil products and chemicals. We prepare annual strategic and financial plans that test different scenarios and their impact on prices on our businesses and company as a whole. These plans are appraised regularly throughout the year, especially during periods of significant price and demand volatility as experienced in 2020. We also aim to maintain a strong balance sheet to provide resilience against weak market prices.</p>
<p>Our ability to deliver competitive returns and pursue commercial opportunities depends in part on the accuracy of our price assumptions.</p> <p>We use a range of oil and gas price assumptions, which we review on a periodic basis. These ranges help us to evaluate the robustness of our capital allocation for our evaluation of projects and commercial opportunities. If our assumptions prove to be incorrect, it could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See "Market overview" on page 40.</p>	<p>The range of commodity prices used in our project and portfolio evaluations is subject to a rigorous assessment of short-, medium- and long-term market drivers. These drivers include the extent and pace of the energy transition.</p>
<p>Our ability to achieve our strategic objectives depends on how we react to competitive forces.</p> <p>We face competition in all our businesses. In the crude oil, natural gas, Oil Products and Chemicals businesses we seek to differentiate our products, but many of them are competing in commodity-type markets. Accordingly, failure to manage our costs and our operational performance could result in a material adverse effect on our earnings, cash flows and financial condition. We also compete with state-owned oil and gas entities with access to vast financial resources. State-owned entities could be motivated by political or other factors in making their business decisions. Accordingly, when bidding on new leases or projects, we could find ourselves at a competitive disadvantage because these state-owned entities may not require a competitive return. If we are unable to obtain competitive returns when bidding on new leases or projects, this could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See "Strategy and outlook" on page 20.</p>	<p>We continually assess the external environment – the markets and the underlying economic, political, social and environmental drivers that shape them – to evaluate changes in competitive forces and business models. We use multiple future scenarios to assess the resilience of our strategy. We maintain business strategies and plans that focus on actions and capabilities to create and sustain competitive advantage.</p>

STRATEGIC RISKS *continued*

Risk description	How this risk is managed
<p>If we fail to stay in step with the pace and extent of society's demands with regard to the energy transition to a low-carbon future, we could fail in sustaining and growing our business.</p> <p>The pace and extent of the energy transition could pose a risk to Shell if our own transition towards decarbonisation moves at a different speed to society. If we are slower than society, customers may prefer a different supplier which would adversely impact our reputation and demand for our products. If we move much faster than society, we risk investing in technologies, markets or low-carbon products that are unsuccessful because there is limited demand for them. This could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See "Strategy and outlook" on page 21 and "Climate change and energy transition" on page 97.</p>	<p>We actively monitor societal developments, such as regulation-driven carbon-pricing mechanisms and customer-driven preferences for products. We incorporate these into scenarios which provide insights into how the energy transition may unfold in the medium and long term. These insights and those from various other external scenarios (such as the IPCC Special Report 1.5°C) guide us how we set our strategic direction, capital allocation and carbon emission commitments. We have updated our strategy and organisational structure to be more focused on the sectors where our customers operate, in order to make us better able to compete in the current evolving energy landscape.</p>
<p>Rising climate change concerns and the effects of the energy transition have led and could lead to a decrease in demand and potentially affect prices for fossil fuels. This may also lead to additional legal and/or regulatory measures which could result in project delays or cancellations, potential litigation, operational restrictions and additional compliance obligations.</p> <p>Societal demand for urgent action has increased especially after the Intergovernmental Panel on Climate Change (IPCC) 1.5°C special report of 2018 and the Paris Agreement's goal to keep the rise in global average temperature this century to well below two degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius. Society's increasing focus on climate change and the effects of the energy transition has created a risk landscape that is changing rapidly in response to a wide range of stakeholder actions at global, local and business levels. The potential impact and likelihood of climate change effects on Shell could vary across different time horizons, depending on the specific components of the risk.</p> <p>We expect that a growing share of our GHG emissions will be subject to regulation, resulting in increased compliance costs and operational restrictions. Regulators may seek to limit certain fossil fuel projects or make it more difficult to obtain required permits. Achieving our target to become net zero on all emissions from our operations will result in additional cost. We also expect that actions by customers to reduce their emissions will continue to lower demand and potentially affect prices for fossil fuels, as will GHG emissions regulation through taxes, fees and/or other incentives. This could be a factor contributing to additional provisions for our assets and result in lower earnings, cancelled projects and potential impairment of certain assets.</p> <p>The physical effects of climate change such as, but not limited to, increases in temperature and sea levels and fluctuations in water levels could also adversely affect our operations and supply chains.</p> <p>Some groups are putting pressure on certain investors to divest their investments in fossil fuel companies. If this were to continue, it could have a material adverse effect on the price of our securities and our ability to access capital markets. Groups are also putting pressure on commercial and investment banks to stop financing fossil fuel companies. According to press reports, some financial institutions have started to limit their exposure to certain fossil fuel projects. Accordingly, our ability to use financing for these types of future projects may be adversely affected. This could also adversely affect our potential partners' ability to finance their portion of costs, either through equity or debt.</p> <p>In some countries, governments, regulators, organisations and individuals have filed lawsuits seeking to hold fossil fuel companies liable for costs associated with climate change. While we believe these lawsuits to be without merit, losing any of them could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>In summary, rising climate change concerns and effects of the energy transition have led and could lead to a decrease in demand and potentially affect prices for fossil fuels. If we are unable to find economically viable, publicly acceptable solutions that reduce our GHG emissions and/or GHG intensity for new and existing projects and for the products we sell, we could experience financial penalties or extra costs, delayed or cancelled projects, potential impairments of our assets, additional provisions and/or reduced production and product sales. This could have a material adverse effect on our earnings, cash flows and financial condition.</p>	<p>Our response to the evolving risk landscape requires transparency and clarity around our plans and actions to achieve our climate target. We have a climate change risk management structure which is supported by standards, policies and controls, as part of our health, safety, security and environment and social performance (HSSE & SP) control framework. Climate change and risks resulting from GHG emissions are reviewed and managed in accordance with other significant risks through the Board and Executive Committee. We have established several dedicated climate change and GHG-related forums at different levels of the organisation. These forums seek to address, monitor and review climate change issues. Our strategy to assess and manage risks and opportunities resulting from climate change includes considering different time horizons and their relevance to risk identification and business planning.</p> <p>Overall, mitigation of the risk is addressed through our strategy to accelerate the transition to net-zero emissions, purposefully and profitably. This approach has three components:</p> <ul style="list-style-type: none"> ■ reducing the GHG-emissions intensity of our operations. We expect to reduce our carbon intensity primarily through altering our product mix as customer (Scope 3) emissions represent the largest component of our carbon intensity. Our aim is to achieve this by shifting the focus of our portfolio as we build our power, hydrogen, biofuels, carbon capture and storage and nature-based solutions businesses and activities; ■ demonstrating resilience by adopting the guidance on disclosure by the Task Force on Climate-related Financial Disclosures; and ■ working towards our target to become a net-zero emissions energy business by 2050, in step with society. <p>For further explanations of our climate change governance, risk management, climate ambition and strategy, our portfolio and performance, please refer to the section "Climate change and energy transition" on page 98.</p> <p>For further explanations of how we manage the risk of the physical effects of climate change affecting our operations and supply chains, please refer to the risk factor "The nature of our operations exposes us, and the communities in which we work, to a wide range of health, safety, security and environment risks".</p>

STRATEGIC RISKS continued

Risk description	How this risk is managed
<p>We seek to execute divestments in pursuing our strategy. We may be unable to divest these assets successfully in line with our strategy.</p> <p>We may be unable to divest assets at acceptable prices or within the timeline envisaged because of market conditions or credit risk. This would result in increased pressure on our cash position and potential impairments. In some cases, we have also retained certain liabilities following a divestment. Even in cases where we have not expressly retained certain liabilities, we may still be held liable for past acts, failures to act or liabilities that are different from those foreseen. We may also face liabilities if a purchaser fails to honour their commitments. Accordingly, if any of the above circumstances arise, this could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See “Strategy and outlook” on page 21.</p>	<p>We continually monitor market developments to assess potential divestments in pursuing our strategy. We carefully tailor our sales processes to buyers’ perceived expectations so we can deliver the most competitive outcomes. As a general principle, the sales processes are configured so that buyers will acquire the assets including all related liabilities. For some assets, Shell may agree to retain certain liabilities. We monitor these liabilities closely and make appropriate provisions for them.</p>
<p>We operate in more than 70 countries that have differing degrees of political, legal and fiscal stability. This exposes us to a wide range of political developments that could result in changes to contractual terms, laws and regulations. We and our joint arrangements and associates also face the risk of litigation and disputes worldwide.</p> <p>Developments in politics, laws and regulations can and do affect our operations. Potential impacts include: forced divestment of assets; expropriation of property; cancellation or forced renegotiation of contract rights; additional taxes including windfall taxes, restrictions on deductions and retroactive tax claims; antitrust claims; changes to trade compliance regulations; price controls; local content requirements; foreign exchange controls; changes to environmental regulations; changes to regulatory interpretations and enforcement; and changes to disclosure requirements. Tensions between nation states can also affect our business. Any of these, individually or in aggregate, could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>In 2020, many governments ran deficits to deal with the economic impacts of the COVID-19 pandemic. Given the ongoing nature of the pandemic, there will be uncertain long-term fiscal consequences, with possible subsequent effects on government policies that affect Shell’s business interests.</p> <p>From time to time, social and political factors play a role in unprecedented and unanticipated judicial outcomes that could adversely affect Shell. Non-compliance with policies and regulations could result in regulatory investigations, litigation and, ultimately, sanctions. Certain governments and regulatory bodies have, in Shell’s opinion, exceeded their constitutional authority by: attempting unilaterally to amend or cancel existing agreements or arrangements; failing to honour existing contractual commitments; and seeking to adjudicate disputes between private litigants. Certain governments have also adopted laws and regulations that could potentially conflict with other countries’ laws and regulations, potentially subjecting us to both criminal and civil sanctions. Such developments and outcomes could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See “Other regulatory and statutory information” on page 187.</p>	<p>We continually monitor geopolitical developments and societal issues relevant to our interests. Our Legal and Tax functions are organised globally and support our business lines in ensuring compliance with local laws and fiscal regulations. Our Government Relations department engages with governments in countries where we operate to understand and influence local policies and to advocate Shell’s position on topics relevant to our industry. We are prepared to exit a country if we believe we can no longer operate there in accordance with our standards and applicable law, and we have done so in the past.</p>

OPERATIONAL RISKS

Risk description

Our future hydrocarbon production depends on the delivery of large and integrated projects, and our ability to replace proved oil and gas reserves.

We face numerous challenges in developing capital projects, especially those which are large and integrated. Challenges include: uncertain geology; frontier conditions; the existence and availability of necessary technology and engineering resources; the availability of skilled labour; the existence of transportation infrastructure; project delays; the expiration of licences; delays in obtaining required permits; potential cost overruns; and technical, fiscal, regulatory, political and other conditions. These challenges are particularly relevant in certain developing and emerging-market countries, in frontier areas and in deep-water fields, such as off the coast of Mexico. We may fail to assess or manage these and other risks properly. Such potential obstacles could impair our delivery of these projects, our ability to fulfil the full potential value of the project as assessed when the investment was approved, and/or our ability to fulfil related contractual commitments. This could lead to impairments and could have a material adverse effect on our earnings, cash flows and financial condition.

Future oil and gas production will depend on our access to new proved reserves through exploration, negotiations with governments and other owners of proved reserves and acquisitions, and through developing and applying new technologies and recovery processes to existing fields. Failure to replace proved reserves could result in an accelerated decrease of future production, potentially having a material adverse effect on our earnings, cash flows and financial condition.

Oil and gas production available for sale

	Million boe [A]		
	2020	2019	2018
Shell subsidiaries	1,104	1,182	1,179
Shell share of joint ventures and associates	135	156	159
Total	1,239	1,338	1,338

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

Proved developed and undeveloped oil and gas reserves [A][B] (at December 31)

	Million boe [C]		
	December 31, 2020	December 31, 2019	December 31, 2018
Shell subsidiaries	8,222	9,980	10,294
Shell share of joint ventures and associates	902	1,116	1,285
Total	9,124	11,096	11,578
Attributable to non-controlling interest in Shell subsidiaries	322	304	331

[A] We manage our total proved reserves base without distinguishing between proved reserves from subsidiaries and those from joint ventures and associates.

[B] Includes proved reserves associated with future production that will be consumed in operations.

[C] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

See "Shell story" on page 16.

The estimation of proved oil and gas reserves involves subjective judgements based on available information and the application of complex rules. This means subsequent downward adjustments are possible.

The estimation of proved oil and gas reserves involves subjective judgements and determinations based on available geological, technical, contractual and economic information. Estimates can change over time due to new information from production or drilling activities, changes in economic factors, such as oil and gas prices, alterations in the regulatory policies of host governments, or other events. Estimates also change to reflect acquisitions, divestments, new discoveries, extensions of existing fields and mines, and improved recovery techniques. Published proved oil and gas reserves estimates could also be subject to correction because of errors in the application of published rules and changes in guidance. Downward adjustments could indicate lower future production volumes and could also lead to impairment of assets. This could have a material adverse effect on our earnings, cash flows and financial condition.

See "Supplementary information – oil and gas (unaudited)" on page 265.

How this risk is managed

We continue to explore for and mature hydrocarbons across our Deep Water, Conventional Oil and Gas, Shales and Integrated Gas businesses. We use our subsurface, project and technical expertise, and actively manage non-technical risks across a diversified portfolio of opportunities and projects. This involves adopting an integrated approach for all stages, from basin choice to development. We use competitive techniques and benchmark our approach internally and externally.

A central group of reserves experts undertakes the primary assurance of the proved reserves bookings. A multidisciplinary committee reviews and endorses all major proved reserves bookings. Shell's Audit Committee reviews all proved reserves bookings and Shell's Executive Committee is responsible for final approval. The Internal Audit function also provides further assurance through audits of the control framework, including the information disclosed in "Supplementary information – oil and gas (unaudited)".

RISK FACTORS continued

OPERATIONAL RISKS continued

Risk description	How this risk is managed
<p>The nature of our operations exposes us, and the communities in which we work, to a wide range of health, safety, security and environment risks.</p> <p>The health, safety, security and environment (HSSE) risks to which we and the communities in which we work are potentially exposed cover a wide spectrum, given the geographic range, operational diversity and technical complexity of our operations. These risks include the effects of natural disasters (including weather events), earthquakes, social unrest, pandemic diseases, criminal actions by external parties, and safety lapses. If a major risk materialises, such as an explosion or hydrocarbon leak or spill, this could result in injuries, loss of life, environmental harm, disruption of business activities, loss or suspension of permits, loss of our licence to operate and loss of our ability to bid on mineral rights. Accordingly, this could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>Our operations are subject to extensive HSSE regulatory requirements that often change and are likely to become more stringent over time. Governments could require operators to adjust their future production plans, as has occurred in the Netherlands, affecting production and costs. We could incur significant extra costs in the future because of the need to comply with such requirements. We could also incur significant extra costs due to violations of or liabilities under laws and regulations that involve elements such as fines, penalties, clean-up costs and third-party claims. Therefore, if HSSE risks materialise, they could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See “Environment and society” on page 86.</p>	<p>We have standards and a clear governance structure to help manage HSSE risks and avoid potential adverse effects. The standards and governance structure also help us to develop mitigation strategies aimed at ensuring that if an HSSE risk materialises, we avoid catastrophic consequences and have ways of trying to remediate any environmental damage. Our standards and governance structure are defined in our Health, Safety, Security, Environment and Social Performance (HSSE & SP) control framework and supporting guidance documents. The process safety and HSSE & SP assurance team provides assurance on the effectiveness of HSSE & SP controls to the Board. We routinely practise implementing our emergency response plans to significant risks (such as a spill, toxic substances, fire or explosion).</p> <p>We have assessed the impact of COVID-19 on activities and we are implementing measures to minimise the adverse effect of the pandemic on our operations. These measures include monitoring the level of infections among staff, ensuring the safety and well-being of all staff, (particularly critical staff who continue to operate our assets), scenario planning, deploying continuity plans and ensuring our sites and offices are “COVID safe”.</p>
<p>A further erosion of the business and operating environment in Nigeria could have a material adverse effect on us.</p> <p>In our Nigerian operations, we face various risks and adverse conditions. These include: security issues affecting the safety of our people, host communities and operations; sabotage and theft; our ability to enforce existing contractual rights; litigation; limited infrastructure; potential legislation that could increase our taxes or operating costs; the effect of lower oil and gas prices on the government budget; and regional instability created by militant activities. These risks or adverse conditions could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See “Upstream” on page 58.</p>	<p>We test the economic and operational resilience of our Nigerian projects against a wide range of assumptions and scenarios. We seek to proportionally share risks and funding commitments with joint-venture partners. When we participate in joint ventures in Nigeria, we require that they operate to internationally accepted business standards. We monitor the security situation, and liaise with host communities, governmental and non-governmental organisations to help promote peaceful and safe operations.</p>
<p>An erosion of our business reputation could have a material adverse effect on our brand, our ability to secure new resources or access capital markets, and on our licence to operate.</p> <p>Our reputation is an important asset. The Shell General Business Principles (Principles) govern how Shell and its individual companies conduct their affairs, and the Shell Code of Conduct tells employees and contract staff how to behave in line with the Principles. Our challenge is to ensure that all employees and contract staff comply with the Principles and the Code of Conduct. Real or perceived failures of governance or regulatory compliance or a perceived lack of understanding of how our operations affect surrounding communities could harm our reputation.</p> <p>Societal expectations of businesses are increasing, with a focus on business ethics, quality of products, contribution to society, safety and minimising damage to the environment. There is increasing focus on the role of oil and gas in the context of climate change and energy transition. This could negatively affect our brand, reputation and licence to operate, which could limit our ability to deliver our strategy, reduce consumer demand for our branded and non-branded products, harm our ability to secure new resources and contracts, and restrict our ability to access capital markets or attract staff. Many other factors, including the materialisation of the risks discussed in several of the other risk factors, could negatively affect our reputation and could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See “Other Regulatory and Statutory Information” on page 185 and “Our people” on page 110.</p>	<p>We continually assess and monitor the external environment for potential risks to our reputation. We engage in ongoing dialogue with our key stakeholders such as investors, industry and trade groups, universities, governments and non-governmental organisations (NGOs) to gain greater insights into societal expectations of our business. We have mitigation plans for identified brand and reputation risks at the Group, country and line of business level. Our country chairs are responsible for the implementation of country reputation plans which are updated annually. We continually develop and defend our brand in line with Shell’s purpose and promises, and target our investments to drive brand differentiation, relevance and preference.</p>

Risk description	How this risk is managed
<p>We rely heavily on information technology systems in our operations.</p> <p>The operation of many of our business processes depends on reliable information technology (IT) systems. Our IT systems are increasingly concentrated in terms of geography and number of systems. They are dependent on key contractors supporting the delivery of IT services. During 2020, information and cyber-security risks developed and changed rapidly. Globally the COVID-19 pandemic and geopolitical tensions have altered the IT threat landscape, increasing the frequency and ingenuity of malware attacks and increasing the temptation to attack targets for financial gain. Also, the prevalence of remote working introduces additional risk because it expands the IT threat landscape. We have experienced breaches and disruptions to our critical IT services in the past. These factors continue to contribute to potential breaches and disruptions of critical IT services. Additionally, breaches can lead to data privacy issues. If the breaches are not detected early and responded to effectively, they could harm our reputation and have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See “Corporate” on page 80.</p>	<p>We continually measure and improve our cyber-security capabilities. To reduce the likelihood of successful cyber-attacks, our cyber-security capabilities are embedded into our IT systems. Our IT is protected by detective and protective technologies. Identification and assessment capabilities are built into our IT support processes and adhere to industry best practices. When external companies provide us with IT services, the security of those services is managed through contractual clauses and supplier assurance reports. Shell invests constantly in efforts to embed and improve our controls and monitoring. For example, we improved our global web content filtering capability in response to the challenge of increased remote working in 2020. If breaches occur, all entities, including ones that have yet to be fully integrated into Shell's systems and processes, are required to report the incident and use Shell's information security capabilities.</p>
<p>Our business exposes us to risks of social instability, criminality, civil unrest, terrorism, piracy, cyber-disruption and acts of war that could have a material adverse effect on our operations.</p> <p>As seen in recent years, these risks can manifest themselves in the countries where we operate and elsewhere. These risks affect people and assets. Potential risks include: acts of terrorism; acts of criminality including maritime piracy; cyber-espionage or disruptive cyber-attacks; conflicts including war, civil unrest and environmental and climate activism (including disruptions by non-governmental and political organisations).</p> <p>The above risks can threaten the safe operation of our facilities and the transport of our products. They can harm the well-being of our people, inflict loss of life and injuries, damage the environment and disrupt our operational activities. These risks could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See “Environment and society” on pages 87.</p>	<p>We seek to obtain the best possible information to enable us to assess threats and risks. We conduct detailed assessments for all our sites and activities, and implement appropriate measures to deter, detect and respond to security risks. Further mitigations include strengthening the security of sites, reducing our exposure as appropriate, journey management, information risk management, crisis management and business continuity measures. We conduct training and awareness campaigns for staff and provide them with travel and health advice and access to 24/7 assistance while travelling.</p>
<p>Production from the Groningen field in the Netherlands causes earthquakes that affect local communities.</p> <p>Shell and ExxonMobil are 50:50 shareholders in Nederlandse Aardolie Maatschappij B.V. (NAM). An important part of NAM's gas production comes from the onshore Groningen gas field, in which EBN, a Dutch government entity, has a 40% interest and NAM a 60% interest. The gas field is in the process of being closed down due to earthquakes induced by gas production. Some of these earthquakes have damaged houses and other structures in the region, resulting in complaints and lawsuits from the local community. The government has announced it intends to accelerate the close-down, bringing the end of production forward from 2030 to possibly mid-2022. The exact shut-in date depends on security of supply considerations and is still to be decided. While we expect the earlier closing down of the Groningen gas field to further reduce the number and strength of earthquakes in the region, any additional earthquakes could have further adverse effects on our earnings, cash flows and financial condition.</p> <p>See “Upstream” on page 55.</p>	<p>NAM is working with the Dutch government and other stakeholders to fulfil its obligations to residents of the area. These include compensating for damage caused by the earthquakes and paying to strengthen houses where this is required for safety considerations. Negotiations with the state are being conducted to determine how to manage the accelerated close-down. Specific remediations within the agreed scope of responsibilities are planned. NAM's joint-venture partners will review its financial robustness against different scenarios for Groningen's liabilities and costs, with the aim of the venture being able to self-fund any additional expenses and claims.</p>

RISK FACTORS continued

OPERATIONAL RISKS continued

Risk description	How this risk is managed
<p>We are exposed to treasury and trading risks, including liquidity risk, interest rate risk, foreign exchange risk and credit risk. We are affected by the global macroeconomic environment and the conditions of financial and commodity markets.</p> <p>Our subsidiaries, joint arrangements and associates are subject to differing economic and financial market conditions around the world. Political or economic instability affects such markets.</p> <p>We use debt instruments, such as bonds and commercial paper, to raise significant amounts of capital. Should our access to debt markets become more difficult, the potential impact on our liquidity could have a material adverse effect on our operations. Our financing costs could also be affected by interest rate fluctuations or any credit rating deterioration.</p> <p>We are exposed to changes in currency values and to exchange controls as a result of our substantial international operations. Our reporting currency is the US dollar, although, to a material extent, we also hold assets and are exposed to liabilities in other currencies. While we undertake some foreign exchange hedging, we do not do so for all our activities. Even where hedging is in place, it may not function as expected.</p> <p>We are exposed to credit risk; our counterparties could fail or be unable to meet their payment and/or performance obligations under contractual arrangements. Although we do not have significant direct exposure to sovereign debt, it is possible that our partners and customers may have exposure which could impair their ability to meet their obligations. Our pension plans invest in government bonds, and could therefore be affected by a sovereign debt downgrade or other default.</p> <p>If any of the above risks materialise, they could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See “Liquidity and capital resources” on page 81 and Note 19 to the “Consolidated Financial Statements” on pages 251-255.</p>	<p>We use various financial instruments for managing exposure to foreign exchange and interest rate movements. Our treasury operations are highly centralised and seek to manage credit exposures associated with our substantial cash, foreign exchange and interest rate positions. Our portfolio of cash investments is diversified to avoid concentrating risk in any one instrument, country or counterparty. Other than in exceptional cases, the use of external derivative instruments is confined to specialist trading and central treasury organisations that have the appropriate skills, experience, supervision, control and reporting systems. We have credit risk policies in place which seek to ensure that products are sold to customers with appropriate creditworthiness. These policies include detailed credit analysis and monitoring of customers against counterparty credit limits. Where appropriate, netting arrangements, credit insurance, prepayments and collateral are used to manage credit risk. We maintain committed credit facilities. Management believes it has access to sufficient debt funding sources (capital markets) and to undrawn committed borrowing facilities to meet foreseeable requirements.</p>
<p>Our future performance depends on the successful development and deployment of new technologies and new products.</p> <p>Technology and innovation are essential to our efforts to meet the world’s energy demands competitively. If we fail to continue developing or deploying technology and new products, or fail to make full, effective use of our data in a timely and cost-effective manner, there could be a material adverse effect on the delivery of our strategy and our licence to operate. We operate in environments where advanced technologies are used. In developing new technologies and new products, unknown or unforeseeable technological failures or environmental and health effects could harm our reputation and licence to operate or expose us to litigation or sanctions. The associated costs of new technology are sometimes underestimated. Sometimes the development of new technology is subject to delays. If we are unable to develop the right technology and products in a timely and cost-effective manner, or if we develop technologies and products that harm the environment or people’s health, there could be a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See “Shell story” on page 17.</p>	<p>Shell’s Technology organisation and the relevant business lines work together to determine the content, scope and budget for developing new technology that supports our activities. The new technology is developed to ensure portfolio alignment with Shell’s strategic ambitions and deployment commitments. A significant proportion of Shell’s technology contributes to Shell’s New Energies portfolio and Net Carbon Footprint target, and is built around key relationships with leading academic research institutes and universities. We also benefit from working with start-ups. In our Shell GameChanger programme, we help companies to mature early-stage technologies. In our Shell Ventures scheme, we invest in and partner with start-ups and small and medium-sized enterprises that are in the early stages of developing new technologies.</p>
<p>We have substantial pension commitments, the funding of which is subject to capital market risks and other factors.</p> <p>Liabilities associated with defined benefit pension plans are significant, and the cash funding requirement of such plans can also involve significant liabilities. They both depend on various assumptions. Volatility in capital markets or government policies could affect investment performance and interest rates, causing significant changes to the funding level of future liabilities. Changes in assumptions for mortality, retirement age or pensionable remuneration at retirement could also cause significant changes to the funding level of future liabilities. We operate a number of defined benefit pension plans and, in case of a shortfall, we could be required to make substantial cash contributions (depending on the applicable local regulations). This could result in a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See “Liquidity and capital resources” on page 81.</p>	<p>A pensions forum chaired by the Chief Financial Officer oversees Shell’s input to pension strategy, policy and operation. A risk committee supports the forum in reviewing the results of assurance processes with respect to pension risks. Local trustees manage the funded defined benefit pension plans, and the contributions paid are based on independent actuarial valuations that align with local regulations.</p>

Risk description	How this risk is managed
<p>We mainly self-insure our risk exposure. We could incur significant losses from different types of risks that are not covered by insurance from third-party insurers.</p> <p>Our insurance subsidiaries provide hazard insurance coverage to other Shell entities, who may insure a portion of their risk exposures with third parties. Such insurance would not provide any material coverage in the event of a large-scale safety or environmental incident. Accordingly, in the event of a material incident, we would have to meet our obligations without access to material proceeds from third-party insurance companies. Therefore, we may incur significant losses from different types of risks that are not covered by insurance from third-party insurers, potentially resulting in a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See “Corporate” on page 80.</p>	<p>We continually assess the safety performance of our operations and make risk mitigation recommendations, where relevant, to keep the risk of an accident as low as possible. Our insurance subsidiaries are adequately capitalised and they may transfer risks to third-party insurers where economical, effective and relevant.</p>
<p>Many of our major projects and operations are conducted in joint arrangements or with associates. This could reduce our degree of control and our ability to identify and manage risks.</p> <p>When we are not the operator, we have less influence and control over the behaviour, performance and operating costs of joint arrangements or associates. Despite having less control, we could still be exposed to the risks associated with these operations, including reputational, litigation (where joint and several liability could apply) and government sanction risks. For example, our partners or members of a joint arrangement or an associate, (particularly local partners in developing countries), may be unable to meet their financial or other obligations to projects, threatening the viability of a given project. Where we are the operator of a joint arrangement, the other partner(s) could still be able to veto or block certain decisions, which could be to our overall detriment. Accordingly, where we have limited influence, we are exposed to operational risks that could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See “Other Regulatory and Statutory Information” on page 187.</p>	<p>Shell appoints a Joint Venture Asset Manager, whose responsibility is to manage performance and create and protect value for Shell. The Joint Venture Asset Manager seeks to influence operators and other partners to adapt their practices in order to drive value appropriately and to mitigate identified risks. An annual assurance review assesses how the joint venture’s standards and processes align with those of Shell. The Joint Venture Asset Manager follows up on any gaps identified.</p>


CONDUCT RISKS

Risk description	How this risk is managed
<p>We are exposed to commodity trading risks, including market and operational risks.</p> <p>Commodity trading is an important component of our Upstream, Integrated Gas, Oil Products and Chemicals businesses and is integrated with our supply business. Processing, managing and monitoring many trading transactions across the world, some of them complex, exposes us to operational and market risks, including commodity price risks which saw significant levels of volatility in 2020. We use derivative instruments such as futures and contracts for differences to hedge market risks. We do not hedge all our activities and where hedging is in place, it may not function as expected. The risk of ineffective controls and oversight of trading activities, and the risk that traders could deliberately act outside limits and controls, either individually or as a group, could have material adverse effects on our earnings, cash flows and financial condition.</p> <p>See “Liquidity and capital resources” on page 81 and Note 19 to the “Consolidated Financial Statements” on pages 251-255.</p>	<p>In effecting commodity trades and derivative contracts, the company operates within procedures and policies designed to ensure that risks are managed within authorised limits. For example, the use of external derivative instruments is confined to specialist trading organisations that have the appropriate skills, experience, supervision, control and reporting systems. Our trading organisation has a compliance manual addressing our operational risks which all staff are required to follow. Senior Management regularly reviews mandated trading limits. We monitor market risk exposure daily, using value-at-risk (VAR) techniques. We monitor trading positions against limits every day. We use marking to fair value to assess trading exposures where appropriate, with a department that is independent of the traders reviewing the market values applied. In response to the COVID-19 pandemic, trader monitoring tools have been upgraded. During the period of extreme market volatility, additional oversight has been provided by a dedicated ‘Liquidity Forum’, chaired by senior executives in our trading organisation. We have increased the monitoring of the financial resilience of our customers, suppliers and the clearing houses that we deal with.</p>

RISK FACTORS continued

CONDUCT RISKS continued

Risk description	How this risk is managed
<p>Violations of antitrust and competition laws carry fines and expose us and/or our employees to criminal sanctions and civil suits.</p> <p>Antitrust and competition laws apply to Shell and its joint arrangements and associates in the vast majority of countries where we do business. Shell and its joint arrangements and associates have been fined for violations of antitrust and competition laws in the past. This includes a number of fines by the European Commission Directorate-General for Competition (DG COMP). Because of DG COMP's fining guidelines, any future conviction of Shell or any of its joint arrangements or associates for violation of EU competition law could potentially result in significantly larger fines and have a material adverse effect on us. Violation of antitrust laws is a criminal offence in many countries, and individuals can be imprisoned or fined. In certain circumstances, directors may receive director disqualification orders. It is also now common for persons or corporations allegedly injured by antitrust violations to sue for damages. Any violation of these laws can harm our reputation and could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See "Other Regulatory and Statutory Information" on pages 186.</p>	<p>We maintain an antitrust programme with adequate resources, a comprehensive governance structure and established reporting lines. Staff receive clear guidance that includes requirements in Shell's Ethics and Compliance Manual, an antitrust-specific website, training modules where completion is monitored and regular messages from Shell leaders on the importance of managing antitrust risks. Staff must understand and comply with the "Protect Shell Policy", which explains Shell's position on managing antitrust risks in engagements with parties external to Shell. As result of the COVID-19 pandemic, we have issued guidance to address antitrust risks arising from the disruption to supply chains, including procurement guidance which outlines the risks associated with exchanging information and collaborating with Shell's procurement competitors.</p>
<p>Violations of anti-bribery, tax-evasion and anti-money laundering laws carry fines and expose us and/or our employees to criminal sanctions, civil suits and ancillary consequences (such as debarment and the revocation of licences).</p> <p>Anti-bribery, tax-evasion and anti-money laundering laws apply to Shell, its joint arrangements and associates in all countries where we do business. Shell and its joint arrangements and associates have in the past settled with the US Securities and Exchange Commission regarding violations of the US Foreign Corrupt Practices Act. Any violation of anti-bribery, tax-evasion or anti-money laundering laws, including those potential violations associated with Shell Nigeria Exploration and Production Company Limited's investment in Nigerian oil block OPL 245 and the 2011 settlement of litigation pertaining to that block, could harm our reputation or have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See "Our people" on pages 110, "Other Regulatory and Statutory Information" on page 186 and Note 25 to the "Consolidated Financial Statements" on pages 260-262.</p>	<p>We maintain an anti-bribery and anti-money-laundering (ABC/AML) programme with adequate resources, a comprehensive governance structure and established reporting lines. Staff receive clear guidance which includes requirements in Shell's Ethics and Compliance Manual, an ABC/AML-specific website, training modules where completion is monitored and regular messages from Shell leaders on the importance of managing ABC/AML risks. As regards OPL 245, the 2011 settlement was a fully legal transaction with Eni and the Federal Government of Nigeria, represented by the most senior officials of the relevant ministries. We maintain our view that there is no basis to convict Shell, or any of our former employees who are also on trial in Milan. In response to the COVID-19 pandemic, we have set up fast-track processes to deal with relief donation requests. These processes include counterparty due diligence and are supported by Shell's Ethics and Compliance Office.</p>
<p>Violations of data protection laws carry fines and expose us and/or our employees to criminal sanctions and civil suits.</p> <p>Data protection laws apply to Shell and its joint arrangements and associates in the vast majority of countries where we do business. Most of the countries we operate in have data protection laws and regulations. In some countries that are key to Shell's business operations, legislation continues to be amended or introduced. Shell must be able to adapt dynamically to such legislative changes and be capable of updating our internal programmes if necessary. The EU General Data Protection Regulation (GDPR), which came into effect in May 2018, imposed increased financial penalties of up to a maximum of 4% of global annual turnover. It requires mandatory breach notification in certain situations, the standard which is also followed outside the EU (particularly in Asia). Non-compliance with data protection laws could expose us to regulatory investigations, which could result in fines, penalties and harm to our reputation. With regard to data breaches, we have breached the GDPR in the past and some investigations are still ongoing with European regulators. To date, no material fines have been imposed, but no assurance can be provided that future breaches would have similar outcomes. In addition to imposing fines, regulators may also issue orders to stop processing personal data, which could disrupt operations. We could also be subject to litigation from persons or entities allegedly affected by data protection violations.</p> <p>With data privacy legislation now in force in the USA, the risk of class actions is increased. Class actions after large-scale data breaches are increasingly common in the UK.</p> <p>The COVID-19 pandemic has increased the level of processing of personal data to track employees, suppliers or other visitors to our premises. Some governments require immediate disclosure of information, including sensitive personal data, to identify infected individuals, with some mandating technologies such as tracing applications on all devices, including corporate mobile phones.</p> <p>Violation of data protection laws is a criminal offence in some countries, and individuals can be imprisoned or fined. Any violation of these laws or harm to our reputation could have a material adverse effect on our earnings, cash flows and financial condition.</p> <p>See "Other Regulatory and Statutory Information" on page 186.</p>	<p>We maintain a data privacy programme with adequate resources, a comprehensive governance structure and established reporting lines. Shell has had Binding Corporate Rules in place for the last 10 years. These rules are part of a group wide global programme to ensure consistent levels of data protection across the group. Staff receive clear guidance which includes requirements in Shell's Ethics and Compliance Manual, a website focusing on data privacy, training modules where completion is monitored, and regular messages from Shell leaders on the importance of managing data privacy risks.</p> <p>We have revised the requirements for incident management that are set out in our Binding Corporate Rules, in order to comply with GDPR reporting requirements. We have revised our approach to privacy impact assessments, also to comply with GDPR reporting requirements. We use our Privacy by Design programme to enhance our controls in this area. We continue to address challenges with compliance in data-heavy companies controlled by Shell but not fully integrated into our systems. IT remediation work remains a priority in such companies, as does the strengthening of programmes to support data privacy compliance.</p> <p>To respond to the increased risk resulting from the pandemic, we have developed policies on temperature screening and published a guidance note on "Privacy Best Practices for COVID-19".</p>

Risk description	How this risk is managed
<p>Violations of trade compliance laws and regulations, including sanctions, carry fines and expose us and our employees to criminal sanctions and civil suits.</p> <p>We use “trade compliance” as an umbrella term for various national and international laws designed to regulate the movement of items across national boundaries and restrict or prohibit trade and other dealings with certain parties. The number and breadth of such laws continue to expand. For example, the EU and the USA continue to impose restrictions and prohibitions on certain transactions involving countries such as Syria, Venezuela, Russia and Cuba. The USA continues to impose comprehensive sanctions against Iran, while the EU and other nations continue to maintain targeted sanctions. The EU and the USA imposed restrictions and controls on defined oil and gas activities in Russia in 2014, and these remain in force. The USA introduced further restrictions regarding Russia in 2017, expanding them in 2018. The EU and the USA introduced sectoral sanctions against Venezuela in 2017, with the USA expanding them in 2018 and 2019. The US sanctions primarily target the government of Venezuela and the oil industry. Many other nations are also adopting trade-control programmes similar to those administered by the EU and the USA. The expansion of sanctions, the frequent additions of prohibited parties, the number of markets in which we operate and the large number of transactions we process, make compliance with all sanctions complex and sometimes challenging. Shell has voluntarily self-disclosed potential violations of sanctions in the past. The COVID-19 pandemic has increased trade compliance risks, due to factors such as growing state involvement in business dealings, the need to maintain and develop business opportunities and cross-border movement of goods and technologies, and the increasing likelihood that counterparties will change ownership as the economic crisis continues.</p> <p>Any violation of sanctions could lead to loss of import or export privileges and significant penalties on or prosecution of Shell or its employees. This could harm our reputation and have a material adverse effect on our earnings, cash flows and financial condition.</p> <p> See “Other Regulatory and Statutory Information” on page 186.</p>	<p>We continue to develop and maintain a trade compliance programme with adequate resources, a comprehensive governance structure and established reporting lines. Staff receive clear guidance, which includes requirements in Shell’s Ethics and Compliance Manual, a specific website for trade compliance, training modules where completion is monitored and regular messages from Shell leaders on the importance of managing trade compliance risks. The effectiveness of the trade compliance programme is assessed annually (or more frequently if necessary). In response to the COVID-19 pandemic, we have promoted an increased focus on compliance and assurance. For example, in Trading and Supply we have promoted a particular focus on compliance with trade controls in high-risk areas such as port agency, inspections and terminal operations.</p>

Investors should also consider the following, which could limit shareholder remedies.

OTHER (Generally applicable to an investment in securities)

Risk description	How this risk is managed
<p>The Company’s Articles of Association determine the jurisdiction for shareholder disputes. This could limit shareholder remedies.</p> <p>Our Articles of Association generally require that all disputes between our shareholders in such capacity and the Company or our subsidiaries (or our Directors or former Directors), or between the Company and our Directors or former Directors, be exclusively resolved by arbitration in The Hague, the Netherlands, under the Rules of Arbitration of the International Chamber of Commerce. Our Articles of Association also provide that, if this provision is to be determined invalid or unenforceable for any reason, the dispute could only be brought before the courts of England and Wales. Accordingly, the ability of shareholders to obtain monetary or other relief, including in respect of securities law claims, could be determined in accordance with these provisions.</p>	

MARKET OVERVIEW

We maintain a large business portfolio across an integrated value chain and are exposed to crude oil, natural gas, hydrocarbon product and chemical prices (see “Risk factors” on page 28). This diversified portfolio helps us mitigate the impact of price volatility. Our annual planning cycle and periodic portfolio reviews aim to ensure that our levels of capital investment and operating expenses are appropriate in the context of a volatile price environment. We test the resilience of our projects and other opportunities against a range of crude oil, natural gas, oil product and chemical prices and costs. We also aim to maintain a strong balance sheet to provide resilience against weak market prices.

GLOBAL ECONOMIC GROWTH

The COVID-19 pandemic has delivered an enormous global economic shock, leading to steep recessions in many countries. In the World Economic Outlook of January 2021, the International Monetary Fund (IMF) estimates that despite unprecedented policy support, global GDP contracted by 3.5% in 2020, one of the deepest global recessions in history. The most severe economic downturns occurred in India, Western Europe, the Middle East, and Latin America. China was the only major economy that recorded economic growth.

Developed countries were particularly vulnerable to lockdown measures, because of their economic structure. Services and consumption, which account for a higher share of GDP in developed countries, were disproportionately affected by restrictions on movement and closures of hospitality and leisure facilities. Developing economies suffered from collapses in capital inflows and commodity prices, and from a sharp compression in consumption and investment. Massive fiscal and monetary support measures were deployed in the major economies. In China, the authorities funded infrastructure investments. In the USA and Europe, government transfers supplemented incomes and supported businesses, in order to prevent deeper declines in employment and disposable income.

Led by mainland China, the Asia-Pacific region led the recovery during the year, as public health measures helped to contain community transmission of COVID-19. In other countries, the pandemic proved more difficult to control. European countries experienced renewed rises in infection rates during the fourth quarter of 2020. They responded by reinstating restrictions on activities that have a high risk of transmitting COVID-19.

Encouraging news on vaccines and improvements in therapeutics have increased the chances of a recovery in 2021, but the global economic outlook remains precarious, because markets fear that more virulent variants of COVID-19 could trigger additional waves of infections. The deep recessions triggered by the pandemic could leave lasting scars in the form of: lower investment by companies; high unemployment; increased global debt; and a potential retreat from global trade and supply linkages. There is concern that these effects may well restrict growth in the medium term.

GLOBAL PRICES, DEMAND AND SUPPLY

The following table provides an overview of the main crude oil and natural gas price markers to which we are exposed:

Oil and gas average industry prices [A]

	2020	2019	2018
Brent (\$/b)	42	64	71
West Texas Intermediate (\$/b)	39	57	65
Henry Hub (\$/MMBtu)	2.0	2.5	3.1
UK National Balancing Point (pence/therm)	25	35	60
Japan Customs-cleared Crude (\$/b)	46	67	73

[A] Yearly average prices are based on daily spot prices. The 2020 average price for Japan Customs-cleared Crude excludes December data.

CRUDE OIL

On a daily average basis, Brent crude oil, an international benchmark, traded between \$13 per barrel (/b) and \$70/b in 2020, ending the year around \$50/b. Brent crude oil prices averaged \$42/b for the year, 34% (or \$22/b) lower than in 2019.

In 2020, oil markets experienced unprecedented developments in demand driven by the COVID-19 pandemic. At the start of 2020, global oil demand for the year was expected to grow by 1.2 million barrels per day (b/d). Then in January, oil demand started to contract because demand fell in China as lockdown was imposed to contain the virus outbreak. In subsequent months, oil demand contracted further as the outbreak in China evolved into a global pandemic and lockdowns were introduced across the world. In April, oil demand fell to its lowest level, around 22 million b/d below year-average demand in 2019, according to an estimate of the International Energy Agency (IEA). Contraction of such magnitude has never been recorded before. Country lockdowns deeply impacted transportation sectors, especially passenger road and passenger air in Organisation for Economic Co-operation and Development (OECD) economies. In subsequent months, oil demand started recovering, but only partially, because resurgences of COVID-19 triggered re-imposition of social distancing and travel restrictions. By the fourth quarter, global oil demand was still estimated to be around 5.5 million b/d below the 2019 level, according to the Oil Market Report published by the IEA in January 2021. Averaged for the full year, oil demand contracted by around 9 million b/d, or 9%, to 91.2 million b/d. Oil demand fell by 5.7 million b/d in OECD economies, and by 3.2 million b/d in non-OECD economies. By contrast, oil demand in 2019 was 0.8 million b/d higher than in 2018.

In 2020, oil markets also experienced unprecedented developments in supply. In March, there was a serious disagreement within the OPEC+ alliance, which consists of OPEC members and co-operating non-OPEC resource holders such as Russia. Saudi Arabia and Russia failed to agree on what to do about falling demand for oil. Saudi Arabia responded to the disagreement by boosting its production to almost 12 million b/d, a monthly record. By April, storage capacity was filling up quickly and oil prices were falling rapidly. On April 12, the OPEC+ alliance agreed to jointly reduce production by an unprecedented 9.7 million b/d for May and June. For the month of June, Saudi Arabia voluntarily cut production further, by around 1 million b/d. For the rest of the year, the OPEC+ alliance agreed on and complied with a production cut of 7.7 million b/d.

In April, supply from outside the OPEC+ alliance also started to fall, most notably in the USA. The US Energy Information Administration reported a supply contraction of around 2 million b/d by the end of May, from a level of around 13 million b/d at the start of the year. US producers cut budgets, leading to an unprecedented fall in the number of oil drill rigs to around 26% of the total at the start of the year. Supply from the USA occasionally fell even further to around 10 million b/d because of production shut-ins during the hurricane season.

In aggregate, production of oil supply in 2020 is estimated in the Oil Market Report at 93.9 million b/d, which is 6.7 million b/d lower than in 2019. OPEC production is estimated to have fallen by 3.8 million b/d. Supply from the USA fell by 0.8 million b/d from 2019. By contrast, global oil supply in 2019 was 0.1 million b/d higher than in 2018.

Daily average oil prices reached a low at the end of April before the OPEC+ supply curtailments came into effect. Brent crude oil prices fell to around \$14/b. Contract prices of some crude grades, such as West Texas Intermediate (WTI), even traded well below \$0/b for a short period. Brent crude oil prices started to recover from May and traded in a price range of around \$35-45/b from June. Towards the end of 2020, announcements of promising COVID-19 vaccines supported Brent crude oil prices, allowing them to break through the upper end of this range.

On a yearly average basis, WTI crude oil traded at a discount of about \$2.5/b to Brent crude oil in 2020, compared with \$7/b in 2019. The discount narrowed from 2019 because falling US supply prevented bottlenecks in pipeline capacity from the landlocked Cushing storage hub to the US Gulf Coast. According to the US Energy Information Administration, US crude oil exports increased further to a yearly average of around 3.1 million b/d in 2020, up by 0.1 million b/d from 2019. This helped to ensure a narrow price differential between Brent and WTI.

Looking ahead, the IMF's global economic outlook indicates some increase in global economic growth, which should support oil demand growth.

Demand growth could accelerate further if vaccines can help contain COVID-19 and allow a return to pre-pandemic demand patterns in perhaps two or three years. According to the IEA, global oil demand is projected to increase by around 5.4 million b/d for 2021 to reach 96.6 million b/d. This is still 3.4 million b/d less than in 2019. OPEC+ members may have to carefully balance supply growth with sustained production curtailments in order to achieve price stability. In the near term, once demand has recovered to 2019 levels, the need for OPEC+ cuts may diminish. If there is further demand growth, tightness of supply could even develop. This is because any supply growth from the US shale basins could be limited, since US operators have shifted their focus from volume to value. We expect this shift to be permanent.

The supply growth potential from outside OPEC+ and the USA could be limited by industry-wide lack of investment in new supply projects which also tend to have a long lead time.

In the near term, prices could rise if demand is quicker to recover and OPEC+ members successfully constrain supply. On the other hand, the price environment could weaken if the impact of COVID-19 prevents full demand recovery, and/or OPEC and the non-OPEC resource holders relax their production agreement. The price environment could also weaken if there is an increase in supply from other non-OPEC producers, such as US shale producers.

NATURAL GAS

Global gas demand is estimated to have declined by around 2.4% in 2020, in contrast with the 2.5% annual growth rate observed since the start of the century. The deterioration in gas demand for power generation and in industry was mainly caused by lockdowns related to COVID-19. Resilient gas demand for heating helped offset the overall decline. Demand declined across all regions except non-OECD Asia. In non-OECD Asia, demand grew in China, which experienced a robust recovery after mitigating the impacts of COVID-19. Outside China, aggregate gas demand in non-OECD Asia remained flat year-on-year.

In 2020, global LNG imports were almost unchanged from 2019, rising by about 2 million tonnes year-on-year to 360 million tonnes. Growth in LNG supply capacity was mostly limited to the USA, where 21 million tonnes of new liquefaction started commercial operations in 2020. Liquefaction plants already in operation in the USA responded to the weak gas price environment by significantly curtailing production in the middle of the year. Supply from major LNG-exporting countries such as Egypt, Malaysia and Norway was also lower year-on-year because of operational disruptions and shut-ins to prevent economic losses.

Natural gas prices can vary from region to region.

In the USA, the natural gas price at the Henry Hub averaged \$2.0 per million British thermal units (MMBtu) in 2020, 21% lower than in 2019. It traded in a range of \$1.5 to 3.2/MMBtu. In the earlier part of 2020, there was downward pressure on prices because of decreased demand from a mild winter, lower LNG exports and a weak domestic market caused by COVID-19. Supply fell because activity declined as producers cut investments and because lower oil production meant there was less associated gas. During the summer, prices found support from growing demand for gas that could generate power for cooling during the hotter months of the year. Later in 2020, demand strengthened because of storage ahead of the winter season and increasing US LNG exports.

In Europe, the average price at the UK National Balancing Point (NBP) in 2020 was 28% lower than in 2019. At the main continental gas trading hubs – in the Netherlands, Belgium and Germany – prices were also lower, as reflected by weaker Dutch Title Transfer Facility (TTF) prices. European gas prices were lower because of: the slump in demand in power generation and industry; robust supply of pipeline gas; well-filled gas storage inventories at the start of the year; and competition with renewables in power.

We also produce and sell natural gas in regions where supply, demand and regulatory circumstances differ markedly from those in the USA or Europe.

Long-term contracted LNG prices in the Asia-Pacific region in 2020 were lower than in 2019 because they are predominantly indexed to oil prices, particularly the Japan Customs-cleared Crude (JCC) index which dropped by an 32% year-on-year, tracking Brent crude prices. Meanwhile, delivered North Asia spot prices, reflected by the Japan Korea Marker, declined by 20% compared with 2019, because of oversupply in the global LNG market and weak demand.

Looking ahead, we expect gas markets in North America, Europe and Asia-Pacific to find support from markets recovering from the pandemic. Price developments are very uncertain and dependent on many factors.

MARKET OVERVIEW continued

In the USA, Henry Hub gas prices are expected to increase over the next few years. This is because while production of gas is expected to recover by perhaps late 2021, it could lag behind demand, which may grow earlier, to supply LNG exports and exports to Mexico by pipeline, and to supply residential and industrial users. The Henry Hub gas price could rise more than expected if oil prices stay low, leading to the Permian Basin producing less oil and supplying less associated gas as a result.

On the other hand, if producers increase investments substantially, the extra supply could exert downward pressure on prices.

In Europe, we believe gas prices will be increasingly influenced by the cost of LNG imports from the USA. In the Asia-Pacific region, long-term gas prices are expected to continue to be strongly influenced by oil prices. Spot prices are expected to be increasingly influenced by gas supply and demand fundamentals.

CRUDE OIL AND NATURAL GAS PRICE ASSUMPTIONS

Our ability to deliver competitive returns and pursue commercial opportunities ultimately depends on the accuracy of our price assumptions (see "Risk factors" on page 28). We use a rigorous assessment of short-, medium- and long-term market uncertainties to determine what ranges of future crude oil and natural gas prices to use in project and portfolio evaluations. Market uncertainties include, for example, future economic conditions, geopolitics, actions by major resource holders, production costs, technological progress and the balance of supply and demand. See also Note 8 to the "Consolidated Financial Statements" on pages 234-238.

REFINING MARGINS

Refining marker average industry gross margins

	\$/b		
	2020	2019	2018
US West Coast	8.5	13.5	11.5
US Gulf Coast Coking	2.3	4.9	7.0
Rotterdam Complex	0.4	2.3	2.5
Singapore	(0.5)	(0.6)	1.4

Industry gross refining margins weakened in 2020 because demand for oil products was significantly reduced by the fall in economic activity and increase in travel restrictions caused by COVID-19. Demand for transportation fuels such as gasoline for passenger cars and kerosene for air transportation was hit particularly hard. During most of the second half of the year, mobility and the resulting demand for transportation fuels improved in some parts of the world, especially in China and South-east Asia. At the end of the year, new waves of COVID-19 infections in Europe and the Americas severely limited any global increase in demand for transportation fuels.

On January 1, 2020, the new International Maritime Organization low-sulphur shipping fuel specification came into effect, limiting the sulphur content of maritime fuel to 0.5%. This had a limited effect on margins because of the economic slowdown in 2020 and because companies had prepared for the new regulations by building inventory in the second half of 2019.

The destruction of demand caused by COVID-19 led to industry idling some refinery capacity. Permanent refinery closures were also announced in 2020, but construction of new capacity did occur during the year, especially in the Middle East and Asia.

The outlook for refining margins for the next few years will be influenced by the uncertainty around the pace of economic and demand recovery from the pandemic, and by the continued addition of new refinery capacity in the Middle East and Asia, often integrated with chemicals production. On balance, refining marker margins are expected to remain under pressure for 2021.

PETROCHEMICAL MARGINS

Cracker industry margins [A]

	\$/tonne		
	2020	2019	2018
North East/South East Asia naphtha	362	302	594
Western Europe naphtha	513	528	562
US ethane	433	440	412

[A] ICIS data is quoted. Cracker margins have been revised from the fourth quarter 2019 onwards due to updated cracker margin calculation methodology by ICIS. Further revisions based on available market information to external industry data provider up to the end of the period.

Cracker margins were volatile during 2020 because of how COVID-19 affected demand. Overall margins, however, were broadly similar to those in 2019. The effect on chemicals depended on end use. Some sectors, such as automotive, were hit particularly hard, while others, such as packaging, showed robust demand. Chinese demand recovered relatively quickly because the virus was swiftly brought under control. Overall chemicals demand was not hit as hard as GDP. West European cracker margins were supported by the sudden fall in the price of crude oil in March and April. The fact that crude oil was at a lower price than in 2019 reduced naphtha feedstock costs, which reduced product prices. This in turn put pressure on US ethane cracker margins, although plentiful ethane supply helped counter the impact.

The outlook for petrochemical margins in 2021 and beyond depends on feedstock costs and supply and demand balances. Demand for petrochemicals will be affected by the speed and extent of recovery from the COVID-19 pandemic. Supply of petrochemicals will depend on the net capacity effect of new builds and plant closures (taking into account any delays or cancellations in building new plants or closing old ones). Product prices reflect the prices of raw materials, which are closely linked to crude oil and natural gas prices. The balance of all these factors will drive margins.

The statements in this "Market overview" section, including those related to our price forecasts, are forward-looking statements based on management's current expectations and certain material assumptions and, accordingly, involve risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied herein. See "About this Report" on pages iii-iv and "Risk factors" on pages 28-37.

SUMMARY OF RESULTS

Key statistics

	\$ million, except where indicated		
	2020	2019	2018
(Loss)/income for the period	(21,534)	16,432	23,906
Current cost of supplies adjustment	1,833	(605)	458
Total segment earnings [A][B], of which:	(19,701)	15,827	24,364
Integrated Gas	(6,278)	8,628	11,444
Upstream	(10,785)	3,855	6,490
Oil Products	(494)	6,139	6,025
Chemicals	808	478	1,884
Corporate	(2,952)	(3,273)	(1,479)
Identified Items [B]	(24,767)	(1,192)	2,429
Adjusted Earnings [B]	4,846	16,462	21,404
Capital expenditure	16,585	22,971	23,011
Cash capital expenditure [B]	17,827	23,919	24,078
Operating expenses [B]	34,789	37,893	39,316
Return on average capital employed [B]	(6.8)%	6.7%	9.4%
Net Debt at December 31 [B]	75,386	79,093	51,428
Gearing at December 31	32.2%	29.3%	20.3%
Oil and gas production (thousand boe/d)	3,386	3,665	3,666
Proved oil and gas reserves at December 31 (million boe)	9,124	11,096	11,578

[A] Segment earnings are presented on a current cost of supplies basis. See Note 4 to the "Consolidated Financial Statements" on pages 230-232.

[B] See "Non-GAAP measures reconciliations" on pages 305-306.

EARNINGS 2020-2019

Income for the period was a loss of \$21,534 million in 2020, compared with earnings of \$16,432 million in 2019. After current cost of supplies adjustment, total segment earnings were a loss of \$(19,701) million in 2020, compared with earnings of \$15,827 million in 2019.

Earnings on a current cost of supplies basis (CCS earnings) exclude the effect of changes in the oil price on inventory carrying amounts, after making allowance for the tax effect. The purchase price of volumes sold in the period is based on the current cost of supplies during the same period, rather than on the historic cost calculated on a first-in, first-out (FIFO) basis. Therefore, when oil prices are decreasing, CCS earnings are likely to be higher than earnings calculated on a FIFO basis and, when prices are increasing, CCS earnings are likely to be lower than earnings calculated on a FIFO basis.

Integrated Gas earnings in 2020 were a loss of \$6,278 million, compared with earnings of \$8,628 million in 2019. The decrease was mainly driven by higher impairments, lower realised oil, LNG and gas prices, higher charges related to fair value accounting of commodity derivatives and lower contributions from marketing and trading. These effects were partly offset by lower operating expenses. See "Integrated Gas" on pages 46-52.

Upstream earnings in 2020 were a loss of \$10,785 million, compared with earnings of \$3,855 million in 2019. The decrease was mainly driven by lower realised oil and gas prices, higher impairments, higher losses on sales of assets, lower production volumes and unfavourable deferred tax movements. This was partly offset by lower operating expenses and lower well write-offs. See "Upstream" on pages 53-60.

Oil Products earnings in 2020 were a loss of \$494 million, compared with earnings of \$6,139 million in 2019. The decrease was mainly driven by higher impairments, lower combined Refining and Trading margins as well as lower marketing margins. This was partly offset by lower operating expenses and other items mainly including taxation movements. See "Oil Products" on pages 70-76.

Chemicals earnings in 2020 were \$808 million, compared with \$478 million in 2019. The increase was mainly driven by lower tax and operating expenses and higher chemicals prices, which was partly offset by higher redundancy and restructuring charges and higher depreciation, depletion and amortisation. See "Chemicals" on pages 77-79.

Corporate segment in 2020 was an expense of \$2,952 million, compared with \$3,273 million in 2019. The lower expense was mainly driven by the favourable deferred tax movements. See "Corporate" on page 80.

EARNINGS 2019-2018

Income for the period was \$16,432 million in 2019, compared with \$23,906 million in 2018. After current cost of supplies adjustment, total segment earnings were \$15,827 million in 2019, compared with \$24,364 million in 2018.

Integrated Gas earnings in 2019 were \$8,628 million, compared with \$11,444 million in 2018. The decrease was mainly driven by lower gains on sale of assets, lower realised oil, LNG and gas prices, higher impairments, higher operating expenses, negative movements in deferred tax positions and lower liquids production volumes. These effects were partly offset by stronger contributions from LNG marketing and trading, and gains related to the fair value accounting of commodity derivatives. See "Integrated Gas" on pages 46-52.

Upstream earnings in 2019 were \$3,855 million, compared with \$6,490 million in 2018. The decrease was mainly driven by higher impairments, lower realised oil and gas prices, higher depreciation and higher well write-offs. This was partly offset by increased gains on sale of assets and higher volumes. See "Upstream" on pages 53-60.

Oil Products earnings in 2019 were \$6,139 million, compared with \$6,025 million in 2018. The increase was mainly driven by higher Marketing margins and lower operating expenses partly offset by lower Refining and Trading margins. See "Oil Products" on pages 70-76.

SUMMARY OF RESULTS continued

Chemicals earnings in 2019 were \$478 million, compared with \$1,884 million in 2018. The decrease was mainly driven by lower margins and higher legal provisions. See "Chemicals" on pages 77-79.

Corporate segment in 2019 was an expense of \$3,273 million, compared with \$1,479 million in 2018. The higher loss was mainly driven by the introduction of IFRS 16 and reduced capitalised interest, as well as reduced tax credits from financing and one-off charges. See "Corporate" on page 80.

PRODUCTION AVAILABLE FOR SALE

Oil and gas production available for sale in 2020 was 1,239 million barrels of oil equivalent (boe), or 3,386 thousand boe per day (boe/d), compared with 1,338 million boe, or 3,665 thousand boe/d, in 2019. In 2020, lower production was due to the impact of divestments, higher maintenance, demand reduction and OPEC+ restrictions. New fields and ramp-ups offset the impact of field declines.

Oil and gas production available for sale [A]

	Thousand boe/d		
	2020	2019	2018
Crude oil and natural gas liquids	1,752	1,823	1,749
Synthetic crude oil	51	52	53
Natural gas [B]	1,583	1,790	1,863
Total	3,386	3,665	3,666
Of which:			
Integrated Gas	911	922	957
Upstream	2,424	2,691	2,656
Oil sands (reported as part of Oil Products)	51	52	53

[A] See "Oil and gas information" on pages 61-69.

[B] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

PROVED RESERVES

The proved oil and gas reserves of Shell subsidiaries and the Shell share of the proved oil and gas reserves of joint ventures and associates are summarised in "Oil and gas information" on pages 61-69 and set out in more detail in "Supplementary information – oil and gas (unaudited)" on pages 265-282.

Before taking production into account, our proved reserves decreased by 686 million boe in 2020. This comprised decreases of 614 million boe from Shell subsidiaries and decreases of 72 million boe from the Shell share of joint ventures and associates. The decrease from Shell subsidiaries included a net decrease of 607 million boe from revisions and reclassifications, an increase of 88 million from extensions and discoveries and a net decrease of 95 million boe related to purchases and sales of minerals in place. The decrease of 72 million boe from the Shell share of joint ventures and associates comprises a net decrease of 73 million boe from revisions and reclassifications.

In 2020, total oil and gas production was 1,286 million boe, of which 1,239 million boe was available for sale and 47 million boe was consumed in operations. Production available for sale from subsidiaries was 1,104 million boe and 40 million boe was consumed in operations. The Shell share of the production available for sale of joint ventures and associates was 135 million boe and 7 million boe was consumed in operations.

Accordingly, after taking production into account, our proved reserves decreased by 1,972 million boe in 2020, to 9,124 million boe at December 31, 2020, with a decrease of 1,758 million boe from subsidiaries and a decrease of 214 million boe from the Shell share of joint ventures and associates.

CASH CAPITAL EXPENDITURE AND OTHER INFORMATION

Cash capital expenditure was \$17.8 billion in 2020, compared with \$23.9 billion in 2019.

Operating expenses decreased by \$3.1 billion in 2020, to \$34.8 billion.

Our return on average capital employed (ROACE) decreased to (6.8)%, compared with 6.7% in 2019, mainly driven by lower income in 2020.

Net debt was \$75.4 billion at the end of 2020, compared with \$79.1 billion at the end of 2019, mainly driven by lower share buybacks and dividend payments.

Gearing was 32.2% at the end of 2020, compared with 29.3% at the end of 2019, mainly driven by lower earnings in 2020.

SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

See Note 2 to the "Consolidated Financial Statements" on pages 221-229.

LEGAL PROCEEDINGS

See Note 25 to the "Consolidated Financial Statements" on pages 260-262.

PERFORMANCE INDICATORS

These indicators enable management to evaluate Shell's performance against our strategy and operating plans. Those that are used in the determination of the Executive Directors' remuneration are asterisked below and on the following page. See "Directors' Remuneration Report" on pages 153-156.

FINANCIAL

Total shareholder return (%)*

(32.7) 2019: 0.5

Total shareholder return (TSR) is the difference between the share price at the beginning of the year and the share price at the end of the year (each averaged over 90 days), plus gross dividends delivered during the calendar year (reinvested quarterly), expressed as a percentage of the share price at the beginning of the year (averaged over 90 days). The data used are a weighted average in dollars for A and B shares. The TSRs of major publicly traded oil and gas companies can be compared directly, providing a way to determine how we are performing relative to our industry peers.

Cash flow from operating activities (\$ million)*

34,105 2019: 42,178

Cash flow from operating activities is the total of all the cash receipts and payments associated with our sales of oil, gas, chemicals and other products. The components that provide a reconciliation from income for the period are listed in the "Consolidated Statement of Cash Flows". This indicator reflects our ability to generate cash to service and reduce our debt and for distributions to shareholders and for investments.

See "Liquidity and capital resources" on pages 81-84.

Free cash flow (\$ million)*

20,828 2019: 26,399

Free cash flow is the sum of "Cash flow from operating activities" and "Cash flow from investing activities", which are listed in the "Consolidated Statement of Cash Flows". This indicator is used to evaluate the cash available for financing activities, including dividend payments, after investment in maintaining and growing our business.

See "Non-GAAP measures reconciliations" on pages 305-306.

Organic free cash flow (\$ million)

17,634 2019: 20,116

Organic free cash flow is defined as free cash flow excluding the cash flows from acquisition and divestment activities. It is a measure used by management to evaluate the generation of cash flow without these activities.

See "Non-GAAP measures reconciliations" on page 305-306.

Return on average capital employed (%)*

(6.8) 2019: 6.7

ROACE is defined as income for the period, adjusted for after-tax interest expense, as a percentage of the average capital employed during the year. Capital employed is the sum of total equity and total debt. ROACE measures the efficiency of our utilisation of the capital that we employ and is a common measure of business performance.

See "Summary of results" on pages 41-42 and "Non-GAAP measures reconciliations" on pages 305-306.

Adjusted earnings (\$ million)

4,846 2019: 16,462

Adjusted earnings are income/(loss) attributable to shareholders plus cost of sales adjustment and excluding identified items. This measure aims to facilitate a comparative understanding of Shell's financial performance from period to period by removing the effects of oil price changes on inventory carrying amounts and removing the effects of identified items. These items are in some cases driven by external factors and may, either individually or collectively, hinder the comparative understanding of Shell's financial results from period to period. This measure excludes earnings attributable to non-controlling interest.

See "Non-GAAP measures reconciliations" on pages 305-306.

Adjusted earnings per share (\$)

0.62 2019: 2.04

Adjusted earnings per share is calculated as adjusted earnings, divided by the weighted average number of shares used as the basis for basic earnings per share.

See "Non-GAAP measures reconciliations" on pages 305-306.

Divestment proceeds (\$ million)

4,010 2019: 7,871

Divestment proceeds represent cash received from divestment activities in the period. This is the sum of the following lines from the "Consolidated Statement of Cash flows": proceeds from sale of property, plant and equipment and businesses; proceeds from sale of joint ventures and associates [A]; and proceeds from sale of equity securities.

[A] includes \$313 million (2019: \$155 million) of long-term loan repayments received from joint ventures and associates.

See "Non-GAAP measures reconciliations" on pages 305-306.

PERFORMANCE INDICATORS continued

FINANCIAL continued

Cash capital expenditure (\$ million)

17,827 2019: 23,919

Cash capital expenditure is the sum of capital expenditure, investments in joint ventures and associates, and investments in equity securities, as reported in the "Consolidated Statement of Cash flows". It is used to monitor investing activities on a cash basis, excluding items such as lease additions that do not necessarily result in cash outflows in the period.

See "Non-GAAP measures reconciliations" on pages 305-306.

Net debt (\$ million)

75,386 2019: 79,093

Net debt is defined as the sum of current and non-current debt, less cash and cash equivalents. The net debt calculation includes the fair value of derivative financial instruments used to hedge foreign exchange, interest rate risks relating to debt and associated collateral balances. The inclusion of these debt-related derivative balances reduces the volatility of net debt caused by fluctuations in foreign exchange and interest rates, and eliminates the potential impact of related collateral payments or receipts.

See "Note 14 Debt and Lease Arrangements" on pages 241-243.

Gearing (%)

32.2 2019: 29.3

Gearing is defined as net debt as a percentage of total capital (net debt plus total equity) at December 31, and is a measure of the degree to which our operations are financed by debt.

See "Liquidity and capital resources" on page 81-84 and "Note 14 Debt and Lease Arrangements" on pages 241-243.

OPERATIONAL

Production available for sale (thousand boe/d) *

3,386 2019: 3,665

Production is the sum of all the average daily volumes of unrefined oil and natural gas produced for sale by Shell subsidiaries and Shell's share of those produced for sale by joint ventures and associates. The unrefined oil comprises crude oil, natural gas liquids (NGLs), synthetic crude oil and bitumen. The gas volume is converted into equivalent barrels of oil to make the summation possible.

See "Summary of results" on pages 41-42.

LNG liquefaction volumes (million tonnes) *

33.2 2019: 35.6

LNG liquefaction volumes is a measure of the operational performance of our Integrated Gas business and LNG market demand.

See "Integrated Gas" on pages 46-52.

Refinery and chemical plant availability (%) *

95.5 2019: 90.8

Refinery and chemical plant availability is the weighted average of the actual uptime of plants as a percentage of their maximum possible uptime. The weighting is based on the capital employed, adjusted for cash and non-current liabilities. This indicator is a measure of the operational excellence of our refinery and chemical plant facilities.

See "Oil Products" on pages 70-76 and "Chemicals" on pages 77-79.

Project delivery on schedule (%) *

48 2019: 90

Project delivery on budget (%) *

104 2019: 99

Project delivery reflects our capability to complete major projects on time and within budget on the basis of the targets set in our annual business plan. Project delivery on schedule measures the percentage of projects delivered on schedule. Project delivery on budget reflects the aggregate cost against the aggregate budget for those projects, where a figure greater than 100% means over-budget.

Proved oil and gas reserves (million boe)

9,124 2019: 11,096

Proved oil and gas reserves are the total estimated quantities of oil and gas from Shell subsidiaries and Shell's share from joint ventures and associates that geoscience and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs, at December 31, under existing economic conditions, operating methods and government regulations. Gas volumes are converted into boe using a factor of 5,800 scf/b. Reserves estimates are subject to change owing to a wide variety of factors, some of which are unpredictable.

See "Risk factors" on pages 28-37, "Summary of results" on pages 41-42, "Oil and gas information" on pages 61-69 and "Supplementary information – oil and gas (unaudited)" on pages 265-282.

SAFETY AND ENVIRONMENT

Total recordable case frequency (injuries per million working hours) *

0.7 2019: 0.9

Total recordable case frequency (TRCF) is the number of employee and contract staff injuries requiring medical treatment or time off for every million hours worked. It is a standard measure of occupational safety.

See "Environment and society" on pages 85-93.

Number of operational Tier 1 and 2 process safety events *

103 2019: 130

A Tier 1 process safety event is an unplanned or uncontrolled release of any material, including non-toxic and non-flammable materials, from a process with the greatest actual consequence resulting in harm to employees, contract staff, or a neighbouring community, damage to equipment, or exceeding a threshold quantity, as defined by the API Recommended Practice 754 and IOGP Standard 456. A Tier 2 process safety event is a release of lesser consequence.

See "Environment and society" on pages 85-93.

Upstream and Integrated Gas GHG intensity (tonnes of CO₂ equivalent/tonne of hydrocarbon production available for sale) *

0.16 2019: 0.17

Upstream/midstream GHG intensity is a measure of GHG emissions (direct and indirect GHG emissions associated with imported energy, excluding emissions from exported energy), expressed in metric tonnes of CO₂ equivalent, emitted into the atmosphere per metric tonne of hydrocarbon production available for sale.

See "Climate change and energy transition" on pages 94-107.

Refining GHG intensity (tonnes of CO₂ equivalent/UEDC™) *

1.05 2019: 1.06

Refining GHG intensity is a measure of GHG emissions (direct and indirect GHG emissions associated with imported energy, excluding emissions from exported energy), expressed in metric tonnes of CO₂ equivalent, emitted into the atmosphere per unit of Utilised Equivalent Distillation Capacity (UEDC™). UEDC™ is a proprietary metric of Solomon Associates. It is a complexity-weighted normalisation parameter that reflects the operating cost intensity of a refinery based on the size and configuration of its particular mix of process and non-process facilities.

See "Climate change and energy transition" on pages 94-107.

Chemicals GHG intensity (tonnes of CO₂ equivalent/tonne petrochemicals produced) *

0.98 2019: 1.04

Chemicals GHG intensity is a measure of GHG emissions (direct and indirect GHG emissions associated with imported energy, excluding emissions from exported energy), expressed in metric tonnes of CO₂ equivalent, emitted into the atmosphere per metric tonne of steam cracker, high-value petrochemicals production.

See "Climate change and energy transition" on pages 94-107.

Number of operational spills of more than 100 kilograms

68 2019: 67

The operational spills indicator is the number of incidents in respect of activities where we are the operator in which 100 kilograms or more of oil or oil products were spilled as a result of those activities and reached the environment.

See "Environment and society" on page 85-93.

Direct GHG emissions (million tonnes of CO₂ equivalent)

63 2019: 70

Direct GHG emissions from facilities operated by Shell, expressed in million tonnes of CO₂ equivalent.

See "Climate change and energy transition" on pages 94-107.

Net Carbon Footprint (grams of CO₂ equivalent per megajoule) *

75 2019: 78

Net Carbon Footprint is a comprehensive measure of the life-cycle carbon intensity of the energy products we sell. It is a weighted average of the life-cycle CO₂ intensities of different energy products, normalised to the same point relative to their final end use. It includes emissions from the extraction, transportation and processing of crude oil or gas or other feedstocks, transport of products, and our customers' emissions from the use of products we sell. Also included are emissions from elements of this life cycle not owned by Shell, such as oil and gas processed by Shell but not produced by Shell; or from oil products and electricity marketed by Shell that have not been processed or generated at a Shell facility. Emissions compensated through various measures are also included, such as emissions mitigated by nature-based solutions and carbon capture and storage technology.

See "Climate change and energy transition" on pages 94-107.

INTEGRATED GAS

Key statistics

	\$ million, except where indicated		
	2020	2019	2018
Segment earnings	(6,278)	8,628	11,444
Including:			
Revenue (including inter-segment sales)	36,697	45,602	48,795
Share of profit of joint ventures and associates	562	1,791	2,273
Interest and other income	14	263	2,230
Operating expenses [A]	6,555	6,667	6,014
Exploration	611	281	208
Depreciation, depletion and amortisation	17,704	6,238	4,850
Taxation charge	(2,507)	2,242	2,795
Identified Items [A]	(10,661)	(326)	2,045
Adjusted Earnings [A]	4,383	8,955	9,399
Capital expenditure	3,661	3,851	3,262
Cash capital expenditure [A]	4,301	4,299	3,819
Oil and gas production available for sale (thousand boe/d)	911	922	957
LNG liquefaction volumes (million tonnes)	33.2	35.6	34.3

[A] See "Non-GAAP measures reconciliations" on pages 305-306.

OVERVIEW

Our Integrated Gas segment includes liquefied natural gas (LNG) activities and the conversion of natural gas into gas-to-liquids (GTL) fuels and other products, as well as our New Energies businesses which were rebranded to Renewables and Energy Solutions in 2021. The segment includes natural gas and liquids exploration and extraction, and the operation of upstream and midstream infrastructure that delivers gas and liquids to market. It markets and trades natural gas, LNG, electricity and carbon-emission rights, and markets and sells LNG as a fuel for heavy-duty vehicles and marine vessels.

BUSINESS CONDITIONS

Global gas demand is estimated to have declined by around 2.4% in 2020, in contrast with the 2.5% annual growth rate observed since the start of the century. The deterioration in gas demand for power generation and in industry was mainly caused by lockdowns related to COVID-19. Resilient gas demand for heating helped offset the overall decline. Demand declined across all regions except non-OECD Asia. In non-OECD Asia, demand grew in China, which experienced a robust recovery after mitigating the impacts of COVID-19. Outside China, aggregate gas demand in non-OECD Asia remained flat year-on-year.

In 2020, global LNG imports were almost unchanged from 2019, rising by about 2 million tonnes year-on-year to 360 million tonnes. Growth in LNG supply capacity was mostly limited to the USA, where 21 million tonnes of new liquefaction started commercial operations in 2020. Liquefaction plants already in operation in the USA responded to the weak gas price environment by significantly curtailing production in the middle of the year. Supply from major LNG-exporting countries such as Egypt, Malaysia and Norway was also lower year-on-year because of operational disruptions and shut-ins to prevent economic losses.

Natural gas prices can vary from region to region.

In the USA, the natural gas price at the Henry Hub averaged \$2.0 per million British thermal units (MMBtu) in 2020, 21% lower than in 2019. It traded in a range of \$1.5 to 3.2/MMBtu.

In Europe, the average price at the UK National Balancing Point (NBP) in 2020 was 28% lower than in 2019. At the main continental gas trading hubs – in the Netherlands, Belgium and Germany – prices were also lower, as reflected by weaker Dutch Title Transfer Facility (TTF) prices.

Long-term contracted LNG prices in the Asia-Pacific region in 2020 were lower than in 2019 because they are predominantly indexed to oil prices, particularly the Japan Customs-cleared Crude (JCC) index which dropped by an 32% year-on-year, tracking Brent crude prices. Meanwhile, delivered North Asia spot prices, reflected by the Japan Korea Marker, declined by 20% compared with 2019.

See "Market overview" on pages 38-40.

PRODUCTION AVAILABLE FOR SALE

In 2020, production was 333 million barrels of oil equivalent (boe), or 911 thousand boe per day (boe/d), compared with 336 million boe, or 922 thousand boe/d in 2019. Natural gas production was 83% of total production in 2020 and 2019. In 2020 natural gas production decreased by 1% compared with 2019. This was mainly because of extended maintenance at the Prelude floating liquefied natural gas (FLNG) facility and maintenance activities at the Gorgon project in Australia, as well as lower wells performance. These were partially offset by the transfer of Raspetco operations in Egypt from the Upstream segment and field ramp-ups. Liquids production decreased by 2%, in line with the decrease in natural gas production.

LNG LIQUEFACTION VOLUMES

LNG liquefaction volumes of 33.2 million tonnes in 2020 were 6% lower than in 2019, mainly driven by lower feedgas availability, higher maintenance activities, primarily at Prelude FLNG and Gorgon, as well as cargo timing.

LNG sales volumes of 69.67 million tonnes in 2020 were 6% lower than in 2019, driven by lower LNG liquefaction volumes partly offset by higher purchases from third parties.

Through our Shell Energy organisation, we market a portion of our share of equity production of LNG and sell and market LNG volumes around the world through our hubs in the UK, Dubai and Singapore. Shell has term sales contracts for the majority of our LNG liquefaction and term purchase contracts. We are able to maximize the income we generate from our LNG cargos through our shipping network, regasification terminals and ability to purchase and deliver LNG spot cargos from third parties. For example, if one customer does not need a scheduled cargo, we can deliver that cargo to another customer who is in need. Similarly, if a customer needs an additional cargo not available from our production facilities, we can contract with third parties to deliver the additional cargo. We also conduct paper trades primarily to manage commodity price risk related to sales and purchase contracts. We also sell trucked LNG in China, Singapore and Europe.

INTEGRATED GAS DATA TABLE

LNG liquefaction volumes

	Million tonnes		
	2020	2019	2018
Australia	11.8	12.5	12.1
Brunei	1.6	1.6	1.6
Egypt	0.2	0.4	0.3
Malaysia	—	—	0.6 [A]
Nigeria	5.3	5.3	5.1
Norway	0.1	0.1	0.1
Oman	2.5	2.6	2.4
Peru	0.9	0.9	0.8
Qatar	2.4	2.5	2.3
Russia	3.1	3.0	3.1
Trinidad and Tobago	5.4	6.7	5.8
United States	0.1	0.1	—
Total	33.2	35.6	34.3

[A] Includes LNG liquefaction volumes related to our share in equity securities of Malaysia LNG Tiga, which were disposed of in 2018.

EARNINGS 2020-2019

Segment earnings in 2020 were a loss of \$6,278 million, which included a net charge of \$10,661 million. The net charge reflected impairment charges of \$9,282 million mainly reflecting revisions to mid- and long-term price outlook assumptions and primarily related to the Queensland Curtis LNG and Prelude FLNG operations in Australia. It also comprised a net charge of \$969 million due to the fair value accounting of commodity derivatives and a charge of \$607 million related to onerous contract provisions.

Segment earnings in 2019 were \$8,628 million, which included a net charge of \$326 million. The net charge mainly reflected impairment charges of \$890 million mostly in Australia, negative movements in deferred tax positions of \$292 million in Australia and write-offs of \$131 million in Trinidad and Tobago. These were partly offset by a gain of \$787 million related to the fair value accounting of commodity derivatives and a gain of \$203 million on a sale of assets in Australia.

Excluding the net charge described above, segment earnings were \$4,383 million in 2020 compared with \$8,955 million in 2019. Earnings were negatively impacted by lower realised LNG, oil and gas prices, and lower contributions from marketing and trading, partly offset by lower operating expenses.

EARNINGS 2019-2018

Segment earnings in 2019 were \$8,628 million, which included a net charge of \$326 million as described above.

Segment earnings in 2018 were \$11,444 million, which included a net gain of \$2,045 million. The net gain primarily reflected gains of \$1,937 million on sale of assets, mainly related to the divestment of assets in Thailand, New Zealand and India. It also comprised a gain of \$481 million related to the fair value accounting of commodity derivatives and impairment charges of \$371 million related to investments in Trinidad and Tobago and Shell's investment in a joint venture.

Excluding the net charge above, segment earnings were \$8,955 million in 2019 compared with \$9,399 million in 2018. Earnings were negatively impacted by lower realised oil, LNG and gas prices, higher operating expenses (of which about 50% related to New Energies, reflecting underlying business growth), and lower liquids production volumes, partly offset by significantly stronger contributions from LNG marketing and trading.

CASH CAPITAL EXPENDITURE

Cash capital expenditure in 2020 was \$4.3 billion, unchanged from \$4.3 billion in 2019. Our cash capital expenditure is expected to be around \$6 billion in 2021.

PORTFOLIO AND BUSINESS DEVELOPMENT

Key portfolio events in 2020 included the following:

- In February 2020, we announced that we will build and operate our first industrial-scale solar electricity farm near Wandoan in central Queensland, Australia. The solar farm will generate 120 MW of solar electricity and is expected to be completed in early 2021.
- In March 2020, we decided not to proceed with an equity interest in the proposed Lake Charles LNG project. Energy Transfer will take over as the project developer.
- In July 2020, the CrossWind consortium, a joint venture between Shell in the Netherlands and Eneco, was awarded the tender for the offshore wind farm Hollandse Kust (noord). Both companies have already taken their final investment decisions (FID) on the project. The consortium plans to have Hollandse Kust (noord) operational in 2023 with an installed capacity of 759 MW.

The following major milestones were reached in 2020:

- In April 2020, we took a FID to develop the first phase of Arrow Energy's Surat Gas Project in Queensland, Australia. This decision will bring up to 90 billion cubic feet per year of new gas by the end of the decade, which will flow to Shell-operated QGC to be sold locally and exported through its plant on Curtis Island.
- In May 2020, we took a FID on a new LNG processing unit known as Train 7 at Nigeria LNG (NLNG).
- In August 2020, the tenth and final movable modular liquefaction system (MMLS) unit at the Elba Island export terminal in Georgia, USA, was delivered to the energy infrastructure company Kinder Morgan.
- In August 2020, the Blauwwind consortium, which is developing offshore wind projects in the Netherlands, achieved its first power.

We continued our divestment activities for selected assets during 2020, including:

- In December, QGC Common Facilities Company Pty Ltd, a wholly-owned subsidiary of Shell, announced it had agreed to the sale of a 26.25% interest in the Queensland Curtis LNG (QCLNG) Common Facilities to Global Infrastructure Partners Australia. The transaction is subject to regulatory approval in Australia and customary conditions. It is expected to complete in the first half of 2021.

INTEGRATED GAS continued

BUSINESS AND PROPERTY

Integrated Gas

Our complete list of LNG and GTL plants in operation and under construction in which we have an interest is provided below.

LNG liquefaction plants in operation at December 31, 2020

	Asset	Location	Shell interest (%)	100% capacity (mtpa) [A]	Shell-operated
Europe					
Norway	Gasnor	Bergen	100	0.3	Yes
Asia					
Brunei	Brunei LNG	Lumut	25	7.6	No
Oman	Oman LNG	Sur	30	7.1	No
	Qalhat LNG	Sur	11 [B]	3.7	No
Qatar	Qatargas 4 [C]	Ras Laffan	30	7.8	No
Russia	Sakhalin LNG [C]	Prigorodnoye	27.5	10.9	No
Oceania					
Australia	Australia North West Shelf [C]	Karratha	16.7	16.9	No
	Gorgon LNG [C]	Barrow Island	25	15.6	No
	Prelude [C] [D]	Browse Basin	67.5	3.6	Yes
	Queensland Curtis LNG T1 [C]	Curtis Island	50	4.3	Yes
	Queensland Curtis LNG T2 [C]	Curtis Island	97.5	4.3	Yes
Africa					
Egypt [E]	Egyptian LNG T1	Idku	35.5	3.6	No
	Egyptian LNG T2	Idku	38	3.6	No
Nigeria	Nigeria LNG	Bonny	25.6	24.1	No
South America					
Peru	Peru LNG	Pampa Melchorita	20	4.5	No
Trinidad and Tobago	Atlantic LNG T1	Point Fortin	46	3	No
	Atlantic LNG T2/T3	Point Fortin	57.5	6.6	No
	Atlantic LNG T4	Point Fortin	51.1	5.2	No

[A] 100% capacity represents the total capacity that all trains can process as reported by the operator.

[B] Interest, or part of the interest, is held via indirect shareholding.

[C] These assets are clustered as integrated assets and have onshore or offshore upstream production.

[D] Following a number of operational issues and shutdown since February 2020, Prelude continues to progress towards safe and reliable operations with LNG rundown restart in late December 2020.

[E] In January 2014, force majeure notices were issued under the LNG agreements as a result of domestic gas diversions severely restricting volumes available to the ELNG plant. These notices remain in place.

LNG liquefaction plants under construction at December 31, 2020

	Asset	Location	Shell interest (%)	100% capacity (mtpa) [A]	Shell-operated
Africa					
Nigeria	Train 7 [B]	Bonny	25.6	7.6	No
North America					
Canada	LNG Canada T1-2 [C]	Kitimat	40.0	14.0	No

[A] 100% capacity represents the total capacity that all trains can process as reported by the operator.

[B] First LNG is expected in the middle of the 2020s.

[C] Construction started in October 2018 and first LNG is expected before the middle of the 2020s.

GTL plants in operation at December 31, 2020

	Asset	Location	Shell interest (%)	100% capacity (b/d) [A]	Shell-operated
Asia					
Malaysia	Shell MDS	Bintulu	72.0	14,700	Yes
Qatar	Pearl	Ras Laffan	100.0	140,000	Yes

[A] 100% capacity represents the total capacity of the plant.

We also have interests and rights in various regasification terminals listed below. Extension of leases or rights beyond the periods mentioned below will be reviewed on a case-by-case basis.

LNG regasification terminals

Project name	Location	Shell capacity rights (mtpa)	Capacity rights period	Status	Shell interest (%) and Rights
Altamira	Tamaulipas, Mexico	3.3 [A]	2006–2021	In operation	Leased
Costa Azul	Baja California, Mexico	2.7	2008–2028	In operation	Leased
Cove Point	Lusby, MD, USA	1.8	2003–2023	In operation	Leased
Dragon LNG	Milford Haven, UK	3.1	2009–2029	In operation	50
Elba Island Expansion	Elba Island, GA, USA	4.2	2010–2035	In operation	Leased
Elba Island	Elba Island, GA, USA	2.8	2006–2036	In operation	Leased
Elba Island	Elba Island, GA, USA	4.6	2003–2027	In operation	Leased
GATE (Gas Access to Europe)	Rotterdam, The Netherlands	1.5	2015–2031	In operation	Capacity rights
Shell Energy India Pvt Ltd (formerly Hazira)	Gujarat, India	5	2005–2035	In operation	100
Lake Charles	Lake Charles, LA, USA	4.4	2002–2030	In operation	Leased
Lake Charles Expansion	Lake Charles, LA, USA	8.7	2005–2030	In operation	Leased
Singapore SGM	SLNG, Singapore	up to 3.0 [B]	2013–2029	In operation	Import rights
Singapore SETL	SLNG, Singapore	up to 1.0 [C]	2018–2035	In operation	Import rights
Shell LNG Gibraltar	Gibraltar	up to 0.04	2018–2038	In operation	51

[A] 100% capacity rights are held by Gas del Litoral joint venture with which Shell has a contract to supply 75% of the volumes. Our capacity rights end in September 2021 and the contract will not be renewed.

[B] Exclusive licence to import LNG and sell regasified LNG in Singapore for up to 3.0 mtpa.

[C] Second licence to import LNG and sell regasified LNG in Singapore.

Our Integrates Gas business also includes oil and natural gas production, exploration and development in the following locations:

Australia

We have interests in offshore production, LNG liquefaction and exploration licences in the North West Shelf (NWS) and Greater Gorgon areas of the Carnarvon Basin and in the Browse Basin. Woodside is the operator on behalf of the NWS joint venture (Shell interest 16.7%). We have a 25% interest in the Chevron-operated Gorgon LNG joint venture that includes offshore production.

We relinquished positions in asset and exploration areas in the Exmouth Plateau, leading to us relinquishing four exploration permits in the Exmouth Plateau in June 2020.

Our interests in the Browse basin include joint arrangements, with Shell as the operator, for the Prelude field (Shell interest 67.5%), the pre-FID Crux gas and condensate field (Shell interest 82%), and other backfill and contingent resources for Prelude FLNG, including the Bratwurst field (Shell interest 100%). Bratwurst, discovered in 2019, is currently under evaluation as a future backfill opportunity.



QGC is one of Australia's leading natural gas producers.

We are also a partner in the Browse joint arrangement (Shell interest 27%) covering the Brecknock, Calliance and Torosa gas fields, which are under development and operated by Woodside.

We also operate the Queensland Curtis LNG (QCLNG) venture's natural gas operations, including wells, compression stations and processing plants, in Queensland's Surat Basin. We have interests ranging from 44% to 74% in 25 field compression stations and six central processing plants. Our production of natural gas from the onshore Surat Basin supplies the QCLNG liquefaction plant and the domestic gas market.

We have a 50% interest in Arrow, a Queensland-based joint venture with China National Petroleum Corporation (CNPC). Arrow owns coal-bed methane assets and a domestic power business.

Bolivia

We hold a 37.5% participating interest in the Caipipendi block where we produce and explore. We also have a 25% interest in Tarija XX West block where we produce from the Itaú field. We have the rights to explore and further develop the onshore Huacareta block (Shell interest 100% during exploration), and we are exploring there. We hold a 15% participating interest in the Repsol-operated Inguazu exploration.

China

We jointly develop and produce from the onshore Changbei tight-gas field under a production-sharing contract (PSC) with CNPC. In 2017, we took the FID on the Changbei II Phase 1 project and started drilling activity in early 2019.

Egypt

We have a 25% interest in the Burullus Gas Company (Burullus), a self-operated joint venture which operates the West Delta Deep Marine concession (Shell interest 50%) and supplies gas to the domestic market and the Egyptian LNG plant. We have a 50% interest in the Rashid Petroleum Company (Rashpetco), a self-operated joint venture which operates the Rosetta concession (Shell interest 100%).

We have a 60% interest in the development rights for the Harmattan Deep discovery and the Notus discovery offshore the Nile Delta.

INTEGRATED GAS continued

Indonesia

We have a 35% interest in the INPEX Masela Ltd joint venture which owns and operates the offshore Masela block.

Oman

In February 2019, we signed an interim upstream agreement that detailed a funding and work programme for 2019 and 2020 to develop gas resources for projects to help meet the Sultanate of Oman's growing need for energy. The other signatories were Petroleum Development Oman (PDO), Oman Oil Company (OOC) and Total. The project covers investments in gas exploration and production.

Qatar

We operate the Pearl GTL plant (Shell interest 100%) in Qatar under a development and PSC with the government. The fully integrated facility has the capacity to produce, process and transport 1.6 billion standard cubic feet per day (scf/d) of gas from Qatar's North Field.

We have a 30% interest in Qatargas 4, which comprises integrated facilities to produce about 1.4 billion scf/d of gas from Qatar's North Field, an onshore gas-processing facility.

Russia

We have a 27.5% interest in Sakhalin-2, the joint venture with Gazprom, an integrated oil and gas project located on Sakhalin island.

Singapore

We have a 50% interest in a joint venture with KS Investments (the investment arm of Keppel Group) that holds a licence to supply LNG fuel for vessels in the Port of Singapore. We have aggregator licences to import LNG into Singapore and market the gas to power plants and other customers.

Tanzania

We operate and have a 60% interest in Blocks 1 and 4 offshore southern Tanzania. In June 2020, the government granted a 4.5-year licence extension for both blocks. We continue to develop a potential domestic gas and LNG project.

Trinidad and Tobago

We have interests in three concessions with producing fields: Central Block (Shell interest 65%), East Coast Marine Area (ECMA) (Shell interest 100%) and North Coast Marine Area (NCMA) (Shell interest 80.5%). We also own a 100% interest in Block 5(c), 90% interest in Block 22 and 80% interest in NCMA 4 which include five undeveloped discoveries. Our interests range from 35% to 100% in exploration activities in Blocks 5(d), 6(d), and Atlantic Area Blocks 3, 5, and 6.

USA

We have offtake rights via a lease to 100% of the capacity (2.5 mtpa) of the Kinder Morgan-operated Elba Island liquefaction plant in Georgia which consists of 10 MMLS units. We also lease regasification capacity on Elba Island with a contracted capacity of 11.6 mtpa.

Other

We have a 17.9% share in the West African Gas Pipeline Company Limited which owns and operates a 678-kilometre pipeline transporting gas from Nigeria to Ghana, Benin and Togo.

We have a 40% interest in a gas pipeline connecting Uruguay to Argentina.

We have a 35% interest in Cyprus Block 12, holding the Aphrodite discovery, which is currently under appraisal. In Colombia, we have a 60% interest in two deep-water blocks that we operate and 50% interests in three other blocks that we operate. We have interests in offshore blocks in Myanmar. We have a 90% interest in one exploration block licence in Namibia.

Renewables and Energy Solutions

Renewables and Energy Solutions includes power generation, trading and supply, hydrogen and nature-based solutions.

The Renewables and Energy Solutions portfolio is being built through organic growth and acquisitions. Most of these opportunities are in sectors that are different from Shell's existing oil and gas businesses, but have some similarities and/or adjacencies to our downstream and gas and power trading businesses. Shell-controlled Renewables and Energy Solutions companies are subject to the Shell Control Framework. Some are not yet in full compliance with the Shell Control Framework and we are working to bring them into compliance with this framework in a fit-for-purpose manner.

In 2020, cash capital expenditure in Renewables and Energy Solutions amounted to \$0.9 billion.



Shell is investing in renewables such as wind power.

Power

In the UK, through Shell Energy Retail, we supply 100% renewable electricity via the purchase of renewable energy guarantees of origin (REGO) certificates, and natural gas and smart home technology to more than 900 thousand homes. In Germany, we supply electricity and/or gas to more than 80 thousand homes through Shell Energy Retail GmbH.

Through Sonnen, we provide battery storage systems to homes with solar panels, with over 60 thousand installations globally. Through our London-based energy technology firm Limejump, we manage distributed, renewable and flexible power generation assets in supplying power to the UK national grid.

Our Shell Recharge electric vehicle (EV) charging service offers ways for drivers to recharge their vehicles at home, at their destination or during their journey. Shell New Energies is also developing charging networks for EV drivers through our NewMotion and Greenlots subsidiaries. NewMotion operates around 60 thousand private electric charge points in the Netherlands, Germany, France and the UK.

Greenlots provides EV charging posts, charging network software and grid services. It operates 8 thousand charge points for businesses and private drivers in the USA, Canada and Singapore.

Through MP2, we provide retail electricity and renewable energy solutions to commercial and industrial customers across the USA.

Silicon Ranch is an independent power producer and Shell's US solar platform, with a diverse portfolio of operating facilities including utility-scale solar.

In Australia, through ERM, we are the second-largest electricity retailer serving commercial and industrial customers.



Shell Recharge allows drivers to charge their electric vehicles.

Our major renewable power projects in operation and in development are listed below:

Renewable power projects in operation

Project	Location	Shell interest (%)	100% capacity (MW)	Type	Theme	Shell-operated
Silicon Ranch	USA	46.47	1,130	Solar Developer	Solar	No
Cleantech Solar	Asia	24.5 [A]	252	Solar Developer	Solar	No
Moerdijk	The Netherlands	100	27	Solar Operations	Solar	Yes
Noordzee Wind NL	The Netherlands	50	108	Offshore Wind JV	Offshore wind	No
Brazos, TX	USA	100	160	Onshore wind Operations	Onshore wind	Yes
Whitewater Hill, CA	USA	50	61.5	Onshore wind Operations	Onshore wind	No
Rock River, WY	USA	50	49	Onshore wind Operations	Onshore wind	No
Cabazon Pass, CA	USA	50	41	Onshore wind Operations	Onshore wind	No
Sohar Solar Quabas	Oman	100	34	Solar Development	Solar	Yes
Emmen	The Netherlands	100	12	Solar Development	Solar	Yes
Heerenveen	The Netherlands	100	14.5	Solar Development	Solar	Yes

[A] Shell interest in Cleantech is 49% where Cleantech owns 50% of the projects. Therefore 24.5% Shell interest is reported.

Renewable power projects under construction

Project	Location	Shell interest (%)	100% capacity (MW)	Type	Theme	Shell-operated
Gangarri	Australia	100	120	Solar Development	Solar	Yes
Silicon Ranch [A]	USA	46.47	1,744	Solar Developer	Solar	No
Cleantech Solar [A]	Asia	24.5 [B]	174	Solar Developer	Solar	No
CrossWind	The Netherlands	79.9	759	Offshore Wind Development	Offshore wind	No
Borssele III and IV	The Netherlands	20	731.5	Offshore Wind Development	Offshore wind	No
Sas van Gent	The Netherlands	100	29.6	Solar Development	Solar	Yes

[A] These solar projects are shown in Projects in operation and under construction as they are in multiple phases.

[B] Shell interest in Cleantech is 49% where Cleantech owns 50% of the projects. Therefore 24.5% Shell interest is reported.

Renewable power projects in development

Projects in development represent various earlier stages where FID has not yet been taken.

Project	Location	Shell interest (%)	100% capacity (MW)	Type	Theme	Shell-operated
GBI	France	29.5	28.5	Offshore Wind JV	Offshore wind	Yes
Mayflower	USA	50	1,600	Offshore Wind JV	Offshore wind	No
Atlantic Shores	USA	50	2,500	Offshore Wind JV	Offshore wind	No
Pottendijk	The Netherlands	100	100	Solar and Onshore Wind	Onshore Renewable Power	Yes

INTEGRATED GAS continued

Hydrogen

We are part of joint ventures and alliances that have built hydrogen filling stations for passenger cars in Canada, Germany, the UK and the US state of California. We have announced plans to build several hydrogen filling stations in the Netherlands, the first of which opened in the fourth quarter of 2020.

We aim to complete the construction of a 10 MW electrolyser at our Rheinland refinery in Germany by mid-2021. In China, Shell and Zhangjiakou City Transport have signed a joint-venture agreement to build a 20 MW renewable power electrolyser and hydrogen refuelling stations in Zhangjiakou City in the Beijing-Tianjin-Hebei region.



Shell opened its first hydrogen refuelling station in the Netherlands in 2020.

Nature-based solutions

In 2020, we completed the acquisition of Select Carbon, a specialist company that partners with farmers, pastoralists and other landowners in Australia to develop carbon farming projects, where plants are grown and soil managed to absorb carbon dioxide from the atmosphere. Select Carbon represents the first corporate acquisition for our nature-based solutions programme. This programme invests in forests, grasslands, wetlands and other natural ecosystems around the world to offset emissions by using plants to absorb carbon dioxide. The investment in natural ecosystems also helps biodiversity.

Marketing and Trading

We also market and trade natural gas, power and carbon-emission rights in multiple markets in North and South America, Europe, Asia and Australia, of which a portion includes equity volumes from our upstream operations.

We have set up a power marketing and trading business in the Philippines and China which began operations in 2020.

UPSTREAM

Key statistics

	\$ million, except where indicated		
	2020	2019	2018
Segment earnings	(10,785)	3,855	6,490
Including:			
Revenue (including inter-segment sales)	28,330	45,217	46,584
Share of profit of joint ventures and associates	(7)	379	285
Interest and other income	542	2,180	605
Operating expenses [A]	10,983	11,582	11,690
Exploration	1,136	2,073	1,132
Depreciation, depletion and amortisation	23,119	16,881	12,871
Taxation charge/(credit)	(467)	5,878	8,756
Identified Items [A]	(7,933)	(598)	19
Adjusted Earnings [A]	(2,852)	4,452	6,472
Capital expenditure	6,911	10,003	12,002
Cash capital expenditure [A]	7,296	10,205	12,134
Oil and gas production available for sale (thousand boe/d)	2,424	2,691	2,656

[A] See "Non-GAAP measures reconciliations" on pages 305-306.

OVERVIEW

Our Upstream business explores for and extracts crude oil, natural gas and natural gas liquids. It also markets and transports oil and gas, and operates infrastructure necessary to deliver them to market.

BUSINESS CONDITIONS

In 2020, oil markets experienced unprecedented developments in demand driven by the COVID-19 pandemic. At the start of 2020, global oil demand for the year was expected to grow by 1.2 million barrels per day (b/d). Then in January, oil demand started to contract because demand fell in China as lockdown was imposed to contain the virus outbreak. In subsequent months, oil demand contracted further as the outbreak in China evolved into a global pandemic and lockdowns were introduced across the world. In April, oil demand fell to its lowest level, around 22 million b/d below year-average demand in 2019, according to an estimate of the International Energy Agency (IEA). Contraction of such magnitude has never been recorded before. Country lockdowns deeply impacted transportation sectors, especially passenger road and passenger air in Organisation for Economic Co-operation and Development (OECD) economies. In subsequent months, oil demand started recovering, but only partially, because resurgences of COVID-19 triggered re-imposition of social distancing and travel restrictions. By the fourth quarter, global oil demand was still estimated to be around 5.5 million b/d below the 2019 level, according to the Oil Market Report published by the IEA in January 2021. Averaged for the full year, oil demand contracted by around 9 million b/d, or 9%, to 91.2 million b/d. Oil demand fell by 5.7 million b/d in OECD economies, and by 3.2 million b/d in non-OECD economies. By contrast, oil demand in 2019 was 0.8 million b/d higher than in 2018.

On a daily average basis, Brent crude oil, an international benchmark, traded between \$13 per barrel (/b) and \$70/b in 2020, ending the year around \$50/b. Brent crude oil prices averaged \$42/b for the year, 34% (or \$22/b) lower than in 2019.

On a yearly average basis, WTI crude oil traded at a discount of about \$2.5/b to Brent crude oil in 2020, compared with \$7/b in 2019. The discount narrowed from 2019 because falling US supply prevented bottlenecks in pipeline capacity from the landlocked Cushing storage hub to the US Gulf Coast. According to the US Energy Information Administration, US crude oil exports increased further to a yearly average of around 3.1 million b/d in 2020, up by 0.1 million b/d from 2019. This helped to ensure a narrow price differential between Brent and WTI.

Global gas demand is estimated to have declined by around 2.4% in 2020, in contrast with the 2.5% annual growth rate observed since the start of the century. The deterioration in gas demand for power generation and in industry was mainly caused by lockdowns related to COVID-19. Resilient gas demand for heating helped offset the overall decline. Demand declined across all regions except non-OECD Asia. In non-OECD Asia, demand grew in China, which experienced a robust recovery after mitigating the impacts of COVID-19. Outside China, aggregate gas demand in non-OECD Asia remained flat year-on-year.

In the USA, the natural gas price at the Henry Hub averaged \$2.0 per million British thermal units (MMBtu) in 2020, 21% lower than in 2019. It traded in a range of \$1.5 to 3.2/MMBtu. In the earlier part of 2020, there was downward pressure on prices because of decreased demand from a mild winter, lower LNG exports and a weak domestic market caused by COVID-19. Supply fell because activity declined as producers cut investments and because lower oil production meant there was less associated gas. During the summer, prices found support from growing demand for gas that could generate power for cooling during the hotter months of the year. Later in 2020, demand strengthened because of storage ahead of the winter season and increasing US LNG exports.

In Europe, the average price at the UK National Balancing Point (NBP) in 2020 was 28% lower than in 2019. At the main continental gas trading hubs – in the Netherlands, Belgium and Germany – prices were also lower, as reflected by weaker Dutch Title Transfer Facility (TTF) prices. European gas prices were lower because of: the slump in demand in power generation and industry; robust supply of pipeline gas; well-filled gas storage inventories at the start of the year; and competition with renewables in power.

See "Market overview" on pages 38-40.

PRODUCTION AVAILABLE FOR SALE

In 2020, production was 887 million boe, or 2,424 thousand boe/d, compared with 982 million boe, or 2,691 thousand boe/d in 2019. Liquids production decreased by 4% and natural gas production decreased by 19% compared with 2019.

UPSTREAM continued

The decrease in liquids production was mainly caused by divestments, OPEC+ curtailment, higher maintenance and hurricanes in the Gulf of Mexico interrupting production. Increased production from ramp-ups and new field start-ups more than offset field decline. The decrease in gas production was mainly caused by divestments, lower demand from Nederlandse Aardolie Maatschappij B.V. (NAM) in the Netherlands, and the transfer of Rashpetco operations in Egypt from Upstream to Shell's Integrated Gas segment.

We expect that oil production peaked in 2019. Going forward, we expect a gradual reduction in oil production of around 1-2% each year, including divestments and natural decline.

EARNINGS 2020-2019

Segment earnings in 2020 were a loss of \$10,785 million, which included a net charge of \$6,447 million related to impairments, primarily in the US Gulf of Mexico, unconventional assets in North America, offshore assets in Brazil and Europe, and a project in Nigeria (OPL245), mainly triggered by revision of Shell's mid- and long-term commodity price and updated Appomattox sub surface understanding. Also included was a net charge of \$782 million related to the impact of the weakening Brazilian real on a deferred tax position.

Segment earnings in 2019 were \$3,855 million, which included a net charge of \$1,930 million related to impairments, primarily in the US Appalachia unconventional gas assets and a drilling rig joint venture, partly offset by a gain of \$1,609 million on sale of assets, mainly in Denmark and the US Gulf of Mexico.

Excluding the net charges described above, segment earnings in 2020 were a loss of \$2,852 million, compared with a profit of \$4,452 million in 2019. Earnings excluding the net charges were adversely impacted by lower prices and lower volumes, mainly driven by the unfavourable macroeconomic conditions as described in the business condition section and severe weather conditions in the Gulf of Mexico.

In the second quarter of 2020, we made cost interventions by reducing the size of our contingent workforce and initiating an organisational review in line with Reshape.

EARNINGS 2019-2018

Segment earnings in 2019 were \$3,855 million, which included a net charge of \$598 million as described above.

Segment earnings in 2018 were \$6,490 million, which included a net gain of \$19 million. This included a net gain of \$888 million on sale of assets, mainly related to our divestments in Iraq, Malaysia, Oman and Ireland, and a gain of \$152 million related to the fair value accounting of commodity derivatives. These gains were partly offset by a charge of \$561 million related to the impact of the weakening of the Brazilian real on a deferred tax position, a net impairment charge of \$350 million mainly related to assets in North America and deep-water rig joint ventures, and a charge of \$90 million related to the release of historic currency differences.

Excluding the net charges described above, segment earnings in 2019 were \$4,452 million compared with \$6,472 million in 2018. Earnings excluding the net charge were adversely impacted by lower realised oil and gas prices, higher depreciation and higher well write-offs, mainly in Albania and Kazakhstan, partly offset by higher sales volumes associated with the timing of liftings.

CASH CAPITAL EXPENDITURE

Cash capital expenditure in 2020 was \$7.3 billion, compared with \$10.2 billion in 2019. Our cash capital expenditure is expected to be around \$8 billion in 2021.

Lower cash capital expenditure in 2020 was mainly driven by actions to preserve cash. The lower cash capital expenditure and capital investments in 2020 also reflected our continuing efforts to improve capital efficiency by pursuing developments which cost less.

PORTFOLIO AND BUSINESS DEVELOPMENT

We took the following key portfolio decisions during 2020:

- In Argentina, in January 2020, partnering with Equinor, we completed the acquisition of Schlumberger's 60% interest in the Bandurria Sur block, located in the Vaca Muerta Basin (Shell interest 30%).
- In Brazil, in August 2020, we took the final investment decision (FID) to contract the Mero 3 floating production, storage and offloading (FPSO) vessel to be deployed at the Mero field within the offshore Santos Basin.
- In Brunei, in March 2020, we completed the acquisition of deep-water exploration Block CA-1 (Shell interest 86.95%).
- In Kazakhstan, in December 2020, we successfully settled a long-running contractual dispute with the Republic of Kazakhstan government about the profit share between the parties in the Karachaganak joint venture. Shell paid \$424 million as its share of the settlement.
- In Norway, in May 2020, partnering with Equinor and Total, we made a final investment decision on the Northern Lights carbon capture and storage (CCS) project. The project will involve the capture, transport and storage of carbon dioxide produced from industrial regions around the Norwegian continental shelf. Equinor is the operator of the project.
- In Russia, in April 2020, we cancelled our acquisition of the 50% participation interest in LLC Meretoyahaneftgaz from Gazprom Neft.
- In Russia, with Gazprom Neft, we established a joint venture (Shell interest 50%) to explore and develop the Leskinsky and Pukhutsayakhsky blocks in the Gydan peninsula, in north-western Siberia. The deal was completed in November 2020.
- In September, we agreed to acquire seven exploration licences in four countries from Kosmos Energy. Suriname represents a new country entry for Shell. In São Tomé and Príncipe, we will deepen our position in two blocks and enter two others. In both Namibia and South Africa, we will expand our position in two blocks. Transfer has been completed in Suriname, São Tomé and Príncipe and Namibia. South Africa is expected to complete in 2021.
- In the US Gulf of Mexico, in March 2020, we acquired seven blocks across multiple plays in the Gulf of Mexico Lease 254.

We achieved the following operational milestones in 2020:

- In Brazil, Atapu 1, (the FPSO vessel P-70), came on stream and delivered first oil in June.

We continued to divest selected assets during 2020, including:

- In Brazil, in June 2020, we sold a 30% interest in the Gato do Mato project in the Santos Basin. We are still the project operator, with a 50% interest.
- In Brazil, we agreed to sell our 23% interest in the P-71 FPSO vessel, the deal is expected to be completed in the first quarter of 2021.
- In Canada, in August 2020, we completed the sale of our Tourmaline shares.
- In Canada, we agreed to sell our Duvernay shale light oil position in Alberta. The deal is expected to be completed in the second quarter of 2021.
- In Nigeria, we agreed to sell our 30% interest in oil mining lease (OML17). The deal was completed in January 2021.
- In the USA, we completed the sale of our Appalachia shale gas position. The deal was completed in July 2020.
- In Egypt, we agreed to sell our onshore assets in the Western Desert. The deal is expected to be completed in the second half of 2021.

BUSINESS AND PROPERTY

Our subsidiaries, joint ventures and associates are involved in all aspects of upstream activities, including such matters as land tenure, entitlement to produced hydrocarbons, production rates, royalties, pricing, environmental protection, social impact, exports, taxes and foreign exchange.

The conditions of the leases, licences and contracts under which oil and gas interests are held vary from country to country. In almost all cases outside North America, legal agreements are generally granted by, or entered into with, a government, state-owned company, government-run oil and gas company or agency. The exploration risk usually rests with the independent oil and gas company. In North America, these agreements may also be with private parties that own mineral rights. Of these agreements, the following are most relevant to our interests:

- Licences (or concessions), which entitle the holder to explore for hydrocarbons and exploit any commercial discoveries. Under a licence, the holder bears the risk of exploration, development and production activities, and is responsible for financing these activities. In principle, the licence holder is entitled to the totality of production less any royalties in kind. The government, state-owned company or government-run oil and gas company may sometimes enter into a joint arrangement as a participant, sharing the rights and obligations of the licence but usually without sharing the exploration risk. In a few cases, the state-owned company, government-run oil and gas company or agency has an option to purchase a certain share of production.
- Lease agreements, which are typically used in North America and are usually governed by terms similar to licences. Participants may include governments or private entities. Royalties are either paid in cash or in kind.
- Production-sharing contracts (PSCs) entered into with a government, state-owned company or government-run oil and gas company. PSCs generally oblige the independent oil and gas company, as contractor, to provide all the financing and bear the risk of exploration, development and production activities in exchange for a share of the production. Usually, this share consists of a fixed or variable part that is reserved for the recovery of the contractor's cost (cost oil). The remaining production is split with the government, state-owned company or government-run oil and gas company on a fixed or volume/revenue-dependent basis. In some cases, the government, state-owned company or government-run oil and gas company will participate in the rights and obligations of the contractor and will share in the costs of development and production. Such participation can be across the venture or on a field-by-field basis. Additionally, as the price of oil or gas increases above certain predetermined levels, the independent oil and gas company's entitlement share of production normally decreases, and vice versa. Accordingly, its interest in a project may not be the same as its entitlement.

Europe Italy

We have a 39% interest in the Val d'Agri producing concession, operated by ENI.

We also have a 25% interest in the Tempa Rossa producing concession operated by Total.

Netherlands

Shell and ExxonMobil are 50:50 shareholders in Nederlandse Aardolie Maatschappij B.V. (NAM). A significant part of NAM's gas production comes from the onshore Groningen gas field, in which NAM holds a 60% interest. The remaining 40% interest is held by EBN, a Dutch government entity.

Production from the Groningen field induces earthquakes that have damaged houses and other buildings and structures in the region. This has led to complaints and claims for compensation for damage from the local community. NAM is working with the Dutch government and other stakeholders to fulfil its obligations to the residents of the area. These obligations include compensating for earthquake damage.

Since 2013, the Dutch Minister of Economic Affairs and Climate (the Minister) has set an annual production level for the Groningen field, taking into account all interests, including residents' safety, security of supply in the domestic gas market and supply commitments in EU member states. The production level in the gas year 2019-2020 (ending October 1, 2020) was 8.7 billion cubic meters.

In June 2018, NAM's shareholders and the Dutch government signed a heads of agreement (HoA) to reduce production from Groningen and to ensure the financial robustness of NAM to fulfil its obligations. In the HoA, NAM's shareholders agreed not to declare dividends for 2018 and 2019. Dividend payments in 2020 and beyond will be made only if a solvency ratio of 25% is reached and maintained. In September 2018, detailed agreements were signed to further implement the HoA. As part of these agreements, Shell guarantees NAM's payment obligations vis-à-vis the Dutch government in relation to earthquake-related damages and costs of strengthening houses, up to a maximum of 30%. This maximum equates to Shell's indirect interest in the Groningen production system.

In conjunction with the HoA, it was agreed that NAM would cease all involvement in handling damage claims or strengthening buildings to make them safe. The Dutch government has stepped into these two roles and has developed legislation and policies to deal with earthquake-related matters. One of the consequences of the legislation is that duty of care has shifted from NAM to the Dutch government. The Dutch government passes on to NAM the cost of the elements for which NAM is liable. There are escalation and arbitration options to settle any disputes.

In September 2019, the government issued an update announcing that it was able to reduce Groningen production faster, stopping production in 2022, eight years earlier than initially planned. Negotiations are ongoing between the government and the NAM shareholders regarding the compensation payable by the government to NAM in order to restore the balance of the package of arrangements laid down in the 2018 HoA. If no agreement can be reached on such re-balancing, NAM shareholders can go to arbitration to resolve the matter.

NAM also has a 60% interest in the Schoonebeek oil field and operates 25 other hydrocarbon production licences. Some of these are onshore and others are offshore in the North Sea.

UPSTREAM continued

Norway

We are a partner in 27 production licences on the Norwegian continental shelf. We are the operator in 14 of these, of which two are producing: the Knarr field (Shell interest 45%), and the Ormen Lange gas field (Shell interest 17.8%). We have a non-operated interest in the producing field Troll.

We are a partner in the Northern Lights carbon dioxide transport and storage project. In this phase the partnership is governed by a collaboration agreement between Equinor, Shell and Total (equal partners).



The Nyhamna gas plant processes gas from the Ormen Lange field, 120 kilometres off the Norwegian coast.

UK

We operate a significant number of our interests on the UK continental shelf under a 50:50 joint-venture agreement with ExxonMobil. On February 24, 2021, ExxonMobil announced that it had signed an agreement with HitecVision (through its wholly owned portfolio company Neo Energy) for the sale of most of its non-operated upstream assets in the UK central and northern North Sea, including a number of interests subject to the Shell ExxonMobil 50:50 joint venture agreement. The sale, which ExxonMobil expects will close later in 2021, is subject to regulatory and third-party approvals. In addition to our oil and gas production from North Sea fields, we have various interests in the Atlantic Margin area where we are not the operator, principally in the West of Shetland area (Clair, Shell interest 28%), and Schiehallion (Shell interest 44.89%).

In 2020, new production came on stream in the Fram (Shell interest 32%), Shearwater (Shell interest 28%) and Pierce (Shell interest 92.52%) fields. We are a participant in the Acorn project, which is in its early stages and will involve carbon capture, utilisation and storage (CCUS) and hydrogen production (joint venture, Shell interest 25%).

We continued with decommissioning Heather assets and the Curlew FPSO, and continued Brent decommissioning. In June 2020 the Pioneering Spirit vessel safely completed the single-lift removal of the 17,000-tonne Brent Alpha topside from the North Sea. This was followed in August 2020 by the SSCV Sleipnir vessel safely lifting and removing the upper portion of the Brent Alpha jacket. Brent Alpha is the third of four platforms, after Brent Delta and Brent Bravo, to be decommissioned and removed from the Brent oil and gas field. In July 2020, the UK government approved the Brent Alpha decommissioning programme, including the derogation to leave in place the Brent Alpha steel jacket footings. A decision on the proposed derogations to leave in place each of the gravity-based concrete installations of Brent Bravo, Brent Charlie and Brent Delta is expected in the first half of 2021.

Rest of Europe

We also have interests in Albania, Bulgaria and Germany.

Asia (including the Middle East and Russia) Brunei

Shell and the Brunei government are 50:50 shareholders in Brunei Shell Petroleum Company Sendirian Berhad (BSP). BSP has long-term oil and gas concession rights onshore and offshore Brunei, and sells most of its gas production to Brunei LNG Sendirian Berhad (see "Integrated Gas" on pages 46-52), with the remainder (23% in 2020) sold in the domestic market.

In addition to our interest in BSP, we have a 35% non-operating interest in the offshore Block B concession, where gas and condensate are produced from the Maharaja Lela field.

We also have non-operating interest in a gas holding area for deep-water exploration Block CA-2 (Shell interest 12.5%), under a PSC. The exploration acreage in Block CA-2 was relinquished in 2020.

We completed the acquisition of Total E&P Deep Offshore Borneo B.V. on March 31, 2020, and renamed the company Shell Exploration and Production Brunei B.V. The acquisition gives us an operator interest in the deep-water Block CA-1 (Shell interest 86.95%), under a PSC.

Iraq

We have a 44% interest in the Basrah Gas Company, which gathers, treats and processes associated gas that was previously being flared from the Rumaila, West Qurna 1 and Zubair fields. The processed gas and associated products, such as condensate and LPG, are sold to the domestic market. Any surplus condensate and LPG is exported.

Kazakhstan

We are the joint operator of the onshore Karachaganak oil and condensate field (Shell interest 29.3%), where we have a licence until the end of 2037. In December 2020, we successfully settled a long-running contractual dispute with the Republic of Kazakhstan government about the profit share between the parties in the Karachaganak joint venture. Shell paid \$424 million as its share of the settlement.

We have an interest in the North Caspian Sea production-sharing agreement (Shell interest 16.8%) which includes the Kashagan field in the Kazakh sector of the Caspian Sea. The North Caspian Operating Company is the operator. This shallow-water field covers an area of around 3,400 square kilometres. Phase 1 development of the field is expected to lead to plateau oil production capacity of around 66 thousand boe/d (Shell interest) by 2021, with the possibility of increases after later phases of development.



The Pioneering Spirit vessel has now lifted and removed the topsides of Brent Alpha, Brent Bravo and Brent Delta.

We have a 7.4% interest in the Caspian Pipeline Consortium, which owns and operates an oil pipeline running from the Caspian Sea to the Black Sea, across parts of Kazakhstan and Russia.

Malaysia

We explore for and produce oil and gas offshore Sabah and Sarawak under 16 PSCs, in which our interests range from 20% to 85%.

Early in 2020, the Malaysian Inland Revenue Board (MIRB) started a tax audit on Sabah and Sarawak Contiguous, which comprises the Sabah and Sarawak upstream businesses. This resulted in preliminary audit findings. The Company has determined it is probable that each uncertain tax treatment used in its income tax filings will ultimately be defensible, either during the next phase of the audit or on appeal to the courts. To date, no notices of additional assessments have been received.

Offshore Sabah, we operate two producing oil fields. These are the Gumusut-Kakap deep-water field (Shell interest 29%), and the Malikai deep-water field (Shell interest 35%). In August 2020, we took FID on phase 3 of the Gumusut-Kakap project. The project involves drilling four subsea wells, (two oil producers and two water injectors), to enhance Gumusut-Kakap's expected recoverable oil volumes.

In October 2020, drilling started for phase 2 of the Malikai project. Phase 2 is expected to deliver first oil in 2021. We also have a 21% interest in the Siakap North-Petai deep-water field and a 30% interest in the Kebabangan field, both operated by third parties. We also have exploration interests in Blocks SB-J, SB-G, SB-N, SB-3G, ND-6 and ND-7.

Offshore Sarawak, in 2020 we were the operator of eight producing gas fields (Shell interest 30%-50%) and one field producing oil and gas (Shell interest 50%). Shell handed over interest and operations of the E11 field/hub, one of the eight producing gas fields, to Petronas at the end of December 2020. After a binding heads of agreement (HoA) in December 2019 to extend the MLNG PSC, the PSC and joint operating agreement (JOA) were amended on November 16, 2020. Under the extended MLNG PSC, as of January 1, 2021, Shell (with 40% interest) will continue to be the operator of the F6 and F23 hubs and the producing E8, F13 East and F13 West fields. Shell will also continue to be the operator for new exploration acreage and new fields (F22, F27, Selasih).

Shell is also the operator for Block SK318 PSC (Shell interest 75%), which contains the discovered Rosmari, Marjoram and Timi fields.

In Block SK408 (Shell interest 30%), first gas was successfully produced from the Gorek field in May 2020 and from Bakong in June 2020. The block also contains the producing Larak gas field.



First oil and gas for phase 2 of the E6 project in Malaysia is expected in 2021.

For SK308 PSC, first oil and gas for phase 2 of the E6 project is expected in 2021.

First gas is expected from the Pegaga field in Block SK320 (Shell interest 20%) by the fourth quarter of 2021.

Nearly all the gas produced offshore Sarawak is supplied to Malaysia LNG and to our gas-to-liquids plant in Bintulu. See "Integrated Gas" on pages 46-52.

Shell has exploration interests in Block SK320. Exploration periods expired in June 2020 for Blocks SK318 and SK408, and in December 2020 for Block SK319. We also have a 40% interest in the amended 2011 Baram Delta enhanced oil recovery PSC, and a 50% interest in Block SK-307.

Oman

We have a 34% interest in the Block 6 concession and its operator Petroleum Development Oman (PDO); the Omani government has a 60% interest. PDO is the operator of more than 200 oil fields, mainly located in central and southern Oman, over an area of 90,874 square kilometres.

We have a 50% interest in the Block 42 exploration and production-sharing agreement. Oman Oil (OQ) has the remaining 50% interest. Shell is the operator of Block 42, an area of 31,068 square kilometres. We have signed an exploration and production-sharing agreement that makes us the operator and gives us a 100% working interest in Block 55, an area of 7,564 square kilometres.

Russia

We have a 50% interest in Salym Petroleum Development N.V., a joint venture with Gazprom Neft that is developing the Salym fields in the Khanty Mansiysk Autonomous District of western Siberia. In March 2020, Salym Petroleum Development N.V. expanded its area of operations by acquiring a 100% interest in LLC Salymsky 2, holder of the licence for the Salymsky 2 block.

Shell and Gazprom Neft each have a 50% interest in the Khanty-Mansiysk Petroleum Alliance VOF partnership. Through this, Shell is a holder of 50% of shares in the JSC Khanty-Mansiysk Petroleum Alliance. Acquisition of the 50% participating interest in LLC Meretoyahaneftgaz from Gazprom Neft through the VOF was cancelled in April 2020. Since then, neither Khanty-Mansiysk Petroleum Alliance VOF partnership nor JSC Khanty-Mansiysk Petroleum Alliance has undertaken any significant activities.

Because European Union and US sanctions prohibit certain defined oil and gas activities in Russia, we have since 2014 suspended our support to Salym Petroleum Development N.V. and JSC Khanty-Mansiysk Petroleum Alliance in relation to shale oil activities.

In November 2020, Shell acquired from Gazprom Neft a 50% shareholding in LLC Gazpromneft-Aero Bryansk, which holds the Leskinsky and Pukhutsayakhsky licences on the Gydan peninsula. The joint venture will be managed by Gazprom Neft and Shell on a parity basis aiming to develop an exploration cluster in the north-eastern part of the Gydan Peninsula.

United Arab Emirates

In Abu Dhabi, we have a 15% interest in the licence of ADNOC Gas Processing. ADNOC Gas Processing exports propane, butane and heavier-liquid hydrocarbons, which it extracts from the wet gas associated with the oil produced by ADNOC Onshore.

UPSTREAM continued

Syria

Shell holds a 65% interest in Shell Petroleum Development B.V. (SSPD), a joint venture between Shell and the China National Petroleum Corporation (CNPC). SSPD holds a 31.3% interest in Al Furat Petroleum Company (AFPC), a Syrian joint stock company, which performs operations under SSPD contracts. In December 2011, in compliance with international sanctions on Syria, including European Council Decision 2011/782/CFSP, Shell suspended all exploration and production activities in Syria.

Rest of Asia

We also have interests in Kuwait, the Philippines and Turkey. In the Philippines, Shell is exploring options to divest its interest in SC 38 (Malampaya).

Africa

Egypt

We have a 50% interest in the Badr Petroleum Company (BAPETCO), a joint venture between Shell and the Egyptian General Petroleum Corporation (EGPC). BAPETCO operates 10 oil- and gas-producing concessions and two exploration concessions, (North East Obaiyed, North Matruh), in the Western Desert. We also have onshore concessions with 100% Shell interest (West El Fayum, South East Horus, South Abu Sennan) and one producing concession extension (Bed 2-17). In 2021, we agreed to sell our onshore upstream assets in Egypt. The deal is expected to be completed in the second half of 2021.

Nigeria

Our share of production, onshore and offshore, in Nigeria was 223 thousand boe/d in 2020, compared with 266 thousand boe/d in 2019. Security issues, sabotage and crude oil theft in the Niger Delta remained significant challenges in 2020.

Onshore

The Shell Petroleum Development Company of Nigeria Limited (SPDC) is the operator of a joint venture (Shell interest 30%) that, after the completion of the sale of its interest in OML 17 on 15 January 2021, has 16 Niger Delta onshore oil mining leases (OML).

SPDC started litigation in May 2019 against the Federal Government (FGN) in the domestic court to challenge the non-renewal of oil mining lease 11 (OML 11). In August 2019, the Federal High Court ruled in favour of SPDC, affirming that it has fulfilled its obligations under the law for the renewal of OML 11. The court ordered the FGN to renew OML 11 for 20 years. In December 2019, the court refused to grant an application by the FGN to suspend the implementation of the judgement. The FGN appealed the court's decision and, in February 2021, the Court of Appeal granted a stay of the judgment in favour of FGN thereby suspending implementation pending a determination of the appeal on the merits. SPDC is taking various steps to protect its right to continue operating OML 11 pending a determination of the appeal.

In separate litigation, in August 2020, the Rivers State Government (RVSG) obtained judgment against SPDC. This judgement, by the Rivers State High Court, sought to reinstate the RVSG's purported purchase of SPDC's interest in OML 11. The purported purchase was said to have

occurred through a court-auction sale arising out of the Ejema Ebubu (Ogoniland) community litigation. SPDC has appealed against the judgement of the Rivers State High Court.

Notwithstanding the FGN appeal and the judgement in favour of the RVSG, SPDC continues to operate OML 11. In doing so, it is supported by the August 2019 Federal High Court judgement in its favour, which remains in force.

SPDC supplies gas to Nigeria LNG Ltd (see "Integrated Gas" on pages 46-52) mainly through its Gbaran-Ubie and Soku projects.

Offshore

Our main offshore deep-water activities are carried out by Shell Nigeria Exploration and Production Company Limited (SNEPCO, Shell interest 100%). SNEPCO has interests in four deep-water blocks, three of which are under PSC terms: the producing assets Bonga (OML 118) and Erha (OML 133) and the non-producing asset Bolia Chota (OML 135). SNEPCO operates OMLs 118 (including the Bonga field FPSO, Shell interest 55%) and 135 (Bolia and Doro, Shell interest 55%) and has a 43.8% non-operating interest in OML 133 (including the Erha FPSO). Separately, SNEPCO holds a 50% non-operating interest in oil prospecting licence (OPL) 245 (Zabazaba, Etan) under a production-sharing agreement.

Authorities in various countries are investigating our investment in Nigerian oil block OPL 245 and the 2011 settlement of litigation pertaining to that block. See Note 25 to the "Consolidated Financial Statements" on pages 260-262.

SPDC also has three shallow-water licences (OMLs 74, 77 and 79) and a 40% interest in the non-Shell-operated Sunlink joint venture that has one shallow-water licence (OML 144).

In our Nigerian operations, we face various risks and adverse conditions which could have a significant adverse effect on our operational performance, earnings, cash flows and financial condition (see "Risk factors" on pages 28-37). There are limitations to the extent to which we can mitigate these risks. We carry out regular portfolio assessments to remain a competitive player in Nigeria for the long term. We support the Nigerian government's efforts to improve the efficiency, functionality and domestic benefits of Nigeria's oil and gas industry. We monitor legislative developments and the security situation. We liaise with host communities, governmental and non-governmental organisations to help promote peace and safe operations. We continue to be transparent about how we manage and report spills, and how we deploy oil-spill response capability and technology. We implement a maintenance strategy to support sustainable equipment reliability and have begun a multi-year programme to reduce routine flaring of associated gas. See "Climate change and energy transition" on pages 94-107.

Rest of Africa

We also have interests in Algeria, Mauritania, Namibia, São Tomé and Príncipe, South Africa, Tanzania and Tunisia.

North America

Bitumen and synthetic crude oil

From January 1, 2020, our interest in bitumen and synthetic crude oil is reported in the Oil Products segment. Comparative information has not been restated.

Canada

We have mineral leases mainly in Alberta and British Columbia. We produce and market natural gas, natural gas liquids and condensate.

Shales

We have around 1.3 million net mineral acres, primarily in the Duvernay play in Alberta and the Montney play in British Columbia. Our Groundbirch asset in British Columbia will be an integral part of the LNG Canada value chain. We currently operate four natural gas processing area facilities in British Columbia. In 2021 we agreed to sell our Duvernay shale light oil position in Alberta. The deal is expected to be completed in the second quarter of 2021.

In 2020, we drilled and brought 17 wells on stream. We have interests in 757 productive wells.

USA

We produce oil and gas in deep water in the Gulf of Mexico, heavy oil in California and oil and gas in Texas. The majority of our oil and gas production interests are acquired under leases granted by the owner of the minerals underlying the relevant acreage, including many leases for federal offshore tracts. Such leases usually run on an initial fixed term that is automatically extended by the establishment of production for as long as production continues, subject to compliance with the terms of the lease (including, in the case of federal leases, extensive regulations imposed by federal law). Our total share of production in the USA was 571 thousand boe/d in 2020.

Gulf of Mexico

The Gulf of Mexico is our major production area in the USA and accounts for around 55% of our oil and gas production in the country. We have an interest in around 315 active federal offshore leases and secured a further 19 blocks as an outcome of the US Gulf of Mexico Lease Sale 256 held in November 2020. Our share of production averaged 313 thousand boe/d in 2020.

We are the operator of eight production hubs – Mars, Olympus, Auger, Perdido, Ursa, Enchilada/Salsa, Appomattox and Stones – and the West Delta 143 processing facilities (Shell interests ranging from 33% to 100%). We continue to produce from Coulomb (Shell interest 100%) which ties into the Na Kika platform, where Shell has a 50% non-operating interest.

We continued exploration, development and abandonment activities in the Gulf of Mexico in 2020.

We continued the ramp-up of the Appomattox floating production system, which started production in May 2019. We also advanced the development of Povernap and Vito, which are both in the execution phase. Povernap, a subsea tie-back to the Olympus production hub, is expected to produce up to 35 thousand boe/d. Vito, Shell's eleventh deep-water project in the Gulf of Mexico, is expected to achieve first oil in 2022 and reach around 100 thousand boe/d at peak rates.

The 2020 Atlantic hurricane season adversely impacted production at our US Gulf of Mexico assets. We experienced extended shutdowns at our Auger and Enchilada/Salsa production hubs because of the storms and the subsequent recovery efforts.



The Turritella FPSO in the Gulf of Mexico.

Shales

We have around 410 thousand net mineral acres. Our activity is focused in the Permian Basin, following our divestment of the Appalachia asset. This was completed in July 2020 and covered the sale of around 443 thousand net leasehold acres across Pennsylvania, with around 358 producing wells in the Marcellus and Utica shale formations, and associated facilities in Tioga County. The transaction also included the transfer of owned and operated midstream infrastructure.



Our shales activity in the USA is focused on the Permian Basin.

In 2020, we drilled and brought on stream 181 wells. We have interests in 1,588 productive wells and operate eight central processing facilities.

California

We have a 51.8% interest in Aera Energy LLC which operates around 13 thousand wells in the San Joaquin Valley in California, mostly producing heavy oil and associated gas.

Alaska

We have sold or relinquished all frontier licences in Alaska and have no plans for frontier exploration offshore Alaska. We retain two exploration acreage positions in the long-established North Slope area of Alaska. One is a non-operating interest of 50% in 13 federal leases held since 2007 and operated by ENI. The other position consists of 18 state leases in nearby West Harrison Bay that have been held since 2012, which we plan to turn over to an alternative operator.

UPSTREAM continued

Rest of North America

Shell has equity in nine deep-water licences and one shallow-water licence in Mexico (Shell interest 40%-100%). We are currently evaluating these positions through exploration drilling.

In November 2020, we agreed a farm-in transaction with the China National Offshore Oil Corporation (CNOOC) E&P Mexico, acquiring a participating interest (Shell interest 30%) in the deep-water round 1.4 Block 4 exploration licence in the offshore Mexico Perdido. This transaction is subject to regulatory approval.

South America

Argentina Shales

We have more than 178 thousand net mineral acres in the Vaca Muerta Basin, a liquids- and gas-rich play located in the Neuquén Province. The operated acreage includes blocks in Cruz de Lorena and Sierras Blancas (Shell interest 90%), Coiron Amargo Sur Oeste (Shell interest 80%), and Bajada de Añelo (Shell interest 50%). We have a 45% non-Shell-operated interest in the Rincon La Ceniza and La Escalonada blocks.

In 2020, we drilled and brought 23 wells on stream. We have interests in 88 producing wells. We have a 90% interest in our operated Sierras Blancas/Cruz de Lorena central processing facility.

In 2020, in a 50:50 partnership with Equinor, we acquired a 60% working interest (Shell 30% interest) in the Bandurria Sur block, operated by YPF S.A., in the Vaca Muerta Basin.

Offshore

We have two frontier exploration blocks offshore Argentina. For both blocks, Shell is the operator with a 60% interest.

Brazil

Our total share of production in Brazil was an average of 394 thousand boe/d in 2020.

Our operated portfolio consists of offshore assets in:

- the Bijupirá and Salema fields (Shell interest 80%) and the BC-10 field (Shell interest 50%) in the Campos Basin;
- the Gato do Mato field in the Santos Basin and the adjacent Sul de Gato do Mato area (Shell interest 50%, after the completed sale of a 30% stake to Ecopetrol in 2020), subject to unitisation, with development options under evaluation; and
- a total of 17 exploration blocks in the following areas:
 - Barreirinhas Basin (10 blocks with Shell interests ranging from 50% to 100%);
 - Santos Basin (Alto Cabo Frio Oeste PSC, Shell interest 55%; Saturno PSC, Shell interest 45%);
 - Potiguar Basin (POT-M-948, Shell interest 100%); and
 - Campos Basin (C-M-659, Shell interest 40%; C-M-713, Shell interest 40%; C-M-791, Shell interest 40% and C-M-757, Shell interest 100%). (Block C-M-757 was awarded to Shell in the National Petroleum Agency (ANP) permanent offer round in December 2020 and is awaiting ratification.)

Our non-operated portfolio consists of the following fields in the offshore Santos Basin:

- Sapinhoá field (Shell interest 30%, operated by Petrobras), straddling the BM-S-9 and Entorno de Sapinhoá blocks, already unitised;
- Lapa field (Shell interest 30%, operated by Total) in Block BM-S-9A;
- Berbigão and Sururu fields (Shell interest 25%, subject to ongoing discussions about unitisation agreements, operated by Petrobras) in Block BM-S-11A;
- Atapu field (Shell interest 4%, unitised in September 2019) in Block BM-S-11A;
- Lula field in Block BM-S-11, recently renamed the Tupi field because of a court decision (subject to unitisation in effect since April 2019, Shell interest 23%, operated by Petrobras);
- Iracema field in Block BM-S-11 (Shell interest 25%, not subject to unitisation, operated by Petrobras); and
- Mero field in the Libra PSC area (Shell interest 20%, unitisation with an adjoining area still subject to government approval, operated by Petrobras).

In addition to the producing assets, we hold interests in two non-operated exploration blocks in the Santos Basin:

- BM-S-50, containing the Sagitário discovery (Shell interest 20%, operated by Petrobras); and
- Tres Marias (Shell interest 40%, operated by Petrobras).

We also hold interests in two non-operated exploration blocks in the Potiguar Basin:

- POT-M-859 (Shell interest 40%, operated by Petrobras); and
- POT-M-952 (Shell interest 40%, operated by Petrobras).



P69 FPSO produces oil and gas in the pre-salt Santos basin, offshore Brazil. Photo credit: Agência Petrobras.

The activities of operated and non-operated fields are currently supported by 17 producing deep-water FPSOs, of which the 17th (P-70) delivered first oil in June 2020. Two additional FPSOs are expected to be brought online over the period 2022-2023 (Mero 1 and Mero 2). In August 2020, we announced the final investment decision to contract the Mero 3 FPSO vessel to be deployed at the Mero field. We agreed to sell our 23% interest in the P-71 FPSO, the deal is expected to be completed in the first quarter of 2021.

Rest of South America

We also have interests in Suriname and Uruguay.

TRADING AND SUPPLY

We market and trade crude oil from most of our Upstream operations.

OIL AND GAS INFORMATION

Proved developed and undeveloped reserves of Shell subsidiaries and Shell share of joint ventures and associates

	Crude oil and natural gas liquids (million barrels)	Synthetic crude oil (million barrels)	Bitumen (million barrels)	Natural gas (thousand million scf)	Total (million boe)[A]
Shell subsidiaries					
Increase/(decrease) in 2020:					
Revisions and reclassifications	(63)	57	-	(3,477)	(607)
Improved recovery	-	-	-	-	-
Extensions and discoveries	48	-	-	228	88
Purchases and sales of minerals in place	8	-	-	(599)	(95)
Total before taking production into account	(7)	57	-	(3,848)	(614)
Production [B]	(606)	(20)	-	(3,012)	(1,144)
Total	(613)	37	-	(6,860)	(1,758)
At January 1, 2020	4,374	607	-	28,992	9,980
At December 31, 2020	3,761	644	-	22,132	8,222
Shell share of joint ventures and associates					
Increase/(decrease) in 2020:					
Revisions and reclassifications	(32)	-	-	(234)	(73)
Improved recovery	-	-	-	-	-
Extensions and discoveries	1	-	-	2	1
Purchases and sales of minerals in place	-	-	-	-	-
Total before taking production into account	(31)	-	-	(232)	(72)
Production [C]	(36)	-	-	(615)	(142)
Total	(67)	-	-	(847)	(214)
At January 1, 2020	283	-	-	4,829	1,116
At December 31, 2020	216	-	-	3,982	902
Total					
Increase/(decrease) before taking production into account	(38)	57	-	(4,080)	(686)
Production	(642)	(20)	-	(3,627)	(1,286)
Increase/(decrease)	(680)	37	-	(7,707)	(1,972)
At January 1, 2020	4,657	607	-	33,821	11,096
At December 31, 2020	3,977	644	-	26,114	9,124
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31, 2020					
	-	322	-	-	322

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 standard cubic feet (scf) per barrel.

[B] Included 40 million boe consumed in operations (natural gas: 225 thousand million scf; synthetic crude oil: 1 million barrels).

[C] Included 7 million boe consumed in operations (natural gas: 42 thousand million scf).

OIL AND GAS INFORMATION continued

PROVED RESERVES

The proved oil and gas reserves of Shell subsidiaries and the Shell share of the proved oil and gas reserves of joint ventures and associates are set out in more detail in "Supplementary information – oil and gas (unaudited)" on pages 265-282.

Before taking production into account, our proved reserves decreased by 686 million boe in 2020. This comprised of decreases of 614 million boe from Shell subsidiaries and of decreases of 72 million boe from the Shell share of joint ventures and associates.

After taking production into account, our proved reserves decreased by 1,972 million boe in 2020 to 9,124 million boe at December 31, 2020.

SHELL SUBSIDIARIES

Before taking production into account, Shell subsidiaries' proved reserves decreased by 614 million boe in 2020. This comprised decreases of 7 million barrels of crude oil and natural gas liquids and 664 million boe (3,848 thousand million scf) of natural gas and an increase of 57 million barrels of synthetic crude oil. The 614 million boe decrease is the net effect of a net decrease of 607 million boe from revisions and reclassifications, an increase of 88 million boe from extensions and discoveries, and a net decrease of 95 million boe related to purchases and sales of minerals in place. On January 15th 2021 Shell announced that the Shell Petroleum Development Company of Nigeria Limited (SPDC) had completed the sale of its 30% interest in Oil Mining Lease (OML17) in the Eastern Niger Delta, and associated infrastructure. Proved reserves at end-2020 associated with this transaction were 26 million boe.

After taking into account production of 1,144 million boe (of which 40 million boe were consumed in operations), Shell subsidiaries' proved reserves decreased by 1,758 million boe in 2020 to 8,222 million boe. In 2020, Shell subsidiaries' proved developed reserves (PD) decreased by 872 million boe to 6,978 million boe, and proved undeveloped reserves (PUD) decreased by 886 million boe to 1,244 million boe.

SHELL SHARE OF JOINT VENTURES AND ASSOCIATES

Before taking production into account, the Shell share of joint ventures and associates' proved reserves decreased by 72 million boe in 2020. This comprised a decrease of 31 million barrels of crude oil and natural gas liquids and a decrease of 41 million boe (232 thousand million scf) of natural gas. The 72 million boe decrease comprises a net decrease of 73 million boe from revisions and reclassifications and an increase of 1 million boe from extensions and discoveries.

After taking into account production of 142 million boe (of which 7 million boe were consumed in operations), the Shell share of joint ventures and associates' proved reserves decreased by 214 million boe to 902 million boe at December 31, 2020.

The Shell share of joint ventures and associates' PD decreased by 169 million boe to 791 million boe, and proved undeveloped reserves (PUD) decreased by 45 million boe to 111 million boe.

For further information, see "Supplementary Information – oil and gas (unaudited)" on pages 265-282.

PROVED UNDEVELOPED RESERVES

In 2020, Shell subsidiaries and the Shell share of joint ventures and associates' PUD decreased by 932 million boe to 1,355 million boe. There were decreases of 339 million boe due to maturation to proved developed – mainly 98 million boe in Brazil, 95 million boe in the USA and 146 million boe spread across other countries. There were also decreases of 682 million boe due to other revisions resulting mainly from a combination of lower year average price and reductions in planned

capital expenditure (mainly in Australia (354 million boe), USA (121 million boe) and Brazil (100 million boe)), partly offset by net increases of 89 million boe due to extensions and discoveries.

In addition to the maturation of 339 million boe from PUD to PD, 75 million boe was matured to PD from contingent resources through PUD as a result of project execution during the year.

PUD held for five years or more (PUD5+) at December 31, 2020, amounted to 184 million boe, a decrease of 74 million boe compared with the end of 2019. These PUD5+ remain undeveloped because development either requires the installation of compression equipment and the drilling of additional wells, which will be executed when required to support existing gas delivery commitments (Russia), or will take longer than five years because of the complexity and scale of the project (Australia and the UK).

The decrease in PUD5+ during 2020 was driven mainly by changes in Jansz-lo (Australia) and Clair (UK).

The fields with the largest PUD5+ at December 31, 2020, were Lunskeye (Russia), Gorgon and Jansz-lo (Australia) and Clair (UK).

During 2020, we spent \$6.5 billion on development activities related to PUD maturation.

DELIVERY COMMITMENTS

We sell crude oil and natural gas from our producing operations under a variety of contractual obligations. Most contracts generally commit us to sell quantities based on production from specified properties, although some natural gas sales contracts specify delivery of fixed and determinable quantities, as discussed below.

In the past three years, we met our contractual delivery commitments, with the notable exceptions of Egypt, Trinidad and Tobago, and Malaysia. In the period 2021-2023, we are contractually committed to deliver to third parties, joint ventures and associates a total of 7,490 billion scf of natural gas from our subsidiaries, joint ventures and associates. The sales contracts contain a mixture of fixed and variable pricing formulae that are generally referenced to the prevailing market price for crude oil, natural gas or other petroleum products at the time of delivery.

In the period 2021-2023, we expect to meet our delivery commitments for almost all the areas in which they are carried, with an estimated 71.9% coming from PD, 5.5% through the delivery of gas that becomes available to us from paying royalties in cash, and 22.6% from the development of PUD as well as other new projects and purchases.

The key exceptions are:

- BG Egypt Development NOV: The government decision to divert gas from the offshore West Delta Deep Marine fields to domestic use has caused a tangible shortfall of 770 billion scf (83% of the promised gas delivery), expected to continue in the near future leaving LNG gas commitment mostly under force majeure;
- Trinidad and Tobago (East Coast Marine Area and North Coast Marine Area), where PD for all fields fail the economic test at the yearly average price for natural gas. But we expect to cover 86% of our delivery commitments from existing developed resource volumes and new projects, resulting in an expected true shortfall of some 103 billion scf; and
- In Malaysia, one of the third-party gas supply lines which was under maintenance has not been repaired during 2020. Force majeure has been declared, and no penalties have been incurred, resulting in an expected true shortfall of some 72 billion scf (54% of the promised gas delivery).

Summary of proved oil and gas reserves of Shell subsidiaries and Shell share of joint ventures and associates (at December 31, 2020)

Based on average prices for 2020

	Crude oil and natural gas liquids (million barrels)	Natural gas (thousand million scf)	Synthetic crude oil (million barrels)	Total (million boe)[A]
Proved developed				
Europe	108	1,817	-	421
Asia	1,609	12,850	-	3,825
Oceania	68	3,699	-	707
Africa	316	1,341	-	548
North America				
USA	539	669	-	654
Canada	12	720	644	780
South America	675	925	-	834
Total proved developed	3,327	22,021	644	7,769
Proved undeveloped				
Europe	76	886	-	229
Asia	174	755	-	304
Oceania	5	520	-	93
Africa	63	1,022	-	239
North America				
USA	189	132	-	212
Canada	3	575	-	102
South America	140	203	-	176
Total proved undeveloped	650	4,093	-	1,355
Total proved developed and undeveloped				
Europe	184	2,703	-	650
Asia	1,783	13,605	-	4,129
Oceania	73	4,219	-	800
Africa	379	2,363	-	787
North America				
USA	728	801	-	866
Canada	15	1,295	644	882
South America	815	1,128	-	1,010
Total	3,977	26,114	644	9,124
Reserves attributable to non-controlling interest in Shell subsidiaries	-	-	322	322

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

EXPLORATION

We continue to focus and high-grade our portfolio of growth options.

In February 2020:

We acquired a 70% interest as operator of the UK Southern North Sea licences P2304 and P1929 which contain the Resolution gas discovery. Our appraisal programme consists of 3D seismic and a contingent appraisal well.

We added 4,553 square kilometres of exploration licences in the UK and Netherlands Southern North Sea across multiple plays.

We signed a farm-out agreement with Ecopetrol into the Colombia Offshore COL-5, Purple Angel, and Fuerte Sur blocks, as operator with a 50% working interest. Government ratification was obtained in December 2020.

Two exploration blocks, C-M-659 and C-M-713, awarded through Brazil's 16th National Petroleum Agency (ANP) bid round, were ratified. These Shell-operated blocks (Shell interest 40%) are located in the outboard Campos Basin and cover an area of around 1,800 square kilometres. The joint venture has a commitment to acquire 3D seismic in both blocks and to drill one well in Block C-M-659.

In March 2020:

We completed the sale and purchase agreement signed in October 2019 for the acquisition of Total E&P Deep Offshore Borneo B.V. and all its interests in the deep-water exploration Block CA-1 (Shell interest 86.95%) production-sharing agreement (PSA). We assumed operatorship of Block CA-1, with a total area of around 5,800 square kilometres which is largely unexplored. The deal also gave us access to the Jagus East oil field which lies within CA-1.

An exploration and production-sharing agreement for Block 55 in the south-east of the Sultanate of Oman was ratified by Royal Decree. Oman Shell now has a 100% working interest and operatorship of Block 55, with a total area of 7,564 square kilometres. The agreement includes a work programme of regional studies, seismic acquisition and other potential exploration activities.

In US Gulf of Mexico Lease Sale 254, we acquired seven blocks across multiple plays in the US Gulf of Mexico.

In July 2020, we signed a sales and purchase agreement for the Esenin deal, a 50% farm-in into two Gazprom Neft-held blocks on the Gydan peninsula in north-west Siberia, Russia. The deal was finalised in November 2020. The blocks cover an area of around 3,850 square kilometres.

In September 2020, Shell and Kosmos Energy executed a portfolio transaction under which Kosmos divested seven deep-water exploration licences to Shell across four countries: Suriname, São Tomé and Príncipe, Namibia and South Africa. Suriname (Block 42) represents a new country entry for Shell with a 33.33% participating interest. In São Tomé and Príncipe, Shell will expand its position in two blocks – (Block 6 by 25% working interest and Block 11 by 35% working interest) – and enter two others (10 and 13) with a 35% interest in both. In both Namibia and South Africa, Shell will deepen its position by 45% working interest in the two blocks, PEL0039 and NCUD. The agreement received all necessary regulatory approvals and third-party consents in December 2020, with the exception of South Africa which is expected to be completed in 2021.

In November 2020:

We agreed a farm-in transaction with CNOOC E&P Mexico, acquiring a participating interest (Shell interest 30%) in the deep-water round 1.4 Block 4 exploration licence in the offshore Mexico Perdido. This transaction is subject to regulatory approval.

We agreed a farm-in transaction with Impact Africa Limited to acquire a 50% participating interest in the frontier deep-water blocks Transkei/Algoa (ER252) off the east coast of South Africa, with an area of around 46,000 square kilometres. Pursuant to the agreement, we will secure the operatorship from the counterparty. The agreement is subject to customary conditions including regulatory approvals.

In the delayed US Gulf of Mexico Lease Sale 256 held in November 2020, Shell secured a further 19 blocks.

In December 2020:

Our exploration presence in offshore Egypt was bolstered by entries into new blocks in the West Mediterranean and the Red Sea. For the West Mediterranean, Herodotus Block 3 North Ras Kanais (Shell interest 30%) was ratified in December 2020 with more than 4,400 square kilometres of acreage. Red Sea Block 3 (Shell interest 90%, operator) was ratified in December 2020 and covers more than 3,000 square kilometres in an under-explored area south of the Gulf of Suez. Some blocks have been awarded but are yet to be ratified; Red Sea Block 4 (Shell interest 63%, operator) and Herodotus Blocks 6 (North Marina, Shell interest 63%) and 7 (North Cleopatra Offshore, Shell interest 63%) all of which are awaiting government ratification.

In Brazil, we were awarded Block C-M-757 (Outboard Campos Basin) (Shell interest 100%) in the Permanent Offer Bid Round. This is awaiting ratification.

In total, the net undeveloped acreage in our exploration portfolio increased by around 9.4 million acres in 2020. The largest contributions were licence entries in São Tomé and Príncipe, the Sultanate of Oman, the Arab Republic of Egypt, Namibia and the Nation of Brunei. There were some relinquishments and divestments, with the largest being in Australia, Norway and Italy.

For further information, see "Supplementary Information – oil and gas (unaudited)" on pages 265-282.

LOCATION OF OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES

Location of oil and gas exploration and production activities [A] (at December 31, 2020)

	Exploration	Development and/or Production	Shell operator [B]
Europe			
Albania	•		•
Bulgaria	•		•
Cyprus		•	
Germany	•	•	
Italy	•	•	
Netherlands	•	•	•
Norway	•	•	•
UK	•	•	•
Asia			
Brunei	•	•	•
China		•	•
Indonesia		•	
Kazakhstan	•	•	
Malaysia	•	•	•
Myanmar	•		
Oman	•	•	•
Philippines	•	•	•
Qatar		•	•
Russia	•	•	
Turkey	•		•
Oceania			
Australia	•	•	•
Africa			
Egypt	•	•	•
Mauritania	•		•
Morocco	•		
Namibia	•		•
Nigeria	•	•	•
Sao Tome and Principe	•		
South Africa	•		•
Tanzania		•	•
Tunisia		•	•
North America – USA			
Mexico	•		•
USA	•	•	•
North America – Canada			
Canada	•	•	•
South America			
Argentina	•	•	•
Bolivia	•	•	•
Brazil	•	•	•
Colombia	•		•
Suriname	•		•
Trinidad & Tobago	•	•	•
Uruguay	•		•

[A] Includes joint ventures and associates. Where a joint venture or an associate has properties outside its base country, those properties are not shown in this table.

[B] In several countries where "Shell operator" is indicated, Shell is the operator of some but not all exploration and/or production ventures.

OIL AND GAS INFORMATION continued

OIL AND GAS PRODUCTION AVAILABLE FOR SALE

Crude oil and natural gas liquids [A]

	2020		2019		2018	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe						
Denmark	—	—	7,490	—	13,036	—
Italy	11,342	—	9,747	—	10,921	—
Norway	6,914	—	7,025	—	13,528	—
UK	30,061	—	30,677	—	31,431	—
Other [B]	609	1,084	723	1,135	795	1,417
Total Europe	48,926	1,084	55,662	1,135	69,711	1,417
Asia						
Brunei	387	17,094	196	20,002	283	18,738
Kazakhstan	37,769	—	34,269	—	32,432	—
Malaysia	18,494	—	21,993	—	24,650	—
Oman	74,854	—	76,493	—	76,847	—
Russia	20,816	9,050	22,442	9,413	22,003	10,403
Other [B]	30,101	7,629	28,796	7,709	28,769	7,768
Total Asia	182,421	33,773	184,189	37,124	184,984	36,909
Total Oceania [B]	7,416	—	10,058	—	8,883	—
Africa						
Nigeria	48,620	—	56,589	—	53,102	—
Other [B]	8,485	—	7,802	—	8,265	—
Total Africa	57,105	—	64,391	—	61,367	—
North America						
USA	165,169	—	171,204	—	140,035	—
Canada	8,128	—	11,506	—	13,111	—
Total North America	173,297	—	182,710	—	153,146	—
South America						
Brazil	131,339	—	126,366	—	118,681	—
Other [B]	5,072	729	3,900	—	3,414	—
Total South America	136,411	729	130,266	—	122,095	—
Total	605,576	35,586	627,276	38,259	600,186	38,326

[A] Reflects 100% of production of subsidiaries except in respect of production-sharing contracts (PSCs), where the figures shown represent the entitlement of the subsidiaries concerned under those contracts.

[B] Comprises countries where 2020 production was lower than 10,100 thousand barrels or where specific disclosures are prohibited.

Synthetic crude oil

	Thousand barrels		
	2020	2019	2018
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	18,920	19,076	19,514

Natural gas [A]

	2020		2019		Million standard cubic feet	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe						
Denmark	—	—	24,433	—	45,027	—
Germany	35,918	—	41,846	—	40,368	—
Ireland	—	—	—	—	44,833	—
Netherlands	—	131,648	—	244,286	—	271,303
Norway	187,627	—	182,683	—	239,253	—
UK	65,012	—	62,174	—	82,695	—
Other [B]	13,005	—	15,062	—	16,422	—
Total Europe	301,562	131,648	326,198	244,286	468,598	271,303
Asia	—	—				
Brunei	21,025	159,846	22,185	160,648	21,205	157,476
China	46,750	—	44,510	—	42,419	—
Kazakhstan	86,999	—	84,499	—	78,575	—
Malaysia	226,791	—	226,277	—	237,102	—
Philippines	40,549	—	44,374	—	44,017	—
Russia	4,301	142,418	4,563	134,807	4,044	136,652
Thailand	—	—	—	—	25,973	—
Other [B]	411,979	118,153	407,899	118,253	378,785	117,976
Total Asia	838,394	420,417	834,307	413,708	832,120	412,104
Oceania	—	—				
Australia	633,580	20,646	686,956	20,840	648,735	18,923
New Zealand	—	—	—	—	40,153	—
Total Oceania	633,580	20,646	686,956	20,840	688,888	18,923
Africa	—	—				
Egypt	104,946	—	92,169	—	148,721	—
Nigeria	190,982	—	234,332	—	232,899	—
Other [B]	27,438	—	30,266	—	30,669	—
Total Africa	323,366	—	356,767	—	412,289	—
North America	—	—				
USA	255,383	—	389,130	—	355,075	—
Canada	164,451	—	220,005	—	247,890	—
Total North America	419,834	—	609,135	—	602,965	—
South America	—	—				
Bolivia	45,015	—	48,501	—	55,480	—
Brazil	73,914	—	78,526	—	68,865	—
Trinidad and Tobago	141,576	—	159,698	—	104,454	—
Other [B]	9,609	830	8,662	—	8,062	—
Total South America	270,114	830	295,387	—	236,861	—
Total	2,786,850	573,541	3,108,750	678,834	3,241,721	702,330

[A] Reflects 100% of production of subsidiaries except in respect of PSCs, where the figures shown represent the entitlement of the subsidiaries concerned under those contracts.

[B] Comprises countries where 2020 production was lower than 41,795 million scf or where specific disclosures are prohibited.

OIL AND GAS INFORMATION continued

AVERAGE REALISED PRICE BY GEOGRAPHICAL AREA

Crude oil and natural gas liquids

	2020		2019		2018	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe	39.51	39.05	65.11	58.08	68.23	64.24
Asia	38.73	42.51	58.16	65.25	64.06	70.66
Oceania	21.29	—	51.51	—	61.63	—
Africa	41.23	—	65.39	—	71.02	—
North America – USA	34.17	—	54.56	—	61.87	—
North America – Canada	27.17	—	36.61	—	43.72	—
South America	36.01	37.28	56.68	—	62.67	—
Total	36.72	42.31	57.56	65.05	63.96	70.43

\$/barrel

Synthetic crude oil

	2020	2019	2018
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	31.13	50.27	48.90

\$/barrel

Natural gas

	2020		2019		2018	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe	3.66	3.76	5.59	4.95	7.08	4.06
Asia	2.68	4.19	2.66	6.34	2.99	7.06
Oceania	6.21	3.15	8.22	3.91	8.66	4.15
Africa	2.55	—	2.92	—	3.02	—
North America – USA	1.72	—	2.27	—	3.12	—
North America – Canada	1.61	—	1.37	—	1.35	—
South America	1.35	1.90	2.33	—	3.50	—
Total	3.31	4.06	3.95	5.80	4.63	5.74

\$/thousand scf

AVERAGE PRODUCTION COST BY GEOGRAPHICAL AREA**Crude oil, natural gas liquids and natural gas [A]**

	2020		2019		2018	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe	20.50	11.44	14.14	5.76	15.03	6.37
Asia	5.54	6.83	6.30	6.17	6.52	6.24
Oceania	8.92	20.23	9.17	24.49	8.41	32.18
Africa	9.43	—	8.44	—	8.25	—
North America – USA	12.50	—	11.78	—	12.78	—
North America – Canada	10.52	—	11.88	—	11.58	—
South America	5.12	—	6.26	—	8.60	—
Total	8.49	6.94	8.95	6.48	9.66	6.81

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

Synthetic crude oil

	2020	2019	2018
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	18.28	19.29	20.15

OIL PRODUCTS

Key statistics

	\$ million, except where indicated		
	2020	2019	2018
Segment earnings [A]	(494)	6,139	6,025
Including:			
Revenue (including inter-segment sales)	134,930	288,279	327,022
Share of profit of joint ventures and associates [A]	988	1,179	1,101
Interest and other income	(93)	273	393
Operating expenses [B]	13,511	15,730	17,615
Depreciation, depletion and amortisation	10,473	4,461	3,165
Taxation charge [A]	(898)	1,319	1,211
Identified Items [B]	(6,489)	(93)	231
Adjusted Earnings [B]	5,995	6,231	5,794
Capital expenditure	3,236	4,654	4,389
Cash capital expenditure [B]	3,328	4,907	4,643
Refinery utilisation (%) [C]	72	78	78
Refinery processing intake (thousand b/d)	2,063	2,564	2,648
Oil Products sales volumes (thousand b/d)	4,710	6,561	6,783

[A] See Note 4 to the "Consolidated Financial Statements" on pages 230-232. Segment earnings are presented on a current cost of supplies basis.

[B] See "Non-GAAP measures reconciliations" on pages 305-306.

[C] With effect from January 1, 2020, Shell discloses utilisation instead of availability to improve transparency on refinery production volumes. Utilisation is defined as the actual usage of the plants as a percentage of the rated capacity.

OVERVIEW

Our Oil Products business is part of an integrated value chain that refines crude oil and other feedstocks into products that are moved and marketed around the world for domestic, industrial and transport use. The products we sell include gasoline, diesel, heating oil, aviation fuel, marine fuel, low-carbon fuels, lubricants, bitumen and sulphur. We also trade crude oil, oil products and petrochemicals. We provide access to electric vehicle charge points at home, at work and on-the-go, including at our forecourts and at a range of public locations.

Our Oil Products activities comprise Refining and Trading, and Marketing. These are referred to as classes of business. Marketing includes Retail, Lubricants, Business-to-Business (B2B), Pipelines and Low-Carbon Fuels (biofuels and renewable natural gas (RNG)). In Trading and Supply, we trade crude oil, oil products and petrochemicals to optimise feedstocks for Refining, to supply our Marketing businesses and third parties, and for our own profit. We also manage Oil Sands activities – the extraction of bitumen from mined Oil Sands and its conversion into synthetic crude oil. Our Oil Sands activities were previously reported under Upstream. As of January 1, 2020, they are reported under Oil Products.

BUSINESS CONDITIONS

In 2020, oil markets experienced unprecedented developments in demand driven by the COVID-19 pandemic. At the start of 2020, global oil demand for the year was expected to grow by 1.2 million barrels per day (b/d). Then in January, oil demand started to contract because demand fell in China as lockdown was imposed to contain the virus outbreak. In subsequent months, oil demand contracted further as the outbreak in China evolved into a global pandemic and lockdowns were introduced across the world. In April, oil demand fell to its lowest level, around 22 million b/d below year-average demand in 2019, according to an estimate of the International Energy Agency (IEA). Contraction of such magnitude has never been recorded before. Country lockdowns deeply impacted transportation sectors, especially passenger road and passenger air in Organisation for Economic Co-operation and Development (OECD) economies. In subsequent months, oil demand started recovering, but only partially, because resurgences of COVID-19 triggered re-imposition of social distancing and travel restrictions. By the fourth quarter, global oil demand was still estimated to be around 5.5 million b/d below the 2019 level, according to the Oil Market Report

published by the IEA in January 2021. Averaged for the full year, oil demand contracted by around 9 million b/d, or 9%, to 91.2 million b/d. Oil demand fell by 5.7 million b/d in OECD economies, and by 3.2 million b/d in non-OECD economies. By contrast, oil demand in 2019 was 0.8 million b/d higher than in 2018.

Industry gross refining margins weakened in 2020 because demand for oil products was significantly reduced by the fall in economic activity and increase in travel restrictions caused by COVID-19. Demand for transportation fuels such as gasoline for passenger cars and kerosene for air transportation was hit particularly hard. During most of the second half of the year, mobility and the resulting demand for transportation fuels improved in some parts of the world, especially in China and South-east Asia. At the end of the year, new waves of COVID-19 infections in Europe and the Americas severely limited any global increase in demand for transportation fuels.

On January 1, 2020, the new International Maritime Organization low-sulphur shipping fuel specification came into effect, limiting the sulphur content of maritime fuel to 0.5%. This had a limited effect on margins because of the economic slowdown in 2020 and because companies had prepared for the new regulations by building inventory in the second half of 2019.

The destruction of demand caused by COVID-19 led to industry idling some refinery capacity. Permanent refinery closures were also announced in 2020, but construction of new capacity did occur during the year, especially in the Middle East and Asia.

See "Market overview" on pages 38-40.

REFINERY UTILISATION

With effect from January 1, 2020, Shell discloses utilisation instead of availability to improve transparency on refinery production volumes. Utilisation is defined as the actual usage of the plants as a percentage of the rated capacity.

Utilisation was 72% in 2020, compared with 78% in 2019. Lower utilisation in 2020 was mainly because of lower demand and economic optimisation of sites.

OIL PRODUCTS SALES

Oil Products sales volumes decreased by 28% in 2020 compared with 2019. The decrease in sales volumes was largely driven by the COVID-19 pandemic affecting Marketing volumes. There was also a reporting change effective from January 1, 2020 and certain additional Oil Products contracts held for trading purposes were reported on a net rather than a gross basis. This reporting change decreased sales volumes by 10%.

EARNINGS 2020-2019

Segment earnings in 2020 came to a loss of \$494 million, 108% lower than in 2019. Earnings in 2020 included a net charge of \$6,489 million, compared with a net charge of \$93 million in 2019 which is described at the end of this section.

Excluding the impact of the net charges, earnings in 2020 were \$5,995 million, compared with \$6,231 million in 2019. Marketing accounted for 76% of these 2020 earnings, Refining for -19% and Trading & Supply for 43%.

The decrease in Oil Products earnings, excluding the net charge, was \$236 million (4%) lower compared with 2019. This was driven by lower Refining and Trading margins (around \$2,400 million), lower Marketing margins (around \$600 million), partly offset by lower operating expenses (around \$2,000 million) and other items mainly including tax movements (around \$700 million).

The decrease in earnings of \$236 million, analysed by class of business was as follows:

- Refining and Trading earnings were \$101 million lower than in 2019, mainly because of lower realised refining margins driven by lower demand because of the pandemic and its effect on the economy. This was partly offset by higher earnings from crude and oil products trading and optimisation, lower operating expenses and favourable deferred tax movements.
- Marketing earnings were \$135 million lower than in 2019, mainly driven by lower sales volumes due to the impact of the pandemic. This was largely offset by strong margins in Retail and Lubricants on account of better margin management, higher penetration of premium fuels and lower operating expenses.

Segment earnings in 2020 included a net charge of \$6,489 million.

This included:

- impairment charges of \$5,530 million (across sites, reflecting revisions to medium- and long-term price outlook assumptions in light of: changes in supply and demand fundamentals in the energy market; macroeconomic conditions; the COVID-19 pandemic; expenditure at Pulau Bukom in Singapore including transformation; and the shutdown of the Convent refinery in Louisiana, USA);
- restructuring costs of \$365 million (mainly shutdown of Convent, Bukom transformation and various initiatives across Oil Products);
- other net charges of \$552 million (mainly onerous contract provisions due to shutdown of Convent); and
- a net charge of \$101 million due to the fair value accounting of commodity derivatives.

These charges were partly offset by:

- net gains from disposal of assets of \$59 million.

Segment earnings in 2019 included a net charge of \$93 million.

This included:

- impairment charges of \$337 million (mainly expenditure at Bukom and other assets);
- costs of \$84 million relating to restructuring (various initiatives across Oil Products);
- net charge of \$66 million due to the fair value accounting of commodity derivatives; and
- other net charges of \$26 million (mainly provision for discount rate change).

The above were partly offset by:

- net gains of \$329 million from disposal of assets; and
- gains from one-off tax items of \$91 million (tax rate changes in Alberta, Canada).

EARNINGS 2019-2018

Segment earnings in 2019 of \$6,139 million were 2% higher than in 2018. Earnings in 2019 included a net charge of \$93 million described above. Earnings in 2018 included a net gain of \$231 million, reflecting gains on disposal of assets of \$273 million (mainly our Oil Products assets in Argentina and other smaller disposals), a net gain from fair value accounting of commodity derivatives of \$224 million, gains from one-off tax items of \$91 million (mainly corporate income tax rate changes in the Netherlands and the USA) and other net gains of \$50 million (which included a one-off gain from the Ontario cap-and-trade scheme). These were partly offset by impairment charges of \$309 million and redundancy and restructuring charges of \$98 million.

Excluding the impact of these items, earnings in 2019 were \$6,231 million, compared with \$5,794 million in 2018. Marketing accounted for 75% of these 2019 earnings, Refining for 4% and Trading & Supply for 21%.

The increase in Oil Products earnings, excluding the net charge, was \$437 million (8%) compared with 2018. The increase was driven by higher Marketing margins (around \$500 million), benefit from foreign exchange (around \$250 million) and the change in accounting policy IFRS 16 (around \$140 million). This was partly offset by lower Refining and Trading margins (around \$400 million) and other impacts resulting in a net charge of around \$50 million. Marketing margins benefited from stronger unit margins. These were partly offset by lower earnings from Raizen, the joint venture (Shell interest 50%) in Brazil, caused by adverse foreign exchange and lower fuel margins. Refining and Trading margins were lower than in 2018, mainly because of lower realised refining margins caused by adverse price variance across all regions, driven by lower global demand growth and an increase in worldwide refining capacity.

CASH CAPITAL EXPENDITURE

Cash capital expenditure (cash capex) was \$3.3 billion in 2020, compared with \$4.9 billion in 2019.

Cash capital expenditure in Refining and Trading decreased by \$1.3 billion mainly because of cash preservation initiatives (lower capital expenditure spends including turnaround deferrals). In Marketing, cash capital expenditure decreased by \$0.3 billion as a result of cash preservation initiatives and reduced spending in US pipelines projects as they are nearing completion. Our cash capital expenditure is expected to be around \$4-4.5 billion in 2021.

OIL PRODUCTS continued

PORTFOLIO AND BUSINESS DEVELOPMENTS

Shell announced its plans to reshape its portfolio of assets and products to meet the cleaner energy needs of its customers in the coming decades. Significant portfolio and business developments during 2020 included:

- In the USA, in February 2020, our subsidiary Equilon Enterprises LLC, doing business as Shell Oil Products US (Shell) completed the sale of the Martinez refinery to PBF Holding Company LLC in the USA for a consideration of \$1.2 billion, which included the refinery and inventory.
- Also in the USA, in March 2020, we announced our intention to sell the Puget Sound refinery in Washington State and Mobile site in Alabama.
- In August 2020, Pilipinas Shell Petroleum Corporation, a subsidiary of Royal Dutch Shell in which we have an interest of 55%, announced that it will permanently shut down its Tabangao Refinery in Batangas City, Philippines, and convert it to a full import terminal.
- In November 2020, we announced that we had begun transforming our Shell Pulau Bukom manufacturing site in Singapore into an energy and chemicals park. This is part of our strategy to integrate our refining portfolio with Chemicals, resulting in approximately six high-value energy and chemicals parks, of which Bukom will be one. Bukom will switch from a crude-oil, fuels-based product slate towards new low-carbon value chains. Crude processing capacity at Bukom will be reduced by around half.
- In November 2020, we announced that we are shutting down the Convent Refinery in Louisiana, USA. Shell continues to assess market interest for the potential divestment of the asset during and after the shutdown, but does not intend to operate it in the future.
- In January 2021, Shell reached an agreement with Postlane for the sale of A/S Dansk Shell in Denmark, which consists of the Fredericia Refinery and local trading and supply activities.
- In January 2021, Shell signed an agreement to acquire 100% of ubitricity, a leading European provider of on-street charging for electric vehicles. The acquisition was completed in February 2021.
- In January 2021, Shell announced the signing of commercial agreements to invest in Varennes Carbon Recycling, the first waste to low-carbon fuels plant in Québec, Canada. Shell will have a 40% interest in the plant, which will use technology developed by Enerkem. The facility will produce low-carbon fuels and renewable chemicals products from non-recyclable waste. Commissioning of the first phase of the facility is scheduled for 2023.

BUSINESS AND PROPERTY

Refining and Trading Refining

We have interests in 13 refineries worldwide, (after converting Tabangao in the Philippines into a terminal and deciding in November 2020 to shut down Convent, in Louisiana, USA). We have the capacity to process a total of 2.2 million barrels of crude oil per day (Shell share, before it was announced that Bukom's crude capacity would reduce by around 200 thousand b/d). The distribution of our refining capacity is 46% in Europe and Africa, 33% in the Americas and 21% in Asia.

Shell's Refining business is transforming. We will further concentrate our refineries portfolio to meet our strategic aims and to capitalise on the strong integration between our customers, trading operations, chemical plants and, increasingly, our low-carbon fuels output.

The six sites expected to form our energy and chemicals parks include Deer Park and Norco in the USA, Scotford in Canada, Pernis in the Netherlands, Rheinland in Germany and Pulau Bukom in Singapore,

Our Bukom refinery will move from a crude-oil, fuels-based product slate towards new, low-carbon products. It will reduce its crude processing capacity as a result by around 200 thousand b/d sometime in July 2021.

In 2020, Pilipinas Shell Petroleum Corporation (PSPC) approved the transformation of the Tabangao refinery into an import terminal. Shell also decided to shut down the Convent Refinery in Louisiana, USA, starting the process in November 2020.

Trading and Supply

Through our main trading offices in London, Houston, Singapore and Rotterdam, we trade crude oil, refined products, chemical feedstocks and environmental products. Trading and Supply trades in physical and financial contracts, lease storage and transportation capacities, and manages shipping and wholesale commercial fuel activities globally.

Operating in around 25 countries, with more than 125 Shell and joint-venture terminals, we believe our supply and distribution infrastructure is well positioned to make deliveries around the world.

Shipping and Maritime enables the safe delivery of the Shell Trading and Supply contracts. This includes supplying feedstocks for our refineries and chemical plants, and finished products such as gasoline, diesel and aviation fuel to our Marketing businesses and customers.

Shell Wholesale Commercial Fuels provides fuels for transport, industry and heating. Our range of products, from reliable main-grade fuels to premium products, is designed to provide tangible vehicle and business benefits.

Oil Sands

Synthetic crude oil is produced by mining bitumen-saturated sands, extracting the bitumen, and transporting it to a processing facility where hydrogen is added to make a wide range of feedstocks for refineries. The Athabasca Oil Sands Project (AOSP) includes the Albion Sands mining and extraction operations, the Scotford upgrader and the Quest carbon capture and storage (CCS) project.

We have a 50% interest in 1745844 Alberta Ltd. (formerly known as Marathon Oil Canada Corporation), which holds a 20% interest in the Athabasca Oil Sands Project. With effect from January 1, 2020, Oil Sands is reported under Oil Products. It was previously reported under Upstream. Prior-period information has been restated for comparative purposes.



The Quest CCS facility in Alberta, Canada.

Marketing Retail

Shell is the world's largest mobility retailer, by number of sites, with almost 46,000 service stations operating in nearly 80 countries at the end of 2020. We operate different models across these markets, from full ownership of retail sites through to brand licensing agreements.

Every day, around 30 million customers visit these sites to buy fuel, convenience items including beverages and fresh food, and services such as lubricant changes and car washes. We offer our business customers Shell Fleet Solutions, through which they can obtain items including fuel cards, road services and carbon-neutral offers.

We have more than 100 years' experience in fuel development. Aided by our partnership with Scuderia Ferrari, we have concentrated on developing fuels with special formulations designed to clean engines and improve performance. We sold such fuels under the Shell V-Power brand in 64 countries in 2020.

In a growing number of markets, we are offering customers lower-emission products and services, including biofuels, electric vehicle fast charging, hydrogen and various gaseous fuels such as LNG. In 2020, we launched carbon-neutral driving offers in five new countries. Across the seven countries where we now offer carbon-neutral driving, we helped offset customer emissions from more than 1 billion litres of fuel by buying carbon credits linked to projects that plant and protect forests, wetlands and other natural ecosystems.

Shell operates more than 60,000 electric vehicle charge points. This includes over 1,000 charge points at Shell forecourts and new locations as well as operated charge points owned by our individual and business customers.

In January 2021, Shell signed an agreement to acquire 100% of ubitricity, a leading European provider of on-street charging for electric vehicles. The move represents a further step in Shell's efforts to support drivers as they switch to lower-carbon transport. The acquisition was completed in February 2021.



Shell offers electric vehicle drivers access to Shell Recharge points in 19 countries.

We have around 50 hydrogen retail sites in Europe and North America, where drivers can fill up their vehicles with hydrogen fuel.

Lubricants

Shell Lubricants has been the number one global finished lubricants supplier in terms of market share for 14 consecutive years, according to Kline & Company data for 2019. Across more than 160 markets, we produce, market and sell technically advanced lubricants for passenger cars, motorcycles, trucks, coaches, and machinery used in the manufacturing, mining, power generation, agriculture and construction sectors.

We also manufacture premium lubricants for conventional vehicles and Shell E-fluids for electric vehicles using gas-to-liquids (GTL) base oils that are made from natural gas at our Pearl GTL plant in Qatar (see "Integrated Gas" on pages 46-52).

We have a global lubricants supply chain with a network of four base oil manufacturing plants, 32 lubricant blending plants, eight grease plants and four GTL base oil storage hubs.

Through our marine activities, we primarily provide the shipping and maritime sectors with lubricants, but also with fuels, chemical products and related technical and digital services. We supply 259 grades of lubricants and six types of fuel to vessels worldwide, ranging from large ocean-going tankers to small fishing boats.

Business-to-Business

Our Business-to-Business (B2B) activities encompass the sale of fuels, speciality products and services to a broad range of commercial customers.

Shell Aviation provides aviation fuel, lubricants and low-carbon solutions globally. In 2020, we collaborated with many organisations to develop a scalable supply of sustainable aviation fuel made from renewable raw materials and waste products. In partnership with World Energy, Shell Aviation has agreed to supply up to 6 million gallons of sustainable aviation fuel to Amazon Air.

Shell Bitumen supplies customers across 60 markets and provides enough bitumen to resurface 500 kilometres of road lanes every day. It also invests in research and development to create innovative products.

Shell Sulphur Solutions is a business that manages the complete value chain of sulphur, from refining to marketing. The business provides sulphur for use in applications such as fertiliser, mining and chemicals. It also develops new technologies for sulphur that benefit sectors such as agriculture.

Pipelines

Shell Pipeline Company LP (Shell interest 100%) operates 9 tank farms across the USA, owns all of the interest in one such tank farm and, through its subsidiaries, has a majority ownership interest in the other 8 tank farms. It transports around 2 billion barrels of crude oil and refined products a year through around 6,000 kilometres of pipelines in the Gulf of Mexico and five US states. Our various non-Shell-operated ownership interests provide a further 14,000 pipeline kilometres.

We carry more than 40 types of crude oil and more than 20 grades of fuel and chemicals, including gasoline, diesel, aviation fuel, chemicals and ethylene.



The Falcon pipeline will run through 155 kilometres of Pennsylvania, West Virginia and Ohio.

OIL PRODUCTS continued

Shell Midstream Partners, L.P., a midstream master limited partnership, owns, operates, develops and acquires pipelines and other midstream assets in the USA. Its assets consist of interests in entities that own pipelines and terminals for crude oil and refined products. These serve as key infrastructure that transports crude oil produced onshore and offshore to the refining markets of the US Gulf Coast and Midwest. Shell Midstream Partners also delivers refined products from these markets to major demand centres. Its assets also include interests in entities that own natural gas and refinery gas pipelines. These transport offshore natural gas to market hubs, and deliver refinery gas from plants and refineries to chemical sites along the Gulf Coast. Shell controls the general partner.

See "Governance – Related Party Transactions" on page 185 for information on transactions between Shell and Shell Midstream Partners, L.P.

Low-Carbon Fuels Biofuels

In 2020, around 9.5 billion litres of biofuels went into Shell's fuels worldwide, which includes Raízen sales.



Harvesting crops used for the processing of biofuel by Raízen, Brazil.

Raízen, our joint venture in Brazil (Shell interest 50%), produced around 2.5 billion litres of ethanol and around 4.4 million tonnes of sugar from sugar cane in 2020. In 2015, Raízen opened its first cellulosic ethanol plant at its Costa Pinto mill in Brazil. This produced almost 25 million litres of ethanol in 2020.

In February 2021, Raízen announced the acquisition of Biosev, adding an additional 50% of production capacity in low-carbon fuels. It will allow to increase Raízen's bioethanol production capacity to a 3.75 billion litres a year. The transaction contributes to Shell's target to be a net-zero emissions energy business by 2050, in step with society.

RNG

Renewable natural gas (RNG), also known as biomethane, is gas derived from processing organic waste in a controlled environment until it is fully interchangeable with conventional natural gas. Shell has taken a final investment decision to construct, own and operate its first renewable compressed natural gas (R-CNG) fuelling site in the USA. This will be at Shell's products distribution complex in Carson, California. The R-CNG will be sourced from Shell's portfolio of anaerobic digestion projects.

BUSINESS ACTIVITIES WITH SUDAN, SYRIA AND CUBA Sudan

We ceased all operational activities in Sudan in 2008. In 2020, we registered a trademark right in Sudan (north) and paid \$8 to the General Intellectual Property Register Office, and \$79 in agent and handling fees.

The renewal of the trademark rights is not indicative of any sales of products in Sudan.

Syria

We ceased all operational activities in Syria in 2011. In 2020, we renewed our trademark rights in Syria and paid \$1,914 to the Directorate of Industrial and Commercial Property Protection, and \$551 in agent and handling fees. The renewal of the trademark rights is not indicative of any sales of products in Syria.

Cuba

We do not have any operational activities in Cuba. In January 2021, we renewed a trademark right in Cuba and paid \$300 to the Cuban Industrial Property Office, and \$420 in agent and handling fees. The registration of this trademark right is not indicative of any sales of products in Cuba.

OIL PRODUCTS DATA TABLES

The tables below reflect Shell subsidiaries and instances where Shell owns the crude oil or feedstocks processed by a refinery. The tables include Martinez refinery until the date of divestment in February 2020, Tabangao refinery until the date of transformation into a terminal in August 2020 and Convent refinery until the date of shutdown in December 2020. Other joint ventures and associates are only included where explicitly stated.

Oil products – cost of crude oil processed or consumed [A]

	\$/barrel		
	2020	2019	2018
Total	35.03	54.97	59.94

[A] Includes Upstream and Integrated Gas margins on crude oil supplied by Shell subsidiaries, joint ventures and associates.

Crude distillation capacity [A]

	Thousand b/stream day [B]		
	2020	2019	2018
Europe	1,059	1,057	1,056
Asia	573	767	767
Africa	90	90	90
Americas	1,028	1,171	1,261
Total	2,750	3,085	3,174

[A] Average operating capacity for the year, excluding mothballed capacity.

[B] Stream day capacity is the maximum capacity with no allowance for downtime.

Oil products – crude oil processed [A]

	Thousand b/d		
	2020	2019	2018
Europe	810	829	897
Asia	292	498	545
Africa	54	55	66
Americas	719	1,004	1,041
Total	1,875	2,386	2,549

[A] Includes natural gas liquids, share of joint ventures and associates and processing for others.

Refinery processing intake [A]

	Thousand b/d		
	2020	2019	2018
Crude oil	1,876	2,342	2,434
Feedstocks	187	222	214
Total	2,063	2,564	2,648
Europe	854	875	896
Asia	302	517	543
Africa	54	55	66
Americas	853	1,117	1,143
Total	2,063	2,564	2,648

[A] Includes crude oil, natural gas liquids and feedstocks processed in crude distillation units and in secondary conversion units.

Refinery processing outturn [A]

	Thousand b/d		
	2020	2019	2018
Gasolines	771	952	966
Kerosines	158	417	321
Gas/Diesel oils	774	818	965
Fuel oil	140	223	284
Other	279	282	321
Total	2,122	2,692	2,858

[A] Excludes own use and products acquired for blending purposes.

Oil Products sales volumes [A][B]

	Thousand b/d		
	2020	2019	2018
Europe			
Gasolines	224	334	323
Kerosines	165	317	294
Gas/Diesel oils	610	720	745
Fuel oil	(42)	138	178
Other products	(19)	278	314
Total	938	1,787	1,854
Asia			
Gasolines	346	408	373
Kerosines	98	208	210
Gas/Diesel oils	455	535	543
Fuel oil	308	330	407
Other products	383	518	620
Total	1,590	2,000	2,153
Africa			
Gasolines	43	46	42
Kerosines	11	13	10
Gas/Diesel oils	59	70	74
Fuel oil	1	2	2
Other products	6	6	6
Total	120	137	134
Americas			
Gasolines	1,136	1,419	1,446
Kerosines	103	239	236
Gas/Diesel oils	496	582	567
Fuel oil	87	120	117
Other products	240	277	276
Total	2,062	2,637	2,642
Total product sales [C][D]			
Gasolines	1,749	2,207	2,184
Kerosines	377	777	750
Gas/Diesel oils	1,620	1,907	1,929
Fuel oil	354	590	704
Other products	610	1,079	1,216
Total	4,710	6,561	6,783

[A] Excludes deliveries to other companies under reciprocal sale and purchase arrangements, that are in the nature of exchanges. Sales of condensate and natural gas liquids are included.

[B] Includes the Shell share of Raizen's sales volumes.

[C] Certain contracts are held for trading purposes and reported net rather than gross. The effect in 2020 was a reduction in oil product sales of approximately 1,284,000 b/d (2019: 546,000 b/d; 2018: 458,000 b/d). With effect from January 1, 2020 certain contracts held for trading purposes and reported net for Europe and Asia regions are consolidated in Europe.

[D] Reported volumes in 2020 and 2019 include the Shell joint ventures' sales volumes from key countries.

OIL PRODUCTS continued

MANUFACTURING PLANTS AT DECEMBER 31, 2020

Refineries in operation

				Thousand barrels/stream day, 100% capacity [B]			
	Location	Asset class	Shell interest (%) [A]	Crude distillation capacity	Thermal cracking/visbreaking/coking	Catalytic cracking	Hydro-cracking
Europe							
Denmark	Fredericia	●	100	74	44	—	—
Germany	Miro [C]		32	313	40	96	—
	Rheinland	● ●	100	354	49	—	90
	Schwedt [C]		38	233	45	59	—
Netherlands	Pernis	● ●	100	443	—	53	103
Asia							
Singapore	Pulau Bukom [D]	● ●	100	504	81	38	61
Africa							
South Africa	Durban [C]	●	36	180	25	37	—
Americas							
Argentina	Buenos Aires [C]	● ●	50	108	20	22	—
Canada							
Alberta	Scotford	●	100	100	—	—	83
Ontario	Sarnia	●	100	85	5	21	10
USA							
Louisiana	Norco	●	100	250	29	119	44
Texas	Deer Park	● ●	50	341	96	75	60
Washington	Puget Sound	● ●	100	149	25	58	—

[A] Shell interest is rounded to the nearest whole percentage point; Shell share of production capacity may differ.

[B] Stream day capacity is the maximum capacity with no allowance for downtime.

[C] Not operated by Shell

[D] Bukom capacity is as on December 31, 2020 prior to the transformation. Crude processing capacity is expected to decrease by around 200 thousand b/d after the transformation sometime in July 2021.

- Integrated refinery and chemical complex
- Refinery complex with cogeneration capacity
- Refinery complex with chemical unit(s)
- Other

BRANDED RETAIL SITES [A]

	2020	2019	2018
Europe	8,071	7,978	7,888
Asia [B]	10,387	10,138	9,754
Oceania [B]	1,071	1,038	1,030
Africa	2,622	2,494	2,502
Americas	23,461	23,021	23,223
Total	45,612	44,669	44,397

[A] Excludes sites closed for more than six months.

[B] Asia includes Turkey and Russia; Oceania includes French Polynesia, Guam, Palau and New Caledonia.

CHEMICALS

Key statistics

	\$ million, except where indicated		
	2020	2019	2018
Segment earnings [A]	808	478	1,884
Including:			
Revenue (including inter-segment sales)	14,571	17,485	23,568
Share of profit of joint ventures and associates [A]	567	546	684
Interest and other income	–	(7)	(53)
Operating expenses [B]	3,235	3,430	3,594
Depreciation, depletion and amortisation	1,116	1,074	1,034
Taxation charge [A]	7	(2)	339
Identified Items [B]	(154)	(263)	(192)
Adjusted Earnings [B]	962	741	2,076
Capital expenditure	2,608	4,068	3,140
Cash capital expenditure [B]	2,640	4,090	3,212
Chemical plant utilisation (%) [C]	80	76	84
Chemicals sales volumes (thousand tonnes)	15,036	15,223	17,644

[A] See Note 4 to the “Consolidated Financial Statements” on pages 230-232. Segment earnings are presented on a current cost of supplies basis.

[B] See “Non-GAAP measures reconciliations” on pages 305-306

[C] With effect from January 1, 2020, Shell discloses utilisation instead of availability to improve transparency on chemicals production volumes. Utilisation is defined as the actual usage of the plants as a percentage of the rated capacity.

OVERVIEW

Our Chemicals business supplies customers with a range of base and intermediate chemicals used to make products that people use every day. We also have major manufacturing plants which are located close to refineries, and our own marketing network.

BUSINESS CONDITIONS

Cracker margins were volatile during 2020 because of how COVID-19 affected demand. Overall margins, however, were broadly similar to those in 2019. The effect on chemicals depended on end use. Some sectors, such as automotive, were hit particularly hard, while others, such as packaging, showed robust demand. Chinese demand recovered relatively quickly because the virus was swiftly brought under control. Overall chemicals demand was not hit as hard as GDP. West European cracker margins were supported by the sudden fall in the price of crude oil in March and April. The fact that crude oil was at a lower price than in 2019 reduced naphtha feedstock costs, which reduced product prices. This in turn put pressure on US ethane cracker margins, although plentiful ethane supply helped counter the impact.

See “Market overview” on pages 38-40.

CHEMICAL PLANT UTILISATION

With effect from January 1, 2020, Shell discloses utilisation instead of availability to improve transparency on chemicals production volumes. Utilisation is defined as the actual usage of the plants as a percentage of the rated capacity.

Chemicals manufacturing plant utilisation was 80% in 2020 compared with 76% in the full year 2019, mainly because of higher maintenance activities in Asia and Europe in 2019, and the impact of strike actions in the Netherlands in 2019.

CHEMICALS SALES

In 2020, Chemicals sales volumes were 15,036 thousand tonnes, which was 1% lower than 2019 sales volumes of 15,223 thousand tonnes due to lower demand.

EARNINGS 2020-2019

Segment earnings in 2020 of \$808 million were 69% higher than in 2019. Earnings in 2020 included a net charge of \$154 million, compared with a net charge in 2019 of \$263 million, which is described at the end of this section.

Excluding the impact of these charges, earnings in 2020 were \$962 million, compared with \$741 million in 2019.

The increase in Chemicals earnings, excluding the net charges, was \$221 million (30%) compared with 2019. This was driven by higher margins (around \$130 million) because of a favourable price environment, lower operating expenses (around \$50 million) as a result of various initiatives, and favourable tax movements (around \$60 million) partly offset by other costs (around \$20 million).

Segment earnings in 2020 included a net charge of \$154 million.

This included:

- impairment charges of \$4 million;
- costs related to restructuring of \$38 million (various initiatives across Chemicals);
- net loss from disposal of assets of \$1 million; and
- other net charges of \$115 million (mainly legal provision).

These charges were partly offset by:

- a net gain from fair value accounting of commodity derivatives of \$4 million.

Segment earnings in 2019 included a net charge of \$263 million.

This included:

- net charges of \$247 million (mainly legal provisions);
- loss of \$11 million from disposal of assets;
- costs of \$5 million related to restructuring; and
- impairment charge of \$4 million.

These charges were partly offset by:

- gain from one-off tax items of \$5 million (tax rate changes in Alberta, Canada).

CHEMICALS continued

EARNINGS 2019-2018

Segment earnings in 2019 of \$478 million were 75% lower than in 2018. Earnings in 2019 included a net charge of \$263 million described above. Earnings in 2018 included a net charge of \$192 million, reflecting impairment charges of \$76 million, a net loss from disposal of \$50 million, redundancy and restructuring charges of \$2 million, and other net charges of \$97 million (related to onerous contracts in connection with decommissioning the Stanlow site). These were partly offset by gains from one-off tax items of \$27 million, (mainly corporate income tax rate changes in the Netherlands), and a net gain of \$6 million from fair value accounting of commodity derivatives.

Excluding the impact of these items, earnings in 2019 were \$741 million, compared with \$2,076 million in 2018.

The decrease in earnings, excluding the net charges, was \$1,335 million (64%) compared with 2018. This was driven by lower margins (around \$1,500 million), partly offset by lower operating costs (around \$140 million) and the change in accounting policy relating to IFRS 16 leases (around \$20 million). Margins were impacted by lower realised base chemicals and intermediate margins and by higher maintenance activities in Asia and Europe, including the impact of strike action in the Netherlands in 2019.

CASH CAPITAL EXPENDITURE

Cash capital expenditure (cash capex) was \$2.6 billion in 2020, compared with \$4.1 billion in 2019.

Cash capex decreased by \$1.5 billion, mainly because of lower spend on account of the COVID-19 pandemic impact in the construction of our cracker facilities in Pennsylvania and cash preservation initiatives. Our cash capex expenditure is expected to be around \$3 billion to \$3.5 billion in 2021.

PORTFOLIO AND BUSINESS DEVELOPMENTS

Significant portfolio and business developments during 2020:

- In the USA, in March 2020, we announced our intention to sell the Mobile site in Alabama.

BUSINESS AND PROPERTY

Manufacturing

Our plants produce a range of base chemicals, including ethylene, propylene and aromatics, and intermediate chemicals such as styrene monomer, propylene oxide, solvents, detergent alcohols, ethylene oxide and ethylene glycol. We have the capacity to produce around 6.5 million tonnes of ethylene a year. We are expanding our product portfolio to include sustainable chemicals, more intermediates and performance chemicals such as polyethylene and polycarbonate. We operate chemical plants worldwide and have a global balance of locations, feedstocks and products that allows us to seize commercial opportunities and get through cycles of lower margins.

Shell's Chemicals business is transforming and will be further integrated with our Refining business. In addition to our standalone, chemicals-only production sites, the six sites (Deer Park and Norco in the USA, Scotford in Canada, Pernis in the Netherlands, Rheinland in Germany and Pulau Bukom in Singapore) are expected to form our energy and chemicals parks. Growth will shift towards performance chemicals and recycled feedstocks.

Marketing

In 2020, we supplied more than 15 million tonnes of petrochemicals to around 1,000 industrial customers worldwide. Products made from chemicals improve everyday life in health care, construction, transport, electronics, agriculture and sports. As global demand for chemicals increases, we plan to grow our business, by understanding and responding to our customers' needs.

BUSINESS ACTIVITIES WITH SUDAN AND SYRIA

Sudan

We ceased all operational activities in Sudan in 2008.

Syria

We ceased supplying polyols, via a Netherlands-based distributor, to private sector customers in Syria in 2018. Polyols are commonly used for the production of foam in mattresses and soft furnishings.

CHEMICALS DATA TABLES

The tables below reflect Shell subsidiaries and instances where Shell owns the crude oil or feedstocks processed by a refinery. The tables also include Martinez until the date of divestment in February 2020. Other joint ventures and associates are only included where explicitly stated.

Ethylene capacity [A]

	Thousand tonnes/year		
	2020	2019	2018
Europe	1,701	1,701	1,701
Asia	2,530	2,530	2,529
Americas	2,268	2,268	2,268
Total	6,499	6,499	6,498

[A] Includes the Shell share of capacity entitlement (offtake rights) of joint ventures and associates, which may be different from nominal equity interest. Nominal capacity is quoted at December 31.

Chemicals sales volumes [A]

	2020	2019	2018
Europe			
Base chemicals	3,490	3,666	4,069
Intermediates and others	1,990	1,872	1,994
Total	5,480	5,538	6,063
Asia			
Base chemicals	1,192	1,057	2,140
Intermediates and others	2,969	2,848	3,082
Total	4,161	3,905	5,222
Americas			
Base chemicals	2,936	3,261	3,842
Intermediates and others	2,459	2,519	2,517
Total	5,395	5,780	6,359
Total product sales			
Base chemicals	7,618	7,984	10,051
Intermediates and others	7,418	7,239	7,593
Total	15,036	15,223	17,644

[A] Excludes feedstock trading and by-products.

Major chemical plants in operation [A]

		Thousand tonnes/year, Shell share capacity [B]				
	Location	Ethylene	Styrene monomer	Ethylene glycol	Higher olefins [C]	Additional products
Europe						
Germany	Rheinland	315	—	—	—	A
Netherlands	Moerdijk	971	815	153	—	A, I
UK	Mossmorran [D]	415	—	—	—	O
Asia						
China	Nanhai [D]	1,100	650	415	—	A, I, P
Singapore	Jurong Island [E]	281	1,069	1,159	—	A, I, P, O
	Pulau Bukom	1,149	—	—	—	A, I
Americas						
Canada	Scotford	—	475	548	—	A, I
USA	Deer Park	836	—	—	—	A, I
	Geismar	—	—	400	1,390	I
	Norco	1,432	—	—	—	A
Total		6,499	3,009	2,675	1,390	

[A] Major chemical plants are large integrated chemical facilities, typically producing a range of chemical products from an array of feedstocks, and are a core part of our global Chemicals business.

[B] Shell share of capacity of subsidiaries, joint arrangements and associates (Shell- and non-Shell-operated), excluding capacity of the Infineum additives joint ventures.

[C] Higher olefins are linear alpha and internal olefins (products range from C4 to C2024).

[D] Not operated by Shell

[E] The polyethylene, polypropylene and olefins production mentioned refers to Shell share of capacity of our non-operated joint ventures Petchem Corporation of Singapore (PCS) and The Polyolefin Company (TPC) which are in Jurong Island.

A Aromatics, lower olefins

I Intermediates

P Polyethylene, polypropylene

O Other

Other chemical locations [A]

	Location	Products
Europe		
Germany	Karlsruhe	A
	Schwedt	A
Netherlands	Pernis	A, I, O
Americas		
Argentina	Buenos Aires	I
Canada	Sarnia	A, I
USA	Mobile	A
	Puget Sound	I

[A] Other chemical locations reflect locations with smaller chemical units, typically serving more local markets.

A Aromatics, lower olefins

I Intermediates

O Other

Earnings

	\$ million		
	2020	2019	2018
Segment earnings	(2,952)	(3,273)	(1,479)
Comprising:			
Net interest [A]	(2,991)	(3,080)	(2,075)
Taxation and other [B]	39	(194)	596
Identified Items	460	109	327
Adjusted Earnings	(3,412)	(3,383)	(1,806)

[A] Mainly Shell's interest expense (excluding accretion expense) and interest income.

[B] Other earnings mainly comprise net foreign exchange gains and losses on financing activities, headquarters and central functions' costs not recovered from business segments, and net gains on sale of properties. This also includes Shell's share of joint ventures and associates' interest income/(expense) and net foreign exchange gains/(losses) on financing activities.

OVERVIEW

The Corporate segment covers the non-operating activities supporting Shell. It comprises Shell's holdings and treasury organisation, self-insurance activities and headquarters and central functions. All finance expense and income and related taxes are included in Corporate segment earnings rather than in the earnings of business segments.

The holdings and treasury organisation manages many of the Corporate entities. It is the point of contact between Shell and external capital markets, conducting a wide range of transactions, such as raising debt instruments and transacting foreign exchange. Treasury centres in London and Singapore support these activities.

Headquarters and central functions provide business support in communications, finance, health, human resources, information technology, legal services, real estate and security. They also provide support for shareholder-related activities. The central functions are supported by business service centres, which process transactions, manage data and produce statutory returns, among other services. Most headquarters and central-function costs are recovered from the business segments. Costs that are not recovered are retained in Corporate.

EARNINGS 2020-2018

Segment earnings in 2020 were an expense of \$2,952 million, compared with \$3,273 million in 2019 and \$1,479 million in 2018.

Net interest decreased by \$89 million compared with 2019. This was primarily due to a decrease in interest expense following reductions in interest rates, partly offset by a reduction in interest income generated on cash balances. In 2019, net interest increased by \$1,005 million compared with 2018. This was primarily due to the adoption of IFRS 16 and reduced capitalised interest.

Taxation and other earnings increased by \$233 million in 2020, compared with 2019. This largely reflected favourable deferred tax impacts due to the strengthening Brazilian real on financing positions and a reduction in Shell's share of financing expenses from joint ventures and associates, partly offset by a foreign exchange loss from adverse exchange rate movements. In 2019, taxation and other earnings decreased by \$790 million compared with 2018, because of reduced tax credits from financing and one-off charges, and unfavourable exchange rate movements producing net foreign exchange losses.

SELF-INSURANCE

We mainly self-insure our risk exposure. Capital is set aside to meet self-insurance obligations (see "Risk factors" on page 35). We seek to ensure this capital is at least as much as would be held in third-party insurance markets. Periodic surveys of key assets provide knowledge and best practices aimed at reducing exposure to hazards. Follow-up actions are monitored to completion.

INFORMATION TECHNOLOGY AND CYBER-SECURITY

Given our digitalisation efforts and increasing reliance on information technology (IT) systems for our operations, we continually monitor external

developments and actively share information on threats and security incidents. Shell employees and contract staff are subject to mandatory courses and regular awareness campaigns aimed at protecting us against cyber-threats. We periodically test and adapt cyber-security response processes and seek to enhance our security monitoring capability.

Given our dependence on IT systems for our operations and the increasing role of digital technologies across our business, we are aware that cyber-security attacks could cause significant harm to Shell in the form of loss of productivity, loss of intellectual property, regulatory fines and/or reputational damage. As a result, we continuously measure and, where required, further improve our cyber-security capabilities to reduce the likelihood of successful cyber-attacks. Our cyber-security capabilities are embedded into our IT systems, and our IT landscape is protected by various detective and protective technologies. The identification and assessment capabilities are built into our support processes and adhere to industry best practices. The security of IT services, operated by external IT companies, is managed through contractual clauses and additionally through formal supplier assurance reports for critical IT services.

Shell is frequently subjected to cyber-attacks and the pandemic in 2020 caused an increase in such activity. COVID-19 necessitated a switch from office to remote working, which changed and increased the attack surface. Shell's CyberDefence Team responded by enhancing cyber-security controls for remote connectivity, strengthening its monitoring/detection, and taking additional measures to improve cyber-awareness.

In 2020, malicious actors infiltrated several companies and government agencies through a supply chain attack via SolarWinds Orion software. They injected malware into an update that was distributed to SolarWinds' customers globally, allowing the actors to access SolarWinds systems and from there attempt to access other systems. Shell uses SolarWinds software. We detected the malicious SolarWinds applications in our environment, and isolated and removed them. No evidence has been found that any Shell systems were accessed by the attackers. Shell has followed the US Cybersecurity and Infrastructure Security Agency's guidance to rebuild and/or patch affected systems.

In 2020, none of the cyber-security events led to known breaches of our business-critical IT landscape and, as such, did not result in any material business impact. When significant incidents happen, they are addressed through a robust incident management framework and, if needed, will result in appropriate follow-up actions, including notifications towards regulators. See "Risk factors" on Page 33.

BRAND VALUE

In January 2021, Shell's brand value was estimated at \$42.2 billion in Brand Finance Global 500 2021, the annual report by leading brand valuation consultancy Brand Finance. This was down 11% compared with 2020, but up 33% compared with 2016. According to the valuation the Shell brand remains the most valued in the oil and gas industry and the gap to second place widened from \$761 million in 2020 to \$4.7 billion in 2021. The report also showed that Shell's brand rating stayed at AAA, unchanged from 2020.

LIQUIDITY AND CAPITAL RESOURCES

We manage our businesses to deliver strong cash flows to fund investment for profitable growth. Management's priorities for applying Shell's cash are first the reduction of net debt to \$65 billion and, on achieving this milestone, distributing a total of 20-30% of cash flow from operations to shareholders. Remaining cash will be allocated to disciplined and measured capital expenditure growth and further debt reduction.

FINANCIAL CONDITION AND LIQUIDITY

Despite the weak macroeconomic and commodity price environment during the COVID-19 pandemic, Shell Group generated cash flow from operations of \$34.1 billion and free cash flow of \$20.8 billion in 2020. Through the course of the year, Shell took decisive actions (including reducing costs, rebasing the dividends and not continuing with the next tranche of the share buyback programme following completion of the seventh tranche) to increase liquidity and underpin the strength of the balance sheet, positioning the business to navigate the challenging environment and supporting long-term value creation. Reflecting mitigating actions taken, net debt decreased to \$75.4 billion at December 31, 2020 (December 31, 2019: \$79.1 billion). Gearing increased to 32.2% at December 31, 2020, compared with 29.3% at December 31, 2019 due to the reduction in equity mainly driven by lower earnings in 2020. Note 14 to the Consolidated Financial Statements on page 241-243 provides information on our debt arrangements, including net debt and gearing definitions.

LIQUIDITY

We satisfy our funding and working capital requirements from the cash generated from our operations, the issuance of debt and divestments. In 2020, access to the international debt capital markets remained strong, with our debt principally financed from these markets through central debt programmes consisting of:

- a \$10 billion global commercial paper (CP) programme, with maturities not exceeding 270 days;
- a \$10 billion US CP programme, with maturities not exceeding 397 days;
- an unlimited Euro medium-term note (EMTN) programme (also referred to as the Multi-Currency Debt Securities Programme); and
- an unlimited US universal shelf (US shelf) registration.

All these CP, EMTN and US shelf issuances are issued by Shell International Finance B.V., the issuance company for Shell, with its debt being guaranteed by Royal Dutch Shell plc (the Company). We plan to file a new US shelf registration statement with the Securities and Exchange Commission shortly after the filing of our Annual Report on Form 20-F.

We also maintain committed credit facilities. The core facilities, totalling \$10 billion, were extended in December 2020 with \$2 billion now expiring in 2021 and \$8 billion in 2025. Each facility includes a further one-year extension option at the discretion of each lender. Both remained undrawn at December 31, 2020. These core facilities and internally available liquidity provide back-up coverage for our CP programmes. In addition, in April 2020, to increase liquidity amid COVID-19-related uncertainties, Shell entered into a dual currency \$7.2 billion and EUR 4.4 billion revolving credit facility expiring in April 2021, with two six-month extension options at our discretion. This facility remains undrawn. The extension options have not been exercised, and the facility will expire in April 2021. Other than certain borrowing by local subsidiaries, we do not have any other committed credit facilities.

Our total debt increased by \$11.6 billion to \$108 billion at December 31, 2020. The total debt excluding leases will mature as follows: 16% in 2021; 6% in 2022; 7% in 2023; 6% in 2024; and 64% in 2025 and beyond. The portion of debt maturing in 2021 is expected to be repaid from a combination of cash balances, cash generated from operations, divestments and the issuance of new debt.

In 2020, we issued \$6.3 billion of bonds under our US shelf registration and \$6.7 billion equivalent under our EMTN programme. Periodically, for working capital purposes, we issued CP. We believe our working capital is sufficient for current requirements.

While our subsidiaries are subject to restrictions, such as foreign withholding taxes on the transfer of funds in the form of cash dividends, loans or advances, such restrictions are not expected to have a material impact on our ability to meet our cash obligations.

MARKET RISK AND CREDIT RISK

We are affected by the global macroeconomic environment as well as financial and commodity market conditions. This exposes us to treasury and trading risks, including liquidity risk, market risk (interest rate risk, foreign exchange risk and commodity price risk) and credit risk. See "Risk factors" on page 34 and Note 19 to the "Consolidated Financial Statements" on pages 251-255. The size and scope of our businesses require a robust financial control framework and effective management of our various risk exposures.

We utilise various financial instruments for managing exposure to commodity price, foreign exchange and interest rate movements. Our treasury and trading operations are highly centralised and seek to manage credit exposures associated with our substantial cash, commodity, foreign exchange and interest rate positions. Our portfolio of cash investments is diversified to avoid concentrating risk in any one instrument, country or counterparty. Other than in exceptional cases, the use of external derivative instruments is confined to specialist trading and central treasury organisations that have appropriate skills, experience, supervision, control and reporting systems. Credit risk policies are in place to ensure that sales of products are made to customers with appropriate creditworthiness, and include detailed credit analysis and monitoring of customers against counterparty credit limits. Where appropriate, netting arrangements, credit insurance, prepayments and collateral are used to manage credit risk. We maintain a committed credit facility. Management believes it has access to sufficient debt funding sources (capital markets) and to undrawn committed borrowing facilities to meet foreseeable requirements.

PENSION COMMITMENTS

We have substantial pension commitments, the funding of which is subject to capital market risks (see "Risk factors" on page 32). We address key pension risks in a number of ways. Principal among these is the Pensions Forum, chaired by the Chief Financial Officer, which oversees Shell's input to pension strategy, policy and operation. A risk committee supports the forum in reviewing the results of assurance processes in respect of pensions risks. In general, local trustees manage the funded defined benefit pension plans, with contributions paid based on independent actuarial valuations in accordance with local regulations. Our total employer contributions to funded and unfunded defined benefit pension plans were \$0.6 billion in 2020 and are estimated to be \$1.6 billion in 2021. See Note 17 to the Consolidated Financial Statements on pages 246-249.

Capitalisation table

	\$ million	
	December 31, 2020	December 31, 2019
Equity attributable to Royal Dutch Shell plc shareholders	155,310	186,476
Current debt	16,899	15,064
Non-current debt	91,115	81,360
Total debt [A]	108,014	96,424
Total capitalisation	263,324	282,900

[A] Of total debt, \$79.4 billion (2019: \$65.7 billion) was unsecured and \$28.6 billion (2019: \$30.7 billion) was secured. See Note 14 to the "Consolidated Financial Statements" on pages 241-243 for further disclosure on debt.

LIQUIDITY AND CAPITAL RESOURCES continued

STATEMENT OF CASH FLOWS

Cash flow from operating activities in 2020 was an inflow of \$34.1 billion, compared with \$42.2 billion in 2019, mainly due to lower earnings. The decrease in cash flow from operating activities in 2019, compared with \$53.1 billion in 2018, was mainly due to lower earnings and an unfavourable working capital impact.

Cash flow from investing activities in 2020 was an outflow of \$13.3 billion, compared with an outflow of \$15.8 billion in 2019. The decreased cash outflow was mainly due to lower capital expenditure in 2020. The increased cash outflow in 2019 compared with \$13.7 billion in 2018 was mainly due to lower proceeds from the sale of equity securities, partly offset by higher proceeds from sale of assets in 2019.

Cash flow from financing activities in 2020 was an outflow of \$7.2 billion, compared with outflows of \$35.2 billion in 2019 and \$32.5 billion in 2018, due to lower dividends payments to Royal Dutch Shell plc shareholders of \$7.4 billion (2019: \$15.2 billion; 2018: \$15.7 billion), net issuance of debt of \$5.6 billion (2019: \$3.4 billion net repayment; 2018: \$8.3 billion net repayment), and lower repurchases of shares of \$1.7 billion (2019: 10.2 billion; 2018: \$3.9 billion).

Cash and cash equivalents were \$31.8 billion at December 31, 2020 (December 31, 2019: \$18.1 billion; December 31, 2018: \$26.7 billion).

CASH FLOW FROM OPERATING ACTIVITIES

The most significant factors affecting our cash flow from operating activities are earnings, which are mainly impacted by: realised prices for crude oil, natural gas and LNG; production levels of crude oil, natural gas and LNG; chemicals, refining and marketing margins; and movements in working capital.

The impact on earnings from changes in market prices depends on: the extent to which contractual arrangements are tied to market prices; the dynamics of production-sharing contracts; the existence of agreements with governments or state-owned oil and gas companies that have limited sensitivity to crude oil and natural gas prices; tax impacts; and the extent to which changes in commodity prices flow through into operating expenses. Changes in benchmark prices of crude oil and natural gas in any particular period therefore provide only a broad indicator of changes in our Integrated Gas and Upstream earnings in that period. Changes in any one of a range of factors, derived from either within the industry or the broader economic environment, can influence refining and marketing margins. The precise impact of any such changes depends on how the oil markets respond to them. The market response is affected by factors such as: whether the change affects all crude oil types or only a specific grade; regional and global crude oil and refined products inventories; and the collective speed of response of refiners and product marketers in adjusting their operations. As a result, margins fluctuate from region to region and from period to period.

DIVESTMENT AND CASH CAPITAL EXPENDITURE

The level of divestment proceeds and cash capital expenditure in 2020 and 2019 reflects our discipline, and focus on capital efficiency and cash preservation.

Divestment proceeds

	\$ million		
	2020	2019	2018
Integrated Gas	503	723	3,156
Upstream	1,909	5,384	3,364
Oil Products	1,368	1,517	540
Chemicals	26	22	1
Corporate	205	225	3,405
Total divestment proceeds	4,010	7,871	10,465

Cash capital expenditure is used to monitor investing activities on a cash basis, excluding items such as lease additions which do not necessarily result in cash outflows in the period. The capital discipline demonstrated in 2020 allowed us to deliver cash capital expenditure of less than \$20 billion in line with the financial framework initiatives announced in March 2020.

Cash capital expenditure

	\$ million		
	2020	2019	2018
Integrated Gas	4,301	4,299	3,819
Upstream	7,296	10,205	12,134
Oil Products	3,328	4,907	4,643
Chemicals	2,640	4,090	3,212
Corporate	262	418	269
Total cash capital expenditure	17,827	23,919	24,078

Cash flow information [A]

	2020	2019	\$ billion 2018
Cash flow from operating activities excluding working capital movements			
Integrated Gas	10.8	14.8	16.3
Upstream	9.8	19.9	21.4
Oil Products	7.0	10.7	8.5
Chemicals	1.8	1.7	2.8
Corporate	0.1	(0.3)	0.7
Total	29.5	47.0	49.7
(Increase)/decrease in inventories	4.5	(2.6)	2.8
(Increase)/decrease in current receivables	9.6	(0.9)	2.0
Increase/(decrease) in current payables	(9.5)	(1.2)	(1.3)
(Increase)/decrease in working capital	4.6	(4.8)	3.4
Cash flow from operating activities	34.1	42.2	53.1
Cash flow from investing activities	(13.3)	(15.8)	(13.7)
Cash flow from financing activities	(7.2)	(35.2)	(32.5)
Currency translation differences relating to cash and cash equivalents	0.2	0.1	(0.4)
Increase/(decrease) in cash and cash equivalents	13.8	(8.7)	6.4
Cash and cash equivalents at the beginning of the year	18.1	26.7	20.3
Cash and cash equivalents at the end of the year	31.8	18.1	26.7

[A] See the "Consolidated Statement of Cash Flows" on page 220.

DIVIDENDS

Subject to Board approval, Shell aims to grow the dividend per share by around 4% every year, and once the Group's net debt level has reached \$65 billion, the Group will target the distribution of 20-30% of its cash flow from operations to shareholders. The Group may choose to return cash to shareholders through a combination of dividends and share buybacks.

When setting the level of shareholder remuneration, the Board looks at a range of factors, including the macro-environment, the underlying business earnings and cash flow of Shell Group, the current balance sheet, future investment and divestment plans, and existing commitments. We returned \$7.4 billion to our shareholders through dividends in 2020.

The fourth quarter 2020 interim dividend of \$0.1665 per share will be payable to shareholders on the register at February 19, 2021. See Note 23 to the "Consolidated Financial Statements" on page 259. The Board expects that the first quarter 2021 interim dividend will be \$0.1735 per share, representing an increase of around 4% on the fourth quarter 2020 interim dividend.

PURCHASES OF SECURITIES

On July 26, 2018, the Company announced the commencement of a share buyback programme of at least \$25 billion, subject to further progress with debt reduction and oil price conditions. On March 23, 2020, the Company announced that in light of the economic and oil price environment, it had decided not to continue with the next tranche of the share buyback programme following the completion of the tranche announced on January 30, 2020. On April 14, 2020, the seventh tranche of the share buyback programme was completed, and no further tranches were undertaken in 2020.

As at December 31, 2020, 496 million A shares with a nominal value of €34.7 million (\$41.8 million) and 39 million B shares with a nominal value of €2.8 million (\$3.2 million) (6.85% of the Company's total issued share capital at December 31, 2020) had been cumulatively purchased and cancelled since the beginning of this programme, for a total cost of \$15.8 billion including expenses, at an average price of \$29.45 per share.

This was in accordance with the authorities granted by shareholders at the 2018 Annual General Meeting (AGM) for the Company to repurchase up to a maximum of 10% of its issued ordinary shares, excluding treasury shares (834 million ordinary shares), and at the 2019 AGM, to repurchase up to a maximum of 815 million ordinary shares, such authority to expire at the earlier of the close of business on August 21, 2020 and the end of the 2020 AGM. At the 2020 AGM, shareholders granted a renewal of this authority, to repurchase up to a maximum of 783 million ordinary shares, such authority to expire at the earlier of the close of business on August 19, 2021 and the end of the 2021 AGM. As at December 31, 2020, 783 million ordinary shares could still be repurchased under the current AGM authority. The purpose of the share repurchases in 2018 to 2020 was to reduce the issued share capital of the Company.

A new resolution will be proposed at the 2021 AGM to renew the authority for the Company to purchase its own share capital, up to specified limits, for a further year. This proposal will be described in more detail in the 2021 Notice of Annual General Meeting.

Shares are also purchased by the employee share ownership trusts and trust-like entities (see the "Other regulatory and statutory information" on page 185) to meet delivery commitments under employee share plans. All share purchases are made in open-market transactions.

The table below provides information on purchases of shares in 2020 by the Company and affiliated purchasers. Purchases in euros and sterling are converted into dollars using the exchange rate on each transaction date.

LIQUIDITY AND CAPITAL RESOURCES continued

Purchases of equity securities by issuer and affiliated purchasers in 2020 [A]

Purchase period	A shares			B shares			A ADSs [B]	
	Number purchased for employee share plans	Number purchased for cancellation [C]	Weighted average price (\$)[D]	Number purchased for employee share plans	Number purchased for cancellation [C]	Weighted average price (\$)[D]	Number purchased for employee share plans	Weighted average price (\$)[D]
January [E]	—	23,106,521	29.63	—	—	—	1,003,452	59.76
February	—	11,306,918	25.32	—	5,518,503	24.45	—	—
March	—	12,229,299	18.48	—	9,904,356	14.88	133,692	31.25
April	813,021	3,905,280	18.19	1,874,926	7,800,412	17.31	—	—
May	—	—	—	—	—	—	—	—
June	—	—	—	—	—	—	20,109	35.09
July	—	—	—	—	—	—	—	—
August	—	—	—	—	—	—	—	—
September	—	—	—	—	—	—	26,570	26.74
October	—	—	—	—	—	—	—	—
November	3,244,447	—	15.68	113,348	—	13.9	1,509,662	31.36
December	2,783,283	—	18.52	—	—	—	934,246	36.87
Total 2020	6,840,751	50,548,018	24.14	1,988,274	23,223,271	17.9	3,627,731	40.62
January	—	—	—	—	—	—	1,525,265	37.23
Total 2021	—	—	—	—	—	—	1,525,265	37.23

[A] Reported as at settlement date

[B] American Depositary Shares

[C] Under the share buyback programme

[D] Includes stamp duty and brokers' commission

[E] January 2020 number of A shares purchased for cancellation has been revised

CONTRACTUAL OBLIGATIONS

The table below summarises our principal contractual obligations at December 31, 2020, by expected settlement period. The amounts presented have not been offset by any committed third-party revenue in relation to these obligations.

Contractual obligations

	\$ billion				
	Less than 1 year	Between 1 and 3 years	Between 3 and 5 years	5 years and later	Total
Debt [A]	12.8	10.3	12.9	42.3	78.3
Leases	6.1	9.6	7.1	20.0	42.8
Purchase obligations [B]	21.4	24.9	18.1	47.8	112.2
Other long-term contractual liabilities [C]	0.1	0.7	0.6	1.2	2.6
Total	40.4	45.5	38.7	111.3	235.9

[A] See Note 14 to the "Consolidated Financial Statements" on pages 241-243. Debt contractual obligations exclude interest, which is estimated to be \$1.8 billion payable in less than one year, \$3.3 billion between one and three years, \$2.9 billion between three and five years, and \$16.0 billion in five years and later. For this purpose, we assume that interest rates with respect to variable interest rate debt remain constant at the rates in effect at December 31, 2020, and that there is no change in the aggregate principal amount of debt other than repayment at scheduled maturity reflected in the table. Leases definition follows IFRS 16, which was implemented as of January 1, 2019. Lease contractual obligations include interest.

[B] Purchase obligations disclosed in the above table exclude commodity purchase obligations that are not fixed or determinable and are principally intended to be resold in a short period of time through sale agreements with third parties. Examples include long-term non-cancellable LNG and natural gas purchase commitments and commitments to purchase refined products or crude oil at market prices. Inclusion of such commitments would not be meaningful in measuring liquidity and cash flow, as the cash outflows generated by these purchases will generally be offset in the same periods by cash received from the related sales transactions.

[C] Includes all obligations included in "Trade and other payables" and provisions related to onerous contracts included in "Decommissioning and other provisions" in "Non-current liabilities" in the "Consolidated Balance Sheet" that are contractually fixed as to timing and amount. In addition to these amounts, Shell has certain obligations that are not contractually fixed as to timing and amount, including contributions to defined benefit pension plans (see Note 17 to the "Consolidated Financial Statements" on pages 246-249) and obligations associated with decommissioning and restoration (see Note 18 to the "Consolidated Financial Statements" on page 250).

GUARANTEES AND OTHER OFF-BALANCE SHEET ARRANGEMENTS

There were no guarantees and other off-balance sheet arrangements at December 31, 2020, or December 31, 2019, that were reasonably likely to have a material effect on Shell.

FINANCIAL INFORMATION RELATING TO THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST

The results of operations and financial position of the Royal Dutch Shell Dividend Access Trust (the Trust) are included in the consolidated results of operations and financial position of Shell. Certain condensed financial information in respect of the Trust is given below. See "Royal Dutch Shell Dividend Access Trust Financial Statements" on pages 294-297.

The Shell Transport and Trading Company Limited and BG Group Limited have each issued a dividend access share to Computershare Trustees (Jersey) Limited (the Trustee). For the years 2020, 2019 and 2018, the Trust recorded income before tax of £2,777 million, £5,484 million and £5,328 million respectively. In each period, this reflected the amount of dividends received on the dividend access shares.

At December 31, 2020, the Trust had total equity of £nil (December 31, 2019: £nil; December 31, 2018: £nil), reflecting assets of £7 million (December 31, 2019: £3 million; December 31, 2018: £3 million) and unclaimed dividends of £7 million (December 31, 2019: £3 million; December 31, 2018: £3 million). The Trust only records a liability for an unclaimed dividend, to the extent that dividend cheque payments have not been presented within 12 months, have expired or have been returned unrepresented.

ENVIRONMENT AND SOCIETY

OUR APPROACH TO SUSTAINABILITY

Our core values of honesty, integrity and respect for people – first laid out in the Shell General Business Principles more than 40 years ago – underpin our approach to sustainability.

A commitment to contribute to sustainable development was added in 1997. These principles, together with our Code of Conduct, apply to the way we do business and to our conduct with the communities where we operate.

Since 1997, we have worked to embed this sustainability commitment into our strategy, our business processes and decision-making. Sustainability is core to our project planning and operational activities. We aim to provide more and cleaner energy solutions in a responsible manner – in a way that balances short- and long-term interests, and that integrates economic, environmental, and social considerations into decision-making.

Today, we continue to build on these foundations while driving change across the organisation to help society meet its most pressing challenges, including those related to climate change, the environment, diversity and inclusion, and human rights. We seek the views of various groups and individuals about the role of an organisation like Shell in addressing these challenges.

Sustainability reporting boundary and guidelines

Data in this section are reported on a 100% basis in respect of activities where a Shell company is the operator (unless noted otherwise). Reporting on this operational control basis differs from that applied for financial reporting purposes in the “Consolidated Financial Statements” on pages 216-264. Detailed data and information on our 2020 environmental and social performance are expected to be published in the Shell Sustainability Report in April 2021.

We use certain guidelines to inform our reporting on sustainability issues:

- As a member of the World Business Council for Sustainable Development, we support the organisation’s updated criteria for membership from 2022, which includes requirements for corporate transparency.
- We report in line with guidelines developed by IPIECA, the global oil and gas industry association for advancing environmental and social performance.
- The recommendations of the Task Force on Climate-related Financial Disclosures (TCFD) help to guide and inform our reporting. For more information, see the “Climate change and energy transition” section.
- In January 2021, we agreed to adopt the Stakeholder Capitalism Metrics, a set of environmental, social and governance metrics released by the World Economic Forum and its International Business Council.

OUR STRATEGY: POWERING PROGRESS

In February 2021, we announced our updated business strategy, called Powering Progress. It has four main goals in support of our purpose – to power progress together by providing more and cleaner energy solutions:

- generating shareholder value: growing value through a dynamic portfolio and disciplined capital allocation;
- achieving net-zero emissions: working with our customers and across sectors to accelerate the transition to net-zero emissions;
- powering lives: powering lives through our products and activities, and by supporting an inclusive society; and
- respecting nature: protecting the environment, reducing waste and making a positive contribution to biodiversity.

Powering Progress is underpinned by our core values and our focus on safety. These include our commitment to doing business in an ethical and transparent way.

For more information on what we mean by becoming a net-zero emissions business, please refer to “Climate change and energy transition” on pages 94-107.

IMPACT OF THE COVID-19 PANDEMIC – HELPING COLLEAGUES, CUSTOMERS AND COMMUNITIES

The COVID-19 pandemic continues to have a serious impact on people’s health and livelihoods around the world. During 2020, we worked hard to assist in the global fight against the virus, and to support recovery efforts while taking care of our employees, our customers and the communities we work with.

In January 2020, Shell set up our Global Health Alert Monitoring Team to equip Shell staff and companies with information and guidance to remain operational in a responsible way. Certain elements of this approach were adopted as the industry standard by the joint health committee of two acknowledged industry associations: the International Association of Oil & Gas Producers (IOGP), and IPIECA, the global oil and gas industry association for advancing environmental and social performance.

More information on the steps we took to protect our staff is expected to be published in the Shell Sustainability Report in April 2021.

UNITED NATIONS SUSTAINABLE DEVELOPMENT GOALS

The UN’s 17 Sustainable Development Goals (SDGs) seek to address the world’s biggest challenges, including ending poverty, improving health and education, making cities sustainable and tackling climate change.

Governments are responsible for prioritising and implementing approaches that meet the SDGs, but achieving these tasks will require unprecedented collaboration and collective action across businesses, governments and civil society.

We will play our part in helping governments and societies to achieve the SDGs. The goals were one of the considerations in the development of our Powering Progress strategy. Actions we take as part of our Powering Progress strategy can help directly contribute to 13 of the SDGs, while indirectly contributing to others. See our website [shell.com](https://www.shell.com) for information on how Shell and our Powering Progress strategy are contributing to the SDGs.

BOARD OVERSIGHT FOR SUSTAINABILITY

We describe Shell’s overall governance framework on pages 128-129.

It provides information on the roles of the Board, its committees, and the Executive Committee. The Safety, Environment and Sustainability Committee (SESCO) advises the Board on safety, environment including climate change, and Shell’s overall sustainability performance. More information on the SESO’s role and activities during 2020 is provided on page 143-144.

The Annual Report on Remuneration (see page 170) provides details of how the Shell scorecard captures key performance indicators for safety, environment and climate.

SHELL GENERAL BUSINESS PRINCIPLES

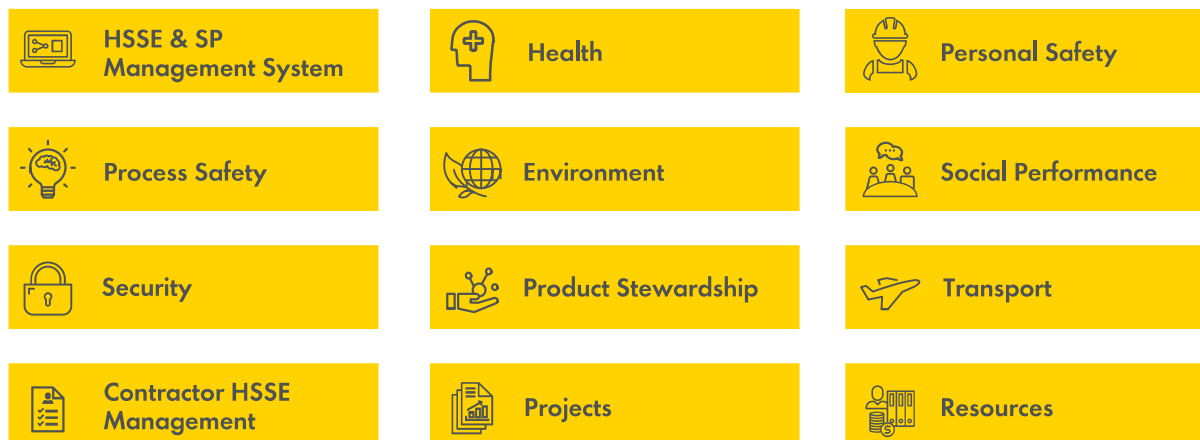
The Shell General Business Principles set out our responsibilities to shareholders, customers, employees, business partners and society. They set the standards for how we conduct business with integrity, care and respect for people, while seeking to protect the environment and establish mutually beneficial relationships with communities. All ventures that a Shell company operates must conduct their activities in line with our business principles.

HSSE & SP Control Framework

The HSSE & SP Control Framework defines mandatory standards, requirements and accountabilities. The framework applies to Shell entities and Shell-operated ventures, including employees and contractor staff.

Mandatory manuals describe:

- Purpose of the manual
- Accountabilities and responsibilities
- Scope
- Requirements to be met



Shell Commitment and Policy on Health, Security, Safety, the Environment and Social Performance

HSSE & SP CONTROL FRAMEWORK

We aim to minimise the environmental impact of new projects and existing operations, and we engage with local communities and non-governmental organisations (NGOs) to understand and respond to their concerns. Shell conducts an environmental, social and health impact assessment for every major project. We determine whether a project qualifies as major by considering its cost and capacity, including the potential consequences of adverse incidents. This helps us to understand and manage how our projects could affect the surrounding environment and local communities. We have standards and a governance structure to help manage potential impacts. We are committed to the safety of our people and contractors. The Shell HSSE & SP Control Framework (CF) specifies the standards for health, safety, security, environment and social performance (HSSE & SP) and the scope for applying these standards. The CF consists of a series of mandatory manuals that align with the Shell Commitment and Policy on HSSE & SP and the Shell Code of Conduct. They are supported by guidance documents and complemented by assurance protocols.

The CF applies to every Shell entity and Shell-operated venture, including all employees and contract staff. The CF defines standards and accountabilities at each organisational level and sets out the procedures and processes that we require people to follow. We require that all significant HSSE & SP risks associated with our business activities are assessed and managed to make them as low as reasonably practicable. Our HSSE & SP functions provide expert advice and support for our businesses.

The Process Safety and HSSE & SP Assurance team provides assurance to the Board on the effectiveness of the HSSE & SP CF through an audit programme. The full Shell portfolio comprises about 200 organisational

groups covered by this programme. Audits are performed with a frequency of between three and five years, depending on the overall risk and complexity of a particular facility or organisational group. Overall, this results in a rolling five-year plan, with every annual plan being approved by the Board. On average, the assurance team conducts about 50 audits per year. The scope of the audits is designed to test risk areas as defined in the CF. This includes the overall HSSE & SP management system and specific requirements for areas such as personal safety, environment and contractor management. Based on audit outcomes, the audit frequency for an entity may be increased. Audit findings and action items identified are documented and tracked to completion by the relevant business.

We expect joint ventures not operated by Shell to apply standards and principles substantially equivalent to our own. We support these joint ventures in their implementation of these standards and principles, and we offer to assist them in their review of the effectiveness of their implementation. Even if such a review is not conducted, we periodically evaluate HSSE & SP risks faced by the ventures that we do not operate. If one of these joint ventures does not meet our HSSE & SP expectations, we seek to improve performance by working with our partners to develop and implement remedial action plans.

Shell aims to work with suppliers that behave in a safe, economically, environmentally and socially responsible manner. Our approach to suppliers is set out in our Shell General Business Principles and Shell Supplier Principles. These cover expectations in areas such as business integrity, health and safety, environment, and human rights.

SAFETY

A focus on safety is one of the pillars that supports our Powering Progress strategy. We build and operate our facilities with the aim of preventing incidents that may damage or harm our employees, contract staff, nearby communities, the environment or our assets. We strive to help improve safety throughout the energy industry by sharing our safety standards and experience with other operators, contractors and professional organisations, including the International Association of Oil & Gas Producers (IOGP) and the Energy Institute.

Safety risks are managed across our businesses through the use of standards, controls and compliance systems. We combine this with a culture of care and an ambition to learn and continually improve. We strive to reduce risks and to minimise the potential impact of any incident.

Our standards also apply to any joint ventures we operate. We seek to improve safety by focusing on the three areas where the safety risks associated with our activities are highest: personal, process and transport. We require and assure ourselves that people responsible for tasks involving a significant safety hazard have the necessary training, skills and competencies. We also take human performance into account when deciding how to approach safety. This means that in order to minimise the risk of people being harmed, we seek to optimise the way people, culture, equipment, work systems and processes interact.

We employ many contractors and we work with them so that they understand our safety requirements. Together we seek to improve safety performance by building skills and expertise, and by creating an inclusive and safe work environment. We expect everyone working for us to comply with our mandatory Life-Saving Rules which set out simple "do's and don'ts" for activities with the highest potential safety risks. Employees are expected to discuss, coach and intervene so that everyone understands how the rules apply to a particular work task. If employees break these rules, we seek to understand why, but individuals may face disciplinary action up to and including termination of employment if they do not follow the Life-Saving Rules. If contract staff break the Life-Saving Rules, they can be removed from the worksite.

The COVID-19 pandemic necessitated new kinds of risk assessments beyond those that are normally conducted in our industry. The results led to us adopting extra measures to take care of our employees, our contractors, our customers and the communities we work with. We identified potential impacts beyond our local operations, and we continue to work hard to help the global fight against the virus and to support recovery efforts.

We took many practical steps to protect the health of our staff, including requiring or encouraging office-based staff to work from home, based on the advice of local authorities. From March 2020, the average occupancy rate of our 18 largest offices fell to around 10% for the rest of the year. Our information technology (IT) teams ensured that thousands of people could work from home each day. At the same time, measures were taken to protect colleagues' health where operations had to be maintained by staff on sites. We created a wide range of tools and resources which also addressed potential mental, physical and social health issues. For example, we set up a programme called Care for Self to encourage staff to pay attention to their physical and mental well-being, and to support them as they did so.

Safety strategy

In 2019, the Board and the Executive Committee spent considerable time reflecting on the worrying safety performance, measured by the number of fatalities, and what needed to change across Shell to prevent fatalities and all other serious incidents. This included conducting a full review of Shell's safety approach, which covered the effectiveness of current preventative tools, such as the Life-Saving Rules and Goal Zero ambition.

We have made progress in improving the safety of operations since the early 2000s. This was largely because of a stronger safety culture, guided by our Goal Zero ambition to achieve no harm and no leaks, more effective standards, and requirements such as the Life-Saving Rules. In recent years the vast majority of fatalities had no link to a breach of the Life-Saving Rules. Sadly, we have been unable to eliminate all fatal incidents involving Shell employees and contractors.

In 2020, we started what is expected to be a multi-year effort to refresh our approach to safety. The purpose is to avoid life-changing injuries and fatalities by building on existing strong foundations. We aim to achieve this with an increased and deliberate focus on human performance. We recognise that people are key to executing complex tasks and to finding solutions to problems. We call the belief that we can always improve, enhance individual capabilities, learn from mistakes and successes, and speak up without being punished a learner mindset. We seek to create conditions that encourage employees and contractors to share ideas and concerns without fear of rejection or punishment. In addition to specific training, events like our annual Safety Day 2020 provided Shell teams and contractors with the chance to reflect on this concept.

We are now building on our current approach to safety with a more consistent focus on the way people, culture, equipment, work systems and processes all interact. The majority of our fatalities over the last five years were down to the complex interaction between these elements. We aim to better understand the gap between how we anticipate work will be done safely and how the work is actually carried out. We continue to work to prevent incidents by maintaining safety barriers and providing training. We acknowledge that people make mistakes and not all incidents may be preventable. As a result, we started to focus more on how people can "fail safely", and on their response in the moment to avoid the risk of a serious injury. This approach is a change of philosophy, put into practice by improving processes for planning and completing work, and debriefing afterwards. In 2020, tangible changes were piloted and deployed for application by employees and contractors. For example, in 2020, we used earlier experience with drones, remote sensing technology, robots and digital technology, such as augmented reality, as lockdowns caused by the COVID-19 pandemic disrupted the movement of people. This technology enabled us to carry out more remote monitoring and to continue to assure data to meet safety and environmental performance reporting standards.

Personal and process safety

We continue to strengthen the safety culture and leadership among our employees and contract staff. This aligns with our focus on caring for people. Our safety goal is to achieve no harm and no leaks across all Shell company operations. We call this our Goal Zero ambition.

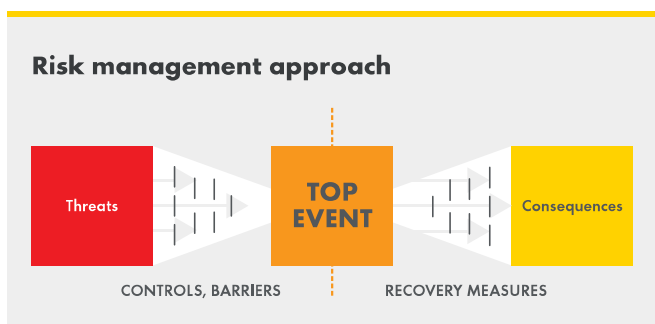
We expect everyone to consider two aspects of their tasks: the hazards that could potentially cause serious harm, and the effectiveness of the barriers in place to avoid serious harm if an incident occurs. In addition to our ongoing safety awareness programmes, we hold an annual global Safety Day to give employees and contractors time to reflect on how to prevent incidents. During Safety Day 2020, we asked all our staff and contractors to reflect on the importance of showing care for each other and ensuring that we are in control of risks with robust barriers in place, particularly under the current challenges of the pandemic. More information on how we implement these measures is expected to be published in our Shell Sustainability Report in April 2021.

Process safety management is about keeping hazardous substances inside pipes, tanks and vessels, and ensuring that well fluids are contained during well construction and well intervention so that they do not harm people or the environment. It starts at the design and construction stage of projects and continues throughout the life cycle of facilities to ensure they are safely operated, well maintained and regularly inspected. Our global

ENVIRONMENT AND SOCIETY continued

standards and operating procedures define our expectations for the controls and physical barriers required to mitigate risks of incidents. For example, to mitigate the risk of an uncontrolled release of hydrocarbons, offshore wells are to be designed with at least two independent barriers in the direction of flow. We regularly inspect, test and maintain these barriers to ensure they meet our standards. In the event of a loss of containment such as a spill or a leak, our standards require the use of independent recovery measures to stop the release from becoming catastrophic. This system of barriers and recovery measures is called a “bow-tie”, a model that visually represents a system where personal and process safety hazards are managed through prevention and response barriers.

We have embedded a set of process safety fundamentals to strengthen barriers that involve critical safety tasks carried out by frontline staff. These fundamentals provide guidelines for good operating practice that should prevent unplanned releases.



We routinely prepare and practise our emergency response to potential incidents such as a spill or a fire. This involves working closely with local services and regulatory agencies to jointly test our plans and procedures. These tests continually improve our readiness to respond. If an incident does occur, we have procedures to reduce the impact on people and the environment.

Transport safety

Transporting large numbers of people, products and equipment by road, rail, sea and air poses safety risks. We seek to reduce these risks by developing best-practice standards within Shell. We also work with specialist contractors, industry bodies, NGOs and governments to find ways of reducing transport safety risks.

Shell employees and contractors drove a combined distance of around 470 million kilometres on business in 2020 in over 50 countries. We run road safety programmes that promote safe driving techniques and behaviour in a number of countries where we operate, for example in India, Malaysia, and the UK. We require everyone driving more than 7,500 kilometres a year on Shell company business on public roads and those who drive in countries with higher road safety risks to take a defensive driving course. We also run an annual online defensive driving course for all who drive on public roads while on Shell company business. Fatigue is one of the most significant risks when on the road. In 2020, at the Shell-operated QGC facility in Queensland, Australia, we worked with four universities and eight contracting companies to evaluate fatigue detection devices and to find the one that performed best in testing. The collaboration was the largest of its kind and involved evaluating around 100 devices on long stretches of Australia's road network. As a result, we aim to start introducing recommended devices in Malaysia in 2021.

We also work to improve general road safety in several communities and countries where we operate, through organisations such as the Global Road Safety Partnership. For example, in India, we continue our road safety campaign which includes eye testing of third-party professional drivers. In 2020, around 20,000 Shell employees and contractors completed such testing.

Safety performance

In 2020, despite the unprecedented challenges faced, Shell and its contractor partners had the safest year that we have ever experienced. It was the first year with zero fatal injuries, and also the best ever process safety performance at ventures operated by Shell. Tragically, two contractors died after they caught COVID-19 during the course of their work for Shell.

Our Total Recordable Case Frequency (injuries per million working hours) was 0.7 in 2020, compared with 0.9 in 2019. There were 103 operational Tier 1 and 2 process safety events in 2020, compared with 130 in 2019. Detailed information on our 2020 safety performance is expected to be published in the Shell Sustainability Report in April 2021.

From 2021, the Total Recordable Case Frequency (TRCF) will be replaced on the Group scorecard by Serious Incidents and Fatalities Frequency (SIF-F). The new metric reflects the number of serious incidents and fatalities per 100 million working hours. The Executive Committee and the Safety, Environment and Sustainability Committee (SESCO) have endorsed the change. Several industry safety leadership groups confirm that root causes for serious and high-potential incidents are often different from the majority of lower-consequence events. Shell's shift is intended to help focus attention on improving its safety systems, and it targets the prevention of life-altering injuries, which aligns with the emphasis on human performance and Goal Zero. We will continue to report on TRCF for benchmarking purposes.

We require incidents to be investigated so we can understand the underlying causes, including technical, behavioural, organisational and human factors. We share learnings and implement mitigations at the site and in the country and business where the incident occurred. We seek to turn incident findings into improved standards or better ways of working that can be applied widely across similar Shell facilities. This is part of embedding the learner mindset approach across the organisation and engaging with contractors to share these learnings.

For example, in 2020, we continued to implement learnings from a tragic roll-over incident that occurred in Pakistan in 2017 and which was not under our operational control. Pakistan continues to be among the countries with the highest risks for road transport. The investigation offered several learnings. Our focus has now moved from technical standards to driver professionalism, including aspects such as fitness to work, training and coaching on the job. One of the most significant risks when on the road is fatigue. Shell Pakistan Limited is managing this through the creation of enhanced awareness for this topic, reduced duty hours and better rest facilities.

In 2021, Shell will take a further step to focus our efforts to enhance safety. We will transition from applying our 12 Life-Saving Rules to using the simplified set of nine Life-Saving Rules of the International Association of Oil & Gas Producers (IOGP). A common approach across the industry makes working within the supply chain easier and can accelerate the adoption of safety measures.

ENVIRONMENT

For many years we have had guiding principles and standards that seek to protect the environment. Now we are stepping up our environmental ambitions and shaping them to contribute to the UN Sustainable Development Goals.

Our environmental ambitions include protecting and enhancing biodiversity – the plant and animal life that is vital for the planet. We are also focusing on using water and other resources more efficiently across all our activities, reusing as much of them as we can.

We are reducing waste from our operations and increasing recycling of plastics. We are helping to improve air quality by reducing emissions from our operations and providing cleaner ways to power transport and industry. Working with our partners and suppliers and developing new collaborations is key. We will join with others across industry, governments, our customers and supply chains to protect nature.

In February 2021, we launched our new environmental framework which focuses on four priority areas: biodiversity, water, circular economy and waste, and air quality. We have set environmental ambitions for 2030 and later, as well as shorter-term goals:

- We will reduce the amount of fresh water consumed in our facilities, starting by reducing fresh-water consumption by 15% by 2025 compared with 2018 levels in areas where there is high pressure on fresh-water resources.
- By 2030, we will increase the amount of recycled plastic in our packaging to 30% and ensure that the packaging we use for our products is reusable or recyclable.
- We are aiming for zero waste by increasing reuse and recycling in our business and supply chains.
- We will demonstrate an overall positive impact on biodiversity from our new projects in areas rich in biodiversity, called critical habitats. This will include investing in conservation and taking steps to safeguard and, where possible, enhance local environments.

We will continue to look for opportunities to go further and will report our progress in a transparent way. We use external standards and guidelines, such as those developed by the World Bank and the International Finance Corporation, to inform our approach. We follow global environmental standards for managing our emissions and discharges, for conserving biodiversity, and for minimising our water use and impact on water resources.

Shell's global environmental standards cover our environmental performance. They include details of how to manage emissions of greenhouse gases (GHG), consume energy more efficiently, reduce gas flaring, prevent spills and leaks of hazardous materials, use less fresh water and conserve biodiversity. We seek to apply our global environmental standards wherever we operate. When planning new major projects, we conduct detailed environmental, social and health impact assessments.

See also "Control Framework" on page 86, more information on how we manage our GHG emission in "Climate change and energy transition" on page 106, and read about our new environmental framework on our website [shell.com](https://www.shell.com).

We believe some areas are too sensitive to enter. Therefore, we made the commitment that we will not explore for or develop oil and gas resources in natural and/or cultural World Heritage Sites.

We aim to minimise the impact of our projects on biodiversity and ecosystems by applying the mitigation hierarchy, a decision-making framework that involves a sequence of four key actions: avoid, minimise, restore and offset. We first aim to avoid impacts on biodiversity and ecosystems. Where our operations have affected biodiversity and communities that rely on biodiversity for their livelihoods, we seek to help restore damaged habitats. We also look for opportunities to make a positive contribution to conservation, also known as a net-positive impact (NPI). For example, to offset and compensate for clearing vegetation and habitat while developing gas resources, the Shell-operated QGC gas project in Australia manages the Valkyrie property, an area with a rich ecosystem. We monitor and measure the impact and seek ways to improve the mitigation strategy.

Managing our impacts on water and ensuring the availability of fresh water is a growing challenge in some parts of the world. Increasing demand for water resources, growing stakeholder expectations and concerns, and water-related legislation may reduce the access to water for our operations. We manage water use carefully, and tailor our use of fresh water to local conditions and requirements. We sometimes use alternatives to fresh water in our operations. These include water that has been recycled from our operations, processed sewage water and desalinated water. For example, the QGC project in Australia produces liquefied natural gas (LNG) from natural gas in a water-scarce region of the Surat Basin in Queensland. Water is produced as a natural by-product during the extraction of gas. Two water plants treat the produced water so that it is suitable for use by local farmers, industry and town water suppliers. We require that all Shell company facilities and projects are assessed to see what risks they might pose to water availability. In places where water is scarce, we develop water-management action plans for using less fresh water, increasing water recycling and closely monitoring water use.

In 2020, our intake of fresh water was 171 million cubic metres, compared with 192 million cubic metres in 2019. The reduction was partly because of divestments in Canada and the USA. Around 90% of our fresh water intake was used for manufacturing oil products and chemicals, with the rest mainly used for oil and gas production. Around 35% of fresh water intake was from public utilities, such as municipal water supplies, with the rest taken from surface water such as rivers and lakes (around 55%) and groundwater (around 10%).

Detailed information on our 2020 environmental performance is expected to be published in the Shell Sustainability Report in April 2021.

See "Climate change and energy transition" on page 106 for more information on how we manage our GHG emissions.

SPILLS

Large spills of crude oil, oil products and chemicals associated with our operations can harm the environment, and result in major clean-up costs, fines and other damages. They can also affect our licence to operate and harm our reputation.

We have requirements and procedures designed to prevent spills. We design, operate and maintain our facilities with the intention of avoiding spills. To further reduce the risk of spills, Shell has routine programmes to reduce failures and maintain the reliability of facilities and pipelines. Our business units are responsible for organising and executing spill responses in line with Shell guidelines and relevant legal and regulatory requirements. Our offshore installations have spill response plans for when an incident occurs. These plans set out response strategies and techniques, available equipment, and trained personnel and contracts. We can engage specialist contracted services for oil-spill response, including vessels, aircraft or other equipment and resources, if required, for large spills. We conduct regular exercises that seek to ensure these plans remain effective and fit for purpose.

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We have further developed our ability to respond to spills to water, and we maintain a global response support network of trained staff to support our worldwide response capability. This is also supported by our global oil spill expertise centre, which tests local capability and maintains our ability globally to respond to a significant spill into a marine environment.

We are involved in several industry consortia formed to improve well-containment capabilities. Shell Offshore Response Company LLC is a founding member of the Marine Well Containment Company, a non-profit industry consortium providing a well-containment response system for the Gulf of Mexico. Shell Response Limited was a founding member of the Subsea Well Response Project, an industry cooperative effort to enhance global well-containment capabilities, which has since become Oil Spill Response Limited, an industry consortium.

Site-specific emergency response plans are maintained in case there is an onshore spill. Like the offshore response plans, these are designed to meet Shell guidelines and relevant local legal and regulatory requirements. The onshore response plans also provide for the initial assessment of incidents and the mobilisation of resources to manage them. In the event of spills on land, businesses are supported by our global Soil & Groundwater team which reviews and implements appropriate remedies. The global Soil & Groundwater Team is engaged throughout the life cycle of our assets. For example, during acquisition and divestment of assets, the team conducts due diligence to identify land contamination liabilities. Through research and development initiatives, the team collaborates with regulators in developing, modifying, and applying sustainable remediation techniques.

Spills still occur for reasons such as operational failure, accidents or unusual corrosion. In 2020, there were 68 operational spills of more than 100 kilograms compared with 67 in 2019. The weight of operational spills of oil and oil products in 2020 was 0.4 thousand tonnes, compared with 0.2 thousand tonnes in 2019. At the time of publication of this Report, there were four spills under investigation in Nigeria that may result in adjustments.

Spills in Nigeria

In the Niger Delta, over the last 10 years, the total number of operational hydrocarbon spills and the volume of oil spilled from them into the environment have been significantly reduced.

Most oil spills in Nigeria's Niger Delta region continue to be caused by crude oil theft or sabotage of oil and gas production facilities, and by illegal oil refining, including the distribution of illegally refined products.

In 2020, the Shell Petroleum Development Company of Nigeria Limited (SPDC) managed to reduce the number of operational spills of more than 100 kilograms to around 0.02 thousand tonnes of crude oil (10 incidents) compared with around 0.03 thousand tonnes of crude oil (seven incidents) in 2019. This was a year-on-year reduction in operational spills of one-third by weight.

To reduce the number of operational spills, SPDC has an ongoing work programme to appraise, maintain and replace key sections of pipelines and flow lines. Over the last nine years, about 1,330 kilometres of pipelines and flow lines have been replaced. This is organised through a pipeline and flow line integrity management system that proactively addresses pipeline integrity. It puts barriers in place where necessary, and recommends when and where pipeline sections should be replaced to prevent failures. In 2018, this integrity management system was enhanced to manage threats arising from frequent pipeline sabotage or vandalism.

Spills caused by sabotage reduced in 2020

In 2020, about 90% oil spills of more than 100 kilograms from the SPDC joint venture's facilities were caused by the illegal activities of third parties. In 2020, the volume of crude oil spills of more than 100 kilograms caused

by sabotage was 1.4 thousand tonnes (122 incidents), compared with 2.3 thousand tonnes (156 incidents) in 2019. The decrease in incidents and volumes was because of improved security and surveillance, including community-based pipeline surveillance.

SPDC continues to undertake initiatives to prevent and reduce spills caused by theft from or sabotage of its facilities in the Niger Delta. In 2020, SPDC continued on-ground surveillance of its areas of operation, including its pipeline network, to mitigate third-party interference and ensure that spills are detected and responded to as quickly as possible.

There are also daily overflights of the most vulnerable segments of the pipeline network to identify any new spills or illegal activity. SPDC has also introduced anti-theft protection mechanisms for key infrastructure such as wellheads and manifolds. The programme to protect wellheads with steel cages continues to help deter theft.

By the end of 2020, 364 cages had been installed, including 73 cages upgraded with CCTV. Only 15 breaches were successful out of 1,706 registered attempts.

Faster response and remediation

Irrespective of the cause, SPDC works to clean up and remediate areas affected by spills originating from its facilities. SPDC reduced the average time to complete recovery of free-phase oil – oil that forms a separate layer and is not mixed with water or soil – from about 13 days in 2016 to about one week in 2020. This is the average time it takes to safely access a damaged site to start joint investigation visits (JIV) with regulators, impacted communities, and in some cases with non-governmental organisations, to clean up oil not mixed with water or soil.

Clean-up activities include bio-remediation which stimulates micro-organisms that naturally break down and use carbon-rich oil as a source of food and energy, effectively removing it. Once clean-up and remediation operations are completed, the work is inspected and, if satisfactory, approved and certified by the Nigerian regulators. With operational spills, SPDC also pays compensation to affected people and communities.

SPDC has been working with the International Union for Conservation of Nature (IUCN) since 2012 to enhance remediation techniques and protect biodiversity at sites affected by oil spills in SPDC's areas of operation in the Niger Delta. Based on this collaboration, SPDC has launched further initiatives to help strengthen its remediation and restoration efforts. In 2020, SPDC, IUCN, the Nigerian Conservation Foundation and Wetlands International worked together on the Niger Delta Biodiversity Technical Advisory Group, which continues to monitor biodiversity recovery at remediated sites.

SPDC also works with a range of stakeholders in the Niger Delta to build greater trust in spill response and clean-up processes. Local communities participate in remediation work for operational spills. Due to the restrictions of COVID-19 there were fewer opportunities to collaborate but the engagement and partnership with communities continued. Various NGOs have sometimes gone on joint investigation visits with SPDC, government regulators and members of affected communities to establish the cause and volume of oil spilled.

SPDC has also implemented several programmes to raise awareness of the negative effects of crude oil theft and illegal oil refining. Examples include community-based pipeline surveillance, and promoting of alternative livelihoods through Shell's flagship youth entrepreneurship programme, Shell LiveWIRE.

Bodo clean-up process

In 2015, SPDC, on behalf of the SPDC joint venture and the Bodo community, signed a memorandum of understanding (MOU) granting SPDC access to begin cleaning up areas affected by two operational spills that occurred in 2008. The MOU also provided for the selection of two international contractors to conduct the clean-up under the oversight of an independent project director. The clean-up project was delayed in 2016 and for most of 2017 because of access challenges from the community. Engagement with the Bodo community and other stakeholders began in September 2015 and was managed by the Bodo Mediation Initiative.

After two years of engagement, in September 2017, it was possible to start the first phase of clean-up and remediation activities. The clean-up consists of three phases:

- 1) removal of oil floating on water surfaces;
- 2) remediation of soil; and
- 3) planting of mangroves and monitoring.

The first phase was completed in August 2018. The contract procurement process for phase two was completed in 2019. Remediation activities in the field started in November 2019. During 2020, work had to be put on hold because of COVID-19 restrictions. Currently, we expect to finalise the activities by about May 2023.

In 2020, the Niger Delta Biodiversity Technical Advisory Group assessed the initial field reports from two pilot sites containing freshwater and swamp forests. The advisory group set out its aims and timeline for work at both sites. Field visits to these remote locations were disrupted by COVID-19 restrictions. The advisory group is also analysing other potential pilot sites identified by SPDC, and planning an engagement session with regulatory agencies in Nigeria.

Ogoniland: commitment to the United Nations Environment Programme

SPDC remains committed to the implementation of the 2011 United Nations Environmental Programme (UNEP) Report on Ogoniland which assessed contamination from oil operations in the region and recommended actions to clean it up. Over the last nine years, SPDC has acted on all and completed most of the UNEP recommendations that were specifically addressed to it as the operator of the joint venture.

The clean-up efforts are led by the Hydrocarbon Pollution and Remediation Project (HYPREP), an agency established by the federal government. In 2018, HYPREP awarded contracts for the first set of remediation projects. In 2019, 21 contractors started operations on 21 lots which add up to 12 of the 67 polluted sites recorded in the UNEP report. Of those 67 sites, two are waste sites without hydrocarbon pollution. In January 2020, HYPREP awarded a further 29 contracts for remediation on 29 lots covering eight polluted sites. The contractors took up remediation activities in the fourth quarter of 2020. Although remediation works continue to make progress, challenges remain. These include re-pollution, lack of contractor funding, land disputes and security issues in Ogoniland.

The UNEP report recommended creating an Ogoni Trust Fund (OTF) with \$1 billion capital, to be co-funded by the Nigerian government, the SPDC joint venture and other operators in the area. The SPDC joint venture remains fully committed to contributing \$900 million to the fund as its share over five years. SPDC JV partners contributed the first instalment of \$180 million for the clean-up by July 2018 and released the second instalment of \$180 million in 2019. HYPREP did not request the release of any funds in 2020. The UNEP continues to monitor the progress of the clean-up exercise via its observer status at both the HYPREP's Governing Council and the Ogoni Trust Fund. Its agencies such as UNDP, UNITAR and UNOPS provide services to HYPREP in the areas of livelihood programmes, training and project services.

HYDRAULIC FRACTURING

Shale oil and gas resources remain a critical part of a modern energy system as we move towards renewable sources. Shale resources are abundant and offer a relatively affordable source of energy. According to US Energy Information Administration (EIA) estimates, there are 7,576.6 trillion cubic feet of unproven technically recoverable wet shale gas resources and 418.9 billion barrels of unproven technically recoverable tight oil resources spread across 46 countries. We believe that developing these resources is critical for meeting the energy needs of growing societies around the world.

The oil and gas industry has used hydraulic fracturing to unlock tight/shale oil and gas resources in vertical wells for decades. In the past 20 years, hydraulic fracturing has also been used in horizontal wells to recover natural gas and oil. The technology has opened up vast resources that were previously thought to be unrecoverable. Hydraulic fracturing has been used by the industry in more than 2.5 million oil and gas wells, many of them in the USA. Hydraulic fracturing involves pumping a fluid that is typically 99.9% water and sand and around 0.1% chemical additives into tight sand or shale rock at high pressure. This creates threadlike fissures – typically the diameter of a human hair – in the rock, making space through which the hydrocarbons can flow more easily.

At Shell, we believe we can explore, develop and produce tight/shale oil and gas resources safely and responsibly. Our operations are underpinned by our Principles for Producing Tight/Shale Oil and Gas (known as Onshore Operating Principles). These provide a framework for protecting the environment and the communities in which we operate. These operating principles cover safety, air quality, water protection and usage, land use and engagement with local communities. We review the Onshore Operating Principles annually and update them as new technologies, challenges and regulatory requirements emerge. We also support appropriate and fit-for-purpose regulations.

We work to reduce greenhouse gas (GHG) emissions associated with our oil and gas development and production. Shell's shale assets implement GHG management plans and have a robust Leak Detection and Repair (LDAR) programme. We are working on multiple fronts to develop cutting-edge technologies that enhance our LDAR programme and enable earlier detection and repair of leaks. As per the Onshore Operating Principles, we seek to minimise routine gas flaring at shale assets. See our website [shell.com](https://www.shell.com) for more information about the GHG management practices, such as the "Onshore Operating Principles in Action: Methane Fact Sheet".

See also "Climate change and energy transition" on page 106.

The availability and quality of water, local environmental conditions and regulatory requirements vary from basin to basin. Therefore, each shale asset develops a tailor-made water management strategy, identifying short- and long-term water needs, options for water sourcing, recycling and sharing, options for treatment and disposal, and options for transportation and storage. The people operating our shale assets aim to minimise the use of water. Depending on local hydro-geologic conditions, they typically use a combination of fresh water, brackish groundwater, produced water and waste water. They actively strive to reduce and ideally eliminate freshwater intake for drilling and hydraulic fracturing operations, by increasing recycling capacity and using municipal water.

Potable groundwater aquifers are isolated from the hydrocarbon-producing shale formations by hundreds of metres of impermeable rock. We often need to drill through potable groundwater aquifers to reach shale formations. We therefore design our drilling, hydraulic fracturing and production activities in ways that aim to maintain isolation from potable groundwater aquifers. Before drilling a well, we conduct a hazard

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assessment in which we analyse risks to groundwater aquifers and develop control measures to reduce those risks. When we drill, we have at least two physical barriers, consisting of steel casing and cement, between the wellbore and potable groundwater aquifers. We continuously monitor wellbore integrity before, during and after hydraulic fracturing and during production activities.

Chemical additives are needed in hydraulic fracturing fluid to carry sand, reduce friction and prevent the growth of bacteria. We have been working to optimise the composition of our hydraulic fracturing fluids since 2015. As a result, we have reduced chemical additive volumes by around 50-60% compared with 2015. Currently, on a volume basis, around 0.1% of our hydraulic-fracturing fluid is chemical additives. We support disclosure of the chemical additives used in hydraulic-fracturing fluids for Shell-operated wells. See our website [shell.com](https://www.shell.com) for more information about our water management practices, such as the "Onshore Operating Principles in Action: Water Fact Sheet".

SEISMICITY

As oil and gas fields mature, seismic activity may occur, depending on the unique geology of individual fields. An example is the Groningen onshore gas field in the Netherlands, where induced earthquakes have occurred since the 1990s. Some of these earthquakes have damaged houses and other structures in the region, resulting in complaints, claims and lawsuits from local home-owners and residents. Actions have been taken to improve safety, liveability and economic prospects in the region. Nederlandse Aardolie Maatschappij B.V. (NAM, Shell interest 50%) operates the gas field. The Dutch government has taken over policy setting and execution of these mitigating actions and the "duty of care" from NAM. NAM continues to carry the costs. The government is also currently instructing NAM on production levels. Production from the onshore Groningen gas field in the Netherlands is expected to stop by 2022 or shortly thereafter.

See "Upstream" on page 55.

Overall, we believe it is relatively unlikely that hydraulic fracturing or well operations for disposing of produced water will induce seismicity that is felt on the surface. Despite this, Shell still takes precautionary measures around induced seismicity, and proactively manages the risk in accordance with, and sometimes beyond, regulatory requirements. We have added precautionary measures around induced seismicity to our Onshore Operating Principles and developed internal guidelines that we apply to our shale assets. They outline a risk assessment process and provide a framework for risk management. Subsurface and surface conditions vary from basin to basin, which means that management practices need to reflect the risk profile of each basin and provide customised responses to the risks. We support fit-for-purpose, science-based state and provincial regulations. See our website [shell.com](https://www.shell.com) for more information about our induced seismicity management practices, such as the "Onshore Operating Principles in Action: Induced Seismicity Fact Sheet".

ENVIRONMENTAL COSTS

We are subject to a variety of environmental laws, regulations and reporting requirements in the countries where we operate. Infringing any of these laws, regulations and requirements could harm our reputation and ability to do business, and result in significant costs, including clean-up costs, fines, sanctions and third-party claims.

Ongoing operating expenses include the costs of preventing unauthorised discharges into the air and water, and the safe disposal and handling of waste.

We place a premium on developing effective technologies that are also safe for the environment. But when operating at the forefront of technology, there is always the possibility that a new technology has environmental impacts that were not assessed, foreseen or determined to be harmful when originally implemented. While we believe we take reasonable precautions to limit these risks, we could be subject to additional remedial, environmental and litigation costs as a result of operations' unknown and unforeseen impacts on the environment. Although these costs have so far not been material to us, no assurance can be given that this will always be the case.

SECURITY

Our operations expose us to criminality, civil unrest, activism, terrorism, cyber-disruption and acts of war that could have a material adverse effect on our business (see "Risk factors" on pages 28-37). We seek to obtain the best possible information to enable us to assess threats and risks. This includes building strong and open relationships with government security agencies. Risk mitigation includes strengthening the security of sites, reducing our exposure as appropriate, journey management, information risk management, crisis management and business continuity measures. We conduct training and awareness campaigns for staff, and provide them with travel advice and access to 24/7 assistance while travelling. We consistently verify the identity of our employees and contract staff, and control their access to our sites and activities, both physical and logistical. We manage and exercise crisis response and management plans.

CONTRIBUTION TO SOCIETY

Shell's businesses are part of society and contribute to it by buying and selling goods and services across economies in various countries and jurisdictions. Our employees, suppliers and contractors are part of the local communities where Shell operates.

In 2020, Shell paid \$47.3 billion to governments (2019: \$61.3 billion). We paid \$3.4 billion in corporate income taxes and \$3.5 billion in government royalties, and collected \$40.4 billion in excise duties, sales taxes and similar levies on our fuel and other products on behalf of governments. In 2020, Shell spent \$39.3 billion (2019: \$44.9 billion) on goods and services from more than 29,000 suppliers globally. For more information about our approach to tax and transparency, see Shell's Tax Contribution Report, available via our website [shell.com](https://www.shell.com).

Supply chain engagement

Our suppliers are critical to our ability to run our businesses. They are involved in almost every step of our operations – and are often key to having a positive impact on local communities and achieving successful business outcomes. Shell aims to work with suppliers, including contractors, that behave in an economically, environmentally and socially responsible manner, as set out in our Shell General Business Principles and Shell Supplier Principles.

The way we engage with our contractors and suppliers is based on our Shell Supplier Principles which are embedded in contracts. They require contractors and suppliers:

- to commit to protect the environment in compliance with all applicable environmental laws and regulations;
- to use energy and natural resources efficiently; and
- to continually look for ways to minimise waste, emissions and discharge of their operations, products and services.

More information about how we engage with contractors and suppliers is expected to be published in the Shell Sustainability Report in April 2021.

NEIGHBOURING COMMUNITIES

Engaging with communities is part of our approach to managing human rights and providing access to remedy. Our global requirements for social performance aim to ensure that we operate responsibly by avoiding or minimising the negative social effects of our operations. The requirements also help us to maximise the benefits of our activities, such as employment and contractual opportunities that can support local economies.

The requirements set clear rules and expectations for how we engage with and respect communities that may be affected by our operations. We require major projects and facilities operated by Shell to have a social performance plan that defines actions for managing potential negative and positive effects on communities. A key part of these plans is identifying the social environment and stakeholders who may be vulnerable to our operations. Another key component is an appropriate community feedback mechanism for listening to queries and responding to them, or resolving complaints in a timely manner. We have specific requirements to avoid, minimise or mitigate potential impacts on the traditional lifestyles and cultural heritage of indigenous people. We also have specific requirements to avoid, minimise or mitigate their involuntary resettlement.

Early in 2020, we launched a new global community feedback tool (CFT). This enables us to globally track and respond to all queries, complaints and positive and negative feedback that we receive. It allows our network of about 100 community liaison officers (CLO) to document all types of feedback. It is accessible via a mobile app and can be used to send feedback received in the field to those who can act to resolve issues. Asset managers can generate reports to help them analyse trends, detect underlying causes, and decide appropriate action.

The CLOs continue to act as a bridge between local communities and our businesses. The CLOs are in our community centres on workdays, receiving visitors and listening to questions or complaints. Members of the community can also contact CLOs via dedicated telephone lines. It is the job of CLOs to take any concerns back to the Shell facility and involve people who are best placed to take action.

We are using a tool based on the United Nations Guiding Principles' criteria to measure the effectiveness of our mechanisms for managing community feedback on our operations.

In 2019, we had assessed the community feedback mechanisms (CFMs) of 32 sites, and in 2020, we helped 14 of these sites to improve their CFMs. The improvement measures involved included:

- promoting public access to and transparency of the sites' CFMs;
- improving written procedures so they are better aligned with global good practice and more reflective of local circumstances;
- providing clear steps for recognising alternative options for communities to seek remedy; and
- respecting people's anonymity and data privacy.

In 2020, we also developed a guide to help sites make their CFMs effective and address local needs. In 2021, we plan to further improve the quality of sites' CFMs.

📄 See our website [shell.com](https://www.shell.com) for more information about our work with communities.

HUMAN RIGHTS

Human rights are fundamental to Shell's core values of honesty, integrity and respect for people. Respect for human rights is embedded in our Shell General Business Principles and in our Code of Conduct. Our approach is informed by the United Nations Guiding Principles on Business and Human Rights.

We work closely with other companies and non-governmental organisations to improve how we apply these principles. We focus on four priority areas where respect for human rights is critical to how we operate: communities, security, labour rights, and supply chain. For each of these areas, we have systems to identify potential impacts and to avoid and mitigate them. For example, our HSSE & SP Control Framework (CF) contains our mandatory standards and manuals that set out how we identify, assess, and manage our impacts on communities where we operate, including any impact on human rights. We require all our companies and contractors to respect the human rights of our workforce and neighbouring communities. Our joint-venture partners are expected to implement our CF or an equivalent.

An internal Human Rights Working Group consisting of experts from different functions advises on and supports the businesses with the implementation and review of our approach to human rights. The group includes an external adviser. A steering committee composed of senior executives provides steer and support to the work of the Human Rights Working Group.

Our approach to due diligence is informed by the United Nations Guiding Principles on Business and Human Rights. Due diligence in each focus area, including human rights, is typically exercised in countries where there may be a risk of an impact on people's human rights. It is supported by experts working within the applicable functions in Shell. We recognise how due diligence helps us to act on our commitment to respect human rights. For example, in our supply chains, where contractors and suppliers are considered to be at risk of having issues with labour rights, we engage with them to assess their management systems, before deciding whether to award a contract. Results of these supplier assessments are evaluated, and where gaps are found, we may work with suppliers and contractors to help them implement corrective action. We may also conduct on-site audits or consider terminating contracts if serious or persistent shortcomings are found.

The most common shortcomings found during our supplier assessments typically relate to policy rather than performance gaps in the following areas:

- freely chosen employment;
- child labour avoidance;
- working hours, wages and benefits;
- dormitory, housing and working conditions;
- humane treatment, equal opportunities and freedom of association; and
- supply chain and performance management.

The Shell Supplier Principles include specific labour and human rights expectations for contractors and suppliers. Shell companies use a joint industry supplier capability assessment that is delivered in collaboration with other operators. This sharing mechanism is intended to support the improvement of working conditions in the participating companies' supply chains.

📄 See our website [shell.com](https://www.shell.com) for more information about our approach to human rights.

CLIMATE CHANGE AND ENERGY TRANSITION

Shell has long recognised that greenhouse gas (GHG) emissions from the use of hydrocarbon-based energy are contributing to the warming of the climate system. In December 2015, 195 nations adopted the Paris Agreement. We welcomed the efforts made to reach this global climate agreement, which came into force in November 2016. We fully support the Paris Agreement's goal to keep the rise in global average temperature this century to well below two degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius. In pursuit of this goal, we also support the vision of a transition towards a net-zero emissions energy system. Shell agrees with the statement of the Intergovernmental Panel on Climate Change (IPCC) special report, Global Warming of 1.5°C that says that in order to limit global warming to 1.5 degrees Celsius above pre-industrial levels, the world economy would need to transform in complex and interconnected ways. Meeting this challenge would require an even more rapid escalation in the scale and pace of change in the coming decades than was foreseen in the Paris Agreement.

Society faces a dual challenge: it must transition to a low-carbon energy future to manage the risks of climate change, while also extending the economic and social benefits of energy to everyone on the planet. This requires, among other things, reducing emissions while also changing how energy is produced, stored, used and made accessible to more people.

Shell recognises that society's attitude towards climate change is shifting rapidly and that it is different in different locations. Regulators in some advanced economies such as the EU and the UK have already started pushing for net-zero emissions by 2050 in an effort to achieve the 1.5 degrees Celsius stretched goal of the Paris Agreement. Potential similar developments in other key locations might lead to similar or more stringent regulatory conditions on Shell's operations and products.

On February 11, 2021, we announced Powering Progress, our new strategy. Powering Progress is our strategy to accelerate progress to net-zero emissions, purposefully and profitably. One of the pillars of this strategy is for Shell to become a net-zero emissions energy business by 2050, in step with society. We believe our net-zero target supports the most ambitious goal of the UN Paris Agreement, to limit warming to 1.5 degrees Celsius above pre-industrial levels. This will require us to transform our business, working with our customers and others, in sectors that are difficult to decarbonise. This includes aviation, shipping, road freight and heavy industries. We also believe that our total oil production peaked in 2019 and our total emissions (Scope 1, 2 and 3) peaked in 2018 at around 1.73 gigatonnes per annum.

Shell's target is to be a net-zero emissions energy business by 2050, in step with society. This means net-zero emissions from our operations – our Scope 1 and 2 emissions – and also net zero from the end use of our products that we sell – our Scope 3 emissions. Our Scope 3 emissions include our customers' emissions from the energy products we produce and sell as well as the life-cycle emissions of the energy products produced by other companies that we resell to our customers. This means that our target covers all the energy we sell, not just the oil and gas we produce and refine ourselves.

But Shell cannot get to net zero without society also being net zero. While we aim to transition slightly ahead of society, where we expect to see higher margins for our low-carbon and renewable energy products, we cannot transition too quickly or we will be trying to sell products that our customers do not want. Accordingly, other than our short-term remuneration targets, all targets are conditional on being in step with society. If society is not on the path to net zero for 2050, it is unlikely that Shell will meet its emissions targets.

We believe it is important for the Board and the management to understand what our shareholders think. Accordingly, in 2021, Shell intends to submit its energy transition strategy to shareholders for an advisory vote at our Annual General Meeting. We will submit our energy transition strategy to such an advisory vote every three years. We will also

seek an advisory vote on the progress we make each year, as disclosed in our Annual Report, starting in 2022.

SHELL'S ABSOLUTE EMISSIONS AND CARBON INTENSITY TARGETS

Our target is to be a net-zero emissions energy business by 2050, in step with society.

Shell's 2050 absolute emissions targets

We aim to achieve these targets in step with society. They are:

- net-zero Scope 1 and Scope 2 emissions from our operations by 2050; and
- net-zero Scope 3 emissions from the energy products we sell by 2050.

Shell's net carbon intensity targets

We aim to achieve these targets in step with society. They are measured by our Net Carbon Footprint (NCF) metric, and are:

- 2030 NCF reduced by 20% from 2016 NCF;
- 2035 NCF reduced by 45% from 2016 NCF; and
- 2050 NCF reduced by 100% from 2016 NCF.

The updated 2035 and 2050 targets reflect that we will start to include all actions taken to reduce emissions when we calculate our net carbon intensity. This includes the actions we take ourselves and actions taken by the users of the energy products we sell.

We will work with our customers to address the emissions created when they use products bought from us (Scope 3) and help them find ways to reduce their emissions and overall carbon footprint to net zero by 2050.

Remuneration targets

We have set specific carbon intensity targets for the following years:

- 2021 NCF reduced by 2-3% from 2016 NCF;
- 2022 NCF reduced by 4-6% from 2016 NCF; and
- 2023 NCF reduced by 6-8% from 2016 NCF.

See below, in this section, for more detail on:

- How we plan to deliver;
- Our climate target;
- Our net carbon intensity targets; and
- Our performance.

See also the Directors' Remuneration Report on page 153-156.

Business milestones

We are taking steps to cut emissions from our existing oil and gas operations, and to avoid generating more in the future.

- We believe our annual oil production peaked in 2019, and we expect our total oil production to decline by 1-2% a year until 2030.
- We do not anticipate any new frontier exploration entries after 2025.
- Natural gas is the least polluting hydrocarbon. We expect the percentage of total gas production in our portfolio to gradually rise to 55% or more by 2030.
- By 2030, we will end routine flaring of gas, which generates carbon emissions, from the assets we operate.
- By 2025, we expect to have kept the methane emissions intensity of Shell-operated assets to below 0.2%.

HOW WE PLAN TO DELIVER

Getting the energy system on a path to net zero will require co-ordinated action between energy providers, energy users and governments. They will need to work together over the coming decades to define rapid, realistic decarbonisation pathways, sector by sector.

We will work with our customers to address the emissions created when they use products bought from us (Scope 3) and help them find ways to reduce their emissions and overall carbon footprint to net zero by 2050.

We are already taking steps to cut emissions from our existing oil and gas operations, and to avoid generating more in the future. We aim to reduce the GHG intensity of our portfolio and we continue to work on improving the energy efficiency of our existing operations. One element of our target is to achieve net-zero emissions from all our operations, as well as from the energy we need to power them.

Shell believes that society must accelerate and increase the scale of all forms of GHG reduction. We are increasing the proportion of lower-carbon products such as natural gas, biofuels, electricity and hydrogen in the mix of products we sell. For example, Amazon Air has secured up to six million gallons of sustainable aviation fuel – made partly from biomass and waste – supplied by Shell Aviation and produced by World Energy. Similarly, we have formed an alliance with Microsoft which includes supply of renewable energy to help them meet their commitment of 100% renewable energy consumption by 2025.

Our shift to energy and chemicals parks means we will reduce our production of traditional fuels by 55% by 2030, from around 100 mtpa to 45 mtpa. We plan to build on Shell's leading position in hydrogen by developing integrated hydrogen hubs to serve industry and heavy-duty transport, aiming to achieve double-digit share of global clean hydrogen sales.

It is not enough for Shell to take action on its own. We can only meet our net-zero target as part of a world that is also heading to net zero. That will require a reduction in the global supply of carbon-based energy, which can only happen if demand for carbon-based energy also reduces. So Shell, as a supplier, must work with customers on a sector-by-sector basis, to develop the right pathways to transition each sector from carbon-based energy to low-carbon solutions.

Shell's marketing business is being restructured on a sectoral basis. This in turn will help us to make progress in working with customers on a sector-by-sector basis.

Our mission is to help the millions of brand-loyal customers whom we serve every day – from individual energy consumers to large businesses – to decarbonise. We have the scale and the competitive advantage to generate profit from this shared ambition.

Our marketing platform is one of the best in the energy industry. Spanning 160 markets, every day we serve more than 30 million customers at our retail sites; and one million businesses.

Our customer access gives us first-hand insights, helping us to deliver what our customers want rather than offering what others think they need.

This will help us to grow our existing marketing platforms profitably, while also increasing the decarbonisation choices across sectors and countries.

Our global ambition is that by 2025 we are operating more than half a million electric-vehicle charging points for businesses, fleets and customers, at our retail sites and people's homes. This number is expected to rise to 2.5 million charging points operated by Shell by 2030. For drivers who are unable to switch to an electric vehicle immediately, we also offer carbon-neutral driving using nature-based carbon offsets, in seven countries including the UK.

We are positioning ourselves to profitably deliver integrated offers by cross-selling to motorists and home energy customers. Our integrated solutions will help our business customers to navigate the challenges and opportunities of decarbonisation.

One such customer is Penske Corporation in the USA. We work closely with this customer across truck leasing, logistics and automotive retail. We provide Penske Corporation with products and services ranging from fuels and lubricants, to electric-vehicle charging and renewable power.

Our approach to commercial road transport is similar to how we work with other hard-to-decarbonise sectors such as shipping and aviation. We are working with transport companies, truck manufacturers and policymakers to identify profitable pathways to decarbonisation.

We are already one of the world's largest blenders and distributors of biofuels, and we will continue to invest in and increase the production of these low-carbon fuels. Over the next decade, we will help customers in Europe, China and on the US West Coast to transition to liquefied natural gas (LNG) and biogas.

Hydrogen also offers a route to lowering emissions. We are part of the H2Accelerate consortium, which looks at ways to create infrastructure for generating and supplying hydrogen across Europe.

In Power, we are working with our customers in different markets, finding commercial ways to meet their specific needs. Our scale, reach, brand strength and trading capability set us up to succeed. An example is our deal to supply Amazon with renewable power, which is helping it to fulfil its climate pledges.

We are also supporting infrastructure development through our investments in Silicon Ranch and Cleantech Solar. Combined, these two companies have over 350 solar farms in the USA and South-east Asia. In Australia and in Oman, Shell is building its first large-scale solar farms.

Shell's infrastructure, systems integration, experience and people put us in a strong position to profitably meet the current and future needs of our customers, helping them and society to decarbonise for a net-zero emissions future.

We are restructuring so that we have marketing teams facing individual sectors. We are also developing a carbon management framework to guide decision-making on investments in assets and businesses that align with our climate target. We intend to have carbon budgets for customer-facing businesses to motivate them to find value growth by switching from high-carbon income to low-carbon income.

Shell believes that the need to reduce GHG emissions will continue to be an important driver in transforming the energy system in this century. This transformation will generate both challenges and opportunities for our existing and future portfolio.

TRANSPARENCY AND COLLABORATION

We support efforts to increase transparency and investors' understanding of companies' strategies for responding to the risks and opportunities of climate change. We do this through engagement with external stakeholders such as industry associations beyond the energy industry, standard setters, non-governmental organisations (NGOs), investors, and initiatives on different topics including climate change. With publications such as our 2020 Sustainability Report and our 2020 Industry Associations Climate Review update (both planned to be published in April 2021) we aim to provide additional information to that in this Report to address requests and recommendations from different reporting frameworks and standards. Some examples of those frameworks and engagements are described below.

- We continue to support the Task Force on Climate-related Financial Disclosures (TCFD) recommendations and apply them to our reporting. We aim to address the recommendations with this Report and other Shell publications such as the 2020 Sustainability Report and 2020 Industry Associations Climate Review update (both due to be published in April 2021), and our latest scenarios Islands, Waves, and Sky 1.5.
- As a member of the Oil and Gas Climate Initiative (OGCI) we are one of a group of 12 national and international energy companies that focus on action that has real impact now and delivers on decarbonisation in the coming decades (see Methane initiatives and collaborations, page 102).

CLIMATE CHANGE AND ENERGY TRANSITION continued

- In December 2020, eight leading energy companies including Shell announced that they had jointly developed and agreed to apply six Energy Transition Principles. These principles aim to support the collective industry acceleration to contribute to the Paris Agreement objectives by delivering progress on reducing GHG emissions, the role of carbon sinks, and the importance of transparency and alignment on climate change with trade associations. The companies are building further on this collaboration to drive more consistency and transparency in greenhouse gas reporting, and in measurement of the emissions which may occur at different points in the value chain.
- We continue to engage with the Science Based Targets initiative (SBTi), and we are a member of its Technical Working Group that is currently working to define the methodology for the oil, gas and integrated energy sector.
- Some governments have introduced carbon pricing mechanisms, which we believe can be an effective way to reduce GHG emissions across the economy at the lowest overall cost to society. We expect more governments to follow. Shell is encouraging carbon pricing mechanisms so that businesses and consumers are further incentivised to improve energy efficiency, provide and switch to lower-carbon options, and reduce carbon emissions. Such mechanisms can also help encourage projects such as CCS facilities and nature-based solutions like the planting of forests. Shell continues to work with governments to produce effective transition plans and policies.

OUR GOVERNANCE OF CLIMATE CHANGE

Climate change and risks resulting from GHG emissions are a significant risk factor for Shell. They are managed in accordance with other significant risks through the Board and the Executive Committee.

📖 See “Other regulatory and statutory information” on pages 182-189.

Shell's climate change risk management structure includes the work of the Board. In 2020, the Board discussed a variety of energy transition and climate change-related subjects. These included environmental topics ahead of Responsible Investment Day and Shell's announcement of its target to be a net-zero emissions energy business by 2050, in step with society. Directors received information on opportunities and priorities in the New Energies area. Throughout the year, Directors were also informed about topics of interest among investors and other stakeholder groups. These included sustainability, governance and the energy transition. During the annual strategy meeting, in virtual format, the Board discussed various topics including the energy transition and its implications.

📖 For more information on the activities of the Board see “Board activities and evaluation” on pages 130-133.

The Board committees play an important role in assisting the Board with regard to governance and oversight of management of climate change risks and opportunities, as described in “Governance” on page 128.

The Safety, Environment and Sustainability Committee (SESCo) assists the Board in reviewing the practices and the performance of the Shell Group of companies, primarily with respect to safety, environment including climate change, and sustainability. When reviewing these areas and deciding how to advise the Board, SESCO takes into account Shell's General Business Principles, Code of Conduct, and HSSE & SP Control Framework. SESCO's duties include reviewing Shell's progress towards meeting our climate targets and the energy transition. SESCO also advises the Remuneration Committee on metrics relating to sustainable development and energy transition.

📖 For more information about SESCO's activities around climate change and energy transition see page 143.

The Remuneration Committee (REMCO) is responsible for determining the Directors' Remuneration Policy, in alignment with our business strategy.

Annual scorecard

Starting in 2021, we are increasing the weight associated with GHG emissions management. The GHG emissions intensity metric and its weight (10%) will remain unaltered, but we will add a new metric that measures the execution of GHG-abatement projects with a weight of 5% (see page 170 for more information).

Performance Share Plan and Long-term Incentive Plan

For 2021 awards made under the Performance Share Plan (PSP), the weighting of the energy transition condition has doubled from 5% to 10%. For 2021, the weighting of the energy transition condition in the Long-term Incentive Plan (LTIP) will also double from 10% to 20%. The target range is a 6-8% reduction in net carbon intensity against the 2016 baseline NCF of 79 grams of carbon dioxide (CO₂) equivalent per megajoule. The other targets linked to our strategic ambitions will also evolve, with the metric connected to commercialising advanced biofuel technology broadening to a measure of growing new cleaner energy product offerings. The targets for the leading energy transition measures are commercially sensitive and will be disclosed retrospectively.

The energy transition condition was included again in the 2020 LTIP awards for Executive Directors and senior executives and was also incorporated into the Performance Share Plan awards made to around 16,500 employees globally.

See “Directors' Remuneration Report” on pages 153-156 for further information. An update on progress on the 2019 and 2020 awards is provided on pages 165.

The Audit Committee has key responsibilities in helping the Board to maintain oversight of areas such as the effectiveness of risk management and internal control. For more information on the work of the Audit Committee see page 145.

The CEO is the most senior individual with accountability for climate change risk. Shell has established specialist forums at different levels of the organisation where climate change and GHG-related matters are addressed, monitored and reviewed. Each Shell entity and each Shell-operated venture is responsible for implementing climate change policies and strategies.

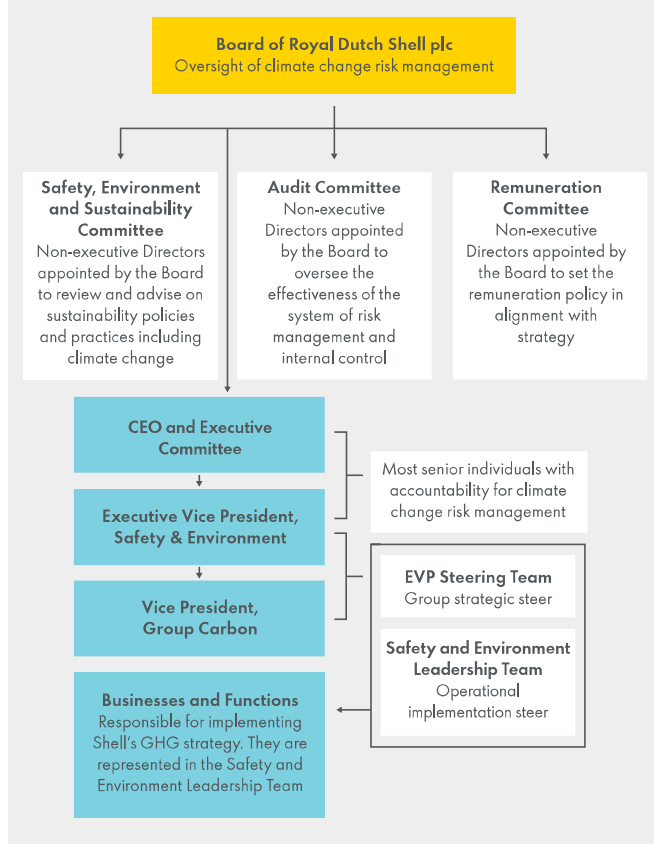
The Executive Vice President (EVP) Safety and Environment, a senior manager who reports directly to the Projects & Technology Director, is accountable for the oversight of GHG issues. This manager's department includes the Group Carbon team and the HSSE & SP Assurance and Reporting team.

Group Carbon is accountable for monitoring and examining the strategic implications of climate change for Shell. Group Carbon also reviews the effects of governmental policy and regulation. It proposes policy positions based on analysis by Shell and external organisations. The team also advises Shell companies to ensure that they are consistent in how they apply our core principles and policies when interacting with policymakers.

Group Carbon also has oversight of Shell's GHG management programme. It helps our lines of business to adopt strategies for managing greenhouse gases. The team includes managers who advise projects on the risks and opportunities of GHG-related issues.

The HSSE & SP Assurance and Reporting team is accountable for the delivery of Shell's non-financial reporting. It is also responsible for auditing the performance of Shell businesses with regards to our HSSE & SP Control Framework requirements, which include climate change risk management.

Climate change management organogram



REORGANISATION IN LINE WITH UPDATED STRATEGY

During 2020, we worked on a comprehensive organisational review in order to enable our new strategy to be effective. We call this project Reshape. The governance of topics around sustainability, including climate change, will not change at the most senior levels of Shell. We are introducing changes at specific levels of the organisation to better address the effects of the strategy update. We expect to adjust the initial structure as we go through the process. Currently, we are working towards going live with the revised organisational structure in the second half of 2021.

For more information, see [Strategy and outlook on page 18](#), and [Our people on page 108](#).

CLIMATE CHANGE RISK MANAGEMENT PROCESS

The framework for managing the climate change and GHG emissions risk is underpinned by Shell's Control Framework and Statement on Risk Management, which are described on pages 186 of the "Other regulatory and statutory information" section of this Report.

For the climate change and GHG emissions risk, several global teams support our businesses in GHG and energy management, comprising a network of experts in subjects related to GHG and risk management. They work globally across our lines of business and assist in:

- identifying and assessing risks;
- planning and implementing responses;
- sharing best practices; and
- monitoring, improving and completing action that affects the objectives and performance of projects and assets.

These teams have created a set of mandatory manuals and complementary guidance documents that are updated periodically and are ultimately based on our HSSE & SP Control Framework (CF). These manuals and documents provide guidance on how to monitor, communicate and report changes in the risk environment, and how to review the effectiveness of actions taken to manage identified risks, including ways to:

- ensure consistent assessment of climate risk across Shell;
- clarify expectations for risk management and reporting, including roles and responsibilities of the risk owners;
- clarify types of assurance activities that may be applicable;
- strengthen decision-making by ensuring that businesses have better awareness and understanding of climate risks (including their likelihood and potential impact) and mitigation plans; and
- enable integration of Shell's reporting.

For more detail on our definition of risk categories and their relationship to different time horizons, see page 98.

The GHG and Energy Management Manual is one of the mandatory manuals of our HSSE & SP Control Framework. It requires that effective steps are taken to track the GHG emissions from Shell's operated and non-operated facilities and the life-cycle emissions of its energy products. The manual also focuses on the efficient operation of existing equipment. This means, for example, using monitoring systems to get real-time information that we can use to make energy-saving changes and identify opportunities for energy-saving investments in the medium term. Shell's scorecard includes GHG measures that create additional incentives for our employees to reduce GHG emissions in our portfolio.

See "Directors' Remuneration Report" on page 153.

The global teams mentioned above support the businesses in monitoring and addressing certain physical risks of climate change. This support includes the input of specialist teams who provide direct technical assistance to facilities, based on their analysis of the potential impacts of climate change in different operating environments. For example, the specialist teams support facilities on an ad hoc basis to address potential operational issues such as flooding of a site that may affect its drainage system.

The teams also provide expertise on how to include considerations of certain potential physical climate change risks in the internal Design and Engineering Practice (DEP) requirements for new projects. The DEPs for new projects are reviewed periodically to take account of changes in the risk environment, including emerging weather and climate factors.

We review our portfolio annually to identify emerging risks from changes in GHG emissions regulations and changing physical conditions. Shell's Group Carbon team provides management with strategic insights on Shell's exposures, risks and opportunities, and recommends actions for Shell to take. Each of Shell's businesses and functions has an assurance committee that considers this risk on a regular basis and coordinates the applicable assurance activities.

At the Group level, the climate change and GHG emissions risk has been identified as a significant risk factor for Shell – see "Risk factors" on page 29. The Executive Committee and Board regularly review this risk in the same way that they do for other significant Group risk factors. Potential impacts and likelihoods are considered and discussed bi-annually. Similarly, the effectiveness of risk responses is also considered and discussed on a regular basis. Where necessary, these reviews are further supplemented by additional in-depth reviews with the relevant management teams. These reviews help to guide operational decisions, maintenance schedules and response planning.

CLIMATE CHANGE AND ENERGY TRANSITION continued

Climate change risk management at project level

Shell requires that the GHG emissions of certain assets and projects are addressed in specific ways. This is described in our internal, mandatory GHG and Energy Management Manual which is part of our HSSE & SP Control Framework (see Environment and society, page 86). This manual specifies the requirements for managing the risks associated with GHGs and energy use, and is owned and signed off by the Vice President Group Carbon. It states that projects with a material GHG footprint must get their targets approved by the Executive Vice President Safety and Environment at certain defined stages. The project's GHG-abatement plan helps to determine the nature of these targets.

Projects under development that are expected to have a material GHG footprint must meet our internal carbon performance standards or industry benchmarks. This indicates that they will be able to compete and prosper in a future where society aims to limit overall GHG emissions.

The performance standards are used as our screening criteria for measuring projects' average lifetime GHG intensity or energy efficiency per asset type. We are working to develop a complete set of standards for our businesses. Performance Standards for the Upstream and Transition pillars are in place, while those for the Growth pillar are under development. The complete set is expected to continue to evolve to incorporate new types of projects that support Shell's portfolio changes in alignment with our NZE energy business target. Our current standards are reviewed and updated annually, based on changes to legislation and external and/or internal benchmarking. The latest update was in 2020. The performance standards were signed off by the Executive Vice President (EVP) accountable for implementation in the relevant businesses, and by the EVP Safety and Environment, who represented the view of a risk owner from outside the relevant business.

We estimate the GHG emissions of facilities in two ways. We apply the performance standards, and we consider the GHG emissions from the use of the products that are manufactured. We assess GHG emissions' impacts alongside economic and technical design factors. These assessments can lead to projects being stopped or designs being changed.

During project development, we consider ways to reduce GHG emissions and whether to include them in the design. Measures considered and adopted have included:

- flaring reduction;
- carbon capture and storage (CCS) capabilities;
- exclusion of high-intensity process equipment;
- using renewable energy; and
- electrification.

Our approach continues to evolve as we increase our understanding of the shifting policy landscape and the differing paces of energy transitions in different regions.

We continue to develop our project managers' and practitioners' competencies for effective GHG emissions management in projects. The Shell Project Academy has been set up to provide competence development programmes that include different ways of learning, such as courses on specific topics and on-the-job training. These courses also aim to ensure sharing of good practice and to encourage collaboration across businesses.

CLIMATE-RELATED RISKS AND OPPORTUNITIES

Our approach for assessing and managing the risks and opportunities associated with climate change includes considering different time horizons. The time horizons and their relevance to risks, opportunities and business planning are as follows:

- Short term (up to three years): we develop detailed financial projections and use them to manage performance and expectations on a three-year cycle.
- Medium term (generally three to 10 years): most of our expected production and earnings in this period come from our existing assets.
- Long term (generally beyond 10 years): for this period, it is expected that the current Shell portfolio will change and evolve with the energy transition. Decision-making and risk identification on the thematic structure of the future portfolio are guided by the pace of society's progress and the aim of being in step with society as it moves towards the goals of the Paris Agreement.

The overall climate change risk consists of four components, based on the nature of our exposure and the options for our mitigation responses. The four components are regulatory risks, commercial risks, physical risks and societal risks:

- Regulatory risks (time horizon: short term) include increased compliance costs for assets and/or products such as carbon costs; restrictions on the use of fossil fuels; and lack of net-zero-aligned global and national policy and frameworks.
- Commercial risks (time horizon: medium to long term) include lower sales volumes and/or margins because of generally reduced or eliminated demand; the possibility of underutilised or stranded oil and gas assets; changing preferences of investors and financial institutions; and additional costs for decarbonisation of operations.
- Physical risks (time horizon ranging from short to long term) include structural damage to assets and downtime caused by acute events; reduced efficiency because of changing ambient conditions; increased operations and maintenance costs; and value-chain disruptions.
- Societal risks (time horizon: continuous) include the potential for a deteriorating relationship with the public, other companies, and governments in countries where Shell operates; class action lawsuits or similar litigation; potential stakeholder criticism related to transparency and clarity around plans and actions to achieve climate targets; and decline in reputation, brand value and competitive advantage.

📄 See "Risk Factors" on page 29.

Climate change and the energy transition have also created some business opportunities for Shell. See also "Our portfolio and climate change" on page 101.

Impact of climate-related risks and opportunities on strategy, planning and business decisions

For Powering Progress, we must evolve our portfolio of assets and the mix of energy that we sell, so we can meet the cleaner energy needs of our customers in the coming decades. We aim to achieve this by repositioning our traditional businesses for resilience and taking advantage of the growth opportunities created by emerging customer needs.

We assess our portfolio decisions, including investments and divestments, against the potential impacts of the energy transition to the use of lower-carbon energy. These include higher regulatory costs linked to carbon emissions and lower demand for oil and gas. We continue to transform our organisation, ensuring that our portfolio is well positioned for the future of energy. In February 2021, we announced our updated strategy (see Strategy and outlook, page 18).

We believe that our business strategy is resilient and adapted to the current implementation of the Paris Agreement, which is now progressing through the mechanism of countries developing their individual nationally determined contributions (NDCs). The Paris Agreement does not stipulate that emissions must fall in all sectors or countries simultaneously, or that all actors within the system will reduce their emissions at the same time or to the same degree. It acknowledges that emissions might even increase in some parts of the world. What is important is that overall emissions fall.

The transition to lower-carbon energy requires major changes to industrial, commercial and residential infrastructure. This takes time and substantial investment. Our annual planning cycle and periodic portfolio reviews aim to ensure that our levels of capital investment and operating expenses are appropriate in the context of an uncertain and changing external environment.

The annual business plan is our way of putting the strategy into effect. A business plan is created, which is then approved by the Board. The plan contains forecasts of Shell's cash flows, and seeks to ensure that we can service financing requirements, pay dividends and fund investment activities.

Shell's business plan includes assumptions about internal and external parameters. Some of the key assumptions relate to:

- commodity prices;
- production levels and product demand;
- exchange rates;
- future carbon costs;
- the schedules of growth programmes; and
- risks and opportunities that may have material impacts on free cash flow.

Shell's strategy recognises that the world is transitioning to a lower-carbon energy system, but acknowledges that the pace and specific path forward remain uncertain and may differ across regions and countries. This means that Shell will need to make agile business decisions in step with society.

Scenario planning is a well-established process for exploring possible future outcomes. Many factors and variables are considered in this exercise. These include the future size and cost of resource bases and macroeconomic, geopolitical, social, technological and regulatory developments. Our portfolio and strategy have been assessed against a wide range of outlooks. These include the potential impacts of various possible energy transition pathways, and changes in societal expectations around climate change. Our latest set of Shell scenarios was one of the many variables used in guiding the updated strategy which we announced in February 2021. One of the key aspects that underpin Shell's financial statements are the oil and gas price and refining margin assumptions. These price assumptions are developed with input from our scenarios and other factors.

GHG elements in the business plans consist of a GHG-emissions forecast, GHG-abatement plan and GHG costs. To assess the resilience of new projects, we consider the potential costs associated with operational GHG emissions. We have developed country-specific short-, medium- and long-term estimates of future carbon costs which are reviewed and updated annually. By 2050, our real-terms carbon cost estimates for all countries are expected to increase to at least \$100 per tonne of GHG emissions.

The process for developing our cost of carbon estimates uses short-term policy outlooks and long-term scenario forecasts, both of which reflect the current nationally determined contributions (NDCs) submitted by countries as part of the Paris Agreement and evolving national policy developments. NDCs under the Paris Agreement are subject to revisions every five years. The United Nations estimate that the current NDCs are consistent with limiting the rise in global average temperature to around three degrees Celsius above pre-industrial levels. In the coming decades, we expect countries to tighten their NDCs to meet the goals of the Paris Agreement. We expect to update our estimates as countries update their NDCs and climate policies. Accordingly, we believe our estimates appropriately reflect society's current implementation of the Paris Agreement. We continue to test the robustness of our projects with a material GHG footprint by using long-term carbon cost estimates that are consistent with limiting the rise in global average temperature to well below two degrees Celsius.

Shell's annual carbon cost exposure is expected to increase over the next decade because of evolving carbon regulations. This expected increase is based on forecasts of Shell's equity share of emissions from operated and non-operated assets, and real-terms carbon cost estimates which range from \$5 to \$110 per tonne of GHG emissions in 2030. This exposure also takes into account the estimated impact of free allowances as relevant to assets based on their location. The regulatory carbon cost estimate is refreshed on an annual basis as part of the development of our business plan.

OUR CLIMATE TARGET

As indicated at the beginning of this section, our long-term climate target is to be a net-zero emissions energy business by 2050, in step with society's progress towards achieving the goal of the UN Paris Agreement on climate change. This target supports the most ambitious goal of the Paris Agreement on climate change to limit the global temperature rise to 1.5 degrees Celsius. We referred to the database developed for the IPCC special report *Global Warming of 1.5°C* while setting this target. We started with all the 1.5 degrees Celsius scenarios and then selected the scenarios which focused on earlier action and placed less reliance on the use of carbon sinks to produce the 1.5 degrees Celsius pathway we have used for target setting.

CLIMATE CHANGE AND ENERGY TRANSITION continued

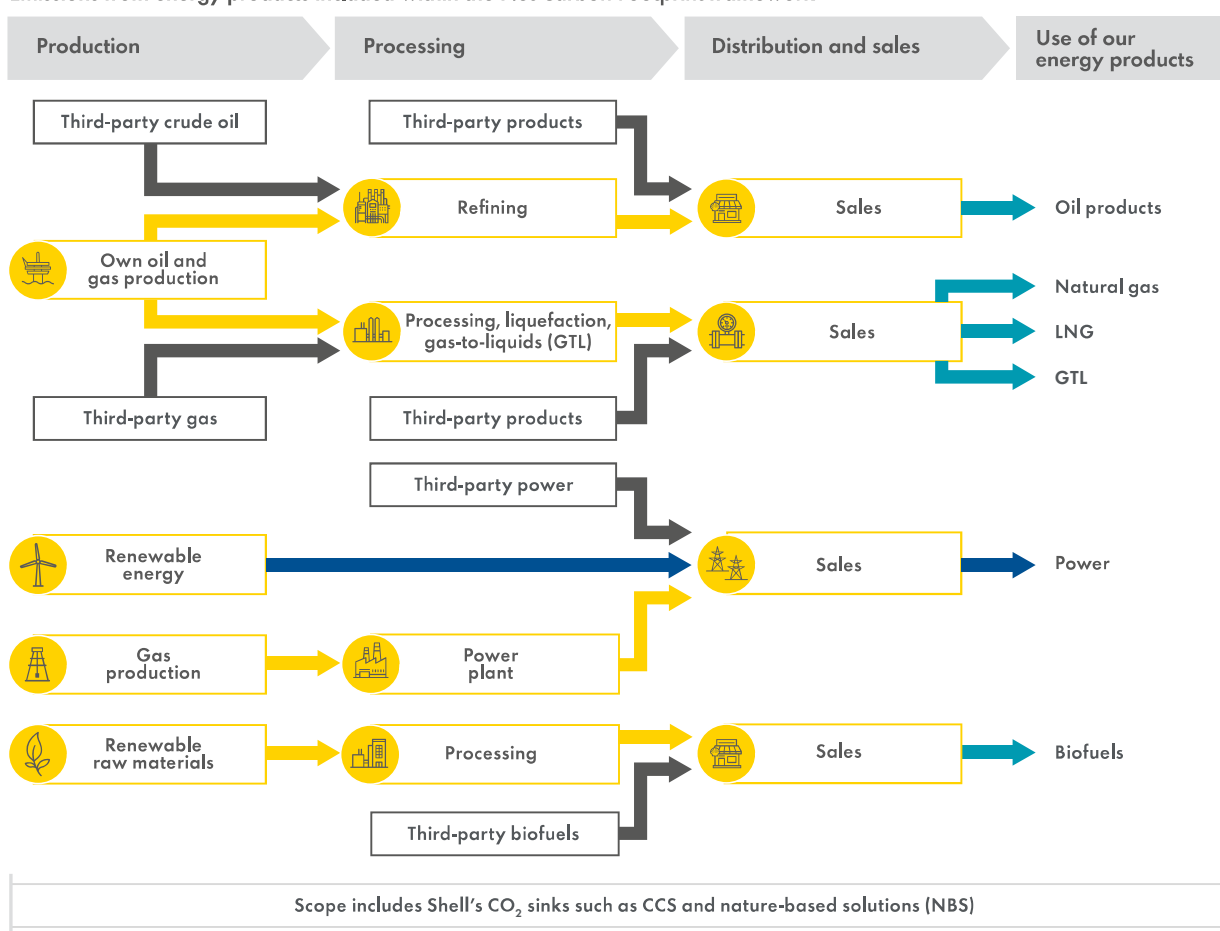
OUR NET CARBON INTENSITY TARGETS

Shell's carbon intensity is the average intensity, weighted by sales volume, of the energy products sold by Shell. This is tracked, measured and reported using the Net Carbon Footprint (NCF) metric and methodology. Our NCF calculation includes the life-cycle greenhouse gas emissions associated with each unit of energy we sell that is used by our customers. This includes the emissions associated with the production, processing, transport and end use of these products. Also included are emissions from other elements of this life cycle not owned or controlled by Shell, such as

oil and gas that we process but do not produce, or emissions from oil products and electricity marketed by Shell that have not been processed or generated at a Shell facility. The calculation also subtracts emissions for those that are stored by using carbon capture and storage (CCS) or are offset using natural carbon sinks, such as forests and wetlands. Chemicals and lubricants products, which are not used to produce energy, are excluded from the scope of this metric. The carbon intensity of the energy products we sell is expressed in grams of carbon dioxide equivalent (CO₂e) per megajoule consumed.

Scope of our Net Carbon Footprint

Emissions from energy products included within the Net Carbon Footprint framework



Impact of physical risks and adaptation measures

The physical effects of climate change may increase Shell's exposure to hazards that could potentially include, for example, higher air and sea temperatures, rising sea levels, an increased chance of flooding and droughts, wildfires and more severe tropical storms. They could potentially impact our operations and supply chains. There could also be potential financial implications, such as increased operating costs and lower revenue because of decreased efficiency.

The potential impacts of physical risks to Shell facilities, where processes, equipment and safety could be affected, are reasonably understood in Shell's oil and gas businesses. For example, rising temperatures could potentially impact the efficiency of our plants, increase equipment corrosion and decrease gas pipeline capacity. Rising sea levels could potentially impact our coastal facilities through increased coastal erosion and flooding, damage to jetties, and salt-water intrusion in freshwater intake.

The potential impacts of physical risks to the wider environment and their indirect effect on our facilities is an area that we continue to monitor and evaluate within the local context. Such risks could potentially disrupt our operations by affecting people, infrastructure or supply chains. For example, wildfires and droughts could disrupt feedstock supply for biofuels or make it difficult to access assets, including areas that support our nature-based solutions programme. Floods, meanwhile, could affect staff and communities in low-lying areas.

Measures to adapt to climate change could help reduce the impact of some of these physical climate change risks. These measures can range from local actions for a specific facility, to more general changes, such as adjustments to engineering design codes and alterations to the set limits and conditions within which facilities are deemed safe to operate. For example, Shell has already completed or started to implement solutions like pumping sand on beaches in to order to stabilise them, dredging works, and using a hovercraft for transport between islands.

OUR PORTFOLIO AND CLIMATE CHANGE

We aim to grow our business in areas that will be essential in the energy transition, and where we see growth in demand over the next decade.

We are seeking cost-effective ways of managing GHG emissions in line with our NCF ambition. We also intend to help customers choose options with lower carbon intensity by bringing to market products with lower carbon intensity, in line with demand. We seek to help reduce global GHG emissions by:

- supplying more natural gas to replace coal for power generation;
- developing carbon capture and storage (CCS);
- implementing energy-efficiency measures in our operations where reasonably practicable;
- developing new fuels for transport such as advanced biofuels and hydrogen;
- maintaining a focus on using natural gas and renewable electricity to generate power; and
- working with nature-based solutions.

See further information on portfolio decisions in "Integrated Gas" on page 47, "Upstream" on page 54, "Oil Products" on page 72, and "Chemicals" on page 78.

NATURAL GAS

Natural gas is the least polluting hydrocarbon. It produces less than one-tenth of the air pollution that coal does when burned to generate electricity. Increasing the role that gas plays in the energy mix is one way countries can take action as the world moves to a net-zero emissions future.

Natural gas is an abundant, secure and readily available source of energy, one of the few that can be used across power generation, industry, the built environment and transport. Gas has significant advantages when used to generate power alongside renewables: it can quickly compensate for dips in supply from solar or wind generation, and can rapidly respond to surges in demand.

In 2020, gas accounted for around 47% of Shell's total production. We are a leading producer, marketer and trader of liquefied natural gas (LNG) and gas-to-liquids (GTL) products. In our new strategy, launched in February 2021, one of the energy transition milestones by 2030 is that we expect the percentage of total gas production in our portfolio to gradually rise to around 55% or more.

See "Integrated Gas" part on page 46.

Methane emissions

Natural gas consists mainly of methane. Methane is a potent greenhouse gas and has a much higher global warming impact than CO₂. Efforts to address climate change therefore require the industry to reduce both deliberate and unintended methane emissions.

The IEA estimates that natural gas operations have an average methane leakage rate of 1.7%. At this rate, natural gas emits between 45% and 55% less GHG than coal when burned at a power plant. Higher levels of methane emissions reduce this benefit.

In 2018, Shell announced an industry-leading target of keeping its methane emissions intensity below 0.2% by 2025. This target covers all the Shell-operated oil and gas facilities in our Upstream and Integrated Gas businesses. The baseline and target intensities are expressed as percentage figures, representing estimated methane emissions from Shell-operated oil and gas facilities as a percentage of the total amount of gas marketed, or the quantity of marketed oil and condensate where facilities have no marketed gas (for example, those that re-inject produced gas). Methane emissions include those from unintentional leaks, venting and incomplete combustion, for example, in flares and turbines.

The largest contributor to our reported methane emissions in 2020 was the flaring and venting of gas (including equipment venting) in our upstream oil and gas operations. We are working to reduce methane emissions from these sources by reducing the overall level of flaring and venting. We also continue to implement programmes across our sites to identify and stop unintended leaks and to replace or repair high-emission equipment, such as high-bleed pneumatic devices. We continue to work on confirming that we have identified all potential methane sources and reported our emissions from these sources in line with regulations and industry standards.

CLIMATE CHANGE AND ENERGY TRANSITION continued

Since 2018, we have tested drone-based leak detection cameras and sensors in our Permian Basin shales asset, where we have more than 400 sites. In 2020, we signed a contract with Avitas, a GE Venture, to expand the use of drones to enhance our existing leak detection and repair programme in the Permian Basin. As a result, we started the drone programme on one of our shales businesses, across sites that have the potential to emit methane.

We played an active role in the advisory committee of The University of Texas at Austin's Project Astra which plans to establish a proof-of-concept network of methane detection sensors in the Permian Basin for high-frequency monitoring.

We have also tested fixed-based methane detection sensors in our Rocky Mountain House (Canada) asset.

At our Shell ONEgas facilities in the North Sea, we have reduced methane emissions by around 55%, (around 2,000 tonnes) since 2017. We have done this through improvements that reduce gas venting, such as minimising valve leakage and substituting nitrogen for natural gas when purging potentially explosive oxygen from equipment. ONEgas also continues efforts to improve the accuracy of its measurement of methane emissions. It is planning a trial of drone-mounted sensors in 2021, to see whether they provide a better way of quantifying emissions from platforms.

Methane initiatives and collaborations

We participate in a number of voluntary initiatives to encourage industry-wide action to reduce methane emissions.

In 2017, we joined the Climate and Clean Air Coalition Oil and Gas Methane Partnership. This brings together industry, governments and NGOs to improve the quantification of methane emissions globally and to work on reducing them.

Also in 2017, Shell formed an industry coalition, supported by organisations such as the Environmental Defense Fund, the UN Environment Programme and the World Bank, to develop a set of Methane Guiding Principles. These principles focus on:

- continually reducing methane emissions;
- advancing strong performance across gas value chains;
- improving the accuracy of methane emissions data;
- advocating sound policies and regulations on methane emissions; and
- increasing transparency.

Shell has been involved in developing all actions associated with the Methane Guiding Principles, including the establishment of a major global outreach programme. This programme seeks to address gaps in knowledge about managing methane emissions. It provides high-quality educational material and courses covering methane science, methane reduction strategies and planning, measurement techniques, technology, policy, and where to get guidance and support. The publicly accessible programme consists of two courses: an executive course for senior managers and executives, and masterclasses for managers of frontline staff. By the end of 2020, the Methane Guiding Principles had been signed by 23 companies.

In 2020, we became a founding signatory to the Oil and Gas Methane Partnership 2.0, the new gold-standard reporting framework that is designed to enhance reporting accuracy and transparency on methane emissions in the oil and gas sector.

The Methane Guiding Principles

The Methane Guiding Principles focus on reducing methane emissions across the natural gas supply chain



1. Continually reduce methane emissions



2. Advance strong performance across the gas supply chain



3. Improve accuracy of methane emissions data



4. Advocate sound policy and regulations on methane emissions



5. Increase transparency

Shell is a member of the Oil and Gas Climate Initiative (OGCI), a CEO-led effort to lead the industry's response to climate change. One of OGCI's focus areas is methane management. In 2018, OGCI announced a target of reducing the collective average methane intensity of its members' aggregated upstream gas and oil operations by one-fifth, to below 0.25% by 2025, with an ambition to achieve 0.2%, which would be a reduction of one-third.

Methane emissions performance

In 2020, our overall methane intensity was 0.06% for facilities with marketed gas and 0.01% for facilities without marketed gas. Intensities at facility level ranged from below 0.01% to 0.6%. We believe our methane emissions are calculated using the best methods currently available: a combination of industry-standard emission factors (established emission rates per throughput or per piece of equipment), engineering calculations and some actual measurements. There are still uncertainties associated with quantifying methane emissions with the available methodologies. To reduce these uncertainties, our Upstream and Integrated Gas businesses are rolling out methane improvement programmes to further improve data quality and reporting. The improvement programmes will also continue leak detection and repair initiatives, and make use of methane abatement opportunities. By 2025, all Shell-operated facilities are expected to have implemented more robust quantification methodologies. Externally, we continue to work on new technologies and improved quantification methods through partnerships and other initiatives such as the OGCI.

Detailed information on our approach to managing methane emissions and performance is expected to be published in the Shell Sustainability Report in April 2021.

RENEWABLES AND ENERGY SOLUTIONS

Renewables and Energy Solutions, formerly New Energies, encompasses Shell's low-carbon businesses. These include Shell's activities in integrated power, hydrogen, nature-based solutions (NBS) and carbon capture and storage (CCS). We want to find ways of helping customers – be they households or businesses – to switch to low-carbon and renewable electricity. That is why we are also developing digitally-enabled platforms that will provide customers with services that make it easier for them to decarbonise and accelerate their progress in this area. We could invest on average \$2.3 billion each year in our Renewables and Energy Solutions business.

📖 See “Integrated Gas” on page 50.

Power

Electricity is the fastest-growing part of the energy system and when generated from renewable sources has a major role to play in reducing GHG emissions. Shell is building an interconnected power business that is designed to be sustainable and offer long-term opportunities. We aim to sell some 560 terawatt hours of electricity a year by 2030, which is twice as much electricity as we sell today. Our integrated power strategy will help Shell in its broader aim to accelerate its transformation into a provider of net-zero emissions energy products and services.

📖 See “Integrated Gas” on page 50.

Low-carbon fuels

Shell believes that low-carbon fuels will play a valuable role in reducing carbon dioxide (CO₂) emissions from the transport sector in the coming decades. Low-carbon fuels projects and operations around the world form part of a wider commitment to provide a range of energy choices for customers.

In 2020, around 9.5 billion litres of biofuels went into Shell's petrol and diesel worldwide. This helped us to make progress towards achieving our climate ambition while complying with applicable mandates and targets in the markets where we operate. Through our own long-established sustainability clauses in supply contracts, we request that all biofuels we buy are produced in ways that are environmentally and socially responsible throughout the production chain. Currently, most available biofuels are produced from cereals, vegetable oils and sugar cane. From cultivation to use, biofuels can emit significantly less CO₂ compared with conventional gasoline. This depends on several factors, such as how the feedstock is cultivated and the way the biofuels are produced. Other challenges include concerns over labour rights, the amount of water used in the production process, and competition for land use between biofuels and food crops.

Over three-quarters of the biofuels we buy are from North American or European feedstock producers. Both regions have regulations for agricultural practices including in relation to sustainability.

We continue to support the adoption of international sustainability standards, including those of the Round Table on Responsible Soy (RTRS), the Roundtable on Sustainable Palm Oil (RSPO) and Bonsucro, an organisation for the certification of sugar cane. We also support the Roundtable on Sustainable Biomaterials (RSB) and the International Sustainability and Carbon Certification (ISCC) scheme for feedstocks. We aim to increase the percentage of volumes that are certified according to these robust multi-stakeholder standards.

Currently, more than 97% of our purchased volumes of biofuels are either covered by our supplier-agreed contract sustainability clauses or certified as sustainable by an independent auditor. We aim to increase the percentage of volumes that are certified according to robust multi-stakeholder standards.

The Raízen joint venture (Shell interest 50%, not operated by Shell) in Brazil has produced low-carbon biofuel from sugar cane since 2011. Through Raízen, Shell is a significant biofuels producer. Raízen hosts the first commercial advanced bioethanol facility and the fourth largest renewable natural gas (RNG) facility in the world.

As part of our target to be a net-zero energy business by 2050, in step with society, we seek to reduce the carbon intensity of the products we sell. This means transforming our refining footprint, keeping sites in key locations but manufacturing low-carbon fuels suitable for use as aviation, road transport and shipping fuels or as a chemical feedstock (for liquid crackers). In 2020, our Rheinland refinery in Germany produced nearly 100 million litres of renewable diesel, produced from sustainably sourced vegetable fats and oils. Our production strategy is anchored around access to competitive feedstock, commercialisation of advanced technology, supportive government policy, and building internal capability.

We are also investing in new facilities that are able to produce sustainable low-carbon fuel suitable for use as aviation, road transport and shipping fuels or chemical feedstock for liquid crackers. Shell's hydro-processed esters and fatty acids (HEFA) technology yields up to 65% low-carbon fuels compared to fossil diesel and aviation equivalent. If HEFA technology is used with green hydrogen – produced by using renewable electricity to split water into hydrogen and oxygen through electrolysis – it can increase the energy content and further reduce the carbon content of the fuels produced.

We are working on a project to add a HEFA facility at our Pernis refinery in the Netherlands. If this project went ahead, production would start in around three to four years. The proposed facility could convert waste fats and oils and other sources into sustainable low carbon vehicle and aviation fuels. A final investment decision has not yet been taken.

CLIMATE CHANGE AND ENERGY TRANSITION continued

In January 2021, Shell announced the signing of commercial agreements to invest in Varennes Carbon Recycling, a plant in Québec, Canada, that will turn waste into chemicals and biofuels. This plant, a joint venture with Enerkem, Proman, Suncor and Invest Quebec (Shell interest 40%), will produce biofuels and renewable chemical products using non-recyclable waste from the industrial, commercial and institutional sectors, from construction, renovation and demolition debris and from residual forest biomass.

In line with our strategy of developing more sustainable feedstocks for transport, we are investing in renewable natural gas (RNG) for use in natural-gas-fuelled vehicles in the USA and Europe. RNG is produced from biogas collected from landfill sites, or via the anaerobic digestion of food waste or manure. It is then processed until it is fully interchangeable with conventional natural gas. The use of RNG in natural-gas vehicles, either in the form of compressed natural gas (CNG) or LNG, offers customers a way to lower their carbon footprint.

The heavy-duty road transport sector is starting to use RNG in its efforts to decarbonise. Shell recently won tenders to supply RNG to fuel around 300 of the Los Angeles (LA) bus fleet and vehicles of the West LA waste haulers fleet.

Shell has taken a final investment decision (FID) to construct, own and operate its first renewable compressed natural gas (R-CNG) fuelling site in the USA. This will be at Shell's products distribution complex in Carson, California. The R-CNG will be sourced from Shell's renewable natural gas projects in the USA, which are currently Shell Junction City in Oregon and Shell Galloway in Plains, Kansas. These convert wastes, such as dairy cow manure and agricultural residues, into pipeline-quality natural gas. Shell will be able to substantially decarbonise the transport of its products from the Carson complex by providing 100% R-CNG to its haulage partners, who are equipped with ultra-low nitrogen oxide natural gas vehicles.

CARBON CAPTURE AND STORAGE

CCS is a technology used for capturing carbon dioxide (CO₂) before it is emitted into the atmosphere, then transporting it, and injecting it into a deep geological formation for permanent storage. The majority of climate change scenarios produced by organisations such as IEA, IPCC and Shell require a large component of CCS in order to achieve the goals of the Paris Agreement. We recognise the scale of the challenge in developing CCS globally as quickly as is required.

In 2020, we refreshed our CCS strategy. We placed greater emphasis on how CCS could enable the energy transition for low-carbon fuels and power, and for industrial hub developments where CO₂ from different industrial sources is routed to a single storage location. We seek to have access to an additional 25 million tonnes a year CCS capacity by 2035.

In 2020, Shell invested around \$70 million in CCS. This included progressing opportunities and operating costs for CCS assets in which Shell has an interest.

By the end of 2020, our Quest CCS project in Canada (Shell interest 10%) had captured and safely stored more than 5.5 million tonnes of CO₂ since it began operating in 2015. Quest CCS was designed to capture about 1 million tonnes of CO₂ each year. The storage reservoir proved to have a significant capacity for CO₂ injection and strong capture reliability with less than 1% downtime annually. This means the facility could exceed its target and reduce estimated costs.

The Gorgon CCS project in Australia (Shell interest 25%, operated by Chevron) started operating in August 2019. It had stored more than 4 million tonnes of CO₂ by the end of 2020.

In Norway, Shell, our project partners and the Norwegian government took the final investment decision (FID) on the Northern Lights CCS project in 2020. This project aims to become the first carbon storage facility with capacity to transport and store CO₂ from industrial facilities in Norway and potentially from across Europe.

Shell is also involved in the Technology Centre Mongstad (TCM), in Norway. TCM is a centre for testing and improving carbon capture technology.

In the Netherlands, we have signed a joint-development agreement to assess the potential to export CO₂ from our Pernis refinery to a Rotterdam-based CO₂ transport and storage provider.

In the UK, we are collaborating with other companies to further understand the potential of CCS. Projects include how to decarbonise our own facilities, to deliver gas power and low-carbon hydrogen.

In other regions, we are pursuing opportunities which are currently in early development phases.

Shell recognises the role of policy as a key enabler for implementing CCS. We are a member of several industry organisations that actively advocate CCS, such as the Zero Emissions Platform in the EU, the American Petroleum Institute in the USA, and the Carbon Capture and Storage Association in the UK. Shell makes representations and contributes to technical and policy papers through these organisations. In 2020, Shell submitted responses to a number of consultations on aspects of CCS, individually and through industry associations, in the EU, USA, UK and other jurisdictions.

Shell is participating in the OGCI's KickStarter initiative to unlock large-scale investment in CCS. The initiative is designed to help decarbonise industrial hubs around the world and started with hubs including North America, North-west Europe and China.

NATURE-BASED SOLUTIONS

We believe that nature will play an important role in the transition to a low-carbon world. Using nature to absorb carbon dioxide helps to limit the overall stock of greenhouse gases in the atmosphere. This can serve as a temporary solution until other low-carbon alternatives are deployed at scale, or it can compensate for emissions that are unavoidable.

As customers' and society's demand for the use of low-carbon products and services grows, nature-based solutions are becoming an increasingly attractive option for emissions offsetting for a range of industries and operators.

Nature-based projects typically involve protecting or redeveloping natural ecosystems such as forests and wetlands, so they can capture and store more carbon. These projects generate carbon emission rights that can be bought by energy consumers around the world. They also support conservation of biodiversity and offer alternative sources of income to local communities.

Nature-based solutions are expected to contribute to meeting our target to be a net-zero emissions energy business by 2050, in step with society.

We have been running a nature-based solutions programme to invest in natural ecosystems since 2019. As well as investing directly in projects that protect or restore nature, we are also working with projects that already generate carbon credits for our customers. In 2020, Shell invested around \$90 million in nature-based projects that reduce or avoid emissions and can also benefit ecosystems by improving biodiversity, water quality and flood protection. This in turn can improve the livelihoods of people in local communities.

Our ambition is to invest around \$100 million per year in nature-based projects that reduce or avoid CO₂ emissions and offer other valuable ecosystem benefits. We aim to use nature-based solutions, in line with the philosophy of avoid, reduce and only then mitigate, to offset emissions of around 120 million tonnes a year by 2030, through projects of the highest independently verified quality.

In 2020, we developed a screening process with clear criteria to help ensure that we invest in nature-based solutions projects that are of high quality and integrity. The criteria include but are not limited to:

- selecting only projects that are certified under credible, high-quality and independent carbon-credit standards;
- selecting projects that deliver wider environmental and social benefits;
- working to ensure project developers maintain appropriate health, safety, security and social governance standards; and
- having an independent third party audit our internal nature-based project screening review and management processes.

In 2019, we started offering what we called “carbon-neutral driving” to our retail customers. We offered service-station customers in the Netherlands and the UK nature-based carbon credits to offset the CO₂ emissions generated by the extraction, refining, distribution and use of the Shell fuel they buy. By the end of 2020, around 18% of Shell’s retail customers in the Netherlands and around 15% of our UK service-station customers were driving carbon neutral. So too were more than 200 fleet customers in 12 countries who took advantage of similar offers for businesses.

In 2020, we continued to roll out our carbon-neutral retail offer in Germany, Austria, Switzerland, and Canada, and via a third-party reseller agreement in Denmark. We also offer a growing range of products with nature-based carbon credits, including home energy in the UK, LNG in Asia, bitumen in Europe, and selected lubricants.

In 2020, we took another step to scale up our activities in natural ecosystems by acquiring Select Carbon, a specialist company that partners with farmers, pastoralists and other landowners in Australia to develop carbon farming projects, where plants are grown and soil managed to absorb carbon dioxide from the atmosphere.

For more information, see the Shell Sustainability Report, due to be published in April 2021.

OUR PERFORMANCE

Shell’s carbon intensity

Shell’s carbon intensity provides an annual measure of the life-cycle emissions intensity of the portfolio of energy products sold. Specifically, we calculate the carbon intensity (gCO₂e/MJ) in terms of the grams of carbon dioxide equivalent (gCO₂e) per unit of energy (MJ) sold. This is measured, tracked and reported using the Net carbon Footprint (NCF) metric and methodology.

Shell’s NCF is not calculated by simply dividing total emissions by total energy, nor is it an inventory of absolute emissions. Instead, Shell calculates the life-cycle carbon intensity of each of the different energy products it sells. Once we have calculated the carbon intensity for each individual energy product, we then calculate the overall carbon intensity by taking a weighted average of the individual product intensities, with the weighting based on their sales volumes. This approach enables like-for-like comparisons across a range of energy products and allows us to establish the average carbon intensity for all the energy products we sell, including renewables.

Finally, we deduct, or “net off”, any emissions that are stored in carbon sinks. For example, we subtract emissions that are stored using carbon capture and storage in our own operations. We also subtract any carbon dioxide emissions that are removed from the atmosphere and stored using natural carbon sinks created using nature-based solutions, such as reforestation.

While Shell’s NCF is an intensity measure and not an inventory of absolute emissions, a notional estimate of the amount of CO₂e emissions covered by the scope of the Net Carbon Footprint calculation can be derived from the final Net Carbon Footprint value for any year.

Net carbon intensity performance Our NCF performance

NCF in the reference year (2016) = 79 gCO ₂ e/MJ		2018	2019	2020
NCF	gCO ₂ e/ MJ	79	78	75
Estimated total energy delivered by Shell [A]	trillion (10 ¹²) MJ	22	21.05	18.4
Estimated total GHG emissions included in NCF [B], [C]	million tonnes CO ₂ e	1,731	1,646	1,384

[A] Retail sales volumes from markets where Shell operates under trademark licensing agreements are excluded from the scope of Shell’s carbon intensity metric

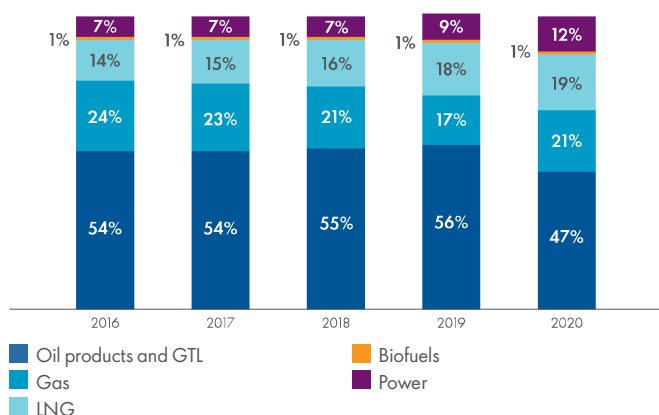
[B] The 2.2 million tonnes of carbon offsets used in 2019, and 3.9 million tonnes of carbon offsets used in 2020 have been subtracted from the estimated total GHG emissions

[C] These numbers include well-to-wheel emissions associated with energy products sold by Shell; they also include the well-to-tank emissions associated with the manufacturing of energy products by others that are sold by Shell. Emissions associated with the manufacturing and use of non-energy products are excluded

We have received third-party limited assurance on our carbon intensity, measured and reported using the Net Carbon Footprint, for the years from 2016 to 2020. Shell’s NCF in 2020 was 75 gCO₂e/MJ, a 4% reduction from the previous year and a 5% reduction from the 2016 reference year. One of the major causes of this larger than expected reduction in 2020 was lower demand for energy, especially for oil and gas. Demand for oil products experienced the most significant reduction, followed by natural gas and LNG. Another important factor contributing to the reduction of the NCF was the increase in our power sales in absolute terms as well as their share of the energy mix sold by Shell. The power we sold also had a lower average emissions intensity than in previous years, which further contributed to the overall NCF reduction.

CLIMATE CHANGE AND ENERGY TRANSITION continued

Share of energy delivered per energy product type [A], [B], [C], [D]

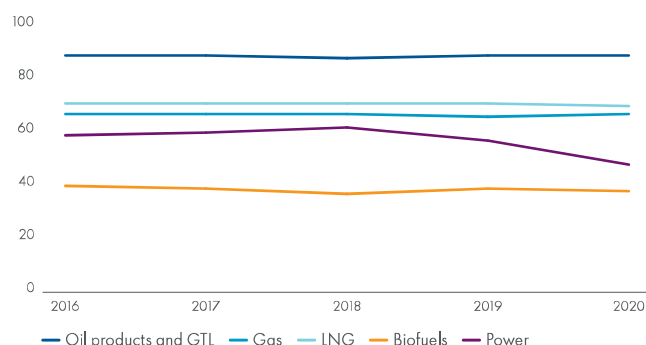


- [A] Percentage of delivered energy may not add up to 100% because of rounding.
 [B] Total volume of energy products sold by Shell, aggregated on an energy basis, with electricity represented as fossil equivalents. This value is derived from energy product sales figures disclosed by Shell in the Annual Report, Form 20-F and the Sustainability Report.
 [C] Lower heating values are used for the energy content of the different products and a fossil-equivalence approach is used to account for electrical energy, so that it is assessed on the same basis as our other energy products.
 [D] Retail sales volumes from markets where Shell operated under trademark licensing agreements are excluded from the scope of Shell's carbon intensity metric.

Carbon intensity of Shell's energy product types

The graph below illustrates the carbon intensity of our delivered energy per product type from 2016 to 2020. Our NCF is calculated by taking a weighted average of these individual carbon intensities, with the weighting based on their sales volumes.

Carbon intensity of Shell's energy product types [A]
(gCO₂e/MJ)



- [A] Emissions included in carbon intensity of power have been calculated using the market-based method in 2020

For hydrocarbon fuels, emissions from end use by customers are by far the biggest contributors to the carbon intensity of the product. As a result, the emissions intensity of hydrocarbon fuels is expected to stay relatively unchanged over time.

This contrasts with the emissions intensity of power, which can be highly variable depending on how it has been generated. To a lesser extent, there is also a contrast between hydrocarbon fuels and biofuels, which can vary significantly in intensity depending on the feedstock and production process used.

The proportion of our renewable power sales and countries where we sell power to the market both affect Shell's overall power mix and its resulting emissions intensity. The carbon intensity of biofuels provided in the graph "Carbon intensity of Shell's energy product types" reflects the global average for biofuels sold by Shell.

Our strategy is to reduce our Net Carbon Footprint, mainly by increasing the proportion of lower-carbon products such as natural gas, biofuels, electricity and hydrogen in the mix of products that we sell to our customers.

GREENHOUSE GAS EMISSIONS

Data in this section are reported on a 100% basis in respect of activities where we are the operator. Reporting on this operational control basis differs from that applied for financial reporting purposes in the "Consolidated Financial Statements" on pages 216-264. Detailed data and information on our 2020 environmental and social performance are expected to be published in the Shell Sustainability Report in April 2021.

GHG Performance

Our direct GHG emissions (Scope 1) decreased from 70 million tonnes of CO₂ equivalent in 2019 to 63 million tonnes of CO₂ equivalent in 2020. The main contributors to this decrease were divestments, (for example, in Canada and the USA), and reduced utilisation at a number of assets caused by lower demand driven by COVID-19. The level of flaring in our Upstream and Integrated Gas businesses combined decreased by around 35% compared with 2019. In 2019, our Prelude floating LNG facility in Australia had experienced an unanticipated spike in flaring during its start-up. In February 2020, we had to shut down Prelude which resulted in a decrease of its GHG emissions by around 80% compared with 2019.

In 2015, we signed up to the World Bank's Zero Routine Flaring by 2030 initiative. This seeks to ensure that all stakeholders, including governments and companies, work together to address routine flaring. Flaring, or burning off, of gas in our Upstream and Integrated Gas businesses contributed around 6% of our overall direct GHG emissions in 2020. Around 35% of this flaring occurred at facilities where there was no infrastructure to capture the gas produced with oil, known as associated gas.

Around 45% of flaring in our Upstream and Integrated Gas facilities in 2020 occurred in assets operated by the Shell Petroleum Development Company of Nigeria Limited (SPDC). Flaring from SPDC-operated facilities decreased by around 15% in 2020 compared with 2019. SPDC, in close collaboration with its joint-venture partners and the Federal Government of Nigeria, continues to make progress towards the objective of ending the continuous flaring of associated gas. Two new gas-gathering projects (Adibawa and Otumara) came on stream at the end of 2017, followed by two more (the Forcados Yokri Integrated Project and Southern Swamp Associated Gas Gathering Solutions) in 2019.

Our indirect GHG emissions associated with imported energy (Scope 2) were 9 million tonnes in 2020 (using market-based method), down from 10 million in 2019, in part driven by divestments (for example in Canada) and lower demand for imported electricity due to reduced utilisation.

Our GHG emissions

		2018	2019	2020
Scope 1 [A]	million tonnes CO ₂	71	70	63
Scope 2 [B]	million tonnes CO ₂	11	10	9
Scope 3 [C]	million tonnes CO ₂	1,637	1,551	1,305

- [A] total direct (Scope 1) GHG emissions from assets and activities under operational control boundary
 [B] total indirect GHG emissions from imported energy (Scope 2) from assets and activities under operational control boundary
 [C] indirect GHG emissions (Scope 3) based on the energy product sales included in the NCF boundary. See our website shell.com for more information on our NCF methodology

Greenhouse gas intensity

In 2020, the three GHG intensity metrics included in the Performance Indicators on page 45 covered over 80% of our total Scope 1 and 2 GHG emissions from assets and activities under our operational control.

The Upstream and Integrated Gas GHG intensity – measured in tonnes of CO₂ equivalent per tonne of hydrocarbon production available for sale – decreased from 0.17 in 2019 to 0.16 in 2020. This was partly because of our Prelude FLNG asset being shut down in February 2020.

The Refining GHG intensity – measured in tonnes of CO₂ equivalent per Solomon's Utilised Equivalent Distillation Capacity (UEDC™) – decreased from 1.06 in 2019 to 1.05 in 2020. This was mainly driven by divestment of our Martinez refinery in the USA.

The Chemicals GHG intensity – measured in tonnes of CO₂ equivalent per tonne of high value chemicals – decreased from 1.04 in 2019 to 0.98 in 2020. This was mainly because of increased utilisation following turnarounds on three of our sites in 2019.

GHG emissions and energy consumption data and information in accordance with UK regulations.

GHG emissions comprise CO₂, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulphur hexafluoride and nitrogen trifluoride. The data are calculated using locally regulated methods where they exist. Where there is no locally regulated method, the data are calculated using the 2009 American Petroleum Institute (API) Compendium of Greenhouse Gas Emissions Methodologies, which is the recognised industry standard under the GHG Protocol Corporate Accounting and Reporting Standard. There are inherent limitations to the accuracy of such data. Oil and gas industry guidelines (API/International Association of Oil & Gas Producers (IOGP)/IPIECA, the global oil and gas industry association for advancing environmental and social performance) indicate that a number of sources of uncertainty can contribute to the overall uncertainty of a corporate emissions inventory.

Greenhouse gas emissions

	2020	2019
Emissions (million tonnes of CO ₂ equivalent)		
Total global direct (Scope 1) [A]	63	70
UK including offshore area [B]	2.0	2.1
Total global energy indirect (Scope 2) [C]	9	10
UK including offshore area [D]	0.0	0.0
Intensity ratio (tonne/tonne)		
All facilities [E]	0.25	0.24

[A] Emissions from the combustion of fuel and the operation of our facilities globally, calculated using global warming potentials from the IPCC's Fourth Assessment Report.

[B] Emissions from the combustion of fuels and the operation of our facilities in the UK and its offshore area, calculated using global warming potentials from the IPCC's Fourth Assessment Report.

[C] Emissions from the purchase of electricity, heat, steam and cooling for our own use globally, calculated using a market-based method as defined by the GHG Protocol Corporate Accounting and Reporting Standard. Using location-based methods, indirect GHG emissions from generation of purchased and consumed energy (electricity, steam, heat and cooling) were 11 million tonnes CO₂e in 2019 and 11 million tonnes CO₂e in 2020.

[D] Emissions from the purchase of electricity, heat, steam and cooling for use by our facilities in the UK including its offshore area, calculated using a market-based method as defined by the GHG Protocol Corporate Accounting and Reporting Standard. Using location-based methods, indirect GHG emissions from generation of purchased energy consumed by our facilities were 0.06 million tonnes CO₂e in 2019 and 0.06 million tonnes in 2020.

[E] In tonnes of total direct and energy indirect GHG emissions per tonne of crude oil and feedstocks processed and petrochemicals produced in downstream manufacturing, oil and gas available for sale, LNG and GTL production in Integrated Gas and Upstream. For an additional breakdown by segment, see Greenhouse gas intensity section above.

The energy consumption data provided below comprise own energy, generated and consumed by our facilities, and supplied energy (electricity, steam and heat) purchased by our facilities for our own use.

Energy consumption data reflect primary (thermal) energy (e.g. the energy content of fuels used to generate electricity, steam, heat, mechanical energy etc.). This includes energy from renewable and non-renewable sources. Own energy generated was calculated by multiplying the volumes of fuels consumed for energy purposes by their respective lower heating values. Own energy generated that was exported to third-party assets or to the power grid is excluded. Thermal energy for purchased and consumed electricity was calculated using actual electricity purchased multiplied by country-specific electricity generation efficiency factors (from IEA statistics). Thermal energy for purchased and consumed steam and heat was calculated from actual steam/heat purchased multiplied by a supplier-specific conversion efficiency, or generic efficiency factor where supplier-specific data were not available.

Energy consumption (billion kilowatt-hours)

	2020	2019
Own energy generated and consumed		
Total energy generated and consumed	202	220
UK including offshore area	7.6	7.6
Purchased and consumed energy		
Total purchased and consumed energy	38	44
UK including offshore area	0.2	0.2
Energy consumption		
Total energy consumed	240	264
UK including offshore area	7.8	7.8

In 2020, we implemented a variety of measures to reduce the energy use and increase the energy efficiency of our operations. Examples of some of the principal measures taken are listed below:

- At our Clipper facility in the UK, we completed a project to optimise the use of compressors.
- At our Bukom facility in Singapore, we completed two projects to minimise energy loss from steam.
- At our Scotford upgrader facility in Canada, we completed several projects to minimise energy use and improve efficiency, for example by removing equipment from service or replacing it with more efficient equipment.
- At our Geismar facility in the USA, we improved flare staging and temperature control which resulted in lower levels of natural gas consumption.
- At our Mobile facility in the USA, we installed new equipment to increase heat transfer between heat exchangers in order to improve the energy efficiency of the units.
- At our GTL facility in Qatar, we completed several projects to reduce energy use and improve efficiency, for example by minimising the generation of excess steam and converting excess energy into electricity for export to the public grid.
- In Brazil, we reduced fuel usage of vessels by optimising how they operate in dynamic position, stand-by and navigation modes.

Detailed information on our 2020 GHG emissions and energy use is expected to be published in the Shell Sustainability Report in April 2021 and on our website.

The statements in this "Climate change and energy transition" section, including those relating to the Net Carbon Footprint targets, are forward-looking statements based on management's current expectations and certain material assumptions and, accordingly, involve risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied herein.

See "About this Report" on pages iii-iv and "Risk factors" on pages 28-37.

OUR PEOPLE

Performing competitively in the evolving energy landscape requires competent and empowered people working safely together across Shell.

EMPLOYEES



87,000

employees at December 31, 2020

REGION



>70

countries in which we operate

TRAINING



234,000

formal training days for employees and joint-venture partners

FEMALE EMPLOYEES



32%

female employees

DIRECTORS



38%

women on the Board of Directors

SENIOR LEADERS



28%

women in senior leadership positions

EXPERIENCED HIRES



957

experienced people joined Shell (31% female)

OPERATIONS CENTRE HIRES



1,879

recruited for Shell Business Operations centres (50% female)

GRADUATE HIRES



160

graduate hires (49% female)

[A] All metrics except the employees metric exclude the employees in certain Upstream, Downstream and Renewables and Energy Solutions (Formerly New Energies) companies that maintain their own HR systems.

[B] As part of its restructuring plans, Shell expects to reduce 7,000-9,000 jobs by the end of 2022.

We recruit, train and remunerate people according to a strategy that aims to organise our businesses effectively. Our people are essential to the successful delivery of the Shell strategy and to sustaining business performance over the long term. Strong engagement helps us to accelerate our people's development, enhance our leadership capabilities and improve employee performance.

EMPLOYEE OVERVIEW

The employee numbers presented here are the full-time equivalent number of people employed by Shell on a full- or part-time basis, working in Shell subsidiaries, Shell-operated joint operations, seconded to non-Shell-operated joint operations, or joint ventures and associates.

At December 31, 2020, there were a total of 87,000 employees in Shell. This total consisted of employees in Shell and employees in certain Upstream, Downstream and Renewables and Energy Solutions (formerly New Energies) companies that operate more autonomously than other Shell subsidiaries and maintain their own HR systems.

The total of 87,000 employees at December 31, 2020 was the same as at December 31, 2019.

There were 81,000 employees in Shell, excluding those in companies with their own HR systems, at December 31, 2018.

As part of Reshape initiative, Shell expects to reduce between 7,000 and 9,000 jobs by the end of 2022, as it seeks to reduce costs and restructures with the aim of becoming a more streamlined, more competitive organisation that is nimbler and better able to respond to customers. The job reductions will include around 1,500 people who have already decided to take voluntary redundancy in 2020, but will exclude anybody who may leave Shell because of divestments. Shell will conduct the job reductions process in accordance with our core values of honesty, integrity and respect for people. We will seek at all times to show care for anyone who loses their role. Job and cost reductions are in comparison with December 31, 2019.

The table below shows actual employee numbers by geographical area. Note 26 to the "Consolidated Financial Statements" on page 262 provides the average number of employees by business segment.

Actual number of employees by geographical area

	2020	2019	Thousand 2018 [A]
Europe	27	27	24
Asia	31	31	28
Oceania	3	2	2
Africa	4	4	4
North America	20	21	21
South America	2	2	2
Total	87	87	81

[A] As revised, numbers have been changed from average number to actual numbers. These numbers exclude those in companies with their own HR systems.

In 2020, a total of 234,000 formal training days were provided for employees and joint-venture partners, compared with 373,000 in 2019. The decrease in formal training was caused by COVID-19-related travel restrictions, which significantly affected classroom and blended training plans. In response to this, we rapidly increased the number of courses that could be attended virtually, and created more digital resources to help our people learn, train and develop their skills. This allowed us to continue to invest in people and capabilities, while maintaining our focus on safety.

EMPLOYEE COMMUNICATION AND INVOLVEMENT

We strive to maintain a healthy employee and industrial relations environment. We seek to ensure that our work practices involve dialogue between management and employees – both directly and, where appropriate, through employee representative bodies. Management regularly engages with our employees through a range of formal and informal channels. These include webcasts and all-staff messages from our Chief Executive Officer (CEO) Ben van Beurden, senior leader webcasts, town halls, team meetings, virtual coffee/chai connects, interviews with Senior Management and online publications via our intranet. For further information on stakeholder engagement, see the "Governance" section on pages 138-139.

We promote safe reporting of views about our processes and practices. In addition to local channels, the Shell Global Helpline enables our people and third parties to report potential breaches of the Shell General Business Principles and Shell Code of Conduct, confidentially and anonymously, in a variety of languages. In 2020, 1,425 cases were reported via the Shell Global Helpline: 1,153 allegations and 272 inquiries. In 2019, 1,686 cases were reported via the Shell Global Helpline: 1,278 allegations and 408 inquiries. Shell Internal Audit (SIA) is the custodian of the Shell Global Helpline process, which is managed by an independent third party. SIA is accountable for ensuring that the Shell Global Helpline functions as intended and that all allegations of Code of Conduct breaches (including bribery and corruption) are investigated and followed up appropriately. The Board has formally delegated to the Audit Committee the responsibility for reviewing the functioning of the Shell Global Helpline and the reports arising from its operation. The Audit Committee is also authorised to establish and monitor the implementation of procedures for the receipt, retention, proportionate and independent investigation and follow-up action of reported matters.

Strong employee engagement is especially important in maintaining strong business delivery in times of change. The Shell People Survey is one of the principal tools used to measure employee engagement, motivation, affiliation and commitment to Shell. It provides insights into employees' views and has had a consistently high response rate. In 2020, the response rate was 86.1%, our highest ever level and an increase of 0.6 percentage points compared with 2019. The average employee engagement score was 78 points out of 100, the same as in 2019. This result gives Shell one of the leading employee engagement scores across a range of industries.

In 2020, we faced the worldwide COVID-19 pandemic. In response, we strengthened the country chair network so we could respond locally to the challenges of the pandemic as experienced by our staff, businesses, suppliers and customers. We also provided global support on health. We offered a home-working ergonomics programme, which involved more than 50,000 staff having a health-based risk assessment, receiving advice and if necessary receiving support to buy office and IT equipment. We established a Care for Self programme to encourage staff to pay attention to their physical and mental well-being, and to support them as they did so. This was considered particularly important, given the stresses placed on staff by the COVID-19 pandemic and lockdowns.

DIVERSITY AND INCLUSION

Our diversity and inclusion approach focuses on hiring, developing and retaining the best people.

Embedding the principles of diversity and inclusion in the way we do business improves our understanding of the needs of our people, partners, suppliers and customers. A diverse workforce, and an inclusive, caring environment that respects and nurtures diverse people, help us to improve our safety and business performance.

We continue to focus on recruiting, developing and promoting more women, and we are supporting initiatives that encourage girls to study science, technology, engineering and mathematics (STEM). We also do this by creating a culture of respect and inclusion. Our CEO Ben van Beurden joined the Catalyst CEO Champions for Change, a group of more than 50 CEOs who pledge to support women's advancement at all levels of leadership. Our CEO actively supports the Shell global gender gap campaign, which seeks to close the gender gap in STEM roles.

In 2020, 49% of our graduate recruits were female, compared with 48% in 2019. At the end of 2020, the proportion of women in senior leadership positions was 27.8 %, an increase of 1.4 percentage points compared with the end of 2019. "Senior leadership positions" is a Shell measure based on salary group levels and is distinct from the term "senior manager" in the statutory disclosures set out below.

Gender diversity data (at December 31, 2020)

	Men		Number	
			Men	Women
Directors of the Company	8	62%	5	38%
Senior managers [A]	632	71%	258	29%
Employees (thousand)	59	68%	28	32%

[A] Senior manager is defined in section 414C(9) of the Companies Act 2006 and, accordingly, the number disclosed comprises the Executive Committee members who were not Directors of the Company, and other directors of Shell subsidiaries.

We are creating an environment where people with disabilities can excel. We will provide support and can make adjustments for people with disabilities through the recruitment process and throughout their careers with Shell, including equal access to valuable educational resources, training programmes, and emphasis on personal and professional development.

Our workplace accessibility service currently serves 83 locations globally. The service is designed to ensure that all employees have access to reasonable physical workplace or other adjustments so that they can work effectively and productively.

To further support our employees with disabilities, we have created internal employee networks, including the enABLE networks that support and highlight the work of disabled employees in Shell. First launched in the UK in 2005, we now have 13 enABLE networks in countries including Brazil, Canada, France, India, the Netherlands, the UK and the USA. The disability and enablement focus area is sponsored by Harry Brekelmans, Executive Director for Projects & Technology and Huibert Vigeveno, Executive Director for Downstream.

Shell is a member of the disability campaign The Valuable 500, which seeks to eliminate the exclusion of disabled people worldwide and ensure disability remains a priority for global business leaders. We are also members of Business Disability Forum, a membership organisation that exists to create a disability smart world by linking businesses, disabled people, and government, and PurpleSpace, a networking and professional development hub for disabled employees, employee network leads and allies from all sectors and trades.

At Shell, we support and enable remarkable people from every background, and strive to be a leader in lesbian, gay, bisexual and transgender (LGBT+) inclusion in the workplace. We have pledged support for the UN LGBTI Standards of Conduct for Business. We benchmark ourselves externally, with consistent top-tier results. For example, in 2020, in the USA we earned a 100% score in the Human Rights Campaign Foundation's Corporate Equality Index, a recognition we have earned annually since 2016. In 2020, Shell has again been benchmarked as a top employer in the Workplace Pride Global Benchmark inclusive workplace survey, scoring 94.2% compared with a median score of 50-60%.

OUR PEOPLE continued

We have also created a global LGBT+ forum consisting of LGBT+ colleagues and allies and backed by members of the Executive Committee. The forum is taking action in a number of areas, for example, strengthening our approach to talent development and industry collaborations, including with non-governmental organisations.

Shell has established a global D&I Council for Race, sponsored by our CEO Ben van Beurden. The council aims to build on our actions to advance diversity in our workforce so it better reflects communities where we work and from which we draw talent. While seeking to drive change across the organisation, the council has identified the USA and the UK as the focus of much of its initial efforts to address diversity and inclusion challenges.

The local national coverage is the number of senior local nationals (both those working in their respective base country and those expatriated) as a percentage of the number of senior leadership positions in their base country. The total number of senior leadership roles has reduced which resulting in the drop of local national coverage.

Local national coverage (at December 31)

	Number of selected key business countries		
	December 31, 2020	December 31, 2019	December 31, 2018
Greater than 80%	10	12	10
Less than 80%	10	8	10
Total	20	20	20

[A] These numbers exclude those in companies with their own HR systems.

CODE OF CONDUCT

In line with the UN Global Compact Principle 10 (businesses should work against corruption in all its forms, including extortion and bribery), we maintain a global anti-bribery and corruption/anti-money laundering (ABC/AML) programme designed to prevent, detect, remediate and learn from potential violations. The programme is underpinned by our commitment to prohibit bribery, money laundering and tax evasion, and to conduct business in line with our Shell General Business Principles and Code of Conduct.

We do not tolerate the direct or indirect offer, payment, solicitation or acceptance of bribes in any form. Facilitation payments are also prohibited. The Shell Code of Conduct includes specific guidance for Shell staff, (which comprises employees and contract staff), on requirements to avoid or declare actual, potential or perceived conflicts of interest, and on offering or accepting gifts and hospitality.

Communications from our leaders emphasise the importance of these commitments and compliance with requirements. These are reinforced with both global and targeted communications to ensure that Shell staff are frequently reminded of their obligations. To support the Code of Conduct, we have mandatory risk-based procedures and controls that address a range of compliance risks and ensure that we focus resources, reporting and attention appropriately. By making a commitment to our core values of honesty, integrity and respect for people, and by following the Code of Conduct, we protect Shell's reputation.

In 2020, the COVID-19 pandemic brought additional focus on conduct risk. Our core values are undermined if decisions are taken which fall short of the expected standards of ethical behaviour and compliance. Conduct risk arises from human behaviour and is influenced by factors in the external environment. The COVID-19 pandemic has impacted individuals

and businesses globally, resulting in a human health crisis, widespread lockdowns and a severe economic recession. As a general position, our response to the pandemic has been to reiterate and emphasise that adherence to Shell's compliance rules (including the Code of Conduct) remains essential to protect our business and to help us make the right decisions for the future. While maintaining this basic position, pragmatic, risk-based mitigations have been implemented where appropriate to increase response speed and efficiency without undermining the intended purpose of our controls.

Our ethics and compliance requirements are articulated through our policies, standards and procedures. They are communicated to Shell employees and contract staff and, where necessary and appropriate, to agents and business partners. We monitor and report internally on adherence with select ethics and compliance requirements, such as mandatory training completion and due diligence screening. We pay particular attention to our due diligence procedures when dealing with third parties. We also make our requirements clear to third parties through a variety of measures such as standard contract clauses. We publish our Ethics and Compliance Manual on [shell.com](https://www.shell.com/ethics) to demonstrate our commitment in this area.

The Shell Ethics and Compliance Office helps the businesses and functions to implement the ABC/AML and other programmes, and monitors and reports on progress. Legal counsel provides legal advice globally and supports the implementation of programmes. The Shell Ethics and Compliance Office regularly reviews and revises all ethics and compliance programmes to ensure they remain up to date with applicable laws, regulations and best practices. This includes incorporating results from relevant internal audits, reviews and investigations, and periodically commissioning external reviews and benchmarking.

A structured framework for ethical decision-making, expanding on the formulation "Is it legal, is it ethical, is it wise?", was developed and tested during the course of 2020 and subsequently reviewed by an independent third-party panel. The framework will be implemented broadly across Shell from 2021. It will support decision-making by requiring Shell staff to think through, in a structured manner, the legal, ethical and external dimensions of the various opportunities and decisions they face in their daily work.

We investigate all good-faith allegations of breaches of the Code of Conduct, however they are raised. We are committed to ensuring all such incidents are investigated by specialists in accordance with our Investigation Principles. Allegations may be raised confidentially and anonymously through several channels, including a Shell Global Helpline operated by an independent provider.

Violation of the Code of Conduct or its policies can result in disciplinary action, up to and including contract termination or dismissal. In some cases, we may report a violation to the relevant authorities, which could lead to legal action, fines or imprisonment.

Internal investigations confirmed 252 substantiated breaches of the Code of Conduct in 2020. As a result, we dismissed or terminated the contracts of a total of 54 employees and contract staff.

EMPLOYEE SHARE PLANS

We have a number of share plans designed to align employees' interests with our performance through share ownership. For information on the share-based compensation plans for Executive Directors, see the "Directors' Remuneration Report" on pages 153-156.

PERFORMANCE SHARE PLAN, LONG-TERM INCENTIVE PLAN AND EXCHANGED AWARDS UNDER THE BG LONG-TERM INCENTIVE PLAN

Under the Performance Share Plan (PSP), 50% of the award is linked to certain indicators described in "Performance indicators" on pages 43-45, averaged over the performance period. From 2017 to 2019, 12.5% of the award was linked to free cash flow (FCF) and the remaining 37.5% was linked to a comparative performance condition which involves a comparison with four of our main competitors over the performance period, based on three performance measures. For 2020 onwards, 11.25% of the award is linked to the FCF measure and 5% is linked to an energy transition measure. The remaining 33.75% is linked to the comparative performance condition. From 2021, 10% of the award is linked to the FCF measure and 10% is linked to an energy transition measure. The remaining 30% is linked to the comparative performance condition.

Under the LTIP awards made in 2017 and 2018, 25% of the award is linked to the FCF measure and the remaining 75% is linked to the comparative performance conditions mentioned above. For 2019 and 2020, 22.5% of the award is linked to the FCF measure and 10% is linked to an energy transition measure. The remaining 67.5% is linked to the comparative performance condition mentioned above. From 2021, 20% of the award is linked to the FCF measure and 20% is linked to an energy transition measure. The remaining 60% is linked to the comparative performance condition.

Separately, following the BG acquisition, certain employee share awards made in 2015 under BG's Long-term Incentive Plan were automatically exchanged for equivalent awards over shares in the Company. The outstanding awards take the form of nil-cost options.

Under all plans, all shares that vest are increased by an amount equal to the notional dividends accrued on those shares during the period from the award date to the vesting date. In certain circumstances, awards may be adjusted before delivery or subject to clawback after delivery. None of the awards result in beneficial ownership until the shares vest.

See Note 21 to the "Consolidated Financial Statements" on page 256.

RESTRICTED SHARE PLAN

Under the Restricted Share Plan, awards are made on a highly selective basis to senior staff. Shares are awarded subject to a three-year retention period. All shares that vest are increased by an amount equal to the notional dividends accrued on those shares during the period from the award date to the vesting date. In certain circumstances, awards may be adjusted before delivery or subject to clawback after delivery.

GLOBAL EMPLOYEE SHARE PURCHASE PLAN

Eligible employees in participating countries may participate in the Global Employee Share Purchase Plan. This plan enables them to make contributions from net pay towards the purchase of the Company's shares at a 15% discount to the market price, either at the start or at the end of an annual cycle, whichever date offers the lower market price.

UK SHELL ALL EMPLOYEE SHARE OWNERSHIP PLAN

Eligible employees of participating Shell companies in the UK may participate in the Shell All Employee Share Ownership Plan, under which monthly contributions from gross pay are made towards the purchase of the Company's shares. For every six shares purchased by the employee, one matching share is provided at no cost to the employee.

UK SHARESAVE SCHEME

Eligible employees of participating Shell companies in the UK have been able to participate in the UK Sharesave Scheme. Options have been granted over the Company's shares at market value on the invitation date. These options are normally exercisable after completion of a three-year or five-year contractual savings period. From 2017 no further grants were made under this plan.

Separately, following the acquisition of BG, certain participants in the BG Sharesave Scheme chose to roll over their outstanding BG share options into options over the Company's shares. The BG option price (at a discount of 20% to market value) was converted into an equivalent Company option price at a ratio agreed with Her Majesty's Revenue and Customs. These options are normally exercisable after completion of a three-year contractual savings period.

Strategic Report signed on behalf of the Board

/s/ Linda M. Coulter

LINDA M. COULTER

Company Secretary
March 10, 2021

GOVERNANCE

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POWERING LIVES

THE BOARD OF ROYAL DUTCH SHELL PLC



CHARLES O. HOLLIDAY
Chair

Tenure

Chair – five years and nine months (appointed Chair May 19, 2015) On Board – 10 years and six months (appointed September 1, 2010) (Chad will be standing down from the Board following the 2021 Annual General Meeting. See page 142 for further information)

Board committee membership

Chair of the Nomination and Succession Committee

Outside interests/commitments

Presiding Director of HCA Holdings, Inc. Director of Deere & Company. Member of the Critical Resource's Senior Advisory Panel. Member of the Royal Academy of Engineering (UK).

Age

73

Nationality

US citizen

Career

Charles (Chad) Holliday was appointed Chair of the Board of Royal Dutch Shell plc with effect from May 19, 2015.

He was Chief Executive Officer of DuPont from 1998 to 2009, and Chairman from 1999 to 2009. He joined DuPont in 1970 after receiving a BS in industrial engineering from the University of Tennessee and held various manufacturing and business assignments, including a six-year Tokyo-based posting as President of DuPont Asia/Pacific.

He has previously served as Chairman of the Bank of America Corporation, The Business Council, Catalyst, the National Academy of Engineering, the Society of Chemical Industry (American Section) and the World Business Council for Sustainable Development. He is a founding member of the International Business Council.

Relevant skills and experience

Chad has a distinguished track record as an international and well-respected businessman. He was originally appointed to the Board as a Non-executive Director in September 2010 and, prior to his May 2015 appointment as Chair of the Board, served as Chair of the Safety, Environment and Sustainability Committee and Member of the Remuneration Committee.

He has a deep understanding of international strategic, commercial and environmental issues, and gained extensive experience in the areas of safety and risk management during his time with DuPont. In his role as Chair, Chad is committed to developing and maintaining a strong dialogue with investors and other key stakeholders. He ensures that their views are considered during Board discussions and decision-making. Chad has a strong interest in, and has demonstrated a strong commitment to, ensuring that the highest standards of corporate governance, safety, ethics and compliance are maintained. Chad is a particularly avid advocate of greater diversity, which is reflected in the Board's current diversity mix and enhanced diversity goals across the Shell Group.



EULEEN GOH
Deputy Chair and Senior
Independent Director

Tenure

Six years and six months (appointed September 1, 2014). Euleen was appointed Deputy Chair and Senior Independent Director on May 20, 2020.

Board committee membership

Member of the Nomination and Succession Committee and member of the Remuneration Committee

Outside interests/commitments

Chairman of SATS Ltd. Trustee of the Singapore Institute of International Affairs Endowment Fund. Chairman of the Singapore Institute of Management Pte Ltd and Non-executive Director of Singapore Health Services Pte Ltd, both of which are not-for-profit organisations.

Age

65

Nationality

Singaporean

Career

Euleen is an Associate of the Institute of Chartered Accountants in England and Wales, a Fellow of the Singapore Institute of Chartered Accountants, and has professional qualifications in banking and taxation. She has held various senior management positions within Standard Chartered Bank and was Chief Executive Officer of Standard Chartered Bank, Singapore, from 2001 until 2006. She is also a Fellow of the Singapore Institute of Directors.

She has also held non-executive appointments on various boards including Aviva plc, MediaCorp Pte Ltd, Singapore Airlines Ltd, Singapore Exchange Ltd, Standard Chartered Bank Malaysia Berhad, Standard Chartered Bank Thai plc, Capitaland Ltd, Temasek Trustees Pte Ltd, DBS Bank Ltd and DBS Group Holdings Ltd. She was previously Non-executive Chairman of the Singapore International Foundation, and Chairman of International Enterprise Singapore and the Accounting Standards Council, Singapore.

Relevant skills and experience

Euleen's current roles as chair of the board of directors of various international organisations provide significant experience in the area of strategy development and international businesses. She is highly regarded both externally and within Shell as a champion of diversity and consistently but constructively challenges the Board and management to continue to progress in this area.

Based in Singapore and having been Chair of the Risk Committee of the largest bank in South-east Asia, Euleen is close to key emerging/growth markets for our business. Euleen's risk management expertise has elevated the Board's deep deliberations around risk governance, and her voice is regularly heard on discussions regarding appropriate risk appetite. Her extensive travel around the world, through her various executive and non-executive roles, has equipped her with broad geopolitical insight and significant knowledge of operating in the Asian market.

Euleen uses her financial acumen and advocacy for diversity to pose probing and insightful questions, both in and beyond the boardroom. This contributes to well-rounded, incisive and inclusive Board discussions.



BEN VAN BEURDEN Chief Executive Officer

Tenure

Seven years and two months (appointed January 1, 2014)

Board committee membership

N/A

Outside interests/commitments

The Board of Daimler AG has proposed to its shareholders that Ben join its Board as a Supervisory Board member (Non-Executive Director). Daimler AG shareholders are scheduled to vote on this proposal at its AGM, scheduled for March 31, 2021.

Age

62

Nationality

Dutch

Career

Ben was Downstream Director from January to September 2013. Before that, he was Executive Vice President Chemicals from 2006 to 2012. In this period, he also served on the boards of a number of leading industry associations, including the International Council of Chemicals Associations and the European Chemical Industry Council. Prior to this, he held a number of operational and commercial roles in Upstream and Downstream, including Vice President Manufacturing Excellence. He joined Shell in 1983, after graduating with a master's degree in chemical engineering from Delft University of Technology, the Netherlands.

Relevant skills and experience

Ben has more than 37 years' experience of working for Shell. He has built a deep understanding of the industry and proven management experience across the technical and commercial roles.

Ben has led Shell to build resilience and deliver strong financial results. In 2016, he steered the Company through the acquisition and integration of the BG Group, which accelerated Shell's business strategy and led to a streamlining divestment programme of \$30 billion of non-core assets.

Under his leadership, Shell has positioned itself to help tackle climate change. In April 2020, Shell set a target of becoming a net-zero emissions energy business by 2050, in step with society.

In 2020, in the unprecedented circumstances of the COVID-19 pandemic, Shell took decisive action to maintain its financial resilience. Ben also led plans for a strategic reorganisation, due to take effect in August 2021, aimed at setting up Shell to succeed in the energy transition by making the business nimbler and better able to respond to customers. In February 2021, Shell set out a detailed strategy to create value for shareholders and society and to achieve its net-zero emissions target.



JESSICA UHL Chief Financial Officer

Tenure

Four years (appointed March 9, 2017)

Board committee membership

N/A

Outside interests/commitments

No external appointments

Age

53

Nationality

US citizen

Career

Jessica was Executive Vice President Finance (EVP) for the Integrated Gas business from January 2016 to March 2017. Previously, she was EVP Finance for Upstream Americas from 2014 to 2015, Vice President Finance for Upstream Americas Unconventionals from 2013 to 2014, VP Controller for Upstream and Projects & Technology from 2010 to 2012, VP Finance for the global Lubricants business from 2009 to 2010, and Head of External Reporting from 2007 to 2009. She joined Shell in 2004 in finance and business development, supporting the Renewables business.

Prior to joining Shell, Jessica worked for Enron in the USA and Panama from 1997 to 2003 and for Citibank in San Francisco, USA, from 1990 to 1996. She obtained a BA from UC Berkeley in 1989 and an MBA at INSEAD in 1997.

Relevant skills and experience

Jessica is a highly regarded executive with a track record of delivering key business objectives, from cost leadership in complex operations to mergers and acquisitions. Jessica's professional background combines an external perspective with more than 16 years of Shell experience: she has held finance leadership roles in Europe and the USA, in Shell's Upstream, Integrated Gas and Downstream businesses, as well as in Projects & Technology and Corporate.

Jessica was appointed CFO in the year following the BG acquisition, when Shell's debt, gearing and development costs were high and when the oil price was still recovering from the lower levels of 2016. Jessica responded to these challenging conditions with enthusiasm, clarity and discipline and has overseen Shell's delivery of industry-leading cash flow from operating activities.

In 2020, Jessica drove decisive counter-measures to protect the long-term financial health of the organisation, strengthen its balance sheet and preserve cash while ensuring the safe continuity of the business.

Jessica has also been a leading voice for transparency in the energy industry, including on taxes and climate change. Under her tenure, Shell has continued to expand and enhance disclosures related to climate change in line with the principles of the Task Force on Climate-Related Financial Disclosures. Under her guidance, from 2019, Shell began publishing an annual Tax Contribution Report. This includes country-by-country report data, a standard set by the Organisation for Economic Co-operation and Development (OECD).

THE BOARD OF ROYAL DUTCH SHELL PLC continued



DICK BOER Independent Non-executive Director

Tenure

Nine months (appointed May 20, 2020)

Board committee membership

Member of the Audit Committee

Outside interests/commitments

Non-executive Director for Nestlé and SHV Holdings; Chairman of the Advisory Board for G-Star RAW; Chairman of the Supervisory Board of Royal Concertgebouw; Chairman of Rijksmuseum Fonds.

Age

63

Nationality

Dutch

Career

Dick was President and Chief Executive Officer of Ahold Delhaize from 2016 to 2018. Prior to the merger between Ahold and Delhaize, he served as President and CEO of Royal Ahold from 2011 to 2016. From 2006 to 2011 he was a member of the Executive Board of Ahold and served as Chief Operating Officer of Ahold Europe from 2006 to 2011.

Dick joined Ahold in 1998 as CEO of Ahold Czech Republic and was appointed President and CEO of Albert Heijn in 2000. In 2003, he also became President and CEO of Ahold's Dutch businesses.

Prior to joining Ahold, Dick spent more than 17 years in various retail positions, for SHV Holdings N.V. in the Netherlands and abroad, and for Unigro N.V.

Relevant skills and experience

Dick is a highly regarded, recently retired chief executive, who has a deep understanding of brands and consumers, and extensive knowledge of the US and European markets, from his time leading one of the world's largest food retail groups. He brings a career's worth of experience at the forefront of retailing and customer service, which extended in more recent years to e-commerce and the digital arena. This experience is most timely as Shell focuses on the growth of our marketing businesses and increasing consumer choices in energy products.

Dick is a balanced leader with sound business judgement and a proven track record in strategic delivery, evidenced by the combination of Ahold and Delhaize. He also has a passion for sustainability and is well aware of the importance of the various stakeholder interests in this area.



NEIL CARSON OBE Independent Non-executive Director

Tenure

One year and nine months (appointed June 1, 2019)

Board committee membership

Chair of the Remuneration Committee and member of the Safety, Environment and Sustainability Committee

Outside interests/commitments

Non-executive Chairman of Oxford Instruments plc

Age

63

Nationality

British

Career

Neil is a former FTSE 100 chief executive. After completing an engineering degree, Neil joined Johnson Matthey in 1980 where he held several senior management positions in the UK and the USA, before being appointed Chief Executive Officer in 2004. Since retiring from Johnson Matthey in 2014, Neil has focused his time on his non-executive roles. He was Chairman of TT Electronics plc from 2015 until May 6, 2020.

Relevant skills and experience

Neil is highly experienced, has a broad industrial outlook and a highly commercial approach with a practical perspective on businesses. He brings a track record of strong operational exposure, familiarity with capital-intensive business and a first-class international perspective on driving value in complex environments. Neil was awarded an OBE for services to the chemical industry in 2016. Neil has used his current and past experience in non-executive positions and, despite being relatively new to the Shell Board, he has already made significant contributions to Board discussions. He has also provided valuable insight based on his former executive position and operational experience. Neil was appointed Chair of the Remuneration Committee on May 20, 2020.



ANN GODBEHERE
Independent Non-executive Director

Tenure

Two years and nine months (appointed May 23, 2018)

Board committee membership

Chair of the Audit Committee, member of the Safety, Environment and Sustainability Committee

Outside interests/commitments

Non-executive Director and audit committee chair of Stellantis N.V., Fellow of the Institute of Chartered Professional Accountants and a Fellow of the Certified General Accountants Association of Canada.

Age

65

Nationality

Canadian and British

Career

Ann started her career with Sun Life of Canada in 1976 in Montreal, Canada. She joined M&G Group in 1981, where she served as Senior Vice President and Controller for both life and health, and property and casualty businesses throughout North America. She joined Swiss Re in 1996, after it acquired the M&G Group, and served as Chief Financial Officer from 2003 to 2007. From 2008 to 2009, she was interim Chief Financial Officer and an Executive Director of Northern Rock bank in the initial period following its nationalisation.

Ann has also held several non-executive director positions at Prudential plc, British American Tobacco plc, UBS AG, and UBS Group AG. Ann served as a non-executive director of Rio Tinto plc and Rio Tinto Limited until May 2019, and she was also Senior Independent Director of Rio Tinto plc. In January 2021, Ann joined the Board of the newly formed Stellantis NV, and she chairs its Audit Committee.

Relevant skills and experience

Ann is a former CFO, a Fellow of the Institute of Chartered Professional Accountants, and has more than 25 years of experience in the financial services sector. She has worked her entire career in international business and has lived in or served on boards in nine countries. Ann makes significant contributions and adds exceptional value by bringing both her extensive experience and a global perspective to Board discussions.

Ann's long and varied international business career powered by her financial acumen is reflected in the insights and constructive challenges she brings to the boardroom. As Audit Committee Chair, Ann leverages her background to ensure robust discussions are consistently held as the Audit Committee delivers its remit.



CATHERINE J. HUGHES
Independent Non-executive Director

Tenure

Three years and nine months (appointed June 1, 2017)

Board committee membership

Member of the Safety, Environment and Sustainability Committee and member of the Remuneration Committee. On March 11, 2021 the Board announced that Catherine would become Chair of the Safety, Environment and Sustainability Committee, effective May 19, 2021.

Outside interests/commitments

-

Age

58

Nationality

Canadian and French

Career

Catherine was Executive Vice President International at Nexen Inc., from January 2012 until her retirement in April 2013, where she was responsible for all oil and gas activities including exploration, production, development and project activities outside Canada. She joined Nexen in 2009 as Vice President Operational Services, Technology and Human Resources.

Prior to joining Nexen Inc., she was Vice President Oil Sands at Husky Oil from 2007 to 2009 and Vice President Exploration & Production Services, from 2005 to 2007. She started her career with Schlumberger in 1986 and held key positions in various countries, including France, Italy, Nigeria, the UK and the USA, and was President of Schlumberger Canada Ltd for five years. She was a Non-executive Director of Statoil from 2013 to 2015. Catherine was up until May 2020, a non-executive Director of SNC-Lavalin Group Inc.

Relevant skills and experience

Catherine contributes through her knowledge of industry and the ease with which she engages with other Directors and managers in the boardroom. With over 30 years of oil and gas sector experience, she brings a geopolitical outlook and deep understanding of the industry. An engineer by training, she has also spent a significant part of her career working in senior human resources roles. The Board highly regards her perspectives on our industry and our most important asset, our people.

Catherine has a strong track record of executing operational discipline with a focus on performance metrics and a continual drive for excellence. Her knowledge of the technology underpinning oil and gas operations, logistics, procurement and supply chains benefits the Board greatly as it considers various projects and investment or divestment proposals.

She also uses her industry knowledge – combined with her commitment to the highest standards of corporate governance and safety, ethics and compliance – in her membership of our Safety, Environment and Sustainability Committee, while using her human resources experience in her membership of the Remuneration Committee.

THE BOARD OF ROYAL DUTCH SHELL PLC continued



MARTINA HUND-MEJEAN Independent Non-executive Director

Tenure

Nine months (appointed May 20, 2020)

Board committee membership

Member of the Audit Committee

Outside interests / commitments

Non-executive Director of Prudential Financial Inc, Colgate-Palmolive Company, and Truata Ltd.

Age

60

Nationality

German and US citizen

Career

Martina was Chief Financial Officer of Mastercard Inc from 2007 to 2019. From 2002 to 2007 she was Senior Vice President, Corporate Treasurer at Tyco International Ltd and from 2000 to 2002 she was Senior Vice President, Treasurer at Lucent Technologies.

Prior to this, Martina spent 12 years with General Motors, undertaking a number of senior roles within their finance operations.

Relevant skills and experience

Originally from Germany, Martina has spent 30 years in the USA and is an experienced global executive. Her financial and operational leadership of technology-focused companies is extremely relevant as Shell explores new technology-enabled business models. Martina also brings diverse sector experience to the Board, most recently from operating at a large global organisation in the highly regulated finance industry.

Martina is known for her straightforward and direct approach. She maintains the highest standards of leadership, strategic thinking and financial stewardship. She also has a strong track record as a mentor and in promoting diversity.

Martina's deep financial knowledge and unique perspective also enables her to make robust, demanding and constructive challenges to our investment considerations to help ensure that our projects are aligned with our strategic intent.



SIR ANDREW MACKENZIE Independent Non-executive Director [A]

Tenure

Five months (appointed October 1, 2020)

Board committee membership

Member of the Nomination and Succession Committee

Outside interests / commitments

Fellow of the Royal Society (FRS)

Age

64

Nationality

British

Career

Sir Andrew joined BHP, the world's largest mining company, in 2008, becoming Group CEO from 2013 to 2019, when he systematically simplified and strengthened the business, and created options for the future. He also made BHP the first miner to pledge to tackle emissions caused when customers use its products.

From 2004 to 2007 at Rio Tinto, he was Head of Industrial Minerals, then Head of Industrial Minerals and Diamonds. Prior to this, Sir Andrew spent 22 years with BP, joining in 1982 in research and development, followed by international operations and technology roles across most business streams and functions – principally in exploration and production and petrochemicals, including as Chief Reservoir Engineer and Chief Technology Officer. Latterly he was Group Vice President for Chemicals in the Americas, then Olefins and Polymers globally.

From 2005 to 2013 Sir Andrew served as a Non-executive Director of Centrica. He has also served on many not-for-profit boards, including public policy think-tanks in the UK and Australia. He was knighted in 2020 for services to business, science, technology and UK-Australia relations.

Relevant skills and experience

Sir Andrew is a highly experienced leader who has managed major international FTSE 100 businesses, and has more than 30 years' experience in the oil and gas, petrochemicals and minerals industry. Following early academic distinction, Sir Andrew made important contributions to geochemistry, including groundbreaking methods for oil exploration and recovery. He was recognised as "one of the world's most influential earth scientists" and made a Fellow of the Royal Society in 2014.

Having lived and worked on five continents, Sir Andrew applies his deep understanding of the energy business and geopolitical outlook to create public-private partnerships and advise governments around the world. As an earth scientist, Sir Andrew has consistently pursued sustainable action on climate change in the interests of access to affordable energy and global development. Sir Andrew brings the wealth of his experience and insights to Shell, where his expertise is already contributing to help Shell navigate the energy transition. Sir Andrew is also a committed champion of gender balance, the rights of indigenous peoples, and of the power of large companies to support social change – all of which align closely with Shell's purpose, strategy and values.

[A] On March 11, 2021, the Board announced the appointment of Sir Andrew Mackenzie as Chair with effect from the conclusion of the 2021 AGM.



ABRAHAM SCHOT
Independent Non-executive Director

Tenure

Five months (appointed October 1, 2020)

Board committee membership

Member of the Safety, Environment and Sustainability Committee

Outside interests/commitments

-

Age

66

Nationality

Dutch

Career

Bram has been a member of the group Board of Volkswagen AG, responsible for the Premium Car Group, CEO of Audi AG, Chairman of Lamborghini and Ducati, responsible for the VW group Commercial Operations and Vice-Chairman of Porsche Holding Salzburg.

From 2011 to 2016 he was a Member of the Board of Volkswagen CV, Executive Vice President responsible for Global Marketing, Sales & Services, New Business Models. In 2017 he became a member of the Board of Audi AG. From 2006 to 2011 Bram was President & CEO of Daimler/Mercedes-Benz Italia & Holding S.p.A. From 2003 to 2006 he was President & CEO of DaimlerChrysler in the Netherlands.

Prior to this, Bram held a number of Director and senior leadership roles within Mercedes-Benz in the Netherlands, having joined the business in 1987 on an executive management programme.

Relevant skills and experience

Bram has over 30 years' experience working in the automotive industry at all levels of the business.

He gained a wealth of knowledge on far-reaching cost optimisation programmes at Audi AG. These helped transform the car company into a provider of electric vehicles that could offer sustainable mobility and succeed in the energy transition. He is well placed to leverage this knowledge in the Shell boardroom as Shell navigates its own transformation and pathway through the energy transition.

Bram has strong principles and regards integrity and compliance as the basis for doing business.

His studies have encompassed innovation and organisational effectiveness, geopolitical environments, shareholder value, corporate social responsibility and risk management, in several countries, which are all highly valued management tools and are already evident in the questions he raises in the boardroom.



SIR NIGEL SHEINWALD GCMG
Independent Non-executive Director

Tenure

Eight years and eight months (appointed July 1, 2012)

On March 11, 2021 the Board announced that Sir Nigel Sheinwald would not be seeking re-election at the 2021 AGM.

Board committee membership

Chair of the Safety, Environment and Sustainability Committee and member of the Nomination and Succession Committee

Outside interests/commitments

Non-executive Director of Invesco Ltd. Senior Adviser to Tanium Inc. and the Universal Music Group. Visiting Professor of King's College, London.

Age

67

Nationality

British

Career

Sir Nigel was a senior British diplomat who served as British Ambassador to the USA from 2007 to 2012, before retiring from the Diplomatic Service. Prior to this, he served as Foreign Policy and Defence Adviser to the Prime Minister and as British Ambassador and Permanent Representative to the European Union in Brussels. He joined the Diplomatic Service in 1976 and served in Brussels, Moscow, Washington and in a wide range of policy roles in London. Since 2012, he has taken on a number of international business roles, and has supported organisations involved in higher education and international affairs.

Relevant skills and experience

Sir Nigel's distinguished track record, which encompasses three of the most senior international roles in British public service, has given him broad geopolitical and public policy experience, and knowledge of regulatory issues, communications and stakeholder management. He has a global and strategic outlook which enables him to identify emerging issues that could present geopolitical or reputational challenges.

Sir Nigel continues to bring a unique government policy perspective to our strategic discussions, particularly on topics such as the energy transition that are strongly influenced by the views of governments and a complex range of interested parties. His many contributions to the Board on this and other strategic and operational topics often reflect the interconnections between geopolitics, business and external stakeholder engagement.

He is accustomed to operating in challenging environments and is committed to active external engagement. This, and his understanding of public policy and regulatory issues through his career in government service and membership of think-tank and university boards, has made him well suited to the role of Chair of our Safety, Environment and Sustainability Committee.

THE BOARD OF ROYAL DUTCH SHELL PLC continued



GERRIT ZALM Independent Non-executive Director

Tenure

Eight years and two months (appointed January 1, 2013)

Board committee membership

Member of the Audit Committee and member of the Remuneration Committee

Outside interests/commitments

Director of Moody's Corporation Inc. and Danske Bank A/S

Age

68

Nationality

Dutch

Career

Gerrit was an adviser to PricewaterhouseCoopers during 2007, Chairman of the Trustees of the International Accounting Standards Board from 2007 to 2010, and an adviser to Permira from 2007 to 2008. He was Chief Economist of DSB Bank from July 2007 to January 2008, Chief Financial Officer from January 2008 to December 2008, and Chairman of the Managing Board of ABN AMRO Bank N.V. from 2010 to 2016. He was Minister of Finance of the Netherlands, twice, from 1994 to 2002 and from 2003 to 2007. In between, he was Chairman of the parliamentary party of the VVD.

Prior to 1994, he was head of the Netherlands Bureau for Economic Policy Analysis, a professor at Vrije Universiteit Amsterdam, and held various positions at the Ministry of Finance and the Ministry of Economic Affairs. He studied general economics at Vrije Universiteit Amsterdam, from where he also received an honorary doctorate in economics.

Relevant skills and experience

An economist by background, Gerrit's distinguished 12-year service as the Minister of Finance of the Netherlands, and his experience gained from his time with ABN AMRO Bank, bring a deep and valuable understanding of Dutch politics and financial markets to the Board. His international financial management expertise and strategic development experience also benefit the Audit Committee.

A highly regarded and seasoned leader in both the public and private spheres, his significant experience in analysing financial commitments from a wider public stakeholder and a global business standpoint serves the Board well, particularly when considering investment proposals. Gerrit consistently and concisely articulates the logic and reasoning behind his views, which he regularly and directly provides to the benefit of the Board and management. His questions often trigger other analytical questions from fellow Directors, deepening and widening Board discussions.



LINDA M. COULTER Company Secretary

Tenure

Four years and two months (appointed January 1, 2017)

Age

53

Nationality

US citizen

Career

Linda was General Counsel of the Upstream Americas business and Head of Legal US, based in the USA, from 2014 to 2016. Previously, she was Group Chief Ethics and Compliance Officer, based in the Netherlands, from 2011 to 2014. Since joining Shell in 1995, she has also held a variety of legal positions in the Shell Oil Company in the USA, including Chemicals Legal Managing Counsel and other senior roles in employment, litigation, and commercial practice.

Relevant skills and experience

Linda is our Company Secretary and plays an important role as Shell's General Counsel Corporate, overseeing corporate legal teams in Canada, the Netherlands, the UK and the USA.

The various legal roles Linda has undertaken at our headquarters, and in supporting both the Upstream and Downstream businesses, have provided her with a strong understanding of our global operations and people. Her experience of engaging with the Board in previous roles, coupled with her broad understanding and engagement across Shell's businesses and functions, helps to ensure that the right matters come to the Board at the right time.

RETIREMENTS IN 2020

GERARD KLEISTERLEE

Retired: May 19, 2020. In line with best practice, Gerard chose not to seek re-election at the 2020 AGM following completion of his third three-year term and retired from the Board.

LINDA STUNTZ

Retired: May 19, 2020. In line with best practice, Linda chose not to seek re-election at the 2020 AGM following completion of her third three-year term and retired from the Board.

ROBERTO SETUBAL

Retired: May 19, 2020. Roberto chose not to seek re-election at the 2020 AGM due to other business commitments in his home country of Brazil and retired from the Board.

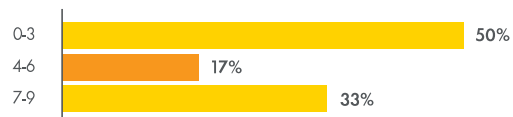
BOARD DIVERSITY

Gender diversity

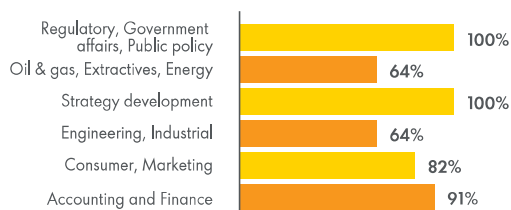


Subject nominations standing for election at the 2021 AGM being approved by shareholders, the Board will have achieved gender parity.

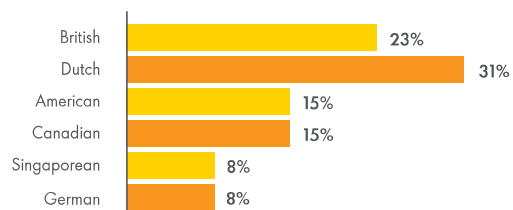
Non-executive Director tenure (years)



Non-executive Director sector experience



Director nationality



ATTENDANCE

The Board met 12 times during 2020. Two meetings were held in The Hague in the Netherlands and the remainder were held virtually in the context of COVID-19 circumstances. Attendance during 2020 for all Board meetings is given in the table opposite [A].

[A] For attendance at Committee meetings during the year, please refer to individual Committee Reports.

[B] Dick Boer joined the Board in May 2020.

[C] Martina Hund-Mejean joined the Board in May 2020.

[D] Gerard Kleisterlee retired from the Board following the AGM in May 2020.

[E] Sir Andrew Mackenzie joined the Board in October 2020.

[F] Bram Schot joined the Board in October 2020.

[G] Roberto Setubal retired from the Board following the AGM in May 2020.

[H] Linda G. Stuntz retired from the Board following the AGM in May 2020.

Board member	Meetings attended
Ben van Beurden	12/12
Dick Boer [B]	7/7
Neil Carson	12/12
Ann Godbehere	12/12
Euleen Goh	12/12
Charles O. Holliday	12/12
Catherine J. Hughes	12/12
Martina Hund-Mejean [C]	7/7
Gerard Kleisterlee [D]	5/5
Sir Andrew Mackenzie [E]	3/3
Bram Schot [F]	3/3
Roberto Setubal [G]	5/5
Sir Nigel Sheinwald	12/12
Linda G. Stuntz [H]	5/5
Jessica Uhl	12/12
Gerrit Zalm	12/12

DIRECTOR INDEPENDENCE

All the Non-executive Directors are considered by the Board to be independent in character and judgement. The Chair is not subject to the Code's independence test other than on appointment.

ETHNIC DIVERSITY

The Board is satisfied that it currently meets the recommendation from the Parker Review.

SENIOR MANAGEMENT

The Senior Management of the Company comprises the Executive Directors, Ben van Beurden and Jessica Uhl, and those listed below. All are members of the Executive Committee (see "Governance Framework" on page 129).



HARRY BREKELMANS Projects & Technology Director

Tenure

Six years and five months (appointed October 2014)

Age

55

Nationality

Dutch

Career

Harry was previously Executive Vice President for Upstream International Operated, based in the Netherlands. He joined Shell in 1990 and has held various management positions in Exploration and Production, Internal Audit, and Group Strategy and Planning. From 2011 to 2013, he was Country Chair Russia and Executive Vice President for Russia and the Caspian region.



DONNY CHING Legal Director

Tenure

Seven years and one month (appointed February 2014)

Age

56

Nationality

Malaysian

Career

Donny was previously General Counsel for Projects & Technology, based in the Netherlands. He joined Shell in 1988 based in Australia and then moved to Hong Kong and later to London. In 2008, he was appointed Head of Legal at Shell Singapore, having served as Associate General Counsel for Gas & Power in Asia-Pacific.



RONAN CASSIDY Chief Human Resources and Corporate Officer

Tenure

Five years and two months (appointed January 2016)

Age

54

Nationality

British

Career

Ronan was previously Executive Vice President Human Resources, Upstream International. He joined Shell in 1988 and has held various human resources positions in Upstream and Downstream.



WAEEL SAWAN Upstream Director

Tenure

One year and eight months (appointed July 2019)

Age

46

Nationality

Lebanese and Canadian

Career

Wael was previously the Executive Vice President of Shell's Deep Water business and was a member of the Upstream Leadership Team. He joined Shell in 1997 and worked in a variety of roles in each of Shell's core business units: Upstream, Integrated Gas and Downstream.



HUIBERT VIGEVENO
Downstream Director

Tenure

One year and two months (appointed January 2020)

Age

51

Nationality

Dutch

Career

Huibert was previously Executive Vice President Global Commercial. He joined Shell in 1995 as a business analyst and led many Downstream businesses across Shell in Europe, Africa, North and South America as well as Asia. In 2009, Huibert was appointed Vice President Supply & Distribution, Europe and Africa. In 2012 he became Executive Chairman of Shell in China, and in 2016 led the integration of BG Group.



MAARTEN WETSELAAR
Integrated Gas, Renewables
and Energy Solutions Director

Tenure

Five years and two months (appointed January 2016)

Age

52

Nationality

Dutch

Career

Maarten was previously Executive Vice President of Integrated Gas, based in Singapore. He joined Shell in 1995 and has held various financial, commercial and general management roles in Downstream, Trading and Upstream.

INTRODUCTION FROM THE CHAIR



CHAD HOLLIDAY

Chair

As mentioned earlier in this Report, I will be vacating my role as Chair of the Board after the 2021 Annual General Meeting (AGM). I very much hope that we will be able to revert back to a more normal AGM, with shareholders physically present at our meeting. We will, though, need to assess whether this is possible, alongside government guidance, closer to the time of the meeting.

It has been a great honour to serve Shell over the last 10 years, and I thank our shareholders for granting me that privilege. As I look back on my time with Shell, 2020 is by far the most memorable year, for many reasons. We came into 2020 off the back of what had already been a difficult 2019 for our industry, with tough macroeconomic conditions, lower liquefied natural gas (LNG) prices and weaker realised refining margins. In the Governance section of the 2019 Annual Report, when I looked forward to the coming year, I highlighted the continuing risk from trade conflicts with difficult-to-predict outcomes, regional geopolitical tensions and the uncertainties of Brexit. Yet we still looked forward with optimism.

In other areas of the 2019 Report we noted the early impact that we were seeing from COVID-19 and the ensuing macroeconomic uncertainty around prices and demand for oil, gas and products. The Risk factors section of the 2019 Report highlighted the potential for COVID-19 to have a material adverse effect on our operations. The months that followed put our words “potential” and “material” into perspective. Economies across the world were decimated. Life and the many freedoms we associated with it changed in ways that are likely to impact people and broader society for many years to come.

As I reflect on how our organisation navigated this environment, what stands out for me is our people. I am immensely proud of them. I was struck by how our people stepped up and continued to deliver in this challenging environment. They continued to work on platforms and refineries, away from their families for extended periods of time, to ensure Shell delivered on its commitments. They worked in retail fuel stations, face-to-face with the public. They went into our offices when they could not do their job from home. The list of what our people did for this organisation is extensive, and in some instances quite humbling. Yet what stands out the most is their care for one another, and the efforts they made to support their colleagues. It is this enduring care for one another that will be my strongest memory over the past decade I have served Shell. It is what defines the culture and heart of this Company.

The rapid changes in response to COVID-19 have prompted positive action in many areas of society. The pandemic has challenged us to look at how we live, what we value, and how we see the future. Our scenarios team has updated its thinking and issued a number of publications which can be found on the Shell website. Governments have stepped up their environmental ambitions. Growth after the virus is expected to be greener. Shell is evolving its strategy to remain aligned with a greener future and to encourage society to choose lower-carbon options. It is our target to be a net-zero emissions energy company by 2050, in step with society. We still believe, though, that society will continue to need oil and gas for many years to come. Oil and gas will continue to be the cash generators that support our investments through the energy transition. They will underpin Shell's delivery of its targets that are aligned with the goals of the Paris Agreement.

BOARD LEADERSHIP AND SHELL'S PURPOSE

The Corporate Governance Code (the “Code”) provides that the Board should promote the long-term sustainable success of Shell, generating value for shareholders and contributing to wider society. The Board believes that Shell's efforts give it an effective framework to play its part in the energy transition as a growing, successful, commercial organisation. In the Board's view, this framework will allow Shell to provide the energy solutions that consumers will want and buy through this period of uncertain change. The Board also thinks that Shell will be able to reduce the carbon intensity of the energy products it supplies and deliver against its recently published targets.

The purpose of Shell is set out in the early pages of this Annual Report. We will continue with the theme of communicating purpose throughout this report, focusing on how our governance operates in practice, and why we believe this is the best approach for Shell.

The Governance report is structured around the key themes of the Code. Our narrative is articulated to provide genuine understanding of how governance supports and protects Shell and our stakeholders.

Although Shell applies the Principles and the spirit of the Code, there are instances where we adopt an approach that is slightly different from that suggested by some of the Code's provisions and we explain these on page 126. In these instances, our governance processes are considered appropriate, given the specific circumstances and a range of factors that are particular to Shell, such as its global nature, size, complexity and history. More detail on Shell's compliance with the Code can be found on pages 126 to 127.

Last year I highlighted the importance of our stakeholders and the greater level of external focus on these groups. We expressed our enthusiasm to build on our engagement with our stakeholder groups in 2020. Sadly, the face-to-face interaction we had hoped for was often made impossible by restrictions on social interaction and travel during the pandemic. Instead, greater use of technology has facilitated online, virtual engagement. The Board was able to visit some of our sites virtually, and engaged in virtual meetings with our broader stakeholders and our people. The Board's discharge of its duty in relation to key stakeholder interests, including those of our workforce, and an explanation of how it considered these when making principal decisions are set out on page 22. On page 130 we provide information about our Board activities and highlight which stakeholders we considered.

Our workforce engagement methods remain unchanged from those previously disclosed. As we implement the proposals from our Reshape reorganisation, we anticipate an enhanced level of workforce engagement, within the parameters of COVID-19 restrictions. We continue to believe that constructive relationships built on mutual respect and transparency help Shell attract and retain employees while supporting greater productivity and operational safety and efficiency. Ensuring that the employee voice is heard in the boardroom in practical ways is key to understanding the broader impact of business decisions, including with respect to organisational culture.

The Board clearly recognises the importance of culture and its link to delivering Shell's purpose and strategy. Given our culture's importance, it requires long-term commitment. The Board believes that our people and safety culture is strong, and takes pride in having such a culture.

Our culture reflects the values of the organisation – honesty, integrity and respect for people. These underpin all the work we do and are embedded in our Strategy and Purpose. The 2020 Board evaluation highlighted that although the Board uses various reports and engagements to assess our culture, a considerable part of this assessment is based on the outcome of the annual employee survey. Although this survey provides informed insight, the Board recognises that this data can have its limitations. For this reason, the Board will undertake a deeper analysis of Shell's culture in 2021.

DIVISION OF RESPONSIBILITIES

More information on how the Board and its Committees support business operations is provided on page 128. Further detail is contained within the Terms of Reference for each Committee, which are provided on our website. Each year the Board committees' Terms of Reference are reviewed and updated, as required.

Maintaining independent judgement on the Board is a fundamental governance principle and one supported by the Board. The Code provides circumstances that it considers are likely to impair, or could appear to impair, a Non-executive Director's independence. One of these is tenure. In the 2019 Annual Report we shared information on Directors that exceeded guidance outlined in the Code with regard to tenure. We also explained when these Directors' tenure was expected to end, and the assessments of their independence that the Nomination and Succession Committee made on behalf of the Board. Some of this information can be found within our Statement of Compliance with the Code, on page 126. A deeper analysis can be found on page 115 of the 2019 Annual Report.

COMPOSITION, SUCCESSION AND EVALUATION

The Director biographies in this Governance report provide insight into our Directors' careers, skills and experience. Our Board diversity reporting also extends beyond gender and nationality, and outlines the varying sector experience across the Board.

At the 2020 AGM, shareholders appointed Dick Boer, Martina Hund-Mejean and Sir Andrew Mackenzie to the Board. In September, Bram Schot was appointed by the Board. After joining the Board, each new member was appointed to one of the Board committees, refreshing the committee's composition. Each Director's biography contains information on their committee memberships. An overview of the new Directors' induction programme can be found on page 142. After the 2020 AGM, Gerard Kleisterlee, Linda Stuntz and Roberto Setubal retired from the Board. The Board is grateful for their years of service.

At the 2021 AGM, as announced on March 11, 2021, Sir Nigel Sheinwald will retire from the Board following nine years of service. He leaves behind a strong leadership track record and the Board is deeply grateful for his many years of dedicated commitment to the business.

The 2021 AGM will also be my last day with Shell. After the meeting, Sir Andrew Mackenzie will succeed me as Chair of the Board. I am delighted to welcome him as my successor. His appointment follows a rigorous search process led by the Deputy Chair and Senior Independent Director. An overview of the Chair succession process can be found on page 142. In addition, as announced on March 11, 2021, the Board intends to propose to the 2021 Annual General Meeting that Jane Lute be appointed a Non-executive Director of the Company with effect from May 19, 2021. If shareholders are supportive of her appointment, we will have achieved gender parity on the Board.

AUDIT, RISK MANAGEMENT AND INTERNAL CONTROL

The Audit Committee assists the Board in maintaining a sound system of risk management and internal control and oversight over Shell's financial reporting. A variety of standing matters and more specific topics are discussed by the Audit Committee throughout the year. As part of the year-end reporting process, the Audit Committee advises the Board on the adequacy of the system of risk management and internal control in place, the appropriateness of the viability statement and going concern basis of accounting. The Audit Committee also advises on whether this Report, taken as a whole, is fair, balanced and understandable and provides the information necessary for stakeholders to assess Shell's position and performance, business model and strategy. More information on the Audit Committee's activities, highlights and priorities can be found in its report on page 145.

Shell is at a point where it must transform itself while facing intense public scrutiny and operating in a rapidly changing, disruptive environment. It must frame and implement its strategy with courage and commitment, but also with the humility to listen, learn and adapt. Shell's Board and leadership must be steadfast, agile and sensitive to the opportunities, risks and rewards confronting the business. I remain confident that all are up to the tasks.

Finally, we hope that this document provides clear reporting and enhances our stakeholders' understanding of our governance processes. I would also like to thank again my fellow Directors, our colleagues and our workforce around the world for their continued and considerable efforts towards the success of the Company.

CHAD HOLLIDAY

Chair
March 10, 2021

STATEMENT OF COMPLIANCE WITH THE UK CORPORATE GOVERNANCE CODE

The Board confirms that, throughout the year, the Company has applied the Principles, both in spirit and in form, and complied with the provisions set out in the UK Corporate Governance Code issued by the Financial Reporting Council (FRC) in July 2018 (the “Code”), with the exception of those provisions noted below. A copy of the Code can be found on the FRC’s website: www.frc.org.uk.

Shell’s governance arrangements have been considered alongside the Code. The information set out in the Directors’ report, including the Board committee reports on (pages 140-156) is intended to provide an explanation of how the Code’s Principles were applied practically throughout the year. We have also provided clear and meaningful explanation below where we believe stakeholders may benefit from more specific information on particular Code provisions.

Chair tenure (Provision 19)

Note: The text relating to Chair tenure is provided by Eileen Goh, Senior Independent Director. Charles O. Holliday (Chad) was appointed as Chair in 2015 after four and a half years on the Board as a Non-executive Director. In September 2019, he reached a tenure of nine years. Chad will be standing down from the Board at the 2021 AGM.

The provisions of the Code address Chair tenure and set a limit of nine years from the date of first appointment to the Board. However, the Code pragmatically acknowledges that this period can be extended for a limited time to facilitate orderly, effective succession planning and the development of a diverse board. In the 2018 Annual Report and Form 20-F, we highlighted that Chad’s tenure had been discussed at numerous shareholder engagements. It was disclosed that shareholders were supportive of the extension of his tenure to the 2021 AGM. This meets the Code’s limited exception, particularly as the Chair was an existing Non-executive Director on appointment. The Board also takes comfort from the support for Chad’s re-election at the 2019 and 2020 AGMs (96% and 95%, respectively, votes in favour) and ongoing support from shareholders.

Retaining Chad on the Board and in the position of Chair until the 2021 AGM was right for the business. Doing so has facilitated a more effective phasing of his succession, particularly given the existing slate of Director tenure at the time of the Code’s issuance with three Directors nearing their ninth year of service. Earlier departure would have been disruptive and could have left a significant deficiency in the Board’s corporate knowledge.

The 2019 independent Board evaluation strongly recognised Chad as an effective Chair. This was again reflected in the findings of the 2020 internal Board evaluation (see pages 132-133). Throughout 2020, Chad continued to exercise objective judgement, despite his tenure exceeding nine years. The Board found that the continuity of his Shell corporate knowledge and experience supported the induction of the new Directors, and that Chad provided continuity and sound leadership of the Board through one of the most challenging years that the business has experienced.

Chad’s innate understanding and knowledge of the Shell Group, coupled with the strong Shell relationships he has established, proved invaluable in 2020. His skills enabled him to balance his challenge of management with pragmatic perspectives of the external pressures upon the business. He has done this while coaching other, particularly new, Non-executive Directors on the intricacies and nuances of the business, so they were better able to challenge management effectively and enhance overall governance.

Workforce engagement (Provision 5)

Our people are essential to the successful delivery of the Shell strategy, and the Board recognises the importance of understanding their views through engagement. However, the size and diversity of our employee base and of our wider workforce complicate the feasibility of implementing any of the three specific workforce engagement methods recommended in the Code. Given the required coverage needed for a global organisation such as ours, the Board believes that its current approach to workforce engagement continues to be pragmatic and effective.

In the 2019 Annual Report, we communicated that the Board had decided that in 2020 it would increase its direct engagements, when the Board, committees and individual Directors visit our sites across the world. We communicated that the Board would also increase its indirect engagements through enhanced stakeholder engagement information being included in relevant management reports. Due to the ongoing COVID-19 pandemic and associated travel restrictions, the direct engagements did not progress as we had hoped. That said, in line with the spirit of this ambition, a number of virtual engagements have been undertaken. Information on stakeholder engagement has also been enhanced in management reporting. The Board also intends to keep under review the effectiveness of the engagements. More information on the current approach and a description of the channels used by the Board, its committees, and the Executive Committee are outlined in “Workforce engagement” on pages 138-139.

Director independence (Provision 10)

In the 2019 Annual Report, we noted that Gerard Kleisterlee had served on the Board for more than nine years, having joined in November 2010. Gerard stepped down from the Board at the 2020 AGM. Therefore, although not currently a Board member, he was a Director for part of the year.

In the 2019 Annual Report, published in March 2020, the Board acknowledged the potential impairment of his independence owing to his length of tenure, as outlined in a Code provision. In the Board’s view, there had been no notable negative change in Gerard’s performance as a Director and in his various Board roles in recent years. The Board continued to regard him as an independent Non-executive Director and undertook a rigorous evaluation to reach this conclusion. Gerard did not participate in his own assessment. A detailed overview of the assessment can be found on page 119 of the 2019 Annual Report.

Appointment of independent Non-executive Director as Senior Independent Director (Provision 12)

Eileen Goh succeeded Gerard Kleisterlee as Deputy Chair and Senior Independent Director, after Gerard's retirement at the 2020 AGM in May. Information on the independence of Gerard, who was the Senior Independent Director for the first four and a half months of the year, is explained under the "Director independence" heading above.

Composition of the Remuneration Committee (Provision 32, independence)

For the period leading up to the 2020 AGM, the Remuneration Committee consisted of five Non-executive Directors, four of whom are deemed to be independent under the Code's parameters, and the fifth (Gerard Kleisterlee) was considered to be independent by the Board for the reasons provided in its explanation. As we approached the end of Gerard's tenure, Remuneration Committee members had served on this committee for periods ranging from less than a year to just over five years. As announced on January 29, 2020, Neil Carson succeeded Gerard in the role of Committee Chair after the 2020 AGM. Neil has been a member of this committee since June 1, 2019 and has previously served on a remuneration committee before joining the Shell Board. Having Gerard remain as Committee Chair beyond his nine-year tenure to the natural conclusion of his tenure at the 2020 AGM was a practical step promoting smooth succession. Further details on the composition of the Remuneration Committee are provided on page 153 of the Remuneration Committee Report.

Corporate governance requirements outside the UK

In addition to complying with applicable corporate governance requirements in the UK, the Company complies with the rules of Euronext Amsterdam as well as Dutch securities laws because of its listing on that exchange. The Company likewise adheres to US securities laws and the New York Stock Exchange (NYSE) rules and regulations because its securities are registered in the USA and listed on the NYSE.

GOVERNANCE FRAMEWORK

BOARD OF DIRECTORS

Board

- The Company has a single-tier Board of Directors headed by a Chair, with executive management led by the Chief Executive Officer. The names of the Directors that held office during the year can be found on pages 114-121. Information on the Directors that are seeking appointment or reappointment is included in the Notice of Annual General Meeting;
- There is no fixed number of times that the Board may meet in one year. In 2019, the Board convened eight times. During 2020, the Board met 12 times, and, as detailed throughout our Strategic Report including the Section 172 statement and activities undertaken throughout the year, works hard to promote the long-term sustainable success of the Company, generating value for shareholders and contributing to wider society. Further information on the Board's work and assessments in relation to strategy, culture, engagement with stakeholders and its workforce can be found as follows:
- The Board's responsibilities are governed by a formal schedule of matters reserved to it and include:
 - Approval of overall strategy and oversight of management;
 - Changes to the corporate and capital structure;
 - Approval of financial reporting and controls (including approval of the Annual Report and Accounts, approval of the Annual Report on Form 20-F, and interim dividends);
 - Oversight of risk management and internal control;
 - Approval of significant contracts;
 - Determining succession planning and new Board appointments;
 - Remuneration for the Chair and Executive Directors; and
- Corporate governance matters.

Board Committees

Audit Committee

- Carries out certain oversight functions on behalf of the Board; and
- Assists the Board in fulfilling its responsibilities in relation to internal control and financial reporting.

More information on the Committee's composition and its role and activities during the year is on pages 145-152.

Safety, Environment and Sustainability Committee

- Carries out certain oversight functions on behalf of the Board; and
- Advises the Board on safety, the environment including climate change, and Shell's overall sustainability performance.

More information on the Committee's composition and its role and activities during the year is on pages 143-144.

Nomination and Succession Committee

- Leads the process for appointments to the Board;
- Recommends Board appointments and re-appointments;
- Reviews and makes recommendations on succession planning; and
- Reviews and makes recommendations on corporate governance guidelines.

More information on the Committee's composition and its role and activities during the year, including its recommendations made to the Board on the application of the Code, is on pages 140-142.

Remuneration Committee

- Determines and agrees with the Board of Directors the remuneration policy for the Chair, Executive Directors and Executive Committee of the Company;
- Within the terms of such agreed policy, determines individual remuneration package for the Chair, Executive Directors and Senior Management (including the Company Secretary); and
- Monitors and makes recommendations regarding the structures and levels of remuneration and levels for other senior executives, if appropriate.

More information on the Committee's composition and its role and activities during the year is on pages 153-156.

Other ad hoc Committees

The Nigeria Special Litigation Committee is an ad hoc committee which has been formed to monitor the status of the OPL-245 litigation and investigations. Its members are Euleen Goh (Chair), Chad Holliday, Ann Godbehere, and Sir Nigel Sheinwald.

BOARD OF DIRECTORS continued**Division of responsibilities**

The roles of the Chair, a non-executive role, and the CEO are separate and clearly defined. The Board has agreed their respective responsibilities and set these out in writing. These are available on request from the Company Secretary.

Chair

- Responsible for ensuring that the Board and its Committees function effectively. One way in which this is achieved is by ensuring Directors receive accurate, timely and clear information; and
- Responsible for making sure that there is an adequate induction and training programme followed by all Directors (see page 142), with assistance from the Company Secretary.

Deputy Chair/Senior Independent Director

- Sounding board for the Chair;
- Serves as an intermediary for the other Directors and shareholders; and
- Leads the annual appraisal of the Chair's performance.

Non-executive Directors

- Appointed by the Board or by shareholders at general meetings and, in accordance with the Code, seek re-election by shareholders on an annual basis;
- Letters of appointment refer to a specific term of office, the provisions of the Code and the Company's Articles of Association;
- Upon appointment, Non-executive Directors confirm they are able to allocate sufficient time to meet the expectations of the role. Appointments are subject to a minimum of three months' notice of termination, and there is no compensation provision for early termination;
- The Non-executive Directors bring a wide range and balance of skills and international business experience. Through their contribution to the Board and Board Committee meetings, they are expected to challenge and help develop proposals on strategy and bring independent judgement on issues of performance and risk; and
- Before each Board meeting, the Chair and Non-executive Directors meet without the Executive Directors being present. At these "pre-meetings", the Non-executive Directors discuss, among other matters, the performance of individual Executive Directors. A number of Non-executive Directors also meet major shareholders over the course of the year.

EXECUTIVE MANAGEMENT**Chief Executive Officer**

- Has overall responsibility for the implementation, by the Executive Committee, of the overall strategy approved by the Board, the operational management of the Company and the business enterprise connected with it; and
- Supported by the Executive Committee that he chairs.

Executive Committee

- Operates under the direction of the Chief Executive Officer (CEO) in support of his responsibility for the overall management of Shell's business. The CEO has final authority in all matters of management that are not within the duties and authorities of the Board or of the shareholders' general meeting; and
- Executive Committee members are listed in the Senior Management biographies on page 122-123.

GOVERNANCE DOCUMENTS AVAILABLE ON WWW.SHELL.COM/INVESTOR

- Articles of Association
- Matters Reserved for the Board
- Board Committee Terms of Reference
- Modern Slavery Statement
- Shell General Business Principles
- Shell Code of Conduct
- Code of Ethics for Executive Directors and Senior Financial Officers

BOARD ACTIVITIES AND EVALUATION

BOARD ACTIVITIES

A rolling Board agenda is reviewed at Board meetings, enabling effective forward management of meetings and focused discussions. Forthcoming Board agenda items are categorised as: Strategy & Portfolio, Delivery & Performance, External Environment, Corporate & Miscellaneous or Standard items. Of the standard items, Board agendas regularly include reports from the Chief Executive Officer, the Chief Financial Officer, other Executive Committee members and from each Board committee. “Core values” moments also feature regularly led by a Director or Executive Committee member. In 2020, “Shell Heroes” vignettes were added to highlight extraordinary staff actions including those exemplifying care for people, society and/or the environment. Updates are also provided from the various businesses and key functions, including Investor Relations; Health and Safety, Security and Environment; Human Resources; and Legal, as well as the Company Secretary. The Board also considers and approves the quarterly, half-year and full-year financial results, shareholder distributions and the associated announcements, and, at most meetings, considers investment, divestment and/or financing proposals. To enable purposeful debates and/or focus on particular aspects of agenda topics, including the impact on key stakeholders, Directors have an opportunity to specify information they require to be provided in advance of Board meetings.

As in previous years and despite COVID-19 travel restrictions, certain Board committees and Non-executive Directors conducted site visits of various Shell operations and overseas offices – albeit virtually in 2020. These virtual visits were designed to provide Directors with first-hand insights into certain businesses, including into key projects and energy transition initiatives. Directors also held various virtual workforce engagements, as well as virtual external stakeholder engagements. More detail on these can be found in the table below and on pages 134-139.

Some of the activities and areas of Board focus over the year are summarised in the table below. The information below is not exhaustive.

Information on other topics discussed by the Board and details of the resulting decisions are covered elsewhere, primarily in the Section 172 Statement contained in the Strategic Report on page 22. In some cases, a brief outline has been provided below and reference given to where additional and more comprehensive information can be found.

June strategy days

In lieu of the traditional physical June Strategy off-site meetings or Board's Strategy Day, virtual meetings were held over the course of three days. As these meetings are usually an opportunity for the Board, and particularly new Directors, to strengthen collegial relationships among Directors and with the Executive Committee, considerable efforts were invested into making these meetings as innovative and engaging as possible. This included incorporating break-out sessions, staff engagements and an external engagement. The Board members were also asked to share light-hearted insights about themselves in advance of the meetings which were woven into informal quizzes. Virtual social events rounded out the end of each day's programme.

The Board Strategy Days included discussions on various topics including the proposed direction for Shell, with strategic alternatives. Topics covered at the sessions included:

- 2020-2022 outlook and responses;
- Project Reshape (Shell's reorganisation);
- strategic pathway and underlying strategic premises;
- energy transition strategy;
- implications of energy transition strategy;
- exploring alternative strategies;
- financial framework;
- strategic alignment next steps;
- staff engagements; and
- external engagement with a significant customer/supplier.

Topic	Discussion/activity/updates included	Examples of outcome/progress	Stakeholders considered
Board leadership and company purpose			
External business environment	<ul style="list-style-type: none"> ■ Received updates on and discussed regional geopolitical issues. ■ Discussions on spread of COVID-19, including global public health response, economic policy response, recession and recovery, oil demand, gas markets outlook. 	<ul style="list-style-type: none"> ■ Considered feedback from investor community on expected financial performance and related risks. ■ Considered how COVID-19 impacts on the business were being managed. Included: key focus on staff health, well-being/care; and identification of, and planning mitigations for, ongoing risks. 	A B C D E F G
Strategy Day	<ul style="list-style-type: none"> ■ Reviewed and discussed progress of strategy agenda including Management recommendations, work on development of alternative strategies, review of strategic options, and considered fundamental macro-environment changes caused by COVID-19. 	<ul style="list-style-type: none"> ■ Alignment on outcomes from virtual Board Strategy Days and on programme of work and preliminary engagement proposal in lead-up to Strategy Day 2021. Energy transition opportunities also discussed. ■ Proposal to use series of external communication events to deepen external understanding of refreshed strategy including financial framework and proposed shareholder distributions component once finalised. 	A B C D E F G

A investor community B employees/workforce/pensioners C regulators/governments D NGOs/civil society stakeholders/academia/think-tanks
 E communities F customers G suppliers/strategic partners

Topic	Discussion/activity/updates included	Examples of outcome/progress	Stakeholders considered
Culture			
Shell People Survey (2019 results)	<ul style="list-style-type: none"> In January 2020, the Board reviewed and discussed the results of the 2019 Shell People Survey. Through analysis and questioning, the Board gained insights on survey topics including: collaboration, working conditions, views on one's job, job security, people development, reputation, total rewards and benefits, diversity and inclusion, operational excellence and internal perspectives on Shell's responsible business aspects. 	<ul style="list-style-type: none"> Although noting the high response rates and overall top quartile employee engagement ratings and high organisational and team leadership ratings, the Board questioned: gaps in certain ratings on a regional basis; workload impacts and potential knock-on implications; whether survey results could help identify correlations with other key performance indicators, including with regard to safety; how the survey could be used to strengthen organisational values and culture even more; and whether learnings were being taken from leaders who had improved their team engagement scores from bottom quartile in 2018 to top quartile in 2019. 	B
Shell People Survey (2020 results)	<ul style="list-style-type: none"> In December 2020, the Board reviewed and discussed the results of the 2020 Shell People Survey. Discussion was immediately preceded by the Board's virtual engagement with a cross-section of staff from Brazil, the USA, the UK, Nigeria and India (see entry under "staff engagements" below for more detail). Through analysis and questioning, the Board gained insights on survey topics including: collaboration; working conditions; views on one's job; job security; people development; reputation; total rewards and benefits; diversity and inclusion; operational excellence; and internal perspectives on Shell's responsible business aspects. 	<ul style="list-style-type: none"> The preceding virtual staff engagement complemented the quantitative survey results by providing a qualitative "barometer" of staff views on numerous topics including aspects of corporate culture. The Board queried management on: retention and motivation of key talent; providing reskilling and upskilling opportunities; finding ways to show staff value given the remuneration measures taken in 2020; and job security challenges and Reshape fatigue. The interactive session helped the Board to monitor Shell's culture and staff engagement in an unprecedented year. The Chair also reminded the Board to retain the context of the engagement and survey feedback as a backdrop reference on the strategic, operational and risk-related topics on the Board's agenda. 	B
Board staff engagements	<ul style="list-style-type: none"> The Board held a number of virtual staff engagements (both at the June Strategy Days and in connection with the 2020 Shell People Survey review). Engagements deliberately included a cross-section of staff (at different levels, from different countries, within different businesses and functions) and included engagements both with and without management. Topics included the working/professional and personal impact of COVID-19, the Reshape reorganisation and the future of Shell. 	<ul style="list-style-type: none"> Gained direct feedback and first-hand insight into the views of staff on COVID-19 impacts (from the perspective of working from home and from the perspective of continuing to work at assets). Positive reflections on flexibility, ergonomic support, more time spent with families (for those working from home), and pride in achieving work. Negative reflections on missing interaction with colleagues, family (for asset workers) and increased workloads due to unprecedented times. The Board also gained insights into staff perspectives on Reshape regarding communications, general views on it, views for the future including ways to unlock future potential, empowering young talent, digitalisation, and diversity. 	B
Audit, risk and internal control			
Safety and Environment	<ul style="list-style-type: none"> Received regular updates from management on safety and environment performance. Periodic updates on the progress of Reshape, impact on staff and culture from a safety and environment perspective also featured regularly in these reports, and in addition to other updates on similar topics. The Board continued to share personal anecdotes and reflections on topics of values and safety at the beginning of each Board meeting. The Safety, Environment and Sustainability Committee and other Board members attended a virtual site visit to the Shell Rheinland refinery in Germany. Directors also met with a minister of the state government of North Rhine-Westphalia. 	<ul style="list-style-type: none"> The updates and subsequent discussions provided the Board with commentary and examples of how safety has continued to permeate Shell culture, including in the context of COVID-19. The use of learnings and insight gained outside Shell added perspective and diversity of thought to Board discussions. The virtual site visit provided Directors with various insights into: the views and priorities of the local workforce; safety and environmental performance; and the planned transformation of the Rheinland site into an energy and chemicals park. 	B D E F G
Risk management and internal control	<ul style="list-style-type: none"> Reviewed Risk Reports, covering external trends, emerging risks, proposed changes to the Group's strategic, operational and conduct and culture risk profiles. 	<ul style="list-style-type: none"> The Board considered the effectiveness of the risk management and internal control system. The Board considered the effects of COVID-19 and the perceived impacts on the Group's strategic, operational and conduct and culture risk profiles. The Board considered the learnings and insights from the organisation's responses to managing the pandemic. 	A E F
COVID-19	<ul style="list-style-type: none"> Received weekly updates from the Group Co-ordination Team on the management of COVID-19 with respect to staff health and well-being/care and the financial position of the business. The Board was also informed of Shell's co-ordinated responses to the pandemic. Discussions on business environment, operational impacts and issues, financial considerations and wider escalating economic impacts, and oil price outlook. 	<ul style="list-style-type: none"> The Board gained insight and clarity about Shell's response to COVID-19 including: its approach to disaster relief and donations; how potential key risks and impacts were being managed; and a recognition of the uncertainty of ongoing developments as a result of the prolonged impact of the pandemic. The Board was provided with the communications shared with staff via different channels, for awareness, to understand frequency of communications and any concerns of the workforce. 	A B C D E F G

A investor community B employees/workforce/pensioners C regulators/governments D NGOs/civil society stakeholders/academia/think-tanks
E communities F customers G suppliers/strategic partners

BOARD ACTIVITIES AND EVALUATION continued

Topic	Discussion/activity/updates included	Examples of outcome/progress	Stakeholders considered
Composition, succession and evaluation			
Succession planning	<ul style="list-style-type: none"> Received recommendations from the Nomination and Succession Committee regarding succession plans and Board composition. 	<ul style="list-style-type: none"> The Board was regularly informed about succession planning arrangements. Please refer to Nomination and Succession Committee report for further details. 	A B D E
Board and committee effectiveness reviews	<ul style="list-style-type: none"> Examined the internal evaluation reports following the assessment that was carried out to review the effectiveness of the Board and each of the committees. The evaluation of the Chair's performance was also considered. The Board also reflected on progress with priorities that had been identified from the previous year's review. 	<ul style="list-style-type: none"> The responses from Directors indicated that in spite of challenges experienced throughout the year, the Board, its committees and the Chair continued to operate effectively. Please refer to Board evaluation on page 132 for further details. 	A B D E F G
Board membership, other appointments	<ul style="list-style-type: none"> Reviewed Directors' tenure, external commitments, conflicts of interests, composition/membership of Board committees and appointments. 	<ul style="list-style-type: none"> The Board approved committee membership changes and appointments to the Board, following recommendations made by the Nomination and Succession Committee. The review of the existing Directors' renewal terms and tenure was postponed so that it would take place after the 2021 AGM, in consideration of succession planning. Please refer to Nomination and Succession Committee report for further details. 	A B D E
Talent overview and senior succession review	<ul style="list-style-type: none"> RDS Senior Succession and Resourcing Review covering Executive Director and Executive Committee (EC) succession, EC direct reports and the senior executive group. 	<ul style="list-style-type: none"> Enhanced insight into Shell talent and future leaders, assurance of robust succession and contingency plans. 	B
Remuneration			
Remuneration and reward matters	<ul style="list-style-type: none"> Review of fees of Directors, taking into consideration any Committee appointments. 	<ul style="list-style-type: none"> The Board accepted the recommendation from the Remuneration Committee for fees to remain the same until the next review scheduled in 2021. 	A B
Governance matters			
Governance	<ul style="list-style-type: none"> Provided with emerging corporate governance developments and updates relating to ethics and compliance matters. Reviewed Modern Slavery Statement and assurance and considered other regulatory and legislative requirements. 	<ul style="list-style-type: none"> The Board was provided with insight into Shell's participation in consultations and projects relating to governance and legislative requirements. 	A B C D E F

A investor community B employees/workforce/pensioners C regulators/governments D NGOs/civil society stakeholders/academia/think-tanks
 E communities F customers G suppliers/strategic partners

BOARD EVALUATION

Board evaluation

The 2020 Board evaluation was facilitated internally, led by the Nomination and Succession Committee (NOMCo) and managed by the Company Secretary.

OCTOBER 2020

NOMCo reviewed questionnaires for in-house Board and committee performance evaluation.

NOVEMBER 2020

Questionnaires made available for Directors and Executive Committee (EC) members to complete online via a secure web-based system operated by Lintstock [A].

DECEMBER 2020

Board reviewed evaluation reports of Board and each committee [B].

A separate report was also produced in relation to the evaluation of the Chair and made available to the Deputy Chair only.



ACTION PLAN AGREED

[A] Lintstock, a London-based corporate advisory firm previously used by Shell for Board performance evaluations

[B] Separate reports were provided for the responses from the Board and the Executive Committee. The reports in relation to the Audit Committee, Nomination and Succession Committee, Safety, Environment and Sustainability Committee and Remuneration Committee were sent to the respective committee chairs.

Insight

The feedback from Board Directors was positive throughout their responses to the evaluation.

Board dynamics – the Non-executive Directors' support and challenge of management was rated very highly, with the quality of the interaction and the openness of the leadership team being commended.

Board oversight – the Board's effectiveness in adjusting its focus and priorities in response to the COVID-19 pandemic was rated very highly. Board oversight of various specific aspects of risk was also rated highly overall, with retention of focus on risk appetite continuing to be a priority. The Board's oversight of the Company's processes for managing and developing senior executive talent, including with regard to diversity, was rated very highly, and will be a continued area of focus.

Management and focus of meetings – themes included: shortening and simplifying Board papers further, and a desire for returning to physical meetings when circumstances permit. The measures implemented to facilitate virtual meetings, induction/onboarding, and ongoing training were rated highly and viewed as very effective.

Stakeholder oversight – the mechanisms by which the Board obtains the views and needs of major investors and employees were highly rated, while noting that the mechanisms for obtaining the views of customers, private/retail investors, communities and suppliers could be enhanced, as feasible and relevant. The Board's effectiveness in monitoring and assessing culture throughout the organisation was rated positively overall.

Delivery against the 2020 ambitions

The COVID-19 pandemic drove unprecedented change throughout 2020, impacting both the short- and longer-term business outlook. Through the use of additional meetings, the Board balanced its focus on short-term operational matters and long-term strategy. Principal decisions made in 2020 were bold and decisive and, where possible, discussions were initiated well in advance of final Board decisions. Acquisitions/divestments and critical strategy shifts were all key agenda items for 2020, and these aligned with the Board ambitions set at the start of the year.

The Board's ambitions on succession were tested during 2020 with the appointment and induction of four Non-executive Directors and the retirement of three Non-executive Directors – all in the context of a virtual environment. Planned improvements to the Director onboarding process were implemented despite the COVID-19 crisis. Simultaneous adaptations were made to ensure there was as much dynamism as feasible within the constraints of having to work virtually. The development of a Board travel calendar was inevitably put on hold. The intention to share details of other induction sessions and committee trips was put into effect, albeit virtually.

On our Board papers ambition, efforts were made to focus information provided to the Board (for example, through optional briefing sessions, one-on-one engagements and advance "polling" of questions/information needs) to enable decision-making on key topics.

Planned enhancements for 2021

The 2020 Board evaluation findings provided areas of focus or priorities for 2021.

Monitoring execution and strategic implementation

This is an area of undeniable importance for the years ahead. The Board will continue to monitor strategic execution with support to Management, enabled by a performance tracking approach.

Company culture and Project Reshape

The Board will continue to monitor the Reshape transformation, enabled by the performance-tracking approach referenced above. It will strengthen its emphasis on culture and workforce engagement (particularly after COVID-19).

Completion of improvement items already in progress

Ensuring smooth Chair succession, oversight of ongoing litigation and potential further optimisation of the induction processes for Non-executive Directors once travel is safely resumed. Likewise, sharing other Director induction sessions, committee trips and Chair visits will continue.

Chair

Ongoing performance evaluation – the Board was very appreciative of the Chair's strong leadership (both of the full Board and individual Directors) during an extremely difficult year. He ensured thoughtful and interactive agendas (despite the required virtual format). It was also considered that he invested purposeful time with all, particularly with new Non-executive Directors, and continued to facilitate strong Board engagement and strong relationships with management. The Directors considered the Board very fortunate to have a Chair functioning at his peak. Board members added that the careful and thorough way in which all decisions this year have been framed, debated and made owes a great deal to the Chair's experience and care, and his relationships with the CEO and Non-executive Directors.

The Chair's focus on strengthening individual Director performance through coaching and feedback continues to be rated highly. His regular contact with Directors between meetings provides continued real-time feedback and reflection. This way of working continues to be regarded as an outstanding aspect of his leadership.

The Deputy Chair communicated the feedback to the Chair, along with requests to:

- ensure knowledge transfer of the Chair's insights and learnings to his successor; and
- continue to carefully balance the airing of divergent views with the need to appropriately converge on Board decisions.

The Chair fully accepted the feedback and agreed to reflect and act upon it.

UNDERSTANDING AND ENGAGING WITH OUR STAKEHOLDERS

Co-operating with our stakeholders and taking the time to understand their different views have always been of high value and importance to the Board. Our commitment to stakeholder engagement is built upon the understanding that knowledge-sharing, widening of experiences and adopting a learner mindset will help us achieve our commercial, environmental and social objectives.

The Board and Shell take their commitment to public collaboration and stakeholder engagement very seriously. In the past this has been easily demonstrated through both virtual and physical events which have served as opportunities to hear directly about stakeholder issues and priorities. This has been harder to navigate in the context of the continuing impact of COVID-19. Our focus on supporting and caring for our colleagues, customers and the communities in which we work has not changed through these unprecedented times.

- We have put the safety and health of our people, customers and other stakeholders first, along with the safe operations of our businesses.
- We have endeavoured to continue to engage with stakeholders, seeking alternative virtually focused opportunities.
- We have endeavoured to engage in a way which is as effective and as safe as possible.

The impact of COVID-19 and subsequent restrictions on travel and public gatherings have inevitably limited the engagements we planned for 2020. Our events have been cancelled, postponed or held in a way that was vastly different from previous years. We have had to think more creatively about engagement, and all of this was done with public health and safety and the advice/law of local governments in mind. The Board was disappointed that there have been fewer possibilities to engage in person. Nonetheless, we remain grateful for the continued support of our stakeholders and look forward to future engagements in the year ahead, when it is safe and appropriate to hold them.

The Directors have continued to consider stakeholders' views in Board discussions and decision-making, as described on page 128. Here, we have categorised our key stakeholders into seven groups and where appropriate, each group is deemed to include both current and potential stakeholders. The stakeholder groups are:

- investor community;
- employees/workforce/pensioners;
- regulators/governments;
- NGOs/civil society stakeholders/academia/think-tanks;
- communities;
- customers; and
- suppliers/strategic partners.

Engagement with our stakeholders goes beyond the Board and is continual. The broader business regularly engages with stakeholders throughout the year, and in the build-up to or during many Shell projects or activities. This engagement is often governed by formulated policies, control frameworks, regulation and legislation. It may differ by region.

Site visits

Various Shell operations and overseas offices are traditionally visited by the Chair, certain Board committees and Non-executive Directors. The visits are designed to provide Directors with:

- first-hand insights into portfolio positions; and
- opportunities to engage directly with stakeholders including employees, partners, communities and NGOs.

Directors were disappointed that site visits were reduced and converted to virtual only as a result of COVID-19. In previous years, and as part of the Board evaluation process, the Directors have reflected on the use of site visits for improving the Board's oversight of risk and concluded that the best way to determine if risks are being properly managed is to visit sites and talk to local management. Similarly, some Directors have used site visits as a way to monitor and assess culture first-hand and have commented on the difficulty of doing that this year. Further observations referenced how visits to key sites played an important part of the induction process for new Board members and provided good opportunities for Board members to get to know each other better.

As noted, alternative arrangements were made where feasible and details of these are described below. Resuming site visits as soon as practically possible was identified as a priority in the 2020 Board evaluation. Further details are provided on page 133.

Shareholders

The Board recognises the importance of two-way communication with the Company's shareholders. The Chair, the Deputy Chair and Senior Independent Director, the Chief Executive Officer, the Chief Financial Officer and the Executive Vice President Investor Relations each meet regularly with major shareholders and report the views of such shareholders to the Board. Committee chairs also seek engagement with shareholders on significant matters related to their areas of responsibility. Over the year, the Chair met with 51 major shareholders, including at roadshows. The Deputy Chair and Senior Independent Director and the Remuneration Committee Chair met with 52 shareholders over the course of the year. A variety of topics were discussed.

Shareholders can also contact Shell directly via the recently updated "Contact us" section of the Shell website. The recent enhancements replace the shareholder email address and allow investors' questions to be properly directed to the Shell team that can assist.

We have also introduced an automated question response tool to assist with the most common questions that we receive. We have reviewed and updated the "Frequently asked questions" section of the Shell website to help investors access information in a time-efficient manner.

Furthermore, other contact details are also provided in the same area be it our registrar, Equiniti, for shareholder queries, our media team, requests for copies of the Annual Report or for general customer enquiries.

The Company's registrar operates an internet access facility for registered shareholders, providing details of their shareholdings. Facilities are also provided for shareholders to lodge proxy appointments electronically. The Corporate Nominee service, facilitated by Equiniti, provides a facility for investors to hold their shares in the Company in paperless form.

Shareholder advisory vote

As announced in February 2021, an advisory shareholder vote will be sought every three years from the 2021 AGM onwards on Shell's energy transition strategy. The Board believes this provides shareholders with an opportunity to exercise a governance role related to climate change.

Board governance event

In the past, the Board has held a biennial governance event, Board Engagement Day, that is attended by Directors including the Chair, Senior Independent Director, Audit Committee Chair and Safety, Environment and Sustainability Committee Chair. It is seen as an opportunity to provide investors with an overview of the Board's roles, activities and its key focus areas including stakeholder engagement.

The last event was held in December 2018, and, as reported in the 2019 Annual Report and 20-F, it was intended that the next event would be held in the latter part of 2020. This was not possible because of the COVID-19 pandemic. The Board understands the value of stakeholder engagements, including this event, to Shell and its stakeholders. The risk of missing important perspectives and insight has been mitigated as much as practically possible over the course of the year by alternative arrangements which are described below. Topics such as stakeholder engagement expectations, Chair tenure, Board succession planning, diversity and inclusion and the Senior Management pipeline have been covered at other events during 2020. The Board is proposing to hold the next event in October 2021 if circumstances permit.

Engagements in 2020

A summary of the main ways in which the Board sought to obtain feedback and understand the views of key stakeholders during 2020 is shown below. Information on engagement with other stakeholders including the workforce is provided on page 138. The way in which stakeholder interests were considered in principal decision-making by the Board in 2020 (Section 172 statement) can be found on pages 22-27. Further insight into our engagement with stakeholders can be found within our Sustainability Report and our report on payments to governments, scheduled for publication in April 2021.

Engagement before event	Event/activity	Director attendance	Subsequent engagement/ feedback
Responsible Investment Annual Briefing			
Investors were engaged and a press release was issued ahead of the event, as in previous years. Investors were informed that the agenda would differ from past occasions and that there were new disclosures which would be shared at the meeting.	In the past, this event has served as an occasion to hear from investors and other stakeholders on environmental, social and governance (ESG) issues that are gaining prominence among the stakeholder community. In 2020, this session was instead used by Shell to share details of its response to the threat of climate change. Stakeholders were also informed about Shell's new target to be a net-zero emissions energy business by 2050, in step with society, and to become an integral part of the future net-zero world. The following were highlighted as ways to achieve this: <ul style="list-style-type: none"> change business plans in line with expectations of society and customers; and shift towards serving the businesses and sectors that are aiming to be net zero by 2050 by establishing pathways to help the energy users we work with to make progress towards net zero. 	CEO Chair	Feedback received following the event included reflections on how the Board had demonstrated thought leadership regarding Shell's targets and science-based methodologies. After the event, there were a number of additional engagements including follow-up meetings and presentations with stakeholders. Public support was received from large groups of investors such as Climate action 100+ regarding the targets announced at the Responsible Investment Annual Briefing.
Shareholder engagement webcast 2020			
The Board sought feedback from the investor community and other stakeholder groups about how it could best and most practically support the needs of stakeholder engagement as it became evident that it would be impossible to hold the AGM in the same way as in previous years.	An additional engagement opportunity was hosted by the Board in advance of the 2020 AGM to provide investors with an opportunity to hear from the Directors and submit questions to them. This was in response to the evolving COVID-19 pandemic, and the UK and Dutch government restrictions. These had resulted in Shell's AGM being held virtually and focusing solely on the business of the meeting, with no live voting or question and answer session. Issues raised by shareholders during the webcast included: <ul style="list-style-type: none"> shareholder returns: whether alternatives to reducing the dividend had or would be considered, and concerns around the impact on share price volatility; the energy transition: clarity on how net-zero target and impact would be monitored/measured as pivoting and other changes occur; and remuneration: whether this would be reviewed in light of dividend cut and whether climate change components of remuneration would be reviewed in light of new NCF targets. 	Board	The webcast facilitated enhanced engagement with institutional investors and allowed more of them to participate compared with previous years. As the webcast was held a week before the AGM, this allowed people to ask questions ahead of voting rather than afterwards. The pre-submission of questions enabled conversations to be grouped into themes and provided structure to the meeting.
2020 AGM			
The Board sought feedback from the investor community and other stakeholder groups prior to the AGM as detailed above. Questions were submitted in advance and answered on the webcast prior to the AGM.	After extensive discussions and meetings, the Board concluded that physical attendance at the AGM was not a responsible course of action as there was a risk that gatherings could expose people to COVID-19. The decision was not taken lightly and was aimed at protecting the health and safety of shareholders, employees, AGM staff and the public, while also respecting the decisions of the Dutch and UK governments to severely restrict/ban public gatherings. The AGM was solely focused on the business of the meeting with minimal physical attendance, live voting or question and answer session. A transcript of the meeting was posted online.	Chair CEO Remuneration Committee Chair/ Deputy Chair/ Senior Independent Director (SID)	The shareholder resolution on climate issues received a small increase in support compared with previous years. Following continued engagement with investors, Shell announced in February 2021 that it would put Shell's energy transition strategy to a shareholder vote every three years. In addition, a progress report will be voted on every year.
Chair roadshow			
A number of meetings were held prior to the roadshow to provide the Chair with insight on particular topics of interest to the investor community.	The Chair provided key investors with an update on the governance of Shell. The main topics included governance, remuneration, energy transition and business outlook. Investors had opportunities to ask the Chair questions about these topics.	Chair	In addition to direct engagement with the Chair, investors also had subsequent dialogue with Shell's Investor Relations team where feedback was provided. Some feedback commended the access to and the availability of the Board members. Their open and transparent approach in engagement with shareholders was also commented on.

UNDERSTANDING AND ENGAGING WITH OUR STAKEHOLDERS continued

Engagement before event	Event/activity	Director attendance	Subsequent engagement/ feedback
Remuneration roadshows			
Engagement was undertaken prior to the meetings so that the Directors were provided with understanding and insight on particular topics of interest.	In the spring of 2020, the then Chair of the Remuneration Committee, Gerard Kleisterlee, (also Senior Independent Director/Deputy Chair), discussed the approach to remuneration and alignment to strategy, the 2019 pay outcomes and proposed 2020 remuneration policy ahead of voting at the 2020 AGM. Calls were held with investors and a video was published on the Shell website. In the latter part of 2020, Neil Carson, who became Chair of the Remuneration Committee in May 2020, held his first roadshow for Shell. It covered the Remuneration Committee's early decision that there would be no 2020 annual bonus and no 2021 merit increase for Senior Management, and also provided an update on Shell's climate targets and 2020 priorities of care, continuity and cash. Neil also sought shareholders' views on managing potential windfall gains that might arise from the 2021 share awards. This helped to inform the Remuneration Committee's approach. Further details are set out in the Remuneration Report.	Remuneration Committee Chair/ Deputy Chair/SID Future Remuneration Committee Chair	Consultation with major shareholders was undertaken prior to the engagements on remuneration-related matters. The conclusion reached during the Remuneration Policy review process was that the policies in place prior to 2020 were closely aligned with strategy and had proven effective at delivering pay-for-performance over a long period. The Remuneration Committee proposed a number of changes to simplify policies and provide greater transparency and to keep pace with developing governance standards. The 2020 Directors' Remuneration Policy received positive support from shareholders at the 2020 AGM.
SID calls			
Following requests from investors, and in line with best practice, engagement with key institutional investors was undertaken as part of the appointment of the Senior Independent Director. Engagement was undertaken and key topics of interest were communicated to the Senior Independent Director, prior to the calls.	Euleen Goh, who assumed the role of SID in May 2020, held several calls with key institutional investors to discuss and outline the process of selecting a new Chair of the Board as part of succession planning. She highlighted the responsibility of the Nomination and Succession Committee in this process and the capabilities that Shell was looking for in a new Chair.	Deputy Chair/SID	Positive feedback for holding the sessions was received. Key reflections from the institutional investors included: the need for the new Chair to support the new strategy; the need for the new Chair to have change management experience over a long period of time since this would be important in the energy transition, as well as a strong understanding and respected stance on climate-related matters; and the usefulness of the new Chair having had CEO experience in a global company within a complex and cyclical industry.
The Institutional Investors Group on Climate Change (IIGCC) meetings			
We have a continuing dialogue with this group throughout the year.	Twice a year, meetings with the IIGCC are held with the CEO, and another with a member of the Executive Committee as part of our engagement and collaboration with the IIGCC and Climate Action 100+. In 2020, the Executive Committee member was Harry Brekelmans. The topics discussed were the energy transition, Shell's new energy ambition, the sectoral approach, and Shell's industry association climate lobbying. In addition to Board engagement, Shell's Chief Climate Change Adviser participated in a presentation as part of a corporate outreach programme. This meeting aimed to help expand investors' understanding of the risks and opportunities that climate change mitigation and adaptation present to companies and how they are responding to the challenges.	CEO	We continue to value and appreciate the collaboration with Climate Action 100+ and their large institutional investor base.
Board visit (virtual)			
Clear briefing materials were provided to each Director ahead of the event.	The Board was provided with an opportunity to engage virtually with staff members at the Shell Pennsylvania Chemicals complex in the USA. During this session, the Board was provided with an overview of Shell's Chemicals strategy, industry outlook, plans to achieve goals and to support the customer experience. The Board also engaged in discussions of a health, safety, security and environment nature,	Board	The Board gained an insight into the development and culture of the operations and maintenance teams. The use and impact of digitalisation tools were highlighted, and the future environmental capabilities of the site were discussed.
Chair visits (face-to-face)			
Engagement prior to the visits helped to formulate the agenda and refine the areas of focus for the respective visits.	Face-to-face visits of various Shell sites by the Chair included Sonnen, the Shell Pernis site and 'Springland site'. The Chair was provided with a view on business context, integrated cash generation and key priorities for the sites and an opportunity to informally connect with staff members about the energy transition, current opportunities and challenges in the business or site where they work.	Chair	The visits provided further opportunity to engage with the workforce and gain a deeper understanding of the business areas and their operations.

Engagement before event	Event/activity	Director attendance	Subsequent engagement/ feedback
Audit Committee Chair visit to Houston (face-to-face)			
Engagement prior to the visits helped to formulate the agenda and refine the areas of focus for the respective visits.	The Audit Committee Chair visited the Country Co-ordination Team, the Shell Technology Centre Houston and other business areas.	Audit Committee Chair	The Audit Committee Chair gained an overview of the US energy transition, and insights into strategy, HSSE, regulatory topics and Shell's deep-water operations. The visit also provided an opportunity to engage with some of Shell's emerging leaders in Houston.
Audit Committee visits (virtual)			
Discussions were held with the relevant country chairs as well as the Audit Committee members ahead of the visits. The purpose of this was to refine the topics for discussion, ensure that key areas of interest were covered and were suitably organised for a virtual environment.	As reported in the 2019 Annual Report, the Audit Committee had planned to visit three sites – Singapore, Kuala Lumpur and Krakow – in 2020. These visits were conducted virtually because of the impact of COVID-19, including travel restrictions. Further information, see "Focus areas for 2020" on page 146 of the Audit Committee Report.	Audit Committee and other Board members	<p>Singapore: The Committee members gained an understanding of the operations of the Shell businesses relating to business controls, ethics and compliance. They obtained insight into the risks, controls and mitigations associated with operating in a COVID-19 environment.</p> <p>Krakow: The Committee was further educated about the energy transition in Shell Poland and gained a deeper understanding of our businesses in Poland including Shell Business Operations (SBO).</p> <p>Kuala Lumpur: The Committee gained an understanding of the operations of the Shell businesses in Malaysia, including the SBO, and more first-hand information about the energy transition in Shell Malaysia.</p>
Safety, Environment and Sustainability Committee visit (virtual)			
Discussions were held with the Safety, Environment and Sustainability Committee members ahead of the visit to formulate the agenda and ensure that key areas of interest were covered.	The Safety, Environment and Sustainability Committee held a series of engaging virtual sessions in lieu of a physical visit to the Shell Rheinland refinery in Germany.	Safety, Environment and Sustainability Committee and other Board members	This visit provided the Committee with many insights, including into the local German context, the views and priorities of the workforce, and the safety and environmental performance of the Rheinland site. Committee members also gained an understanding of energy transition projects under way and the planned transformation of the Rheinland site to an energy and chemicals park. Committee members also met with a government minister of the state government of North Rhine-Westphalia.
Director visits (face-to-face and virtual)			
Discussions were held with the respective Directors ahead of the visit to formulate the agenda and ensure that a natural, open dialogue was encouraged in the various group sessions.	<p>In February and March, a series of staff engagements were held with Directors including staff lunches and an International Women's Day panel discussion.</p> <p>In June, virtual engagement sessions were held with staff members from a range of business areas in order to get a broad spectrum of staff views. (Staff members who attended included people in Trading/projects, staff in Asia who had returned to work, frontline staff in markets, people in Shell business operations and staff directly supporting assets). This engagement was planned as an alternative to the usual face-to-face staff engagements which happen around Executive Committee or Board meetings. Staff members were put into six groups for casual conversations with a few Board members so natural dialogue could flow and Board members could receive a candid view of how staff had been coping during extraordinary times. Discussions were wide-ranging and included discussion of effects of COVID-19 such as:</p> <ul style="list-style-type: none"> ■ how situations had changed for staff and family members; ■ team dynamics and culture at work; ■ whether there were any new ways of working that would be good to keep; and ■ thoughts and reflections on the future. 	Board	The virtual visits provided Directors with opportunities to engage with the workforce as best as possible in the circumstances. They provided an insightful and uplifting part of the traditional off-site meeting. The Directors gained insight and were able to discuss with staff the challenges they had been facing as a result of COVID-19 and the economic downturn.

WORKFORCE ENGAGEMENT

The Board recognises merit in the Code's three mechanisms for engaging with the workforce. As with all the Code's provisions, boards must consider the size and structure of their business, including its international scope, and select an approach that most practically delivers the underlying spirit and ambition of the Code, even if the chosen approach differs from what the Code outlines. The Code does note that alternative methods for workforce engagement are supported where an explanation is provided.

The Code states that its use of the term "workforce" is not meant to align with legal definitions of workforce, employee, worker or similar terms. But for a global organisation bound by the laws of more than 70 countries, blurring the clearly prescribed legal definitions that affect complex issues (such as local HSSE requirements, work contract terms, legal accountability, employment rights) or merging two definitions of the same term could have a notable impact on the business, its operations and its stakeholder relationships (including with suppliers). Therefore, Shell considers its workforce to be employees of companies in the Shell Group. The Board also engages with others outside this group (for example, on site visits), and some of this engagement is shared on page 134.

Although our reporting and formal engagement focuses predominantly on our employees, all individuals working on Shell sites (including Shell offices) are required to undertake certain Shell training (for example, HSSE and Code of Conduct-related training). Adhering to the Life Saving Rules (HSSE) and the Code of Conduct compliance obligations is included within our contracts with suppliers, and the Shell Global Helpline is available for all workers to report matters of concern.

For many years Shell has recognised the importance of engaging with its workforce. Engagement is especially important in maintaining strong business delivery in volatile times of change. We therefore strive to maintain a dialogue between management and our workforce – both directly and where appropriate, through representative bodies. Management regularly engages with the workforce through a range of formal and informal channels, including via webcasts and emails from the Chief Executive Officer and other senior executives, webcasts, townhalls, team meetings, face-to-face gatherings (pre-COVID-19), interviews with Senior Management and online publications via our intranet.

The Board considers effective engagement a key element of its understanding of the Company's ability to create value as it recognises that our people are our greatest asset. Workforce views can help inform the Board on matters such as operational effectiveness, Shell culture, risk identification and strategy development and delivery.

Throughout 2020 the ongoing COVID-19 pandemic impacted how the Board engages with the workforce and it was impossible to implement the enhancements to physical engagement discussed and planned at the start of the year. The Board did undertake a number of virtual engagements, often around the time of scheduled Board discussion. Feedback from these video calls was shared with and discussed by the wider Board. Management also continued to engage extensively throughout the year, implementing a number of focused events to better understand how people were coping with the working environment caused by the COVID-19 pandemic, their mental well-being and what the business could do to better support them. Information from these discussions was provided to the Board via bi-weekly updates.

The Board considers the current workforce engagement approach effective. The information provided in the following table gives examples of various methods of Board engagement.

Board's direct engagements with the workforce

(Because of COVID-19 restrictions in various countries, the engagement activities have mostly been held virtually)

Informal engagement

Chair lunches, prior to the COVID-19 restrictions, were held from time to time with a select cross-section of employees in various regions. Virtual staff engagements have been held by the Board with a select cross-section of employees (diverse by gender, nationality, business or function, profession and level) in various regions and countries. Nomination and Succession Committee members meet with various senior leaders and high-potential individuals throughout the year.

The Chair commented: "I never cease to be impressed by the quality of talent, professionalism, humility and authenticity evident in the individuals with whom our Committee engages. Their diverse backgrounds, capabilities and experience enrich our pipeline in ways that transcend paper credentials. The Nomination and Succession Committee takes its duty of identifying leaders with the "full" package required to deliver our Company's purpose very personally, and we derive confidence from the equivalent personal drive and commitment we see reflected in the talent we meet." In addition, the Nomination and Succession Committee received a detailed briefing alongside that given to the full Board on the results of the annual Shell People Survey, which was completed by more than 86% of employees.

Virtual informal engagement – Board

The Board participated in a number of virtual employee engagements this year in which they had the opportunity to speak to staff in smaller groups, with between two and three Board members in each group. One such event involved staff from various geographical locations at various levels in Shell.

The purpose was for the Board to discuss with staff the challenges they have been facing in the COVID-19 pandemic. Staff were asked to describe: how things have changed for them and their families since the onset of COVID-19; how the current situation has changed the dynamics or culture of their team; and how they felt about the future and what was most on their minds.

Another engagement was towards the end of the year, after the company-wide communications on Reshape's impact on jobs. It focused on people's personal experiences working for Shell, including ways of working, views on the future direction of Shell and perceptions around Reshape. The session was arranged geographically to ensure an international scope and included mid-level employees from Brazil, the USA, the UK, Nigeria and India.

During these engagements Shell people were asked to validate whether the communication, care and support offered by the business was sufficient, and if more was needed. The outcomes of these Board engagements have been discussed in Board meetings and have been incorporated in future communication and support to our people.

Off-site visits

Because of COVID-19 restrictions, site visits were limited to the beginning of the year. Although in some instances we were able to organise virtual visits and meetings, priority was given to running the business operations.

People engagements during Board and/or meetings off-sites.

Meeting talent/leadership teams

Company Chair engaging with various individuals.

The Board attended a virtual site visit to the Pennsylvania Chemicals plant in the USA. This gave Board members an opportunity to speak with another group of Shell's people in the context of a specific, large-scale project which has had to manage multiple staff safety issues, particularly in relation to COVID-19. The Pennsylvania Chemicals site has also required significant management of HSSE and community stakeholder matters. The engagement included an overview of COVID-19 management with a focus on recent preparations for a third wave and a specific discussion of engagement with external stakeholders and management of non-COVID-related risks.

The Board raised numerous questions and challenges in the context of key business decisions which will affect employees, such as refinery closures, the impact on employees and the possibility of retraining and redeployment. They also shared their own experiences of dealing with stakeholders and staff representatives.

Through these more formal engagements, the Chair and other Non-executive Directors (either individually or with their committees) are able to deepen their understanding of how the Company's purpose, strategy and values are embedded in particular businesses, sites and countries. This gives insight into progress made, risks and opportunities. The benefits are mutual. The Board obtains direct insight into local business operations and projects, and local strengths and challenges while our people have an opportunity to better understand the Board and to provide direct feedback on topics of importance to them, their business or function and/or their location.

Employee network and related sessions

Conducted by Directors with, for example, Directors engaging with Shell women's networks activities.

In 2020, panel discussions took place on International Women's Day. Various members of the Board joined these discussions.

Directors involved in these engagements note the opportunity to enrich their understanding of the female perspective within Shell, getting better insights on gender balance and the employee experience in this area.

Formal reports and information updates to the Board

Shell People Survey (anonymous survey facilitated externally)

Annual Board discussion to keep it fully aware of employee engagement levels and quality of leadership across Shell's workforce, and informed on a broad range of subjects including collaboration, working conditions, the job, people development, reputation, benefits and rewards, diversity and inclusion, operational excellence, and responsible business.

The Board considers the Shell People Survey to be one of its principal tools for measuring employee engagement, motivation, affiliation and commitment to Shell. It provides insights into employee views and has a consistently high response rate. In 2020 the response rate was 86%, which was the highest ever. The average employee engagement score was maintained at 78 points out of 100, despite the challenging year and remained top quartile compared with external benchmarks.

The Board also considers this engagement to understand, for example, how Shell is using the survey outcomes in: i) data analytics, for example, to identify potential correlative relationships between employee engagement and safety or ethics and compliance incidents; and ii) strengthening Company culture and values.

Senior Succession and Resourcing Review

The annual Senior Succession and Resourcing Review focused on the strength of senior leadership and plans for its development and succession, while highlighting the breadth, depth and diversity of its pipeline, the developing profile of the leadership cadre, and recruitment and attrition levels.

The Nomination and Succession Committee noted the effectiveness of succession planning, the impact of its associated execution, and the professional, data-driven, integrated approach to leadership and leadership development. It welcomed the continued focus on performance management, proactive management of Shell's talent pipeline, and the focus on advancing Shell's diversity agenda with increased attention on race. Overall this year's insights provided a deeper understanding of the interplay between culture, identity, leadership talent and employee engagement across Shell.

Assessment of key trends and material incidents

Presented by Chief Ethics & Compliance Officer. This is based on the established channels for staff and others to file complaints or report on suspected breaches in relation to the Shell General Business Principles (SGBP), the Code of Conduct or any breaches of law or regulations, including accounting control and auditing concerns.

The update covers Shell employees and our wider stakeholder base. The Board (also via the Audit Committee and SESCo) obtains insight into incidents and reporting levels and remediation which provide indicators of conduct risks and, together with the related Board reports noted below, of the strength of embedding and awareness of the Code of Conduct and SGBP obligations and employees' comfort levels in raising incidents.

Risks

The Board reviews reports on strategic and conduct and culture risks annually, and considers reports on operational risks twice a year. These reports assess current business activities against risk appetite.

Organisational culture

As part of the Reshape restructuring, the Board has been discussing the people strategy, new leadership framework, and safety refresh. Discussions on diversity and inclusion issues such as race also took place to further improve the organisational culture.

The Board also reviewed the Conduct and Culture Risk Report, which included a refreshed dashboard of risk appetite measures aligned with Shell's core values – honesty, integrity and respect for people. Elements measured by the dashboard include: the number of terminations as a result of formally investigated Code of Conduct violations; the number of overdue on mandatory Ethics and Compliance training; anonymous reporting rates on our global helpline; and a selection of Shell People Survey scores. Qualitative assessments of insider threats and our approach to caring for our people were also covered.

Chief Ethics and Compliance Officer Report

Data and insights include information from the Global Helpline, Shell Ethics and Compliance organisation and the Shell People Survey. SESCo continues to strongly support the work of the Chief Ethics and Compliance Officer, including the efforts to ensure a safe working environment where staff feel confident to raise any concerns in good faith.

The Audit Committee is kept updated when matters highlighted through the Global Helpline are investigated, and on the associated remediation. For more information see page 148 of the Audit Committee report.

Assurance activities

Assurance activities, including items raised by businesses and functions (through the Group Assurance Letters process) and independent assurance (from Internal Audit, HSSE, Ethics and Compliance, Reserves Assurance and Reporting), provide additional evidence to the Board of the commitment to high standards of risk management and internal control. The assurance activities ensure that work can be done safely, within regulatory frameworks.

The information provided within these reports further supports the Board's annual review of the effectiveness of the Group's system of risk management and internal control and feeds into the Group scorecard, against which staff bonuses are calculated.

The Shell Control Framework

Significant HSSE, Ethics and Compliance, and more broadly, business control incidents are brought to the attention of Senior Management and the Board through regular reporting.

The Board discussed how the organisation could learn more from incidents and how the business could drive safety performance. The Board shared and discussed examples based on personal experience of how to promote a strong safety culture.

NOMINATION AND SUCCESSION COMMITTEE



CHAD HOLLIDAY

Chair of the Nomination and Succession Committee

Focus areas for 2020

- Appointment and onboarding of four new Non-executive Directors
- Continued discussions about Non-executive Director and Executive Committee succession
- Continued talent engagements with key staff and succession candidates
- Deep dives into the Royal Dutch Shell People Strategy, including culture and identity and end-to-end talent management

Priorities for 2021

- Continued discussions about Non-executive Director and Executive Committee succession
- Continued talent engagements with key staff and succession candidates.
- Continued deep dives into the Royal Dutch Shell People Strategy and culture, with an increased focus on diversity and inclusion and end-to-end talent management

COMMITTEE ATTENDANCE FOR 2020

Committee Member	Member since	Maximum possible meetings	Number of meetings attended	% of meetings attended
Chad Holliday (Chair of the Committee)	May 19, 2015	7	7	100%
Euleen Goh	July 1, 2019	7	7	100%
Gerard Kleisterlee [A]	May 23, 2018	3	2	66.6%
Sir Andrew Mackenzie	Oct 1, 2020	2	2	100%
Sir Nigel Sheinwald	May 20, 2020	4	4	100%
Linda Stuntz [A]	June 1, 2016	3	3	100%

[A] Both Gerard Kleisterlee and Linda Stuntz retired from the Board after the 2020 Annual General Meeting, held on May 19, 2020.

PURPOSE

The Nomination and Succession Committee (the “Committee”) leads the process for appointments to the Board and Senior Management [A] positions, ensures plans are in place for orderly, well-planned succession, and oversees the development of a diverse succession pipeline of candidates. Further, it reviews the Company’s policy and strategy on diversity and inclusion, and monitors the effectiveness of diversity initiatives. It makes recommendations to the Board on corporate governance guidelines, as referred to in the Chair’s statement.

[A] “Senior Management” refers to the Executive Committee and the Company Secretary.

TALENT MANAGEMENT AND SUCCESSION

The Committee is fully engaged with the end-to-end talent management and senior succession planning approach that is deployed within Shell. It plays a key role in senior succession and resourcing and retaining in-depth knowledge of the individuals within the talent pipeline is a Committee priority. In fact, the Committee makes time to personally meet and engage with numerous individuals within the pipeline. The Committee’s oversight and input extend from recruitment to leadership identification and from leadership development to leadership appointment, all of which are underpinned by clearly articulated talent priorities and a commitment to advancing diversity and inclusion across Shell.

The Committee manages Board and Senior Management succession under a structured, proactive methodology. The processes have clear and agreed selection principles for short-, medium- and long-term succession and are aligned with Shell’s strategic priorities.

For Non-executive Director succession, the Committee also follows its Principles for the Strategic Composition of the Board. These principles function much like a policy and include both quantitative and qualitative principles, considering: (i) the overall aspired Board composition and diversity of gender, race and ethnicity, nationality, background, experience and desired skillsets that align with the Company’s strategy and purpose; and (ii) the values, attitudes, and behaviours expected of Directors.

For Senior Management succession, the selection principles include process-specific elements, such as a clear and proactive approach to identifying and developing succession candidates. The principles also outline the long-term structured nature of the succession planning process. There is also great focus on ensuring that the principles reflect the leadership qualities required for future business success and that they advance the progress of diversity in all its forms.

Senior Management principles feature in the Committee’s review of the succession plans which occurs in every Committee meeting. Utilising the principles, the Committee executes changes through a well-defined and diligent process with overall Board engagement. The Committee agrees candidate profiles and meets prospective candidates well ahead of any selection decision being necessary. It also engages the Board early in the process to ensure all Directors have an opportunity to meet and assess prospective candidates. Consequently, some of the leaders whom the Committee and Board have engaged with extensively in the past are now members of the Board or the Executive Committee.

In 2020, the Committee undertook its annual in-depth look at the succession plans for Senior Management across Shell and reviewed the talent pipeline in line with the business outlook. The engagement focused on the depth and breadth of the leadership pipeline, the skills and behaviours required for future success and progress against diversity aspirations and policies. Following the Committee's review, the findings were reported to the Board.

DIVERSITY OF LEADERSHIP

The Committee recognises that continuing to improve all types of diversity at each level of the Shell Group is crucial. Shell aims to be an inclusive workplace where everyone feels valued and respected and has a strong sense of belonging. The Committee's review of diversity objectives and strategies for the Shell Group as a whole also monitors the impact of diversity and inclusion initiatives.

In February 2021 Shell published its diversity aspirations as part of its strategic update. Gender and nationality diversity is increasing, and focus is broadening and deepening in other areas such as race and ethnicity, enablement and LGBT+. When looking at our progress against our ambitions, female representation has steadily improved in recent years. Among experienced recruitment in 2020, Shell companies recruited 31% females, and among graduates 49%. Female representation in the top 1,400 roles ("Senior Leadership" positions) has strengthened by 1.4 percentage points during 2020 to 27.8%, and further improvement is actively pursued. Nationality diversity, such as Asian and American talent, continues to advance in a manner reflective of the business outlook and we have a strong focus on progressing race and ethnic minority representation. The representation of people of colour among Shell's senior leaders in the USA has been actively tracked for many years. It stood at 26.4% at the end 2020, compared with 17.3% in 2016. In the UK, BAME representation among senior leaders was 10.6%, an advance from 7% in 2018.

Senior Leadership is a Shell measure and different from that which we are required to report under the Code, being female representation in Senior Management and their direct reports, where the percentage is 29.5%.

Although the Committee monitors Shell's organisational diversity and inclusion strategies and initiatives, it also holds itself accountable for the Board's own diversity and inclusion. By the end of 2020, the Board's diverse composition clearly met both the Hampton Alexander and Parker Reviews' objectives by reflecting 38.46% female representation with one person meeting BAME criteria. Gender representation was down slightly from May 2020 (when the Board's composition included 42% female representation) as a result of the departure of three Non-executive Directors (one female, two males) and the appointment later in the year of four new Non-executive Directors (one female, three males). But following the 2021 AGM, subject to shareholder approval and for the first time in Shell's history, the Board is expected to reach gender parity with 50% female representation (after the departure of two males and the expected appointment of one female).

 More information on diversity in Shell is provided in the Our people section on page 108.

The People Strategy and culture and identity

In 2020, the Committee conducted an in-depth examination of the Royal Dutch Shell People Strategy, with a particular emphasis on our aspired culture and identity. Leaders are key to delivering the Company's strategic ambitions and animating our aspired identity and culture. Given the critical importance of this issue for the Company's transformation under our Powering Progress strategy, the Committee will conduct further engagements in 2021 to maintain proactive oversight over the issue of leadership and aspired identity and culture.

Committee Activity

In addition to its considerations regarding succession, the Committee made recommendations on corporate governance guidelines, monitored compliance with corporate governance requirements and made recommendations on corporate governance-related disclosures. The Committee continues to monitor and review this area, considering whether and how current Company governance matters should be strengthened. Further insight on some of the Committee's areas of consideration in 2020 is provided below.

Succession [A]	Topic of discussion/Example of Board activity
Recommendation	<ul style="list-style-type: none"> Appointment of Dick Boer, Martina Hund-Mejean, Sir Andrew Mackenzie and Abraham (Bram) Schot to the Board. Changes to the composition of the Board committees.
Review and oversight	<ul style="list-style-type: none"> Royal Dutch Shell Senior Succession and Resourcing Review.
Oversight	<ul style="list-style-type: none"> Royal Dutch Shell People Strategy including culture and identity. End-to-end talent management in Royal Dutch Shell.
Engagement	<ul style="list-style-type: none"> Talent engagements

Governance	Topic of discussion/Example of Board activity
Governing the Board and its committees	<ul style="list-style-type: none"> Reviewed its Principles for the Strategic Composition of the Board. Reviewed its Terms of Reference, and the terms of Reference for other Board committees and the matters reserved to the Board.
Regulation, legislation and other governance-related guidance	<ul style="list-style-type: none"> Key governance matters affecting the Company's external reporting. Other governance and regulatory changes agreed or proposed and their impact or potential impact on the Company, its processes and its reporting.
RDS matters	<ul style="list-style-type: none"> Considered any potential conflicts of interest and the independence of the Non-executive Directors. Review of additional external appointments requested by Directors, with specific focus on the time allocated to all commitments. For Executive Directors, the benefit/relevance to the business of the Director undertaking the additional role is also a key consideration. Determined the process for the 2020 internal Board Evaluation.

Board membership and other appointments	Topic of discussion/Example of Board activity
Directors' tenure, external commitments, conflicts of interests and succession planning	<ul style="list-style-type: none"> Non-executive Director appointments and changes to Committee membership.

Talent overview and senior succession review	Topic of discussion/Example of Board activity
RDS Senior Succession and Resourcing Review covering Executive Director and Executive Committee (EC) succession, EC direct reports, the senior executive group and the overall talent pipeline	<ul style="list-style-type: none"> Enhanced insight of Shell talent and future leaders. Assurance of robust succession and contingency plans.

[A] The Committee was assisted during the year by Russell Reynolds Associates ("Russell Reynolds"), an external global search company whose main role was to propose suitable candidates. Russell Reynolds does not have any connection with the Company other than that of search consultants. The Chair does not participate in discussions regarding his own succession. Russell Reynolds is a signatory to The Voluntary Code of Conduct for Executive Search Firms, which aims to improve board diversity.

NOMINATION AND SUCCESSION COMMITTEE continued

Director Induction and Training

After being appointed to the Board, Directors receive a comprehensive induction tailored to their individual needs. This normally includes site visits and meetings with Senior Management to enable them to build up a detailed understanding of Shell's business and strategy, and the key risks and issues that Shell faces. Existing Directors are also able to join these visits to keep abreast of business developments and progress. With the abnormal COVID-19 circumstances in 2020, the induction programme was quickly adapted to a completely virtual induction.

Although the programme had received praise from new Non-executive Directors over the past several years, enhancements were nonetheless implemented in 2020 despite the required fully virtual implementation.

The enhancements ensured that all onboarding was phased and prioritised based on forthcoming Board agenda items to help ensure the new Non-executive Director "hit the ground running". The enhancements included digital onboarding books for each new Non-executive Director. These onboarding books complemented the existing digital Directors' Handbook and featured:

- overviews of scheduled briefing meetings customised to the Non-executive Director's needs;
- hyperlinks to key Shell publications (external and internal);
- lists of common Shell acronyms;
- key current materials on:
 - Shell's safety and core values;
 - Board governance;
 - Group strategy and portfolio; and
 - key businesses and functions.
- biographies of key executives
- Other enhancements of the onboarding programme for Non-executive Directors included:
 - arranging briefing meetings with key executives (both business and functional) customised to Non-executive Directors' needs;
 - where feasible, pairing up new Non-executive Directors in onboarding briefings to optimise learning while also providing opportunities for collegial relationship-building and increasing efficiencies for the executives; and
 - where possible, arranging virtual site visits (either specifically for onboarding or by inviting the new Directors to committees' virtual site visits).

CHAIR SUCCESSION

Message from Euleen Goh

In early 2018, the process of selecting the next Chair of the Board of Royal Dutch Shell plc began in response to the proposed limit on Chair tenure, outlined in the draft version of the Code. The Nomination and Succession Committee (NOMCo) created a subcommittee, drew up a potential succession timeline, and initiated an internal and external search process. Hans Wijers, the Senior Independent Director at the time, led the subcommittee and the search process. Chad Holliday, the current Chair, was not a member of the subcommittee.

My predecessor Gerard Kleisterlee took over from Hans in May 2018 and refined the selection criteria and succession timeline. The subcommittee agreed what qualities the successful candidate should have, and determined the functional focus elements of the new Chair's role. Accordingly, the subcommittee considered and interviewed multiple candidates.

I assumed leadership of the subcommittee after Gerard retired from the Board at the 2020 AGM. The NOMCo subcommittee further reviewed the required qualities and functional focus elements of the role in the context of the current environment. The subcommittee also examined the main trends and factors affecting the long-term success and future viability of Shell, and the organisation's strategic priorities, consulting on these with the wider Board. One-on-one discussions were held with each Board member. The review and the discussions helped us to refine our search process with a clear and updated understanding of the qualities, skills and attributes that the future Chair should possess.

We engaged with some of our larger investors, as appropriate, seeking input on the skills, attributes and sector knowledge that they considered important for the Chair candidate profile. These discussions were very valuable. They helped inform our search and selection of the most appropriate individual for the role.

After this thorough and robust search process, the Board agreed unanimously at its March 2021 meeting that Sir Andrew Mackenzie should be appointed Chair of the Board with effect from the conclusion of Shell's 2021 Annual General Meeting, scheduled for May 18, 2021.

When reviewing candidates, our preferred qualities and functional focus elements included a strong requirement for a candidate who has experience in leading large, complex, international organisations. The candidate would have had significant experience in capital discipline. He/she should have an ability to balance the transformational changes that Shell needs to make against the timing of these changes as it navigates the energy transition. The successful candidate should have demonstrated sustainable actions with respect to the climate change agenda. An understanding of the energy market was essential, without it being necessary for the candidate to have spent their entire career working in the oil and gas sector.

In Andrew we believe that we have found the required qualities and more. Andrew is a lifelong learner with a collaborative, agile mindset and he is a champion of good governance. His strategic vision has helped operations and companies under his leadership to transform. His leadership performance in the areas of environmental, social and governance (ESG) and climate action are outstanding. He was recently knighted by the Queen of the United Kingdom for his services to business, science and technology. Andrew firmly believes that business can be a force for good, for shareholders and society alike.

Andrew joined the Board in October 2020 and has dedicated significant time to familiarising himself with the business, the people, and the Powering Progress strategy which he and the Board fully support and are committed to delivering together with management.

His broad experience, strategic vision, scientific curiosity and commercial acumen make him the ideal candidate to lead the Board of Royal Dutch Shell plc.

SAFETY, ENVIRONMENT AND SUSTAINABILITY COMMITTEE



SIR NIGEL SHEINWALD GCMG

Chair of the Safety, Environment and Sustainability Committee

FOCUS AREAS FOR 2020

- Safety performance
- Shell's climate targets
- Sustainability metrics for scorecard
- Energy transition metrics for remuneration

PRIORITIES FOR 2021

- Process safety and personal safety
- Progress against climate targets
- Broader sustainability performance
- Assurance programme

COMMITTEE ATTENDANCE FOR 2020

Committee Member	Member since	Maximum possible meetings	Number of meetings attended	% of meetings attended
Sir Nigel Sheinwald (Chair of the Committee)	July 1, 2012	5	5	100%
Neil Carson	June 1, 2019	5	5	100%
Ann Godbehere	May 20, 2020	3	3	100%
Catherine J. Hughes	November 1, 2017	5	5	100%
Bram Schot	October 1, 2020	1	1	100%
Linda Stuntz [A]	May 23, 2018	2	2	100%

[A] Linda Stuntz retired from the Board following the 2020 Annual General Meeting, held on May 19, 2020.

"2020 was an important year for SESCo. We monitored closely and welcomed Shell's much improved safety performance, and contributed actively to the energy transition pathway and new carbon targets developed."

SIR NIGEL SHEINWALD GCMG

PURPOSE

The Safety, Environment and Sustainability Committee (SESCo) assists the Board in reviewing the practices and performance of Shell, primarily with respect to safety, environment including climate change, and broader sustainability.

OVERVIEW

The Committee meets regularly to review and discuss a wide range of important topics. These include the safe and responsible operation of Shell's facilities, environmental protection and greenhouse gas emissions, significant incidents that impact safety and environmental performance, progress towards Shell's climate targets, and energy transition. The Committee also endorses the Shell annual HSSE & SP assurance plan, reviewing the execution of the plan and audit outcomes.

The Committee assesses Shell's overall sustainability performance and provides input to Shell's annual reporting and disclosures on sustainability. It also advises the Remuneration Committee on metrics relating to sustainable development and energy transition that apply to the Executive Committee annual scorecard and long-term incentive plan.

The Committee reviews and considers external stakeholder perspectives in relation to Shell's business, as well as how Shell addresses issues of public concern that could affect its reputation and licence to operate. Examples include plastic waste, methane emissions, human rights, the UN Sustainable Development Goals, and access to energy in low- and middle-income countries.

In line with the strategic importance of the Committee's agenda, the Chair and the Chief Executive Officer regularly attend the Committee meetings for discussions on specific topics.

Royal Dutch Shell plc's Chief Executive Officer and the Executive Committee hold overall accountability for sustainability within Shell, supported by the Executive Vice President for Safety & Environment and other senior managers.

ACTIVITIES

During 2020, the Committee focused on the areas of greatest strategic importance to Shell, in line with its updated Terms of Reference. This allowed the Committee to oversee effectively and thoroughly the practices and performance of the Company with respect to safety, environment including climate change, and broader sustainability.

The Committee was pleased that there were no fatalities in 2020 at Shell-operated ventures, the first year this has been achieved and a testament to Shell's relentless focus on safety. The Committee welcomed Shell's refreshed approach to safety announced in 2020, with its emphasis on the human dimension of safety performance.

The topics discussed in particular depth by the Committee included personal and process safety, Shell's climate targets and the energy transition, and remuneration metrics and targets. The Committee also reviewed Shell companies' operations and the challenges faced in Nigeria and Brazil.

Together with the Audit Committee and Chief Ethics and Compliance Officer, the Committee reviewed the controls and procedures for managing changes to Shell's portfolio. The Committee Chair also held several meetings with senior leaders to discuss specific topics including new fuels, carbon emissions reduction and decommissioning.

SAFETY, ENVIRONMENT AND SUSTAINABILITY COMMITTEE continued

The Committee supported and contributed to Shell's announcement in 2020 that it aims to become a net-zero emissions energy business by 2050, in step with society. The Committee believe this again demonstrates Shell's determination to play its full role in the energy transition. The Committee has had in-depth discussions with management about how Shell's climate ambitions are being put into operation through portfolio changes, the use of nature-based solutions, the development of carbon capture utilisation and storage, and carbon abatement programmes at operated facilities.

Following the Committee's review of remuneration with management, new safety and environment metrics will be introduced for 2021 along with increased weighting for these metrics and energy transition metrics, which should drive further performance improvements.

The Committee closely monitored and strongly supported Shell's response to the COVID-19 pandemic in terms of care for staff and the safe management of operations. The Committee appreciated Shell's rapid deployment of virtual working technology from the start of the pandemic to enable business continuity and support continued HSSE & SP assurance activities across Shell.

The Committee continued to address wider questions of public concern such as plastic waste, methane emissions and human rights. It looks forward to resuming direct engagement with stakeholders once the COVID-19 restrictions come to an end.

For further details on SESCo and how Shell manages sustainability see www.shell.com

SITE VISITS

The Committee postponed its site visits of the Rheinland refinery in Germany and LNG Canada project in British Columbia due to the COVID-19 pandemic. The committee instead conducted a virtual site visit of Rheinland via videoconference. The visit focused on safety and environmental performance and the planned transformation of the Rheinland site into an energy and chemicals park. It also included a meeting with a minister of the state government of North Rhine-Westphalia.

Activities performed	Frequency
Review Shell's practices and performance relating to Safety, including in particular the safe condition and responsible operation of Shell's assets	E
Review Shell's practices and performance relating to environment, including in particular environmental protection and greenhouse gas emissions	E
Review any major incidents that impact Shell's safety and environmental performance	N
Review progress towards meeting Shell's climate targets	M
Endorse Shell's annual Health, Security, Safety, Environment and Social Performance (HSSE & SP) assurance plan	A
Review execution of Shell's HSSE & SP assurance plan and audit outcomes, and review relevant findings from Shell's broader internal audit programme	M
Assess Shell's overall sustainability performance and provide input to Shell's annual reporting and disclosures regarding sustainability	A
Review how Shell addresses other major issues of public concern that could affect Shell's reputation and licence to operate	M
Review and consider external stakeholder perspectives in relation to Shell's business	P
Advise the Remuneration Committee on metrics relating to Sustainable Development and Energy Transition.	A
Committee Activity Key: A Annually P Periodically M Most meetings E Every meeting N As necessary	

AUDIT COMMITTEE REPORT



ANN GODBEHERE
Chair of the Audit Committee

Focus areas for 2020

- Impacts of the COVID-19 pandemic and macroeconomic conditions
- Decommissioning and restoration
- Integrated risk management
- Trading and Supply
- Treasury operations

Priorities for 2021

- New business models and ventures
- Pensions
- Contracting and procurement
- Reshape management framework
- Oil and gas pricing methodology

“The primary role of the AC is to assist the Board in fulfilling its oversight responsibilities in areas such as the integrity of financial reporting, the effectiveness of the risk management framework and system of internal controls as well as consideration of ethics and compliance matters.”

Dear Shareholders,

I am pleased to present our Audit Committee Report for 2020 covering our work over the course of the year including some areas of particular focus.

I begin this report by thanking Roberto Setubal for his contributions as a member of the Audit Committee (AC) since October 2017. Gerrit and I were delighted to be joined by new committee members Martina Hund-Mejean and Dick Boer. Their respective expertise and insights are a valuable addition to the AC.

The primary role of the AC is to assist the Board in fulfilling its oversight responsibilities in areas such as the integrity of financial reporting, the effectiveness of the risk management framework and system of internal controls as well as consideration of ethics and compliance matters. We are also responsible for assessing the quality of the audit performed by, and the independence and objectivity of, the external auditor. The AC also makes a recommendation to the Board on the appointment or reappointment of the external auditor. In addition, we oversee the work and quality of the internal audit function.

Over the course of a year, the AC has a rolling agenda covering a variety of standing matters such as the control framework for the reporting of Shell's oil and gas reserves; information risk management; tax matters; briefings from the Chief Internal Auditor on the effectiveness of Shell's risk management and internal control system and on the outcomes of significant audits and notable control matters, and briefings from the Chief Ethics and Compliance Officer. Specific attention is given to topics that we consider particularly significant, including key areas of judgement relating to Shell's Consolidated Financial Statements, as discussed in more detail later in this report. In 2020, in addition to standing matters, the AC addressed a variety of special focus areas including: the impacts of the COVID-19 pandemic on the controls and assurance environment; the impacts of the macroeconomic conditions on the outlook for commodity prices and refining margin assumptions; the effectiveness of decommissioning and restoration activities; a review of the integrated risk management landscape across Shell; an in-depth look at Shell's treasury operations; and a review of Trading and Supply's risk management strategy and platform, data and systems update. The AC carried out virtual site visits to Shell's operations in Singapore, Krakow, and Kuala Lumpur. In addition, in March prior to a travel ban prompted by COVID-19, I spent three days in Houston visiting all of Shell's operations. These site visits contribute to the AC's understanding of the risks and opportunities arising in key markets and where important functions are carried out. The visits also provide the opportunity for the AC to engage with a diverse range of Shell staff in each location and to hear directly from them.

As climate change and energy transition gained further prominence and to help the AC keep abreast of the Company's efforts and strategies to manage potential impacts on Shell's assets, I became a member of the Safety, Environment and Sustainability Committee in 2020. In addition, the AC requested Ernst and Young LLP (EY), our external auditor, and the Chief Internal Auditor to specify in their respective quarterly reports to the AC what specific steps they have taken to incorporate climate change considerations into all facets of their work.

On a final note, the AC congratulates Shell's Annual Report team on winning the FD Henri Sijthoff Prize for the best 2019 annual report in the "listed companies" category in the Netherlands. The award recognises Shell's pursuit of continual transparency improvements in its communications with external stakeholders.

ANN GODBEHERE
Chair of the Audit Committee
March 10, 2021

AUDIT COMMITTEE REPORT continued

COMMITTEE MEMBERSHIP AND ATTENDANCE FOR 2020

During 2020, the members and meeting attendance of the AC were as follows:

Committee Member	Member since	Maximum possible meetings	Number of meetings attended	% of meetings attended
Ann Godbehere (Chair)	May 23, 2018	6	6	100%
Dick Boer [A]	May 20, 2020	3	3	100%
Martina Hund-Mejean [B]	May 20, 2020	3	3	100%
Roberto Setubal [C]	October 1, 2017	3	3	100%
Gerrit Zalm	March 8 2017	6	6	100%

[A] Dick Boer was appointed to the Board and AC with effect from May 20, 2020.

[B] Martina Hund-Mejean was appointed to the Board and AC with effect from May 20, 2020.

[C] Roberto Setubal stepped down from the Board with effect from May 19, 2020.

All members of the AC are financially literate, independent Non-executive Directors. In respect of the year ended December 31, 2020, for the purposes of the UK Corporate Governance Code, Ann Godbehere and Martina Hund-Mejean with effect from her appointment to the Board and AC on May 20, 2020, both qualify as: a person with "recent and relevant financial experience" and competence in accounting, and, for the purposes of US securities laws, an "audit committee financial expert".

The experience of the AC members outlined on pages 114-121 demonstrates that the AC as a whole has competence relevant to the sector in which Shell operates, and the necessary commercial, regulatory, financial and audit expertise required to fulfil its responsibilities. The AC members have gained further knowledge and experience of the sector as a result of their Board membership and through various in-person and virtual site visits since their respective appointments.

The AC invites the Chief Financial Officer, the Legal Director, the Chief Internal Auditor, the Executive Vice President Taxation and Controller, the Vice President Group Reporting and the external auditor to attend each meeting. The Chief Executive Officer attends each meeting where the quarterly, half-yearly and year-end results are discussed. The Chair of the Board also regularly attends AC meetings. Other members of management attend when requested on specific topics or to provide input on more detailed technical matters that may arise. The AC regularly holds private sessions separately with the Chief Internal Auditor and the external auditor without members of management, except for the Legal Director, being present. Outside of the formal AC meetings the AC Chair meets regularly with each of the Chief Financial Officer, Executive Vice President (EVP) Taxation and Controller, the Chief Internal Auditor, the external auditor, and the Chief Information Officer.

AC REMIT

The roles and responsibilities of the AC, as set out in its Terms of Reference are reviewed annually, taking into account relevant regulatory changes and recommended best practice. The key responsibilities of the AC include, but are not limited to:

- evaluating the effectiveness of the system of risk management and internal control;
- reviewing the integrity of the financial statements, including annual reports, half-year reports, and quarterly financial statements;
- reviewing and discussing with management the appropriateness of judgements involving the application of accounting principles and disclosure rules;
- advising the Board whether, in the AC's view, the Annual Report taken as a whole is fair, balanced and understandable and provides the information necessary for shareholders to assess Shell's position and performance, business model and strategy;
- reviewing the functioning of the Shell Global Helpline and reports arising from its operation;

- overseeing compliance with applicable legal and regulatory requirements, including monitoring ethics and compliance risks;
- monitoring the qualifications, expertise, resources and independence of the internal audit function and the external auditor;
- assessing the internal and external auditors' performance and effectiveness each year and approving related remuneration for the external auditor; and
- recommending to the Board for it to put to the Company's Shareholders for approval at the Annual General Meeting (AGM) to appoint, reappoint, or remove the external auditor.

These responsibilities form the basis of the AC's annual work plan which is adjusted throughout the year as necessary. The AC is authorised to seek any information it requires from management and external parties and to investigate issues or concerns as it deems appropriate. The AC may also obtain independent professional advice at the Company's expense. No such independent advice was required in 2020.

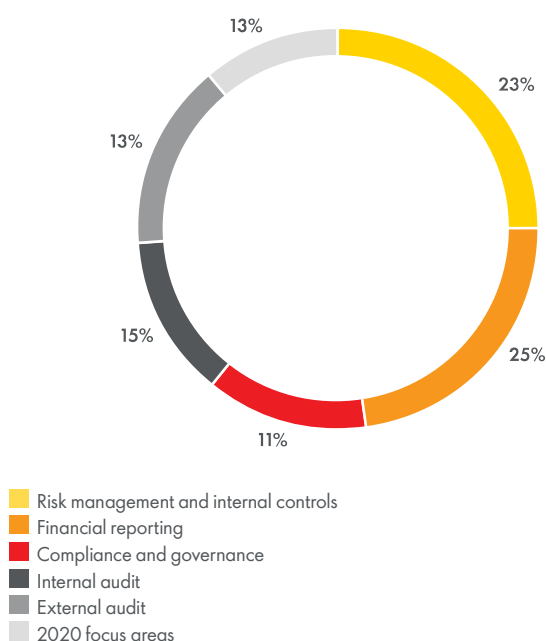
The AC keeps the Board informed of its activities and recommendations, and the Chair of the AC provides an update to the Board after every AC meeting. The AC discusses with the Board if it is not satisfied with or believes that action or improvement is required concerning any aspect of financial reporting, risk management and internal control, compliance or audit-related activities.

A copy of the AC's Terms of Reference, which was updated in 2020 to reflect references affected by the separation of the Annual Report and Form 20-F, can be found at www.shell.com.

AC TOPIC COVERAGE IN 2020

The pie chart below shows the percentage of time the AC spent on various activities during 2020.

2020 AC topic coverage



FOCUS AREAS FOR 2020

The AC was briefed by senior leaders from various business and function areas on the adequacy, design and operating effectiveness of risk management and controls related to the critical activities carried out by their respective business or function. The briefings included information on any enhancements to strengthen controls and how areas identified

for improvement had been addressed. These discussions also covered monitoring activities around risks, and steps being taken to address identified gaps and emerging risk areas. In addition to the significant accounting and reporting areas discussed on page 150, the business and function areas reviewed by the AC in 2020 included the following:

- **Decommissioning and commissioning and restoration (D&R)** – The AC was briefed on the different aspects of the D&R management process in Shell and the key risks and opportunities in D&R. The AC discussed the approach to D&R provisions and the controls in place to enable effective governance of D&R.
- **Integrated risk management** – To provide the AC with further insights into Shell's integrated risk management framework across the organisation, the AC received an overview of the approach to risks, controls and assurance in two business areas: information risk management and Shell aircraft. The AC noted the improvement measures and best practices management has embedded within these two areas.
- **Treasury operations** – Senior Treasury leaders provided the AC with an overview of Shell's centralised treasury operations, which include central debt and capital market activities, liquidity and foreign exchange, cash management and treasury functions. The AC reviewed the overall governance, controls and assurance activities. The AC gained a deeper understanding of how risks, including regulatory and fiscal compliance, are managed. As part of this review, the AC discussed future challenges and opportunities in this area.
- **Trading and Supply's control framework** – Reflecting the growth in this area in recent years and increasing regulatory demands, the AC continued to focus on key control and compliance matters in Trading and Supply. Management updated the AC on the improvements being made within Trading and Supply to strengthen controls and modernise processes, data and systems and on the new hires in the areas of compliance and risk management.

In 2020, the AC carried out three site visits that were conducted virtually because of the travel restrictions in place during the COVID-19 pandemic. The AC visited: Singapore in October 2020; Kuala Lumpur in Malaysia in November and December 2020; and Poland in November 2020 and January 2021. These visits provided the opportunity for the AC to gain a deeper understanding of the various businesses and functions at each location, the local external environment within which those activities take place and how they contribute to Shell achieving its strategic ambitions. In addition to in-depth examinations of specific business areas, topics discussed during the site visits included: an overview of ethics and compliance matters, the challenges of operating during the COVID-19 pandemic for both people and operations, the impact of the energy transition at a local level and results from the Shell People Survey.

RISK MANAGEMENT AND INTERNAL CONTROL

The AC assists the Board in fulfilling its responsibilities in relation to risk management and internal controls by reviewing reports on risks, controls and assurance, including the annual assessment of the system of risk management and internal control, in order to monitor the effectiveness of the procedures for internal control over financial reporting, compliance and operational matters. This annual assessment includes the AC's review of outcomes from the Group Assurance Letter process (a structured internal assessment of compliance with legal and ethical requirements and the Shell Control Framework carried out by each Executive Director) and the Company's evaluation of the internal control over financial reporting as required under Section 404 of the Sarbanes-Oxley Act (SOX 404). The AC updated the Board on compliance with internal controls across the Shell Group and on any major matters for which action or improvement was needed.

Throughout the year, the AC discussed with management the Company's overall approach to risk management and internal control, including compliance, tax and information risk management matters and the adequacy of disclosure controls and procedures. The AC received quarterly reports from the Executive Vice President Taxation and Controller on the

status of actions to address control weaknesses identified during assurance reviews, as well as trend information regarding business incidents and other metrics used to monitor the robustness of the risk management framework and internal control systems. As part of considering the risk management framework, the AC was informed of developments in the legal, regulatory and financial reporting landscape that could affect the Company. The AC was also briefed on litigation matters (see "Governance" on page 187 and Note 25 to the "Consolidated Financial Statements" on pages 260-262).

The AC reviewed on a quarterly basis the status of management's SOX 404 testing of controls and remediation actions to address any identified weaknesses. For 2020, these quarterly reviews also included consideration of how the COVID-19 pandemic affected the controls and assurance landscape, including the financial reporting process. The AC and management discussed the steps taken to maintain an effective control environment to demonstrate "management in control" during the pandemic and to address any new or emerging risks due to the working from home setting during most of 2020.

In particular, the AC dedicated time to the following standing items during 2020:

- **Tax risks** – In addition to the regular review of Shell's tax position, the AC discussed with management new and potential tax legislation developments in various countries and how their potential impact on Shell is being managed. The AC also discussed with management Shell's updated Approach to Tax and proposed responses to the continued demand for greater transparency of tax information, noting for example, Shell's publication of its second Tax Contribution Report in 2020.
- **Information risk management** – The Chief Information Officer briefed the AC on the diverse and expanding risk landscape, including changes in cyber-attacks due to the COVID-19 environment, and regulatory developments. The AC was briefed on activities undertaken in 2020 to address and manage new and evolving risks as well as improvements planned for 2021.
- **Oil and gas reserves control framework** – The AC reviewed the framework in place to support internal reporting and external disclosures. The AC discussed the processes and controls for preventing and/or mitigating the risks of non-compliance with regulatory reporting requirements, and ensuring accurate reserves information is reported in an efficient manner.

In addition to the above discussions with management, on a quarterly basis, the AC and the Chief Internal Auditor discussed the Company's risk management and internal control system, any significant matters arising from the internal audit assurance programme and management's response to significant audit findings and notable control weaknesses including potential improvements and agreed actions. The AC held similar discussions with EY on a quarterly basis.

FINANCIAL REPORTING

In 2020, the AC received comprehensive reports from management and the external auditor on quarterly financial reporting, accounting policies and judgements and reporting matters.

Shell's annual report and accounts for the year ended December 31, 2019 was selected by the Financial Reporting Council (FRC) for their thematic review of a sample of companies' reporting on the impact of climate change and the first full year of adoption of IFRS 16, Leases. The FRC carried out a limited scope review of Shell's disclosures relating to these matters and did not conduct a full review of Shell's 2019 Annual Report and accounts. Following correspondence, the review was closed on February 10, 2021 and certain disclosure improvements have been made to the Consolidated Financial Statements for the year ended December 31, 2020. The AC reviewed Shell's correspondence with the FRC and discussed with management the disclosures incorporated in the Consolidated Financial Statements in response to the FRC review.

AUDIT COMMITTEE REPORT continued

The AC reviewed the Company's 2020 quarterly unaudited interim financial statements, half-yearly report and Annual Report with management and the external auditor. Following the decision to produce a separate Annual Report and Form 20-F beginning with financial year 2019, the AC reviewed the control framework put in place to ensure the disclosures in both reports comply with relevant requirements.

Fair, balanced and understandable assessment

The AC advised the Board that in its view the 2020 Annual Report including the financial statements for the year ended December 31, 2020, taken as a whole, is fair, balanced and understandable and provides the information necessary for shareholders to assess Shell's position and performance, business model and strategy. (See "Governance" on page 189). To arrive at this conclusion, the AC critically assessed drafts of the 2020 Annual Report including the financial statements and discussed with management the process undertaken to ensure that these requirements were met. This process included: verifying that the contents of the 2020 Annual Report are consistent with the information shared with the Board during the year to support their assessment of Shell's position and performance; ensuring that consistent materiality thresholds are applied for favourable and unfavourable items; considering comments from the external auditor; and receiving assurance from the Executive Committee (EC).

Going concern and viability statement

The AC reviewed and considered the Directors' half-year and full-year statements with respect to the going concern basis of accounting. As noted in the viability statement, the Board also reviews the strategic plan which takes account of longer-term forecasts and a wide range of outlooks. Factors considered included: the impact of commodity prices; exchange rates; future carbon costs; agreements like liquid natural gas contract renewals; production levels and product demand, schedules of growth programmes; the financial framework; Shell's business portfolio developments including consideration of the impacts of climate change and Shell's commitment to the Paris Agreement goals; the project funnel to support future growth; and using severe but possible scenarios to run models of the financial impact if certain of Shell's principal risks materialised. The AC considered the mitigating measures and sensitivities that management had applied to the modelling of such scenarios when evaluating the viability statement. The AC also considered the merits of extending the viability statement beyond a period of three years and concluded that the three-year period selected by the Board for the review of Shell's prospects, in line with the operating plan, remained appropriate. The AC supported the going concern basis of accounting and the inclusion of Shell's viability statement in "Governance" on page 183-184 and considered such statement to be in line with best practice guidance issued by the FRC.

Other matters

The AC reviewed: the year-end reported proved oil and gas reserves, including management judgements and adjustments made to reflect changes in geological, technical, contractual and economic information, the Brent crude oil and Henry Hub natural gas long-term price assumptions; estimated refining margins; discount rates used for financial reporting, particularly with respect to impairment testing and decommissioning and other provisions (see Note 2 to the "Consolidated Financial Statements" on pages 221-229 for further information); and the effectiveness of financial controls.

COMPLIANCE AND GOVERNANCE

Ethics and compliance

The AC discussed with the Chief Ethics and Compliance Officer the potential impact of COVID-19 on conduct risk at Shell. The Chief Ethics and Compliance Officer summarised the macro factors affecting conduct risk during the pandemic and the related economic downturn. The AC was updated on management's risk-based approach and mitigation actions taken by Shell in response to these issues, including reinforcing adherence to Shell's compliance rules and Code of Conduct.

In October 2020, the AC and the Safety, Environment and Sustainability Committee held a joint session with the Chief Ethics and Compliance Officer which facilitated an effective discussion of the controls, procedures and governance for managing high risk transactions in Shell, with a particular focus on proposed portfolio activities including new business development opportunities, acquisitions, divestments and joint ventures.

As part of the annual assessment of the system of risk management and internal control, the AC discussed with the Chief Ethics and Compliance Officer his annual report on compliance matters. The report included an overview of the effectiveness of the Shell ethics and compliance programme in managing ethics and compliance risk in Shell's business activities, regulatory developments and compliance risks. The AC also discussed investigations of cases involving ethics and compliance concerns. The AC discussed management's findings in such cases to satisfy itself that a rigorous process had been followed, and, where necessary, appropriate disciplinary actions had been taken and management had embedded learnings into Shell's systems and controls.

Whistleblowing investigations

The AC is responsible for establishing and monitoring the implementation of procedures for the receipt, retention, investigation and follow-up actions of complaints received, including those from the Shell Global Helpline. The AC reviewed whistleblowing reports and internal audit reports and considered management's responses to the findings in these reports.

Regulatory developments

The AC was briefed on regulatory developments in areas including: sustainable finance (in particular management's work on the EU Sustainable Finance Taxonomy); non-financial reporting (in particular management's assessment of the EU Non-Financial Reporting Directive Revision); accounting and reporting; environmental liabilities and treasury activities.

AC annual evaluation

The AC undertakes an annual evaluation of its performance and effectiveness. Consistent with the Board's annual performance evaluation for 2020, the AC's performance evaluation was facilitated by Lintstock Limited, a London-based corporate advisory firm. Each AC member responded to a confidential questionnaire about the AC's performance covering questions on: the management of the AC in areas such as the annual cycle of work, agenda for meetings and time and input in meetings; the quality of the information provided to the AC; the value of the virtual site visits and the AC briefings on specific topics; the effectiveness of the AC's oversight in areas such as financial reporting, risk management and internal control, compliance and governance and the work of internal and external audit; rating the AC's performance in reviewing and assessing significant accounting and reporting judgements; and how to improve the AC's performance. When assessing progress against 2019, the AC concluded it had achieved all the 2020 priorities identified in the 2019 evaluation discussion (including visits to Shell's operations in Singapore, Krakow, and Kuala Lumpur, including the finance operation centres in Krakow and Kuala Lumpur, and reviews related to Trading and Supply, regulatory developments, decommissioning and integrated risk management). The AC discussed the outcome of this review as part of its annual evaluation. The AC concluded that its performance in 2020 had been effective and that it had fulfilled its role in accordance with its Terms of Reference.

In preparing its workplan for 2021, the AC has agreed the following focus areas in addition to the standing items: New business models and ventures; Pensions; Contracting and Procurement; Reshape management framework and oil and gas pricing methodology. As part of its review of new business models and ventures, the AC plans to visit one of Shell's new ventures in 2021.

AUDIT COMMITTEE ACTIVITIES DURING 2020

Activities performed	Frequency
Risk Management and Internal Control	
Reviewed the policies and practices and monitored the effectiveness relating to Shell's risk management and internal control system.	P
Received briefings on regulatory developments.	P
Reviewed management's SOX 404 assessment.	A
Discussed significant matters arising from completed internal audits with the Chief Internal Auditor, management and the external auditors.	Q
Assessed management's response to significant audit findings, recommendations and notable control weaknesses, including potential improvements and agreed actions.	P
Reviewed significant legal matters with Shell's Legal Director.	Q
Considered the oil and gas reserves control framework.	A
Reviewed Shell's information risk management.	P
Reviewed Shell's tax function, key tax risks and Shell's approach to the evolving area of tax transparency.	P
Financial Reporting	
Reviewed Shell's accounting policies and practices, including compliance with accounting and reporting standards.	Q
Assessed the appropriateness of key judgements and the interpretation and application of accounting principles.	Q
Considered the integrity of the year-end financial statements and recommended to the Board whether the audited financial statements should be included in the Annual and statutory reports.	A
Considered the integrity of the half-yearly report and quarterly financial statements.	Q
Reviewed management's assessment of going concern and longer-term viability.	Q
Reviewed Shell's policies with respect to earnings releases; financial performance information and earnings guidance; and significant financial reporting matters.	Q
Reviewed Shell's policies with respect to oil and gas reserves accounting and reporting including the outcome of the oil and gas reserves booking/debooking process.	A
Reviewed the internal controls for financial reporting.	P
Advised the Board of the AC's view on whether, taken as a whole, the Annual Report is fair, balanced and understandable and provides the information necessary for shareholders to assess Shell's position and performance, business model and strategy.	A
Compliance and Governance	
Monitored the receipt, retention, investigation and follow-up actions of complaints received, including those from the Shell Global Helpline.	P
Reviewed with the Chief Ethics and Compliance Officer the implementation and effectiveness of the ethics and compliance programme and function.	A
Discussed compliance with applicable external legal and regulatory requirements.	P
Performed an evaluation of the AC's performance and effectiveness and reported the results to the Board.	A
Reviewed and updated the AC's Terms of Reference.	A
Reviewed the Chief Financial Officer's significant business and investment transactions for potential conflicts or related party transactions.	A
Assessed the Chief Financial Officer's performance.	A
Internal Audit	
Evaluated the quality, efficiency and effectiveness of the internal audit function including the competence, qualifications, expertise, compensation and budget.	A
Reviewed and approved the internal audit function's remit, charter and audit plan.	A
Assessed the performance of the Chief Internal Auditor.	A
External Audit	
Reviewed and approved the engagement letter for EY's annual audit of the Company's consolidated and parent company financial statements.	A
Approved the remuneration for audit and non-audit services, including pre-approval of permissible non-audit services.	Q
Considered the annual external audit plan and monitored the execution and results of the audit.	P
Monitored the qualifications, expertise, resources and independence of EY.	A
Reviewed the Company's representation letter prior to signing by management.	A
Assessed the performance, objectivity and effectiveness of EY, the audit process, the quality of the audit, EY's handling of key judgements, and EY's response to questions from the AC	P
Recommended to the Board that the reappointment of EY be put to the Company's shareholders for approval at the AGM.	A

Committee Activity Key: A Annually Q Quarterly P Periodically

AUDIT COMMITTEE REPORT continued

SIGNIFICANT ACCOUNTING AND REPORTING CONSIDERATIONS

The AC assessed the following significant accounting and reporting areas, including those related to Shell's 2020 Consolidated Financial Statements. The AC was satisfied with how each of the areas below was addressed. As part of this assessment, the AC received reports, requested and received clarifications from management, and sought assurance and received input from the internal and external auditors.

Significant accounting and reporting areas

Subject	Issue	How the AC addressed the issue
IMPAIRMENTS AND IMPAIRMENT REVERSALS See Notes 2, 7, 9 and 8 to the "Consolidated Financial Statements" on pages 221-229 and 233-238	The carrying amount of an asset should be tested for impairment or impairment reversal whenever events or changes in circumstances indicate that the carrying amount for that asset may have changed, such as a change in the outlook for commodity prices and refining margin assumptions and revisions to future activity plans and developments. On classification as held for sale, the carrying amounts of property, plant and equipment (PP&E) and intangible assets are also reviewed.	The AC reviewed the impairment assessments that were performed each quarter. In doing so, the AC considered the updated oil and gas price and refining margin outlooks against market developments and benchmarks. The potential impact of price sensitivities was reviewed and asset-specific risks were considered together with the relevant discount rates applied. The AC also reviewed other significant inputs to impairment assessments, including the held-for-sale classification and the potential impacts of climate change and energy transition. The AC review of impairments covered a significant proportion of the balance sheet.
TAXATION See Notes 2 and 16 to the "Consolidated Financial Statements" on pages 221-229 and 244-246	The determination of tax assets and liabilities requires the application of judgement as to the ultimate outcome, which can change over time. In particular, tax exposures and the recognition of deferred tax assets require management to make assumptions regarding future profitability and are therefore inherently uncertain.	The AC considered the uncertain tax positions and discussed management's assumptions of future taxable profits, and evaluated the appropriateness of the recognition of deferred tax assets and tax liabilities. While recognising that assumptions regarding future taxable profits are inherently uncertain, particularly in light of COVID-19 and the pace of economic recovery in different countries as well as the potential impacts of climate change and energy transition (for example see "Future Refinery Portfolio" below), the AC deemed the resulting assessments of uncertain tax exposures and the recognition of deferred tax assets and tax liabilities to be reasonable.
DISCOUNT RATE FOR PROVISIONS See Notes 2 and 18 to the "Consolidated Financial Statements" on pages 221-229 and 250	A review was carried out to consider the discount rate applied for provisions due to a lower rate for 30-year US Treasury bonds. Due to the significant drop in the rate, management lowered the discount rate for provisions from 3% to 1.75% in Q2 2020.	The AC reviewed the impact of this change on provisions and in particular considered the impact on decommissioning and restoration provisions and corresponding assets.
COVID-19 AND MACRO-ENVIRONMENT See Notes 2, 7, 8, 9, 12, 17 and 18 to the "Consolidated Financial Statements" on pages 221-229; 233-238; 240; and 246-250	As a result of COVID-19 and the macro-environment uncertainty and volatility, a number of accounting implications were discussed with the AC throughout 2020, including: <ul style="list-style-type: none"> ■ impairments and discount rate for provisions (see above); ■ expected credit loss – in particular, the credit risk exposures in Oil Products, Chemicals and Trading; ■ pension remeasurement – defined benefit pension plan obligations and assets are remeasured quarterly, with significant movements in 2020 due to volatility in discount rates, inflation rates and financial markets; and ■ inventory write-down – due to the significant decline in prices in March and April 2020, there was a write-down of some of the Shell Group's inventory to net realisable value. 	The AC discussed and challenged the accounting implications associated with the macro-environment conditions as they evolved throughout 2020.
FUTURE REFINERY PORTFOLIO See Notes 2 and 18 to the "Consolidated Financial Statements" on pages 221-229 and 250	Following Shell's announcement in Q3 2020, the Company intends to transform its refining portfolio during the energy transition from 14 sites into six high-value energy and chemicals parks integrated with Chemicals. Evaluations and decisions are expected to follow on assets that could result in the recognition of significant provisions and charges to earnings.	The AC discussed the accounting implications of these decisions and the recognition of: (i) decommissioning and restoration provisions; (ii) restructuring provisions; (iii) onerous contract provisions; and (iv) impairment considerations.
RESHAPE RESTRUCTURING PROVISIONS See Notes 2 and 18 to the "Consolidated Financial Statements" on pages 221-229 and 250	During 2020 a comprehensive portfolio and organisational review called Reshape was announced which is expected to result in between 7,000-9,000 redundancies and related redundancy provisions and charges are expected to be recognised in 2021.	The AC considered the accounting implications and whether the criteria to recognise a restructuring provision as per IAS 37.72 were fulfilled in 2020. The AC agreed with management that the criteria had not been met by December 31, 2020 and that it was appropriate that the majority of the restructuring provision be recognised in 2021.
SEGMENT REPORTING See Note 4 to the "Consolidated Financial Statements" on pages 230-232	Reflecting a change in the way Shell's CEO reviews and assesses performance, and makes decisions in allocating resources, management reassessed Shell's segment reporting. From January 1, 2020, Shell's reportable segments consist of: Upstream, Integrated Gas, Oil Products, Chemicals, and Corporate.	The AC assessed the appropriateness of the revised reporting segments for 2020 and the restatement of prior periods to the new segments.

INTERNAL AUDIT

Internal audit remit

The internal audit function is an independent assurance function which supports Shell in improving its overall control framework. The internal audit function contributes to the maintenance of a systematic and disciplined approach to evaluate and improve the design and effectiveness of Shell's risk management, control and governance processes. The primary role of the internal audit function, through its assurance and investigation activities, is to safeguard value by protecting Shell's assets, reputation and sustainability in relation to the organisation's defined goals and objectives.

The AC defines the responsibility and scope of the internal audit function and approves its annual plan. The Chief Internal Auditor reports functionally to the Chair of the AC and administratively to the Chief Financial Officer. The Chair of the AC approves, in consultation with the Chief Financial Officer, all decisions regarding the performance evaluation, appointment or removal of the Chief Internal Auditor.

Annual internal audit plan and assessment of internal audit's effectiveness

In 2020, the AC considered and approved the internal audit function's annual audit plan, including focus areas for 2020 consisting of: (i) talent and capability (professional audit development and technical capabilities); (ii) quality (developing first-line staff competence and clarity on self-verification and supervisory controls); (iii) alignment (improved integration of risk management and alignment of assurance processes across Shell); and (iv) engagement (mainly in the area of keeping staff and Shell stakeholders engaged and informed on effective risk management and internal control). The AC assessed the performance of the internal audit function as effective. The AC also assessed the performance of the Chief Internal Auditor.

The Chief Internal Auditor periodically assesses whether the purpose, authority and responsibilities of the internal audit function continue to enable it to accomplish its objectives. The results of this periodic assessment are communicated to the EC and AC. The Chief Internal Auditor maintains an internal quality assurance and improvement programme covering all aspects of internal audit's activities, and evaluates the conformance of these activities with the Chartered Institute of Internal Auditors' standards. The Chief Internal Auditor also assesses the efficiency and effectiveness of internal audit's activities and identifies opportunities for improvement. The results of this annual assessment are discussed with the EC and AC and include a reconfirmation to the AC of the continued validity of the charter of the internal audit function, or proposals for an update. At least every five years, the effectiveness and quality of the internal audit function are assessed externally and the report is reviewed with the AC. An independent assessment of internal audit was conducted in 2018. The next such external assessment is planned to take place in 2023.

EXTERNAL AUDITOR

Annual external audit plan and assessment of external audit's effectiveness

EY reviewed with the AC its audit strategy, scope and plan for the 2020 audit, highlighting any areas which would receive special consideration. The AC considered the annual audit plan, which included assessing whether the planned materiality levels and proposed resources to execute the audit plan were consistent with the audit scope.

EY regularly updated the AC on the status of their procedures and preliminary findings, providing an opportunity for the AC to monitor the execution and results of the audit. The AC and EY discussed how risks to audit quality were addressed, key accounting and audit judgements, material communications between EY and management and any issues arising from them. Quarterly, the AC met privately with EY representatives without management being present in order to encourage open and transparent feedback from both parties. In addition, the AC Chair meets separately with the external auditor on a regular basis.

As part of its oversight of the external auditor, the AC annually assesses the performance and effectiveness of the external auditor and the audit process, including an assessment of the quality of the audit, the handling of key judgements by the auditor, and the auditor's response to questions from the AC. The AC evaluated the objectivity and independence of EY and the quality and effectiveness of the external audit process. As part of its evaluation, the AC considered and discussed: (i) the results of Shell management's internal survey relating to EY's performance over the financial year 2020, which reflected a broadly comparable performance to 2019; (ii) views and recommendations from management and the Chief Internal Auditor; (iii) EY's audit quality priorities and actions by EY as part of its sustainable audit quality programme; (iv) the forthcoming partner rotation and measures EY has taken for an orderly transition; and (v) the AC's own experiences, including interactions with the external auditor, throughout the year. Key criteria of the evaluation included: professionalism in areas including competence, integrity and objectivity; constructive challenge of management and key judgements; efficiency, covering aspects such as service level and innovation in the audit process; thought leadership and value added; and compliance with relevant legislative, regulatory and professional requirements.

The Committee also considered EY's quality assurance procedures, internal quality control procedures, competence and most recent Transparency Report and opportunities for improvement. Taking into account the above, the AC is satisfied that EY has continued to provide a high-quality and effective audit in its fifth year as auditor and has maintained its independence and objectivity.

As required under UK and US auditing standards, the AC received a letter from EY confirming its independence. As required by applicable regulations, EY also informed the AC in writing and discussed with the AC any significant relationships and matters that may reasonably be thought to have an impact on its objectivity and independence.

During 2020, there was no review of EY's audits of Shell's Consolidated Financial Statements by the Audit Quality Review (AQR) team of the FRC. EY reviewed Shell's correspondence with the FRC relating to the FRC's thematic review of a sample of companies' reporting on the impact of climate change and the first full year of adoption of IFRS 16, Leases.

Reappointment

The AC is responsible for considering whether, in order to ensure continuing auditor quality and/or independence, there should be a rotation of the independent registered public accounting firm, including consideration of the advisability and potential impact of conducting a tender process for the appointment of a different independent public accounting firm. The AC is also responsible for making a recommendation to the Board for it to put to the Company's shareholders for approval at the AGM, to appoint, reappoint or remove the external auditor.

AUDIT COMMITTEE REPORT continued

At the AGM in May 2020, the shareholders approved a resolution to reappoint EY as external auditor until the conclusion of the next AGM. EY was first appointed at the AGM in May 2016 following the conclusion of a competitive tender process. The Company has complied with The Statutory Audit Services for Large Companies Market Investigation (Mandatory Use of Competitive Tender Processes and Audit Committee Responsibilities) Order 2014 for the 2020 financial year. The AC acknowledges the UK and Dutch legal requirements relating to mandatory audit rotation and audit tendering under which the Company will be required to tender for the audit no later than the 2026 financial year. The AC regularly reviews auditor performance and may elect to carry out the tender earlier than the 2026 financial year if it determined it would be in the interests of the Company's shareholders to do so.

As 2020 represents the conclusion of EY's first five-year term, the AC reflected upon whether conducting an audit tender at this time would be appropriate. The AC's consideration took into account: the AC remains satisfied with the quality and independence of the audit conducted by EY; given Shell's size and complexity, any new external auditor would need a transition period to develop sufficient understanding of the business; frequent changes of external auditor would be inefficient and could lead to increased risk and the loss of cumulative knowledge; a change in auditor would be expected to have a significant impact on Shell, including on the Finance function; and any change in auditor should be scheduled to limit operational disruption. The AC also considered that the current external audit partner, Mr Allister Wilson, who has held this position since EY's initial appointment in 2016, is rotating off the Shell audit after the 2020 audit. Mr Gary Donald will serve as the audit partner beginning with the 2021 audit engagement.

After due consideration the AC determined that it would not be appropriate to re-tender for the external audit at this time and has recommended to the Board to propose at the 2021 AGM that EY be reappointed as the external auditor of the Company for the year ending December 31, 2021. The recommendation is free from influence by a third party and there are no contractual obligations that restrict the AC's ability to make such a recommendation.

NON-AUDIT SERVICES

The AC maintains an auditor independence policy (AIP) in respect of the provision of services by the external auditor. The AC regularly reviews this policy for necessary changes in response to changes in related standards and regulatory requirements. This policy was updated in January 2020 (and became effective in March 2020) to incorporate the Revised Ethical Standards issued by the FRC in December 2019.

This policy, designed to safeguard auditor objectivity and independence, includes rules relating to the provision of audit services, audit-related services and other non-audit services, and stipulates which services require specific prior approval by the AC.

The policy also defines prohibited services that are not to be provided by the auditor because they represent a risk to the external auditor's independence. Prohibited services are any that relate to management decision-taking or any other service that could compromise auditor independence or the perception thereof. These prohibited services include all services listed as prohibited in the UK and US auditor independence rules.

For certain services that are not prohibited, because of the knowledge and experience of the external auditor and/or for reasons of confidentiality, it can be more efficient or prudent to engage the external auditor rather than another party. This is particularly the case with audit-related assurance services that are closely connected to the audit function where the external auditor has the benefit of knowledge gained from work already performed as part of the audit.

Under the AIP, the AC will only approve services to be carried out by the external auditor or its affiliates where such services do not present a conflict of interest risk in fact or in appearance. The AC reviews quarterly reports from management on the audit and non-audit services reported in accordance with the policy or for which specific prior approval from the AC is being sought. To the extent that the fee value of an additional audit service contract does not individually exceed \$500,000, no prior approval of the AC is required. All non-audit services where the fee for an individual contract exceeds \$100,000 (from January 1 to March 15, 2020, \$50,000), including audit-related services, require individual prior approval by the AC. In each case where the audit or non-audit service contract does not exceed the relevant threshold, the matter is approved by management by delegated authority from the AC and is subsequently presented for approval by the AC at the next quarterly AC meeting. The AC is mindful of the overall proportion of fees for audit and non-audit services in determining whether to approve such services.

The scope of the non-audit services contracted with the external auditor in 2020 consisted mainly of interim reviews and other audit-related assurance services. The associated compensation for these audit-related services and other non-audit services amounted to 5.4% and 3.6%, respectively, of the external auditor's audit and audit-related remuneration.

FEES

After due consideration, the AC approved the auditor's remuneration, satisfying itself that the level of fees payable in respect of the audit and non-audit services provided was appropriate and that an effective, high-quality audit could be conducted for such fees.

 **Note 28 to the "Consolidated Financial Statements" on page 263 provides details of the auditor's remuneration.**

DIRECTORS' REMUNERATION REPORT



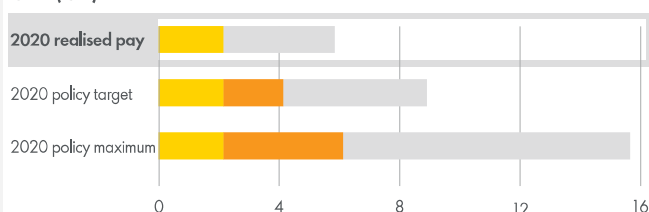
NEIL CARSON

Chair of the Remuneration Committee

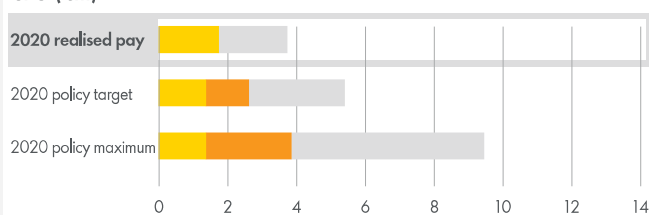
"This year we have recognised the challenges of 2020 faced by all stakeholders, the resilience of the business, and supported achievement of our strategic ambitions in the longer term."

2020 pay compared to policy [A]

CEO (€m)



CFO (€m)



■ Fixed pay
■ Bonus
■ LTIP

[A] Policy target and maximum based on the scenarios as published on page 178

Pay outcomes for Executive Directors

Annual bonus: nil.

LTIP: below-target vesting based on three-year performance.

Single-figure outcome: realised pay below target and a single-figure reduction of 41% for the CEO and 38% for the CFO.

Salary: no increases for 2021.

LTIP: one-off reduction of 2021 award to mitigate risk of windfall gains.

Shareholding requirement: Executive Directors' high personal shareholdings ensured strong alignment with shareholders.

Aligning pay with strategy

LTIP:

- Increased weighting of energy transition condition in the LTIP to 20%.

Annual bonus:

- Refreshed annual bonus scorecard to give greater alignment with updated strategy, with a focus on financial delivery, operational excellence, progress in the energy transition and safety.
- Metrics linked to production and LNG liquefaction volumes removed.
- New Serious Injury and Fatality Frequency (SIF-F) safety metric replaces Total Recordable Case Frequency (TRCF).
- Weighting of safety performance measures increased to 15%.
- Weighting of progress in the energy transition performance measures of 15%.

THIS REPORT

This Directors' Remuneration Report for 2020 has been prepared in accordance with relevant UK corporate governance and legal requirements, in particular Schedule 8 of The Large and Medium-sized Companies and Groups (Accounts and Reports) Regulations 2008 (as amended). The Board has approved this report. This report consists of two further sections:

- the Annual Report on Remuneration (describing 2020 remuneration and the planned implementation of the Directors' Remuneration Policy in 2021); and
- the Directors' Remuneration Policy which was approved by shareholders at the 2020 AGM.

Dear Shareholders,

The Remuneration Committee (REMCO) has worked hard in recent years to engage with shareholders on decision-making and to improve the quality of our disclosures. At the Annual General Meeting in May 2020, when my predecessor, Gerald Kleisterlee, stepped down, there was strong support of the 2019 Annual Report on Remuneration (95.44% in favour) and the 2020 Directors' Remuneration Policy (92.91% in favour). I have since had the opportunity to meet a considerable number of shareholders and I value the openness of these discussions. In such challenging times, these engagements have helped to shape and inform the REMCO's decisions.

COVID-19

The COVID-19 pandemic and its consequences have had an enormous impact in 2020, affecting people around the world and creating extremely challenging conditions for Shell, the energy sector and wider industry. Throughout this period, in addition to the steps to reinforce the financial strength and resilience of its business, Shell's priorities have been the well-being and safety of employees, taking care of customers, and supporting the communities where Shell operates.

DIRECTORS' REMUNERATION REPORT continued

For Shell employees, the pandemic and the changes to the way in which we live and work undoubtedly caused increased anxiety and stress. Shell has sought to provide support in a variety of ways to help our people manage their mental health and bolster resilience during these difficult times. For example; additional leave policies were introduced and flexible working patterns have been encouraged to support families juggling home schooling and caring for dependent parents. Cash allowances for ergonomic office equipment have been provided to those working from home offices, dining tables and bedrooms around the world.

Given the scale of the challenge facing Shell and the uncertainty about the speed of recovery, measures to ensure Shell's financial resilience have also impacted our people. Where required, Shell has sought to manage these sensitively, giving employees certainty and choice wherever possible. For example, towards the start of the pandemic, Shell made the commitment that there would be no new redundancies for three months. It then offered voluntary severance programmes giving those with a preference to leave employment the chance to do so. On pay, base salaries have been protected, with no cuts or temporary reductions made to salary.

The deteriorating global economic situation and significant uncertainties about mid- to longer-term economic conditions meant management and the Board had to take decisive measures to ensure the financial resilience of the Company. These included the decision by the Board to not proceed with the next tranche of the share buyback programme and to rebase the dividend. We have subsequently announced an intent to increase the dividend annually, subject to Board approval. These measures have had a significant effect on our shareholders, and accordingly have influenced the REMCO's decision-making in 2020.

Shell has also taken steps to support customers and communities. These have included providing free food and drinks to health-care professionals and delivery workers at more than 15,000 retail sites across more than 30 countries. We also delivered care packs to frontline workers and essential service drivers in six countries. We have donated fuel vouchers, groceries, hygiene kits and ingredients for sanitising products. In December 2020, Shell made a \$10 million donation to the GAVI vaccine alliance to help fund the COVAX initiative for equitable global access to COVID-19 vaccines. Further information on Shell's contribution to COVID-19 relief efforts will be published in the Shell Sustainability Report in April 2021.

During 2020, many governments introduced packages to support business and stimulate economies as the pandemic negatively affected businesses and jobs. Shell recognises that much of this support was intended to help smaller businesses. Shell has made very limited use of these support measures, and only where it was considered appropriate in the local context.

The REMCO has sought to balance two factors in its deliberations. The first was the response to the headwinds of 2020 and how this has affected our shareholders, our employees and our relationships with customers and governments. Against this, the REMCO has had to weigh the need to achieve Shell's longer-term strategic ambitions as it accelerates its transformation into a provider of net-zero emissions energy products and services.

2020 PERFORMANCE AND REMUNERATION DECISIONS

In 2020, the REMCO was pleased to see improved safety performance, with a reduction in the number of personal and process safety incidents. There were no safety-related fatalities in 2020 in Shell-operated ventures, but there were two COVID-19-related occupational illnesses resulting in death.

Shell has demonstrated resilience despite facing significant headwinds in 2020. Cash flow from operations (CFFO) has been strong, with the Shell Group clearly outperforming our competitors. This reflects the work done over recent years to high-grade the portfolio, the value created from Shell's integrated business model, and the disciplined approach to managing operating expenditure over the year.

For the avoidance of doubt, the Remuneration Committee made no changes to targets under the in-flight annual bonus or LTIP awards.

The share price performance has, of course, been disappointing. The mechanisms in the Remuneration Policy mean there is strong alignment of interests between management and shareholders. The high shareholding targets of 700% of base salary for the CEO and 500% for the CFO, and the three-year post-delivery holding requirements attached to the Long-term Incentive Plan (LTIP) and the 50% portion of the bonus delivered in shares. This meant that Executive Directors have a large investment in Shell, so the share price performance over 2020 has had significant personal impact.

2021 base salary

The REMCO decided in April 2020 that in light of the financial challenges and the need for disciplined management of operating expenses, there would be no salary increases for Executive Directors and Senior Management for 2021. There will also be no salary increase for the majority of Shell employees globally.

Annual bonus

The REMCO had approved a 2020 annual bonus scorecard at its meeting on January 28, 2020, based on Shell's operating plan, but this scorecard was not communicated to participants as within a few weeks it became clear that the operating plan had been overtaken by events and was no longer appropriate. It was decided that targets would not be reset, but that operating priorities would be recast to Care in terms of health, safety and well-being for our people, Continuity for our business to support customers and communities and to Cash management to ensure the financial resilience of Shell. The approved scorecard was set aside and Care, Continuity and Cash quickly became the new framework to reflect on performance.

It had also become clear that there would be difficult financial outcomes ahead. Shell announced a change to the financial framework in March 2020. This included stating that we would not proceed with the next tranche of the share buyback programme and would be rebasing the dividend. In light of this, the REMCO decided that there should be no 2020 annual bonuses for Executive Directors and Senior Management. As no Group scorecard was being published and there would be no measurement of performance against the obsolete 2020 scorecard targets other employees were informed that the Group scorecard outcome for 2020 would be set to zero. This was communicated in April 2020 to allow employees to make financial plans.

After the depths of the crisis, there has been some recovery in commodity prices and the business has been resilient in 2020, delivering strong cash generation relative to our peers and performing strongly on safety. But taking into account all relevant factors such as business performance, impairments, dividend changes and the limited use of government support, the REMCO confirmed that its decision that there should be no 2020 annual bonuses for Executive Directors and Senior Management remained appropriate.

Vesting of 2018 LTIP awards

The financial resilience of Shell and work in recent years to high-grade the portfolio are evident in the vesting outcome of the LTIP, which was 90% out of a maximum of 200% based on relative total shareholder return (TSR), CFFO growth, return on average capital employed (ROACE), and absolute free cash flow (FCF).

- CFFO is measured on a relative basis and Shell ranked first, leading to a vesting outcome of 50%. Total CFFO was \$34 billion in 2020, with more than \$129 billion generated over the three-year vesting period. In absolute terms, this is more than double the CFFO generated in 2020 by our next closest competitor.
- On TSR, Shell ranked third in the peer group. Returning \$55 billion to shareholders over three year performance period in the form of dividends and share buybacks and leading to a vesting outcome of 20%.
- The ROACE performance metric is assessed on a relative basis and Shell ranked third, leading to a vesting outcome of 20%.

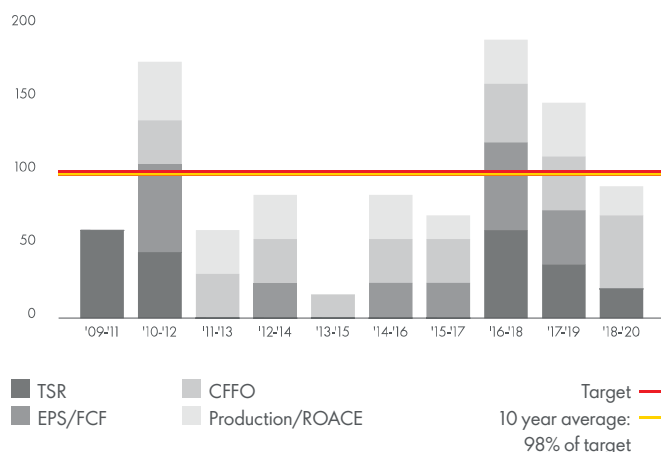
The challenges of 2020 are clearly evident in the outcome on the FCF, which is measured on an absolute basis, based on the sum of the annual operating plan targets over the three year performance period. The outcome, \$87 billion, was below the vesting threshold of \$93 billion (target \$102 billion).

In making the final vesting decision, the REMCO considered the overall performance of Shell during the three-year vesting performance period. In its deliberations, the REMCO paid particular attention to:

- the shareholder experience;
- guidance issued by the investor community and feedback from shareholders regarding the appropriate pay outcomes for 2020 in light of the COVID-19 pandemic;
- the impact of the pandemic on financial outcomes;
- the effectiveness of management over the performance period in developing a high-quality portfolio capable of delivering resilient cash flows;
- the conclusion that there should be no 2020 annual bonuses, which took into account business performance, impairments, dividend changes and the limited use of government support;
- the Committee assured itself that the limited use of government support had not impacted the vesting outcomes; and
- the impact of the high shareholding requirement, which has helped align the interests of Executive Directors and shareholders.

The REMCO also noted it would mean a 10-year average vesting outcome of the LTIP of 98%, demonstrating the effectiveness of the current LTIP structure in delivering alignment with target pay and balancing cyclical performance. Taking all these factors into account, the REMCO determined to vest the 2018 LTIP awards at 90% without using discretion. A formulaic outcome was also applied to the Performance Share Plan (PSP) made to around 16,500 employees annually.

LTIP vesting

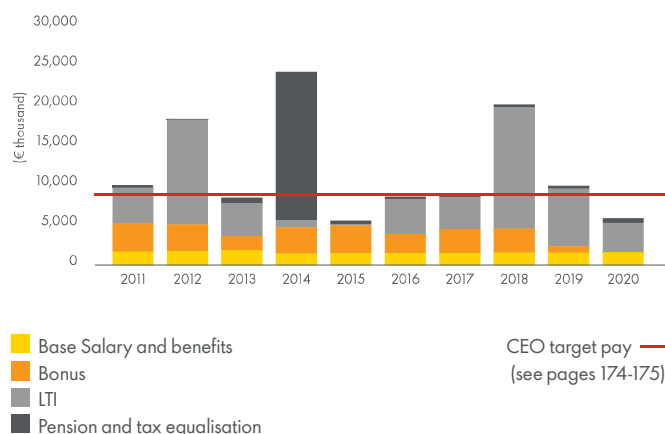


2020 single figure of remuneration

The overall single figure of remuneration for 2020 is €5.8 million for the CEO and €3.7 million for the CFO. This is one of the lowest CEO single figure outcomes in ten years.

In finalising these amounts, the REMCO noted the decline in pay outcomes from the previous year. These, as noted above, were a decline of 41% for the CEO and 38% for the CFO. The REMCO considered that the decision that there should be no 2020 annual bonuses appropriately reflected Shell's 2020 performance outcomes, including the business performance, financial impairments taken in the year and dividend changes. It also considered the strong alignment between Executive Director and shareholder interests through the shareholding requirements. The REMCO also took account of the pay outcomes for employees, the majority of whom received no 2020 bonus and will not receive a 2021 salary increase. The REMCO was satisfied that the remuneration policies had operated as intended and that realised pay in 2020 was appropriate in the context of wider Company performance and the target pay opportunity as illustrated on pages 174-175.

Ten year CEO single figure outcomes



2021 LTIP grants

In considering the response to the challenges of 2020, the REMCO believes it is important to maintain the strong focus on variable pay. The LTIP is an important element of the pay framework. It has been proven to provide a robust link between pay and performance over a sustained period of time. The usual awards are 300% of base salary for the CEO and 270% for the CFO. When determining award sizes, the REMCO has been mindful of the risk of windfall gains, given how the decline in the Shell share price during 2020 affected the number of shares awarded. The REMCO has sought to consider how shareholders will view this issue, in light of their disappointment with returns and the rebasing of the dividend. At the same time, the REMCO has sought to continue paying competitively in line with the approved remuneration policy.

Taking this into account, the REMCO has decided to make a reduction to the award level for 2021 as a one-off acknowledgement of the unique circumstances. Shell's share price has declined approximately 24% for RDS A shares and 16% for RDS.A ADS since the 2020 share awards. The REMCO has decided to reduce the 2021 awards by 50% of the fall in the share price and has therefore reduced the usual LTIP awards for the CEO and CFO. On this basis, the REMCO approved an award of 231,679 RDS A shares for the CEO and 69,972 RDS.A ADS for the CFO on March 5, 2021. The number of shares awarded to the wider employee population also increased to maintain a competitive pay opportunity.

DIRECTORS' REMUNERATION REPORT continued

Regardless of the number of shares awarded, the REMCO will closely scrutinise performance over the vesting period to ensure the highest variable pay outcomes are only achieved for the highest quality of performance across all significant areas of activity. If required, discretion will be used to address windfall gains on vesting. This will take into account the effect of any recovery in demand and energy sector outlook on Shell's share price as well as shareholder experience and management's success in delivering Shell's financial performance and strategic ambitions.

The REMCO will use discretion to override formulaic reward outcomes if they fail to reflect the wider financial or non-financial performance of Shell, or if management has benefited from a general economic or sectoral improvement outside their control. The REMCO has a strong track record of exercising discretion, having used it to adjust the outcome of the annual bonus in five of the past ten years.

EVOLVING REMUNERATION IN LINE WITH STRATEGY

Turning now to the future, I would like to provide further detail on how we intend to link pay to Shell's evolving strategic ambitions.

Powering Progress sets out a strategy to accelerate the transition of our business to net-zero emissions. Reflecting our evolving priorities, in future we will place greater focus on measures connected to succeeding in the energy transition, balanced with the fundamental requirements to deliver financial success, while operating our assets safely, effectively and to plan.

Safety

Safety remains Shell's number one priority, and as part of a refresh of Shell's safety framework, a new Serious Injury and Fatality Frequency (SIF-F) metric will replace Total Recordable Case Frequency (TRCF) as the personal safety metric on the annual bonus scorecard from 2021.

This adjustment is intended to increase attention on the most serious outcomes, to ensure the focus is on identifying and preventing incidents with the potential to cause life-altering injuries. The number of Tier 1 and 2 process safety incidents will be retained as the measure of process safety, with weighting for safety increasing from 10% to 15% (equally split between personal and process safety).

Energy transition

Shell has been at the forefront of linking executive pay to progress towards a lower-carbon future. We set a Net Carbon Footprint (NCF) target that covers emissions from our customers' use of our products as well as our own operational emissions, and have directly linked employee and management pay to three-year targets aligned with the NCF target. The LTIP energy transition performance metric includes the short-term targets relating to the NCF target and a number of other strategic business transformation targets that measure Shell's progress towards achieving our longer-term ambitions.

These measures extend the link between pay and the energy transition well beyond the linkage provided by short-term sustainability metrics that focus on operations. When we introduced these measures, Shell was the only major energy company to link long-term incentive pay in this way. We believe we are still among the front-runners in terms of the breadth and detail of our energy transition pay metrics.

Our original targets were calibrated to keep Shell in step with a society working to meet the goals of the 2015 Paris Agreement and to restrict the rise in global average temperature this century to well below two degrees Celsius above pre-industrial levels. But societal views have evolved rapidly and large parts of society have now set their sights on the most ambitious goal in the Paris Agreement: to limit the global temperature rise to 1.5 degrees Celsius. Shell recognised this, and in 2020 announced an updated target to be a net-zero emissions energy business by 2050, in step with society.

The connection to remuneration will strengthen with the updated strategy. We intend to reflect them in the following ways:

- As an energy user. Shell has a target to achieve net-zero operational emissions (Scope 1 and 2) by 2050, in step with society. In the annual bonus, progress will be linked to performance assessment based on the greenhouse gas (GHG) intensity of our main business lines and, from 2021, a new GHG-abatement target.
- As an energy provider. We have significantly raised our net carbon intensity target in step with achieving a 1.5 degrees Celsius future. We will measure this using our NCF metric. Meaningful carbon intensity reductions will require significant business transformations with longer timescales and are therefore best reflected in the LTIP. We are increasing the weighting of the energy transition condition to account for 20% of the LTIP (up from 10%), putting it on the same level as the financial measures (TSR, CFFO, FCF and ROACE), which will each account for 20% of the LTIP.
- As an energy partner. In our role as an energy supplier, we will work with sectors which use energy to help them identify and implement ways to decarbonise and make progress towards a net-zero emissions future. New performance measures will need to be developed in this area before it can be linked to remuneration. The REMCO will assess such performance measures, as is appropriate, in the future.

The connections between remuneration and progress in the energy transition received good support from shareholders during our engagements. These measures will continue to mature as we implement the updated strategy. I also know that many of you are keen to know how we are progressing on the existing energy transition condition and further information is provided on pages 164-165.

Other changes to 2021 remuneration

To ensure that Shell's remuneration structures evolve in line with the recent strategy developments, the following changes will also take place for the 2021 annual bonus scorecard:

- The weighting of the CFFO metric will increase from 30% to 35%, reflecting our commitment to the updated financial framework.
- The strength of Shell is as an integrated energy business and our updated strategy and portfolio choices emphasise operational excellence and the delivery of value rather than volume. To reflect this, we will retire the existing production and LNG liquefaction volume measures. We will introduce a new asset management excellence measure, based on Upstream controllable availability, midstream availability and downstream availability. This is designed to encourage an ongoing focus on running our assets effectively and to schedule. Operational excellence will always be fundamental to our success, but its weighting will decrease from 50% of the scorecard to 35% to allow for increased weightings on CFFO, progress in the energy transition and safety.
- We will further emphasise the importance of achieving progress in the energy transition by making this a separate section of our scorecard. Performance will be based on GHG-emissions-intensity targets and assessments of the delivery of GHG-abatement projects that support our net-zero operational emissions target. These targets will account for 15% of the scorecard.

LOOKING AHEAD

The year ahead promises to be another busy one as we look to continue to enhance our alignment of pay with the updated strategy. I look forward to continuing to engage with shareholders in the coming months and I thank you for your continued support.

NEIL CARSON

Chair of the Remuneration Committee
March 10, 2021

ANNUAL REPORT ON REMUNERATION

The Annual Report on Remuneration sets out:

- the REMCO's responsibilities and activities, page 157;
- remuneration at a glance, page 158;
- Directors' remuneration for 2020, page 159; and
- the statement of the planned implementation of policy in 2021, page 170.

The base currency in this Annual Report on Remuneration is the euro, as this is the currency of the base salary of the Executive Directors. Where amounts are shown in other currencies, an average exchange rate for the relevant year is used, unless a specific date is stated, in which case the average exchange rate for the specific date is used.

REMUNERATION COMMITTEE

Biographies are given on pages 114-120; and the REMCO meeting attendance is set out below:

Committee Member	Member since	Maximum possible meetings	Number of meetings attended	% of meetings attended
Neil Carson (Chair)	June 1, 2019	5	5	100%
Gerard Kleisterlee [A]	May 21, 2014	2	2	100%
Euleen Goh [B]	May 20, 2020	3	3	100%
Catherine Hughes	July 26, 2017	5	5	100%
Sir Nigel Sheinwald [C]	May 24, 2017	2	2	100%
Gerrit Zalm [D]	May 21, 2014	5	4	80%

[A] Gerard Kleisterlee retired from Shell after the 2020 Annual General Meeting, held on May 19, 2020.

[B] Euleen Goh was appointed to the REMCO with effect from May 20, 2020.

[C] Sir Nigel Sheinwald stood down as a member of the REMCO with effect from May 20, 2020.

[D] Gerrit Zalm was unable to attend the December 2020 meeting due to an agenda clash arising from a late rescheduling of the meeting.

The REMCO's key responsibilities include determining:

	Senior Management		
	Executive Directors	Executive Committee	Company Secretary
Performance framework	✓	✗	✗
Remuneration policy	✓	✓	✗
Actual remuneration and benefits	✓	✓	✓
Annual bonus and long-term incentive measures and targets	✓	✓	✓

The REMCO is also responsible for determining the Chair of the Board's remuneration. The REMCO monitors the level and structure of remuneration for senior executives below Senior Management, and makes recommendations if appropriate to ensure consistency and alignment with Shell's remuneration objectives. When setting the policy for Executive Director remuneration, the REMCO reviews and considers workforce remuneration and related policies, and how incentives and rewards align with culture.

In exercising its responsibilities, the REMCO takes into account a variety of stakeholder considerations.

The REMCO operates within its Terms of Reference, which are reviewed annually. They were last updated on March 13, 2019 and are available at www.shell.com.

Advice from within Shell was provided by:

- Ben van Beurden, Chief Executive Officer;
- Ronan Cassidy, Chief Human Resources and Corporate Officer and Secretary to the REMCO; and
- Stephanie Boyde, Executive Vice President Performance and Reward.

The Chair of the Board was consulted on remuneration proposals affecting the CEO, and the CEO was consulted on proposals relating to the CFO and Senior Management.

During 2020, the REMCO met five times and its activities included:

- carefully deliberating on pay quantum for the CEO;
- determining vesting of the 2017 LTIP award for Senior Management;
- deciding on 2019 annual bonus outcome, 2020 base salaries, 2020 target bonuses and 2020 LTIP awards for Senior Management;
- developing the Directors' Remuneration Policy in preparation for the 2020 AGM vote, in consultation with shareholders;
- approving the 2019 Directors' Remuneration Report;
- setting 2020 annual bonus and LTIP performance measures and targets and subsequently making the decision that there should be no annual bonus in 2020;
- considering matters related to business performance, the implications of the COVID-19 pandemic and its impact on employees, and determining that no salary increases would apply for 2021 for Executive Directors and Senior Management;
- considering matters relating to the updated strategy and accelerated transition of our business to net-zero emissions and the potential implications for 2021 annual bonus and LTIP performance measures and targets; and
- monitoring external developments and assessing the impact on the Directors' Remuneration Policy.

In 2020, the REMCO reviewed benchmarking data and analysis on executive pay market developments that were prepared by Shell's internal HR function. The REMCO has not incurred external remuneration adviser fees.

PRINCIPLES

The principles that underpin the REMCO's approach to executive remuneration are set out on page 173.

The REMCO considered the provisions of the UK Corporate Governance code, and in deciding 2020 pay outcomes it has sought to reflect the principles of clarity, simplicity, risk management, predictability, proportionality and alignment with culture.

Shell has a consistent global reward and performance philosophy that sets clear expectations of employees. Through the annual bonus scorecard and the LTIP, remuneration is clearly aligned with Shell's operating plan and strategic ambitions. The same measures apply to Executive Directors and Senior Management and to a significantly broader employee base. This provides alignment throughout the organisation with Shell's culture and strategy. The annual operating plan translates into targets on the annual bonus scorecard, and a quarterly update on performance against scorecard targets is provided to employees. (Exceptionally in 2020, updates on the annual bonus scorecard were not published, this is discussed further on page 154.) Similarly the LTIP is largely based on outperforming the competition, and regular updates on Shell's performance against competitors is provided to employees. In reviewing the Directors' Remuneration Policy, approved at the 2020 AGM, the REMCO sought to make changes that help to simplify remuneration structures (for example, removing the individual performance factor for Executive Directors) and giving more transparent outcomes (for example, removing the bonus asymmetry from the CEO's remuneration structure). To assist in the mitigation of reputational risk and to ensure proportionality, the powers of the REMCO to apply malus and clawback and make discretionary adjustments to variable pay outcomes were expanded, with the intention that the REMCO will use discretion to ensure the highest pay outcomes are delivered only for outstanding performance.

ANNUAL REPORT ON REMUNERATION continued

REMUNERATION AT A GLANCE

2020

FIXED PAY AND SHAREHOLDING

Base salary

€1,588,000 €1,035,000

Ben van Beurden (CEO) Jessica Uhl (CFO)

Pension

Executive Directors participate in the same home-country pension arrangements as other employees

Benefits

Typically include car allowance, transport between home and office, and medical insurance

Shareholding

Target levels, % of base salary at December 31, 2020

700% **500%**
CEO CFO (from 400%)

Actual levels, % of base salary at December 31, 2020

637% **333%**
CEO CFO

ANNUAL BONUS

2020 annual bonus

The REMCO determined that there should be no 2020 annual bonuses.

LONG-TERM INCENTIVE PLAN

2018 – 2020 LTIP vesting outcome

€3,697,574 \$2,377,494

CEO (49% reduction from prior year)

CFO (45% reduction from prior year)

Vesting outcome

Measures	Outcome	Vesting
TSR	1 2 3 4 5	20%
CFFO	1 2 3 4 5	50%
ROACE growth	1 2 3 4 5	20%
FCF		0%
		90% (out of a 200% maximum)

Shares are subject to a three-year holding period which extends beyond an Executive Director's tenure

2021

FIXED PAY AND SHAREHOLDING

Base salary

€1,588,000 €1,035,000

CEO
No change from 2020

CFO

Pension

No change from 2020

Benefits

No change from 2020

Shareholding

Target levels, % of base salary 2021

700% **500%**
CEO CFO

Actual levels, % of base salary March 5, 2021

919% **526%**
CEO CFO

ANNUAL BONUS

Target % of base salary

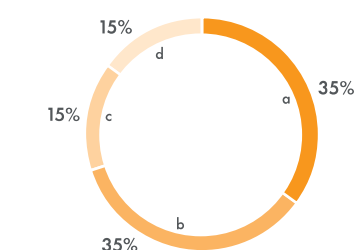
Target

125% **120%**
CEO CFO

Maximum

250% **240%**
CEO CFO

Scorecard architecture



- a **Cash flow from operations** (weighted 35%)
- b **Operational excellence** (Asset management excellence 25%, Project delivery excellence 10%)
- c **Progress in the energy transition** (GHG abatement 5%, GHG management 10%)
- d **Safety** (SIF-F 7.5%, Tier 1 & 2 Process Safety 7.5%)

LONG-TERM INCENTIVE PLAN

Target awards % of base salary

Target – policy

300% **270%**
CEO CFO

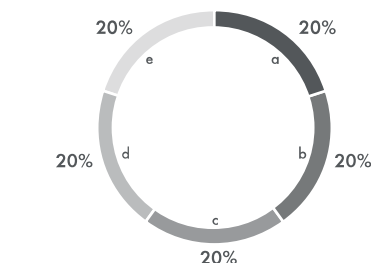
2021 adjusted awards

264.5% **248.5%**
CEO CFO

Maximum

529% **497%**
CEO CFO

Performance conditions



- a **TSR**
- b **ROACE**
- c **CFFO**
- d **FCF**
- e **Energy transition**

DIRECTORS' REMUNERATION FOR 2020

Single total figure of remuneration for Non-executive Directors (audited)

	€ thousand					
	Fees		Taxable benefits [A]		Total	
	2020	2019	2020	2019	2020	2019
Dick Boer [B]	98	-	-	-	98	-
Neil Carson [C]	184	99	-	-	184	99
Ann Godbehere	206	178	-	-	206	178
Euleen Goh	201	201	-	-	201	201
Charles O. Holliday [D]	850	850	69	71	919	921
Catherine J. Hughes	180	200	-	-	180	200
Martina Hund-Mejean [E]	98	-	-	-	98	-
Gerard Kleisterlee [F]	93	242	-	-	93	242
Sir Andrew Mackenzie [G]	37	-	-	-	37	-
Abraham Schot [H]	38	-	-	-	38	-
Roberto Setubal [I]	72	190	1	2	73	192
Sir Nigel Sheinwald	184	187	-	-	184	187
Linda G. Stuntz [J]	73	189	1	8	74	197
Gerrit Zalm	177	177	-	-	177	177

[A] UK regulations require the inclusion of benefits where these would be taxable in the UK, on the assumption that Directors are tax residents in the UK. On this premise, the taxable benefits include the cost of Non-executive Director's occasional business-required partner travel. Shell also pays for travel between home and the head office in The Hague, where Board and committee meetings are typically held, as well as related hotel and subsistence costs. For consistency, these business expenses are not reported as taxable benefits because for most Non-executive Directors this is international travel and hence would not be taxable in the UK.

[B] Appointed as a Director with effect from May 20, 2020.

[C] Appointed as a Director with effect from June 1, 2019.

[D] Including the use of a Shell-provided apartment while in the Hague (2020: €68,942, 2019: €70,624)

[E] Appointed as a Director with effect from May 20, 2020.

[F] Stepped down as a Director with effect from May 20, 2020.

[G] Appointed as a Director with effect from October 1, 2020.

[H] Appointed as a Director with effect from October 1, 2020.

[I] Stepped down as a Director with effect from May 20, 2020.

[J] Stepped down as a Director with effect from May 20, 2020.

Single total figure of remuneration for Executive Directors (audited)

	Ben van Beurden		Jessica Uhl	
	2020	2019	2020	2019
Salaries [A]	1,588	1,557	1,035	1,015
Taxable benefits [B]	16	20	418	326
Pension [C]	540	395	288	261
Total fixed remuneration	2,144	1,972	1,741	1,602
Annual bonus [D]	-	800	-	500
LTIP [E]	3,698	7,191	1,993	3,903
Total variable remuneration	3,698	7,991	1,993	4,403
Total remuneration	5,841	9,963	3,734	6,005
in dollars	6,671	11,155	4,264	6,724
in sterling	5,197	8,746	3,322	5,271

[A] As disclosed in the 2019 Directors' Remuneration Report, the REMCO set Ben van Beurden's base salary for 2020 at €1,588,000 (+2.0% compared with 2019) effective from January 1, 2020, and Jessica Uhl's base salary at €1,035,000 (+2.0% compared with 2019) effective from January 1, 2020.

[B] For Ben van Beurden these include motoring allowance (€14,400) and transport between home and the office (€1,150). Jessica Uhl's benefits include tax equalisation (€392,250), medical insurance (€14,921), transport between home and the office (€10,369) and tax return services (€430). Jessica Uhl's benefits includes tax equalisation of pension contributions to foreign pension plan(s), when they are taxable above a certain pensionable salary threshold or once a double tax treaty exemption ceases, under Dutch law. Tax equalisation is applied for the loss of pension relief for members of a foreign pension plan(s) in their host country. Jessica Uhl's benefits also include tax equalisation of employer contributions to benefits and certain US social taxes that are taxable in the Netherlands. For 2020, the presentation of the single total figure of remuneration has changed to include tax equalisation costs within taxable benefits. The 2019 taxable benefits has been adjusted on this basis and therefore differs from the value presented in the 2019 Annual Report.

[C] For Ben van Beurden, the amount reported for pension consists of a net pay defined contribution amount of €402,825. The amount to be reported for his defined benefit pension accrual is €137,479 calculated in accordance with UK reporting requirements. For Jessica Uhl, the amount reported for pension consists of a defined contribution amount of €103,486 and a defined benefit pension accrual €184,452.

[D] The full value of the bonus, comprising both the 50% delivered in cash and 50% bonus delivered in shares. For 2019, the market price of A shares on February 21, 2020 (€22.735), was used to determine the number of shares delivered, resulting in 9,521 A shares for Ben van Beurden and 5,951 A shares for Jessica Uhl.

[E] Remuneration for performance periods of more than one year, comprising the value of released LTIP awards. The amounts reported for 2020 relate to the 2018 LTIP award, which vested on March 5, 2021, at the market price of €17.85 and \$43.72 for A shares and A ADSs respectively. The value in respect of the LTIP is calculated as the product of: the number of shares of the original award multiplied by the vesting percentage; plus accrued dividend shares; and the market price of A shares or A ADSs at the vesting date. The market price of A ADSs is converted into euros using the exchange rate on the respective date. Share price depreciation accounted for -€1,620,234 on the LTIP for Ben van Beurden and -\$1,058,065 on the LTIP for Jessica Uhl.

ANNUAL REPORT ON REMUNERATION continued

Notes to the single total figure of remuneration for Executive Directors table (audited)

Annual bonus

As disclosed on pages 174-175, the annual bonus is intended to reward delivery of short-term operational targets as derived from Shell's operating plan.

Determination of the 2020 annual bonus

The REMCO had approved a 2020 annual bonus scorecard at its meeting on January 28, 2020, based on Shell's operating plan, which ultimately was not communicated or shared with participants. In March, as the implications of the pandemic became increasingly apparent, it became clear that the operating plan and 2020 scorecard had been overtaken by events and were no longer appropriate. It was decided that targets would not be reset but operating priorities would be recast to Care in terms of health, safety and well-being for our people, Continuity for our business to support customers and communities, and Cash management to ensure the financial resilience of Shell. The approved scorecard was set aside and there was no review of the targets or performance against it (or any other targets for the purposes of calculating bonus entitlements). Care, Continuity and Cash quickly became the new framework to reflect on performance.

It had also become clear that there would be difficult financial outcomes ahead. In March 2020, Shell announced a change to the financial framework. This included stating that we would not be proceeding with the next tranche of the share buyback programme and would be rebasing the dividend. In light of this, the REMCO decided there would be no 2020 annual bonuses for Executive Directors and Senior Management. As no Group scorecard was being published, employees were informed that the Group scorecard outcome for 2020 would be set to zero. This was communicated in April 2020 to allow employees to make financial plans.

After the depths of the crisis, there has been some recovery in commodity prices and the business has been resilient in 2020, delivering strong cash generation relative to our peers and performing strongly on safety. But we are far from the financial success in 2020 that would allow an annual bonus. Taking into account all the relevant factors such as business performance, impairments, dividend changes, and the limited use of government support, the REMCO confirmed that its decision that there should be no 2020 annual bonuses remained appropriate.

For reference, the redundant 2020 annual bonus framework is set out below. Full information of Shell's performance against our Key Performance Indicators can be found on pages 43-45.

2020 annual bonus framework (not used for performance assessment)

Measures [A]	Weight (% of scorecard)
Cash flow from operating activities (\$ billion)	30%
Operational excellence	50%
Production (kboe/d)	12.5%
LNG liquefaction volumes (mtpa)	12.5%
Refinery and chemical plant availability (%)	12.5%
Project delivery on schedule (%)	6.25%
Project delivery on budget (%)	6.25%
Sustainable development	20%
Total recordable case frequency (injuries/million hours)	5%
Operational Tier 1 and 2 process safety events (number)	5%
Upstream and Integrated Gas GHG intensity (tonnes of CO ₂ equivalent/tonne of hydrocarbon production available for sale)	4%
Refining GHG intensity (tonnes CO ₂ equivalent per Solomon's Utilized Equivalent Distillation Capacity (UEDC™))	4%
Chemicals GHG intensity (tonnes CO ₂ equivalent/tonne of petrochemicals production)	2%

[A] These metrics measure the effectiveness with which we operate our assets and portfolio base, assessed against our operational business plan. Shell's longer-term strategic ambitions are measured in the LTIP metrics.

LTIP Vesting

In 2018, Ben van Beurden was granted a conditional LTIP award of 340% (maximum 680%) of base salary and Jessica Uhl an award of 270% (maximum 540%), excluding share price movement and dividends.

In making the vesting decision, the REMCO considered Shell's performance over the three-year vesting period.

There was strong performance on free cash flow (FCF) in 2018, but Shell failed to meet plan targets in 2019 and 2020, and the overall performance outcome over three years fell below threshold.

The REMCO was encouraged by the resilience that Shell displayed over the course of 2020, including its ability to deliver positive cash flows despite very challenging headwinds. Shell ranked first among our competitors in relative CFFO growth. Total CFFO was \$34 billion in 2020, with more than \$129 billion generated over the three-year vesting period. In absolute terms, this is more than double the CFFO generated in 2020 by our next closest competitor. On TSR, Shell ranked third in the comparator group, with \$55 billion distributed to shareholders in the form of dividends and share buybacks. The work done in recent years to focus on capital discipline and get the portfolio to the right size was also reflected in the outcome for return on average capital employed (ROACE), where Shell ranked third among the comparators.

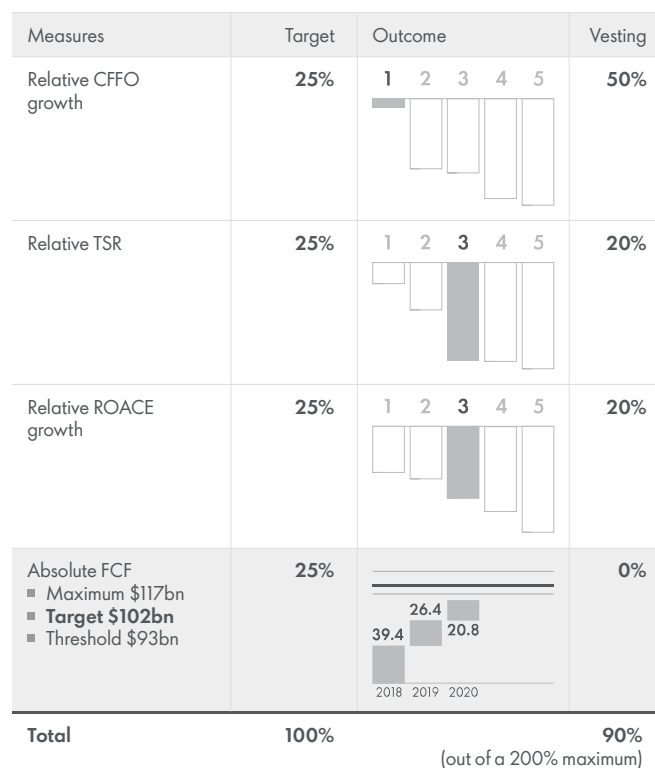
The REMCO also considered the change in share price between award and vesting, and the impact this had on the outcome. The REMCO also reflected on the overall single outcome for the CEO and decided that no adjustment to the vesting outcomes was required.

Accordingly, the REMCO determined that the LTIP should vest at 90% without the use of discretion. This is illustrated opposite.

The CEO's and CFO's vested awards are subject to a further three-year holding period which extends beyond Executive Director tenure.

2018 LTIP vesting outcome – performance metrics

■ Shell □ Comparator oil majors



2018 LTIP vesting outcome

CEO			
Vesting outcome: [A] 190,001 x 90% = 171,001 RDS A shares (€4,672,602)	+	Change in share price: [B] 171,001 x -€9.475 (-€1,620,234)	+
		Accrued dividends: [C] 36,146 RDS A shares (€645,206)	=
			Total LTIP Vesting: [C][D] 207,147 RDS A shares (€3,697,574) ↓ 49% reduction from prior year
CFO			
Vesting outcome: [A] 49,857 x 90% = 44,871 RDS.A ADS (\$3,019,818)	+	Change in share price: [B] 44,871 x -\$23.58 (-\$1,058,058)	+
		Accrued dividends: [C] 9,509 RDS.A ADS (\$415,733)	=
			Total LTIP Vesting: [C][D] 54,380 RDS.A ADS (\$2,377,494) ↓ 45% reduction from prior year

[A] Based on the share price at award of €27.325 for CEO and \$67.30 for CFO.
 [B] Calculated as the opening share price March 5, 2021 minus the share price at the date of award for the CEO €17.85 - €27.325 = -€9.475 and for the CFO \$43.72 - \$67.30 = -\$23.58
 [C] Based on the opening share price on the date of vesting, March 5, 2021 of €17.85 for CEO and \$43.72 for CFO.
 [D] Vested shares are subject to a three-year holding period.

ANNUAL REPORT ON REMUNERATION continued

In determining the final pay outcomes, the REMCO also considered the personal performance of the Executive Directors.

Personal performance 2018 – 2020

Key Goals	Ben van Beurden	Jessica Uhl
Deliver a world-class investment case	<p>Difficult times have demanded strong leadership, which the CEO has provided.</p> <p>In the face of unprecedented headwinds, Shell has shown impressive resilience. This reflects the value of the integrated portfolio and disciplined execution during 2020. The global economic conditions have required decisive action, including the suspension of the share buyback programme and rebasing of the dividend. Shareholder returns are fundamental to the investment case at Shell and the REMCO pays close attention to this when considering performance. These were not easy decisions to make, but the Board believes they were necessary to create resilience, and in combination with other cost preservation measures have contributed to making Shell stronger operationally and financially. The REMCO recognises the central role of the CEO in providing the direction and clarity of purpose that has guided the Company and underpinned this resilience during a challenging 12 months.</p>	<p>The challenges of 2020 have required strong strategic management of Shell's financial framework, and the CFO has played a critical role in ensuring the resilience of Shell during a highly volatile and unpredictable period.</p> <p>Key deliverables included the strong focus on cost discipline and the development of a renewed cash allocation framework which prioritises: capex and progressive dividend growth; net debt reduction (targeting AA credit metrics in the near term); additional shareholder distributions; and growth capex.</p> <p>In terms of broader Company performance, the REMCO recognised the strategic insight that the CFO has provided in terms of effective capital allocation, and portfolio and investment decisions that improve Shell's world-class investment case.</p>
Thrive in the energy transition	<p>The CEO has continued to lead Shell's NCF ambition by driving internal plans and targets, and by integrating business and investment decisions with Shell's longer-term ambitions.</p> <p>In 2020, Shell announced an updated strategic ambition to be a net-zero emissions energy business by 2050, in step with society. It concluded a comprehensive strategy update on how Shell intends to decarbonise energy customers while running legacy businesses for value rather than volume. The design of the new organisation (Project Reshape) necessary to support this strategy update was completed. These activities culminated in the updated strategy announced in February 2021. The REMCO acknowledges the fundamental importance of the CEO using these activities to position Shell for long-term success in the energy transition.</p> <p>Externally, the CEO has played a leading role in the energy transition debate through such initiatives as the first joint statement with institutional shareholders, encouraging other companies to adopt the NCF methodology. He has been instrumental in galvanising coalitions to start action on sectoral decarbonisation. His personal role, for example in the Aviation Clean Skies Initiative, is recognised by both customers and external stakeholders. His interventions have helped in shifting the climate agenda towards the practical measures that will be needed for creating sustained demand for lower-carbon products.</p>	<p>Over the performance period, the CFO has further matured the internal management systems relating to carbon dioxide (CO₂) in decisions about portfolio, planning and resource allocation. The CFO led the publication of the Shell Energy Transition Report, which is aligned with the recommendations of the Task Force on Climate-related Financial Disclosures (TCFD). The report sets out how Shell plans to be resilient to expected changes in the energy system and how its strategy helps it to thrive as the world transitions to lower-carbon energy.</p>
Strengthen societal licence to operate	<p>During 2020, Shell's priority has been the health and safety of our staff and customers. The REMCO recognises the leadership that the CEO has displayed in setting a tone of care and well-being across the organisation in 2020.</p> <p>In terms of HSSE leadership, there was a notable improvement in both personal and process safety in 2020. The number of fatalities under Shell operational control was zero.</p> <p>In 2019, Shell published the Industry Associations Climate Review, which assesses alignment with 19 industry associations on climate-related policy.</p>	<p>The CFO maintained a strong financial disclosure, reporting and control framework.</p> <p>In 2020, Shell published its second Tax Contribution Report, continuing to provide greater transparency around Shell's approach to paying taxes to governments. Over the performance period, the CFO also played a key role in Shell's endorsement of the responsible tax principles set out by the non-profit organisation, The B Team.</p>

The REMCO considered the single-figure outcomes for the CEO and CFO. It noted that the overall remuneration outcomes were 41% (CEO) and 38% (CFO) lower than in 2019. The REMCO was satisfied that these single-figure outcomes represented a fair level of remuneration. In deciding this, the REMCO took account of the challenging global economic conditions in 2020, and the steps necessary to reinforce the financial strength and resilience of Shell. It also considered the strong and positive leadership shown in setting out a clear strategic direction for Shell and ensuring it was supported by the necessary organisational design.

In finalising its remuneration decisions for 2020, the REMCO considered a range of factors, including:

- Shell's performance in 2020 and over the LTIP performance period 2018-2020;
- potential risk adjustment considerations, including safety, ethics and compliance and feedback from the Audit Committee and the Safety, Environment and Sustainability Committee;
- the actions taken to protect value, strengthen the balance sheet and preserve cash;
- the final LTIP vesting outcome;
- the internal relativity of remuneration compared with the variable pay outcomes for the general workforce;

- government support received in 2020. Most of this support was automatic, such as around SGD 55 million under the Singaporean Job Support Scheme and £20 million of business rate relief in the UK. Relief which Shell has applied for is very limited, with the most notable being CAD 34 million received under the Canadian Emergency Wage Subsidy scheme. Careful consideration was given prior to making an application as to whether it was appropriate to take this support. We are comfortable that doing so was appropriate from a Canadian perspective and consistent with doing all that we could to protect jobs and care for employees in the worst phase of the crisis, many of whom work in small communities. The REMCO reviewed and was satisfied that this support had no impact on the mathematical vesting outcome of the LTIP;
- the alignment of the Executive Directors with the shareholder experience through their high shareholding requirements;
- the decision that there should be no 2020 annual bonuses, which took into account business performance, impairments, dividend changes and the use of limited government support;
- feedback from shareholders regarding the appropriate pay outcomes in light of the COVID-19 pandemic; and
- the personal performance of the Executive Directors.

After reflecting on the above factors, the REMCO was satisfied that the remuneration policies had operated as intended.

Pension

Ben van Beurden's pension arrangements comprise a defined benefit plan with a maximum pensionable salary of €98,993; and a net pay defined contribution pension plan with a 2020 employer contribution of 27% of salary in excess of €98,993. He has the option to take cash as an alternative to pension contributions (in either case subject to income tax) and elected to take his benefit in the form of contributions throughout 2020.

The employer contribution levels are in line with those applicable to other Netherlands-based employees. Under the Dutch pension regulations applicable to the pension arrangement in which he participates, the contribution rate increases with age and is shown opposite.

At December 31, 2020, the average employer contribution rate for Netherlands employees who participate in the net pay defined contribution pension arrangement on the same terms as Ben van Beurden was 20%. For reference, in the UK, the average employer contribution rate to the Shell UK defined contribution plan is 20%.

Shell Netherlands Pension Stichting net pay defined contribution ladder

Age	Employer contribution
15 - 19	6.30%
20 - 24	7.54%
25 - 29	8.99%
30 - 34	10.44%
35 - 39	12.31%
40 - 44	14.38%
45 - 49	17.07%
50 - 54	19.77%
55 - 59	23.29%
60 - 64	(2020 rate for Ben van Beurden) 27.02%
65 - 67	30.13%

Jessica Uhl is a member of the Shell US retirement benefit arrangements, which include the Shell Pension Plan (a defined benefit plan), and a defined contribution plan where she receives an employer contribution of 10% of salary. This is the same as the average employer contribution rate for US employees, which was 10%. As for all other pre-2013 members of the Shell Pension Plan, she has an annual choice of two accrual formulas with different forms of benefits, one in the form of a lifetime annuity and the other allowing for a lump-sum payment. She elected to accrue benefits for 2020 under the former. Around 10,000 out of 17,000 Shell US employees have the option of choosing between the two formulas. These arrangements are the same for all employees who joined Shell US at the same time as Jessica Uhl. The difference in pension provision for Jessica Uhl, compared with employees who joined pre-2013, is that her bonus is not pensionable as an Executive Director while for other relevant US employees the bonus is pensionable. She also has a deferred Dutch defined benefit pension plan, as a result of a prior Shell assignment on local Dutch terms and conditions.

The REMCO believes these arrangements are aligned with corporate governance developments in the UK which emphasise the desirability of Executive Directors' pension arrangements being the same as those for the general employee population.

Scheme interests awarded in 2020

Scheme interests awarded to Executive Directors in 2020 (audited)

Scheme interest type	Type of interest awarded	End of performance period	Target award [A]	Potential amount vesting	
				Minimum performance (% of shares awarded) [B]	Maximum performance (% of shares of the target award) [A]
LTIP	Performance shares	December 31, 2022	Ben van Beurden: 200,589 A shares, equivalent to 3.0 x base salary or €4,764,000. Jessica Uhl: 59,062 A ADS shares, equivalent to 2.7 x base salary or €2,794,500	0%	Maximum number of shares vesting is 200% of the shares awarded, before dividends.

[A] The award for Ben van Beurden was based on the closing market price on the date of grant, January 31, 2020, for A shares of €23.75. The award for Jessica Uhl was based on the closing market price on the date of grant, January 31, 2020, for A ADSs of \$52.15.

[B] Minimum performance relates to the lowest level of achievement, for which no reward is given.

ANNUAL REPORT ON REMUNERATION continued

The measures and weightings applying to LTIP awards made in 2020 were: energy transition (10%), FCF (22.5%), TSR (22.5%), ROACE growth (22.5%) and growth in cash flow from operating activities (22.5%).

Absolute measures

Energy transition

The energy transition condition supports delivery of Shell's Net Carbon Footprint (NCF) target.

The condition consists of a mix of leading and lagging measures that set the foundations to contribute to Shell's strategic ambitions in the longer term. They are as follows:

Lagging measure – a measure of our progress in meeting our ambition:

- Net Carbon Footprint: a target for reducing the NCF of the energy products Shell sells (a carbon intensity measure that takes into account their full life-cycle emissions, including customers' emissions associated with using them).

Leading measures – the levers we will use to drive future NCF reduction:

- The growth of our power business: all decarbonisation scenarios recognise that a key way to cut greenhouse gas emissions is to increase electricity use and decarbonise electricity by shifting to renewables and gas-fired power generation. Our ambition to grow our power business is based on selective investments in generation, and in business models based on reselling power generated by others.
- Advanced biofuels and alternative fuels technology: biofuels are expected to play a valuable role in the changing energy mix and are likely to be one of the key decarbonisation levers for sectors that need to continue to use liquid fuels in the foreseeable future, such as some segments of transport and industry. For society and for Shell, commercialisation of advanced biofuel technology is one of the most important steps in energy transition.
- The development of systems to capture and absorb carbon: carbon capture and storage (CCS) and carbon sinks, such as nature-based solutions, are required as part of the global response to climate change.

Targets have been set for each element. Progress in the energy transition is not expected to be linear, because it will reflect the pace of change of society as a whole and the speed at which Shell progresses its strategic business objectives. As a result, targets have been set as ranges. These targets are commercially sensitive, so they will not be disclosed until the end of the performance period (or until they are no longer considered to be commercially sensitive). An update on our progress in relation to the measures is provided on page 165.

The vesting outcome for the part of the award weighted to the energy transition condition ranges from 0% to 200% of award. The REMCO, at its sole discretion, will determine vesting outcomes after considering achievement against the target ranges and feedback from the Safety, Environment and Sustainability Committee (SESCO). In doing so, the REMCO will take into account, in relation to each element, progress over the performance period relative to nearer-term aims in pursuit of the long-term ambition announced by Shell to reduce the NCF of energy products sold, in step with society's drive to meet the goals of the Paris Agreement. The starting point for determining the vesting outcome will be seeing how many of the targets have been met for each of the four areas. One out of four will equal 40%, two will equal 100%, three will equal 150%, and 200% will be achieved for scoring four out of four. It is important to note that performance against these elements will serve simply as a starting point for the REMCO, which will also take into account any other considerations it deems appropriate, including (without limitation) the relative importance of these elements in meeting the long-term ambition announced by Shell. For example, the REMCO may decide to allocate a greater importance to overall performance in relation to the NCF than the other three elements. The REMCO believes this approach is appropriate, given the uncertainties around the speed and direction of progress in the energy transition. The application of any discretion will be fully disclosed and explained by the REMCO.

Operation of energy transition measures in the 2020 LTIP

NCF reduction target

- Measured against 2016 base year (79 grams of CO₂ equivalent per megajoule)

Drive future NCF reduction

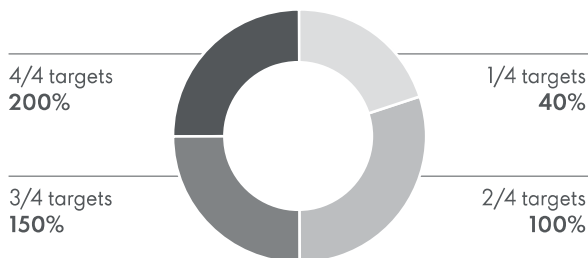
- Growing our power business
- Advanced biofuels technology
- Systems to capture and absorb carbon

2020 – 2022 target

- 3-4% reduction

**Accelerate
the transition
to net-zero
emissions**

Energy transition vesting (basis for the Remuneration Committee's decision) [A]



- 10% weighting
- Combination of leading and lagging measures
- Targets set as ranges
- Commercially sensitive targets, so will be disclosed retrospectively. Annual updates on progress relating to the measures will be provided

[A] The vesting schedule for the energy transition metric will be based on how many of the four targets are met. 1/4 will equal 40% vesting, 2/4 100%, 3/4 150%, and 4/4 200%. The Remuneration Committee may take into account other appropriate considerations, after taking advice from the Safety, Environment and Sustainability Committee. For example, it may increase the weighting of NCF relative to the other performance conditions in making its vesting decision. Any use of discretion will be disclosed and explained.

FCF

The FCF performance condition supports the delivery of our cash flow priorities, which are to service and reduce debt, pay dividends, buy back shares and make future capital investments.

The target for FCF, along with the ranges for threshold and outstanding performance, will be set by reference to Shell's annual operating plans, being the aggregate of our plan FCF targets over the three-year performance period. Given that FCF is heavily influenced by the volatility of oil and gas prices, the annual operating plans are updated each year to set an annual target to reflect a changing oil price premise. As a result, FCF targets are set annually for each annual operating plan and will only be disclosed in aggregate retrospectively after the three-year period. While consideration has been given to setting a three-year target at the outset, the REMCO has determined that such an approach would require adjustments for the oil and gas price premise and other matters at the end of the period, given the unpredictability and volatility in oil and gas prices. The REMCO has a long-standing "no adjustments" policy and therefore believes a more appropriate target-setting approach is to set the target based on the aggregation of the annual operating plans.

The amounts payable under this measure will range from 20% of the available maximum, for threshold performance, to full vesting for outstanding performance. A straight-line vesting schedule will apply for performance between threshold and outstanding.

Relative measures

The relative measures are based on our performance on a number of key financial metrics against the other oil majors.

For relative measures, we measure and rank growth based on the data points at the end of the performance period compared with those at the beginning of the period, using publicly reported data.

- TSR, calculated in US dollars using a 90-day averaging period around the start and end of the performance period;
- ROACE growth. For this purpose, in order to facilitate the comparison, the calculation of ROACE differs from that described in "Performance indicators" on page 43 because there is no adjustment for after-tax interest expense; and
- growth in cash flow from operating activities.

Each relative measure can vest independently with the amounts payable ranging from 0% to 200%, in accordance with the following vesting schedule:

- ranking first equals 200% vesting for the element of the LTIP weighted to that metric;
- ranking second equals 150% vesting for the element of the LTIP weighted to that metric;
- ranking third equals 80% vesting for the element of the LTIP weighted to that metric; and
- ranking fourth or fifth equals 0% vesting for the element weighted to that metric.

TSR Underpin

If the TSR ranking is fourth or fifth, the level of the award that can vest on the basis of the other measures will be capped at 50% of the maximum.

Performance update on energy transition metric Lagging indicator – NCF

Performance measurement is subject to third-party limited assurance. For the year ended December 31, 2020, NCF had reduced to 75 grams of CO₂ equivalent per megajoule, a 5% reduction against the baseline.

Leading indicators – power, advanced biofuels and systems to capture and absorb carbon

These targets are commercially sensitive, so they will not be disclosed until the end of the performance period (or until they are no longer considered

to be commercially sensitive). The REMCO, though, is committed to sharing progress. To date we are seeing positive progress across a range of indicators of future NCF reduction. Specific examples include:

- developments towards growing a material power business, such as the acquisition of ERM Ltd in Australia and investment in renewable energy projects such as CrossWind; and
- progress on the development of systems to capture and absorb carbon, for example the Northern Lights CCS joint venture with our partners, and nature-based solutions projects such as the acquisition of Select Carbon and Climate Bridge.

While many of these initiatives will take time to scale, they represent important steps towards building the organisational capacity and commercial value chains that will lead to future large-scale carbon reductions.

FCF

2019 LTIP award

At December 31, 2020, FCF performance is below target, with below-threshold outcomes for 2019 of \$26.4 billion (target \$35 billion) and for 2020 of \$20.8 billion (target \$38 billion). As one year of FCF performance remains, and 77.5% of the award is subject to relative and energy transition performance conditions, this does not reflect the potential vesting of the award.

2020 LTIP award

At December 31, 2020, FCF performance, \$20.8 billion for 2020, is below threshold (target \$38 billion). As two years of FCF performance remain, and 77.5% of the award is subject to relative and energy transition performance conditions, this does not reflect the potential vesting of the award.

Statement of Directors' shareholding and share interests (audited)

Shareholding guidelines

The REMCO believes that Executive Directors should align their interests with those of shareholders by holding shares in Royal Dutch Shell plc (the Company). The CEO is expected to build a shareholding with a value of 700% of base salary, and the CFO 500%. The shareholding requirement extends post-employment, such that Executive Directors will be required to maintain their shareholding requirement, or the number of shares actually held if this is less than the shareholding requirement, for a period of two years post-employment. There is a Company-sponsored nominee account which allows for restrictions to be applied on the sale or transfer of shares that are subject to holding periods and individual shareholding requirements. The restrictions remain in force beyond the Executive Director's employment.

Only unfettered shares count. Shares delivered that are subject to holding requirements also count towards the guidelines. The values of shares counting towards the shareholding guideline (as a percentage of base salary) for the CEO and CFO were 919% and 526%, respectively, at March 5, 2021. Non-executive Directors are encouraged to hold shares with a value equivalent to 100% of their fixed annual fee and to maintain that holding during their tenure.

Executive Directors' shareholding (audited)

	Shareholding guideline (% of base salary)	Value of shares counting towards guideline (% of base salary at December 31, 2020) [A]
Ben van Beurden	700%	637%
Jessica Uhl	500%	333%

[A] Following the vesting of the 2018 LTIP on March 5, 2021 their respective holdings are Ben van Beurden 919% and Jessica Uhl 526%.

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Directors' share interests

The interests (in shares of the Company or calculated equivalents) of the Directors in office during 2020, including any interests of their connected persons, are set out in the table below.

Directors' share interests (audited)

	January 1, 2020		December 31, 2020	
	A shares	B shares	A shares	B shares
Executive Directors [A]				
Ben van Beurden	647,426	-	866,433 [B]	-
Jessica Uhl	116,168 [C]	-	240,557 [D]	-
Non-executive Directors				
Dick Boer	10,000 [E]	-	10,000	-
Neil Carson	16,000	-	16,000	-
Ann Godbehere	-	4,700 [F]	-	10,000 [G]
Euleen Goh	-	12,895	-	12,895
Charles O. Holliday	-	50,000 [H]	-	50,000 [H]
Catherine J. Hughes	4,080	51,904 [I]	4,080	51,904 [I]
Martina Hund-Mejean	-	1,578 [J]	-	20,000 [K]
Gerard Kleisterlee	5,254	-	15,254 [L]	-
Sir Andrew Mackenzie	-	-	-	10,048
Abraham Schot [M]	-	-	-	-
Roberto Setubal	15,400 [N]	-	15,400 [O]	-
Sir Nigel Sheinwald	-	1,124	-	1,124
Linda G. Stuntz	-	12,400 [P]	-	12,400 [Q]
Gerrit Zalm	2,026	-	2,026	-

[A] Includes vested LTIP awards subject to holding conditions. Excludes unvested interests in shares awarded under the LTIP.

[B] Includes 174,000 RDS A shares pledged with Van Lanschot N.V.

[C] Held as 26,590 RDS A shares and 44,789 ADS (RDS.A ADS). Each RDS.A represents two A shares.

[D] Held as 34,069 RDS A shares and 103,244 ADS (RDS.A ADS). Each RDS.A represents two A shares.

[E] Interests at May 20, 2020, when he was appointed as a Director.

[F] Held as 2,350 ADSs (RDS.B ADS). Each RDS.B represents two B shares.

[G] Held as 5,000 ADSs (RDS.B ADS). Each RDS.B represents two B shares.

[H] Held as 25,000 ADSs (RDS.B ADS). Each RDS.B represents two B shares.

[I] Held as 46,904 RDS B shares and 2,500 ADS (RDS.B. ADS). Each RDS.B represents two B shares.

[J] Interests at May 20, 2020, when she was appointed as a Director. Held as 789 ADS (RDS.B ADS). Each RDS.B represents two B shares.

[K] Held as 10,000 ADSs (RDS.B ADS). Each RDS.B represents two B shares.

[L] Interests at May 19, 2020, when he stood down as a Director.

[M] On August 17, 2020, Bram Schot purchased 5,500 certificates Royal Dutch Shell A Turbo Long 8,2 BNP Paribas Markets (ISIN: NL0009558519) at a price of €5.37 per certificate. These certificates are cash settlement instruments the value of which is linked to the share price of RDS A Shares. In this case, the ratio of the turbo is 1:1 and accordingly 5,500 certificates represent 5,500 RDS A shares. As at March 10, 2021, the leverage is 1.69 but fluctuates depending on the share price. If the share price increases, the leverage will decrease. The finance level is 7.57 and the stop loss level is 8.2. The finance level is adjusted on the 15th of every month. Finance costs are 1.44% on an annual basis. With a turbo long, there is a finance-level and a stop loss-level. If the underlying share price drops below the stop loss-level, the turbo long is terminated. The investor then receives the value of the difference between the finance-level and the level on which the counterparty, in this case BNP Paribas, can close the turbo. Take for example a turbo with a stop loss-level of 10 and a finance-level of 8. When the underlying share price drops below 10, which is the stop loss-level, the buyer will still receive the amount 10-8=2. However, if the shareprice would suddenly drop to 8 or below, the buyer will receive nothing and the total investment is lost. In most cases however, the turbo would be terminated at the stop loss-level, and the buyer receives the amount of the difference between the finance-level and the stop loss-level. The actual amount will be determined by BNP. In addition, on August 27, 2020, Bram Schot purchased 100 Leonteq Express Euro Denominated Certificates on ING, Royal Dutch Shell, Unilever (ISIN: CH0470808913), with a nominal value of €1,000 each at a price of €515 per certificate. These certificates are cash settlement instruments of which payment of a conditional coupon depends for 1/3 on the development of the price of the RDSA A Shares on Euronext Amsterdam and, as such, is a financial instrument linked to the RDSA A Shares. Both transactions took place before Bram Schot became a Director of the Company.

[N] Held as 7,700 ADSs (RDS.A ADS). Each RDS.A represents two A shares.

[O] Interests at May 19, 2020, when he stood down as a Director. Held as 7,700 ADSs (RDS.A ADS). Each RDS.A represents two A shares.

[P] Held as 6,200 ADSs (RDS.A ADS). Each RDS.A represents two A shares.

[Q] Interests at May 19, 2020, when she stood down as a Director. Held as 6,200 ADSs (RDS.A ADS). Each RDS.A represents two A shares.

The only changes to Director's shareholdings as at March 5, 2021 are that:

- Sir Andrew Mackenzie acquired 7,396 RDS B shares on February 15, 2021;
- on February 12, 2021, Bram Schot purchased (i) an additional 2,500 certificates Royal Dutch Shell A Turbo Long 8,2 BNP Paribas Markets (ISIN: NL0009558519) at a price of €7.69 per certificate; and (ii) an additional 50 Leonteq Express Euro Denominated Certificates on ING, Royal Dutch Shell, Unilever (ISIN: CH0470808913), with a nominal value of €1,000 each at price of €715 per certificate; and
- following the vesting of the 2018 LTIP award, Ben van Beurden's share interests increased by 112,100 RDS A shares, and Jessica Uhl's by 28,059 RDS.A ADS.

At March 5, 2021, the Directors and Senior Management (pages 114-123) of the Company beneficially owned, individually and in aggregate (including shares under option), less than 1% of the total shares of each class of the Company shares. These shareholdings are not considered sufficient to affect the independence of the Directors.

Directors' scheme interests

The table below shows the aggregate position for Directors' interests under share schemes at December 31, 2020. These are RDS A shares for Ben van Beurden and A ADS for Jessica Uhl. During the period from December 31, 2020, to March 5, 2021, scheme interests have changed as a result of the vesting of the 2018 LTIP on March 5, 2021, and because of the 2021 LTIP awards made on March 5, 2021, as described on pages 161 and 163 respectively.

Directors' scheme interests (audited)

	Share plan interests [A]					
	LTIP subject to performance conditions [B]		DBP not subject to performance conditions [C]		Total	
	2020	2019	2020	2019	2020	2019
Ben van Beurden [D]	662,751	660,814	-	56,783	662,751	717,597
Jessica Uhl [E]	179,565	173,509	-	-	179,565	173,509

[A] Includes unvested long-term incentive awards and notional dividend shares accrued at December 31. Interests are shown on the basis of the original awards. The shares subject to performance conditions can vest at between 0% and 200%. Dividend shares accumulate each year on an assumed notional LTIP/DBP award. Such dividend shares are disclosed and recorded on the basis of the number of shares conditionally awarded but, when an award vests, dividend shares will be awarded only in relation to vested shares as if the vested shares were held from the award date. Shares released during the year are included in the "Directors' share interests" table.

[B] Total number of unvested LTIP shares at December 31, 2020, including dividend shares accrued on the original LTIP award.

[C] The number of shares deferred from the bonus (original DBP award) and the dividend shares accrued on these at December 31, 2019. DBP awards have been discontinued with the final awards taking place in 2017. No DBP awards remain outstanding following the final vesting of these awards in March 2020. Delivery of the original DBP award and the related accrued dividend shares is not subject to performance condition.

[D] RDS A shares.

[E] RDS.A ADS.

Dilution

In any 10-year period, no more than 5% of the issued ordinary share capital of the Company may be issued or issuable under executive (discretionary) share plans adopted by the Company, or 10% when aggregated with awards under any other employee share plan operated by the Company. To date, no shareholder dilution has resulted from these plans, although it is permitted under the rules of the plans, subject to these limits.

Payments to past Directors (audited)

No payments to past Directors were made in 2020. Payments below €5,000 are not reported as they are considered de minimis.

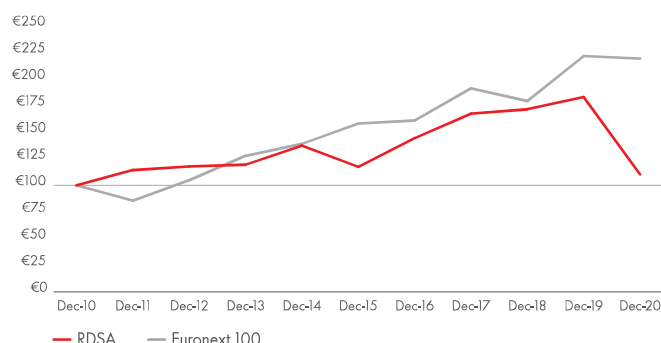
TSR performance and CEO pay

Performance graphs

The graphs compare the TSR performance of Royal Dutch Shell plc over the past 10 financial years with that of the companies comprising the Euronext 100 and the FTSE 100 share indices. The Board regards these indices as appropriate broad market equity indices for comparison, because they are the leading market indices in Royal Dutch Shell plc's home markets.

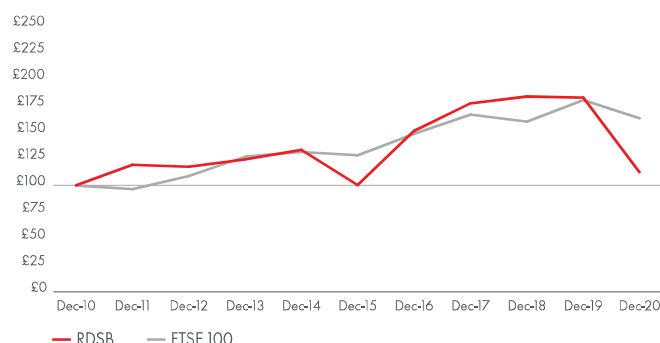
Historical TSR performance (RDSA)

Value of hypothetical €100 holding



Historical TSR performance (RDSB)

Value of hypothetical £100 holding



CEO pay outcomes

The following table sets out the single total figure of remuneration, the annual bonus payment and long-term incentive (LTI) vesting rates compared with the respective maximum opportunity, for the CEO for the past 10 years.

CEO pay outcomes

Year	CEO	Single total figure of remuneration (€000)	Annual bonus award against maximum opportunity	LTI vesting against maximum opportunity
2020	Ben van Beurden	5,841	0%	45%
2019	Ben van Beurden	9,963	21%	74%
2018	Ben van Beurden	20,138	79%	95%
2017	Ben van Beurden	8,909	81%	35%
2016	Ben van Beurden	8,593	66%	42%
2015	Ben van Beurden	5,576	98%	8%
2014	Ben van Beurden [A]	24,198	94%	49%
2013	Peter Voser	8,456	44%	30%
2012	Peter Voser	18,246	83%	88%
2011	Peter Voser	9,941	90%	30%

[A] Ben van Beurden's single total figure for 2014 was impacted by the increase in pension accrual (€10.695 million) calculated under the UK reporting regulations and tax equalisation (€7.905 million) as a result of his promotion and prior assignment to the UK.

Change in remuneration of Directors and employees from 2019 to 2020

As Royal Dutch Shell plc does not have any direct employees, the table below compares the remuneration of the Directors of Royal Dutch Shell plc with an employee comparator group consisting of local employees in the Netherlands, the UK and the USA. The local employee population of these countries is considered to be a suitable employee comparator group because: these are countries with a significant Shell employee base; a large proportion of senior managers come from these countries; and the REMCO considers remuneration levels in these countries when

setting base salaries for Executive Directors. For the purposes of comparison, the change in employee remuneration is calculated by reference to the change in salary scale, benefits and annual bonus for a notional employee in each of the base countries, not by reference to the actual change in pay for a group of employees.

Taxable benefits are those that align with the definition of taxable benefits applying in the respective country. In line with the "Single total figure of remuneration for Executive Directors" table, the annual bonus is included in the year in which it was earned.

Change in remuneration of Directors and employees

	RDS employees	UK, US & NL employees	Executive Directors							Non-executive Directors [A]					
			CEO	CFO	NC	AG	EG	CH	CJH	GK	RS	NS	LS	GZ	
Salaries	N/A	3%	2%	2%	86%	16%	0%	0%	-10%	-62%	-62%	-2%	-61%	0%	
Taxable benefits	N/A	0%	-24%	28%	0%	0%	0%	-2%	0%	0%	-64%	-100%	-93%	0%	
Annual bonus	N/A	-100%	-100%	-100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	

[A] Dick Boer, Martina Hund-Mejean, Sir Andrew Mackenzie and Abraham Schot were appointed as Directors during the course of 2020. They have been excluded from the table, because they had no previous year's remuneration for comparison.

ANNUAL REPORT ON REMUNERATION continued

Relative importance of spend on pay

The table below sets out distributions to shareholders by way of dividends and share buybacks, and remuneration paid to or receivable by employees for the last five years, together with annual percentage changes.

Relative importance of spend on pay

Year	Dividends and share buybacks [A]		Spend on pay (all employees) [B]	
	\$ billion	Annual change	\$ billion	Annual change
2020	9.1	-64%	12.1	-8%
2019	25.4	26%	13.2	-1%
2018	20.2	29%	13.4	-6%
2017	15.6	4%	14.3	-9%
2016	15	25%	15.7	-8%

[A] Dividends paid, which includes the dividends settled in shares via our Scrip Dividend Programme and repurchases of shares as reported in the "Consolidated Statement of Changes in Equity".

[B] Employee costs, excluding redundancy costs, as reported in Note 26 to the "Consolidated Financial Statements".

Spend on pay can be compared with the major costs associated with generating income by referring to the "Consolidated Statement of Income". Over the last five years, the average spend on pay was 5% of the major costs of generating income. These costs are considered to be the sum of: purchases; production and manufacturing expenses; selling, distribution and administrative expenses; research and development; exploration; and depreciation, depletion and amortisation.

Total pension entitlements (audited)

During 2020, Ben van Beurden and Jessica Uhl accrued retirement benefits under defined benefit plans. The pensions accrued under these plans at December 31, 2020 are set out below. The exchange rates used for conversion into euros and dollars are at December 31, 2020.

Accrued pension (audited)

Thousand	Local	€	\$
Ben van Beurden [A]	1,313	1,313	1,615
Jessica Uhl [B]	1,247	1,014	1,247

[A] The accrued benefits are disclosed on a per annum basis.

[B] Jessica Uhl has an annual choice of two accrual formulas with different forms of benefits. One is in the form of a lifetime annuity and the other allows for a lump-sum payment. She elected to accrue benefits up to 2018 under the latter, and the eventual lump-sum benefit is shown. From 2019, she elected to accrue benefits as a lifetime annuity. The value of this accrued benefit at December 31, 2020 was \$8,156 per annum plus a lump sum of \$227,029. She also has a deferred Dutch defined benefit pension plan, as a result of a prior Shell assignment on local Dutch terms and conditions. The age at which Jessica Uhl can receive any pension benefit without an actuarial reduction under this plan is 60. The value of the deferred pension benefit is €3,427 per annum.

The age at which Ben van Beurden can receive any pension benefit without actuarial reduction is 68 and for Jessica Uhl it is 65. Any pension benefits on early retirement are reduced using actuarial factors to reflect early payment. No payments were made in 2020 regarding early retirement or in lieu of retirement benefits.

Please refer to page 163 for further details (Pension).

External appointments

The Executive Directors held no external appointments in 2020.

Statement of voting at 2020 AGM

Shell's 2020 AGM was held on May 19, 2020, in the Netherlands.

The result of the poll in respect of Directors' remuneration was as follows:

Approval of Directors' Remuneration Report

Votes	Number	Percentage
For	3,806,079,000	95.44%
Against	181,791,609	4.56%
Total cast	3,987,870,609 [A]	100.00%
Withheld [B]	25,782,042	

[A] Representing 51.08% of issued share capital.

[B] A vote "withheld" is not a vote under English law and is not counted in the calculation of the proportion of the votes "for" and "against" a resolution.

The result of the poll in respect of the Directors' Remuneration Policy was as follows:

Approval of Directors' Remuneration Policy

Votes	Number	Percentage
For	3,705,707,055	92.91%
Against	282,966,810	7.09%
Total cast	3,988,673,865 [A]	100.00%
Withheld [B]	24,979,832	

[A] Representing 51.09% of issued share capital.

[B] A vote "withheld" is not a vote under English law and is not counted in the calculation of the proportion of the votes "for" and "against" a resolution.

Directors' employment arrangements and letters of appointment

Executive Directors are employed for an indefinite period. Non-executive Directors, including the Chair, have letters of appointment. Details of Executive Directors' employment arrangements can be found in the Directors' Remuneration Policy on page 179.

Further details of Non-executive Directors' terms of appointment can be found in the "Other regulatory and statutory information" on page 189 and the "Governance framework" report on page 128.

Compensation of Directors and Senior Management

During the year ended December 31, 2020, Shell paid and/or accrued compensation totalling \$36 million (2019: \$38 million) to Directors and Senior Management for services in all capacities while serving as a Director or member of Senior Management, including \$3 million (2019: \$3 million) accrued to provide pension, retirement and similar benefits. The amounts stated are those recognised in Shell's income on an IFRS basis. See Note 27 to the "Consolidated Financial Statements". Personal loans or guarantees were not provided to Directors or Senior Management.

CEO pay ratio

	Option	25th percentile pay ratio	Median pay ratio	75th percentile pay ratio
2020	A	93:1	57:1	38:1
Total pay and benefits:		£55,584	£90,972	£136,007
Salary:		£49,117	£75,365	£118,291
2019	A	147:1	87:1	54:1
Total pay and benefits:		£59,419	£100,755	£161,717
Salary:		£40,417	£56,721	£79,991
2018	A	202:1	143:1	92:1
Total pay and benefits:		£88,112	£124,459	£193,027
Salary:		£53,528	£80,407	£96,074

Shell has chosen to use option A to calculate the CEO pay ratio in accordance with guidance from the UK government that this is the preferred approach and the most statistically accurate method for identifying the ratios. Under option A, a comparable single total figure for all UK employees has been calculated in order to identify the employees whose pay and benefits are at the 25th, 50th and 75th percentiles for comparison with the CEO. Employee pay has been calculated based on the total pay and benefits paid in respect of 2020 for all employees who were employed on December 31, 2020. For part-time workers and joiners in the year, pay and benefits have been annualised based on the proportion of their working time in the UK during the year. This is calculated with an approach consistent with the methodology for determining annual bonuses. The REMCO believes that this provides a fair and reasonable calculation of the pay ratios for Shell employees in the UK.

The ratio of the CEO's pay to the median UK worker is 57. The global pay ratio, calculated by comparing the CEO single figure to the average employee headcount cost, is 50. The ratio has changed for 2020 compared with 2019, mainly because of the decrease in the single figure of remuneration for the CEO as a result of no 2020 annual bonus and the lower LTIP vesting outcome in comparison with 2019. The pay and benefits for the 25th, 50th and 75th percentile employees have also reduced in relation to 2019, primarily because there was no annual bonus for the majority of employees. The REMCO believes this outcome is appropriate and consistent with Shell's philosophy of pay for performance.

Workforce engagement

The REMCO took a wide perspective in making the remuneration decisions for 2020 and determining the 2020 policy. As examples, in 2020 the REMCO reviewed the following:

- Aspects of Shell's response to the COVID-19 pandemic that affected employees' pay and benefits. These included the decisions not to increase salaries for 2021 and to set the annual bonus scorecard outcome at zero, as well as policies that supported the health, safety and well-being of employees.
- The provision of retirement benefits to employees across Shell.
- Remuneration markers such as the CEO pay ratio and gender pay reporting under the UK Equality Act 2010 (Gender Pay Gap Information) Regulations and voluntary ethnicity pay reporting in the UK. The REMCO noted Shell's average UK gender pay gap had narrowed in 2020 to 18.0% (from 18.7% in 2019), continuing the positive trend since 2017 (22.2%). This is due to a continued upward trend in the proportion of women in Shell's upper and upper middle pay quartiles, and the REMCO has confidence in the policies Shell has to increase the representation of women at all levels in the organisation. The REMCO also noted, that in the first year of reporting, the average UK ethnicity pay gap was 8.5%.

Executive remuneration structures in Shell are strongly aligned with the broader Shell pay policy:

- In recent years the Group scorecard architecture has been identical to the Executive Committee and Senior Executive scorecard in terms of measures, weightings and targets.
- Executive Directors and Executive Committee members participate in the LTIP. Around 150 Senior Executives participate in the same plan. The measures and metrics for that plan also apply to 50% of the Performance Share Plan (PSP) awarded to around 16,500 employees.
- All employees in the Group participate in the relevant pension plan for their country based on their date of joining. Shell does not operate separate executive pension arrangements.

This consistency means that less explanation of executive remuneration structures is required than in companies where alignment is not the default practice. To support an ongoing dialogue with employees regarding how pay connects to Company strategy, a video was shared with employees, presented by the REMCO Chair, explaining the key features of the new 2020 Directors' Remuneration Policy in March 2020, alongside an article on the Shell intranet sharing why it matters for employees.

ANNUAL REPORT ON REMUNERATION continued

STATEMENT OF 2021 PLANNED IMPLEMENTATION OF POLICY

The Directors' Remuneration Policy as detailed on pages 173-181 took effect from May 19, 2020, after it was approved by shareholders at the 2020 AGM. It will be effective until the 2023 AGM, unless a further policy is proposed by Shell and approved by shareholders before then. This section describes elements of the policy that will apply for 2021.

Executive Directors

Salaries

There will be no salary increases for 2021. Salaries will be maintained at 2020 levels, which are €1,588,000 for Ben van Beurden and €1,035,000 for Jessica Uhl. This is consistent with the approach taken for the majority of employees for 2021.

Annual bonus

To ensure that the scorecard remains well aligned with our strategic and operational priorities, the REMCO has reviewed the structure of the 2021 scorecard. The REMCO has decided to focus on four key areas: financial delivery, operational excellence, progress in the energy transition, and safety.

Cash flow from operations (CFFO) remains the metric we will use to measure financial delivery. This reflects our ability to generate the cash necessary to fund investment in our future business and distributions to our shareholders. We are increasing the weighting of this metric from 30% to 35%.

Production and LNG Liquefaction volumes have been retired as performance metrics. Reflecting the ongoing importance of operational delivery, performance will be assessed against two measures:

- Asset management excellence: measured against availability for Upstream, midstream and downstream, each equally weighted, in order to maintain a strong ongoing focus on operating our assets to plan, delivering scheduled downtime activities on time and minimising unscheduled shutdowns; and
- Project delivery excellence: our ability to successfully execute large and complex projects remains essential, and we will continue measuring how well we deliver our material projects on time and to budget.

We are separating out energy transition to provide a clear and visible focus on the importance of making progress in this area. Measures will initially focus on the operational delivery of our ambitions, and we expect this section of the scorecard to evolve and expand as we accelerate the transition of our business to a net-zero emissions business by 2050, in step with society. For 2021, performance will be assessed against:

- GHG abatement: a new metric that measures execution of GHG abatement projects and sets us on a trajectory towards achieving net-zero operational emissions; and
- GHG emissions intensity: no change to this measure, which sets emission-intensity targets for our main lines of business.

Our commitment to safety remains at the heart of everything we do. We are increasing the weighting on safety in the scorecard to 15%. The measures relating to safety will be as follows:

- Personal safety: a new Serious Injury and Fatality Frequency (SIF-F) metric will replace Total Recordable Case Frequency as our measure of personal safety performance. This is to ensure we focus our attention and learning on those incidents with the potential to cause the most serious harm; and
- Process safety: no change to the number of Tier 1 and 2 operational safety incidents as our measure of process safety.

The performance measures, weightings and link to strategy for the 2021 performance year are set out below:

2021 annual bonus scorecard measures and weightings

Performance measure	Weighting
Financial	35%
Operational excellence	35%
Progress in the Energy Transition	15%
Safety	15%
	Link to strategy
Financial <ul style="list-style-type: none"> ■ Cashflow from operating activities 	Aligned with our financial priorities, reflecting our ability to generate cash to service and reduce debt, pay the dividend and fund capital investment.
Operational excellence <ul style="list-style-type: none"> ■ Asset management excellence ■ Project delivery excellence 	These metrics measure the effectiveness with which we operate our assets and portfolio base. This operational performance underpins the successful delivery of our financial framework and ambitions to progress in the energy transition.
Progress in the Energy Transition <ul style="list-style-type: none"> ■ GHG abatement ■ GHG management 	These metrics are focused on managing and reducing our operational emissions, supporting our ambition to reduce the emissions from the manufacture of our products by 2050.
Safety <ul style="list-style-type: none"> ■ Serious Injury and Fatality Frequency ■ Tier 1 & 2 process safety 	These metrics are designed to ensure an ongoing focus on personal and operational safety.

Annual bonus scorecard targets are not disclosed prospectively because to do so in a meaningful manner would require the disclosure of commercially sensitive information. Scorecard targets will be disclosed in the subsequent Directors' Remuneration Report when they are no longer deemed to be commercially sensitive.

Long-term Incentive Plan

On March 5, 2021, a conditional award of performance shares under the LTIP was made to the Executive Directors resulting in 231,679 Royal Dutch Shell plc A shares (A shares) being conditionally awarded to Ben van Beurden and 69,972 Royal Dutch Shell plc A American Depositary Shares (A ADSs) being conditionally awarded to Jessica Uhl. The award had a face value of 264.5% (maximum performance outcome 529%) of the base salary for the CEO and 248.5% (maximum performance outcome 497%) of the base salary for the CFO, excluding potential share price appreciation and dividends.

In making these awards, the REMCO considered the Company's share price and determined to use the closing share price on the award. But to moderate the impact of any potential windfall gains arising from share price volatility in 2020, the 2021 awards have been reduced 11.8% for the CEO and 8.0% for the CFO from the usual target award levels. This is equivalent to a 50% of the share price reduction since the previous award. Further discussion on the REMCO's approach to managing windfall gains is set out on page 155.

For LTIP awards made in 2021, performance will be assessed over a three-year period based on four financial measures and an energy transition condition. The weighting of the energy transition condition has been increased to 20%, reflecting the increasing importance of delivering on the strategic business transformations required to succeed in the energy transition.

The target for the FCF metric over the three-year performance period will be based on the annual operating plan and shareholder guidance. These targets are considered commercially sensitive and will be disclosed retrospectively, with annual updates on progress provided.

The NCF target range for the 2021-2023 LTIP grant is set as a 6-8% reduction from the 2016 NCF of 79 grams of CO₂ equivalent per megajoule. Our leading measures have also evolved as we have deepened our understanding of the speed and direction of the energy transition and revised our business strategies. For 2021-2023 we will measure performance based on three baskets of leading measures:

- building the foundations of a material Power business;
- growing new clean(er) energy product offerings; and
- developing carbon sinks.

The targets for these leading energy transition measures are commercially sensitive, and will be disclosed retrospectively where possible.

2021 LTIP measures and vesting schedule

■ Absolute measures
□ Relative measures

Energy transition	20%		
Free cash flow		20%	
TSR		20%	
ROACE growth			20%
CFFO growth			20%

Link to strategy

Vesting schedule (% of initial LTIP award)

Energy transition Metrics focused on the strategic business transformations that will seek to enable long-term success in the energy transition.	Metrics: a. NCF reduction target b. Build the foundation of a material Power business c. Grow new clean(er) energy product offerings d. Develop carbon sinks Vesting based on how many targets are achieved: 1/4 = 40% 3/4 = 150% 2/4 = 100% 4/4 = 200% REMCO may take into account other appropriate considerations.
Free cash flow Recognition of the importance of generating cash after net capital expenditure to service and reduce debt, pay dividends, buy back shares and make future capital investments.	Maximum – 200% Target – 100% Threshold – 40% Below threshold – 0%
TSR Assessment of actual value created for shareholders.	1st – 200% 2nd – 150% 3rd – 80% 4th or 5th – nil
ROACE growth Indicator of capital discipline.	
CFFO growth Source of capital expenditure commitments which support sustainable growth based on portfolio and cost management.	
TSR underpin If TSR is in fourth or fifth, vesting is capped at 50% of maximum.	
Holding period Three years post-vesting, which remains in force post-tenure.	

Discretion, adjustment (malus) and recovery (clawback)

Variable pay elements are subject to adjustment (malus) and recovery (clawback) provisions. The REMCO may adjust an award, for example by lapsing part or all of it, reducing the number of shares which would otherwise vest, by imposing additional conditions on it, or imposing a new holding period or applying clawback.

Please refer to the policy section on pages 173, 175 and 177 for a full description of the circumstances under which discretion, malus and clawback might be applied to a variable pay award.

Pension

Ben van Beurden's pension arrangements comprise a defined benefit plan for which the maximum pensionable salary has increased to €100,861 for 2021 and a net pay defined contribution pension plan with an employer contribution of 27% of salary in excess of this amount.

Jessica Uhl's US retirement benefit arrangements include the Shell Pension Plan, a defined benefit plan, and a defined contribution plan with an employer contribution of 10% of salary. She also has a deferred Dutch defined benefit pension plan, as a result of a prior Shell assignment on local Dutch terms and conditions.

Further details of Executive Director pension arrangements can be found on page 163.

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Non-executive Directors' fees

Non-executive Directors' fees 2021

	€	Other fees
Chair of the Board	850,000	Non-executive Directors receive an additional fee of €5,000 for any Board meeting involving intercontinental travel – except for one meeting a year held in a location other than The Hague.
Non-executive Director	135,000	
Senior Independent Director	55,000	
Audit Committee		
Chair [A]	60,000	
Member	25,000	
Safety, Environment and Sustainability Committee		
Chair [A]	35,000	
Member	17,250	
Nomination and Succession Committee		
Chair [A]	25,000	
Member	12,000	
Remuneration Committee		
Chair [A]	40,000	
Member	17,250	

[A] The chair of a committee does not receive an additional fee for membership of that committee.

The Chair's fee is determined by the REMCO and the annual fee for Charles O. Holliday was set at €850,000 upon appointment in 2015 and will remain unchanged for 2021. Mr Holliday will step down as Chair following the 2021 AGM. Following a review of the competitive positioning of the fee by the REMCO, the annual fee for the new Chair will also be €850,000. The Chair of the Board does not receive any additional fee for chairing the Nomination and Succession Committee or attending any other Board committee meeting.

The Non-executive Directors receive a basic fee. There are additional fees for the Senior Independent Director, a Board committee chair or a Board committee member for each committee. Non-executive Directors receive an additional fee of €5,000 for most Board meetings involving intercontinental travel. Business expenses (including transport between home and office and occasional business-required partner travel) and associated tax are paid or reimbursed by Shell. The Chair has use of a Shell-provided apartment while in The Hague.

The Board reviews Non-executive Directors' fees periodically to ensure that they are aligned with those of other major listed companies, using the largest 30 companies by market capitalisation listed on the FTSE and the European Comparator group as the primary points of reference. The last general review was in 2018. There was a review of the Chair of the Board's fee in 2021 and the Nomination and Succession Committee fees in 2019. Fees will remain unchanged for 2021.

DIRECTORS' REMUNERATION POLICY

The Directors' Remuneration Policy sets out:

- A summary of proposed changes to the Directors' Remuneration Policy, page 173;
- Executive Directors' Remuneration Policy, page 174; and
- Non-executive Directors' Remuneration Policy, page 180.

This section describes the Directors' Remuneration Policy (Policy) which, following shareholder approval at the 2020 Annual General Meeting (AGM), came into effect from May 19, 2020, and will be effective until the 2023 AGM, unless a further policy is proposed by Royal Dutch Shell plc (the Company) and approved by shareholders in the meantime.

The principles underpinning the REMCO's approach to executive remuneration are the foundation for everything we do, and are:

- Alignment with Shell's strategy: the Executive Directors' compensation package should be strongly linked to the achievement of stretching targets that are seen as indicators of the execution of Shell's strategy;
- Pay for performance: the majority of the Executive Directors' compensation, (excluding benefits and pensions), should be linked directly to Shell's performance through variable pay instruments;
- Competitiveness: remuneration levels should be determined by reference internally against Shell's Senior Management and externally against companies of comparable size, complexity and global scope;
- Long-term creation of shareholder value: Executive Directors should align their interests with those of shareholders by holding shares in Shell;
- Consistency: the remuneration structure for Executive Directors should generally be consistent with the remuneration structure for Shell's Senior Management. This consistency builds a culture of alignment with Shell's purpose and a common approach to sharing in Shell's success;
- Compliance: decisions should be made in the context of the Shell General Business Principles and Code of Conduct. The REMCO also

seeks to ensure compliance with applicable laws and corporate governance requirements when designing and implementing policies and plans; and

- Risk assessment: the remuneration structures and rewards should meet risk-assessment tests to ensure that shareholder's interests are safeguarded and that inappropriate actions are avoided.

The Executive Directors' remuneration structure is made up of a fixed element of basic pay and two variable elements: the annual bonus (50% delivered in shares) and the Long-term Incentive Plan (LTIP). Variable pay outcomes are conditional on the successful execution of the operating plan in the short term and the delivery of strategic goals and financial outperformance over the longer term. The award of shares under the bonus and LTIP, along with significant shareholding requirements, are intended to ensure executives have a sizeable shareholding in Royal Dutch Shell plc (the Company) and experience the same outcomes as shareholders.

During 2018 and 2019, the REMCO reviewed the Remuneration Policy to ensure that the Policy continues to be aligned with Shell's strategy, including delivery of shareholder returns. REMCO determined that while the current policy remains appropriate in many respects, certain changes will support the REMCO to simplify remuneration structures and address the management of quantum. For each area of the policy, the REMCO has considered market practice, the corporate governance environment and feedback from shareholders. The Safety, Environment and Sustainability Committee (SESCO) has provided input to the development of the sustainable development and energy transition metrics. Any potential conflict of interest is mitigated by the independence of the REMCO members and the REMCO Terms of Reference.

A summary of the main changes to the Policy for the Executive Directors is outlined below. No significant changes were made to the Policy for Non-executive Directors.

Remuneration element	Proposed Changes to Policy	Rationale for the change
Annual Bonus	<ul style="list-style-type: none"> ■ Reduction of the CEO's target bonus from 150% to 125%; and ■ Removal of the individual performance factor for Executive Directors. 	<ul style="list-style-type: none"> ■ Simplification: the asymmetry in the CEO's bonus structure and the inclusion of individual performance factors were creating undue complexity; and ■ Transparency: The annual bonus is now solely linked to the performance of Shell to support clarity and transparency of outcomes.
Long-Term Incentive Plan	<ul style="list-style-type: none"> ■ Reduction of the target LTIP grant from 400% to 300% of base salary; and ■ Inclusion of an energy transition metric. 	<ul style="list-style-type: none"> ■ Management of quantum: to moderate the quantum of pay and assist the REMCO in managing the range of outcomes; and ■ Alignment to strategy: inclusion of the energy transition metric strengthens the LTIP's alignment to Shell's strategy and purpose.
Discretion, Malus and Clawback	<ul style="list-style-type: none"> ■ After reviewing the single figure outcomes for the year, the REMCO will consider an adjustment for the purposes of managing remuneration quantum, taking into account performance, the operation of the remuneration structures and any other relevant considerations. An explanation of any discretionary adjustment would be set out in the relevant Director's Remuneration Report; ■ Alignment of malus and clawback provisions so that these are the same. Inclusion of corporate failure as an adjustment event; and ■ Amendment of provisions in the share plan such that for future grants, awards may be adjusted for any reason. 	<ul style="list-style-type: none"> ■ Corporate governance: to assist the REMCO in managing the risks from behavioural-based incentive schemes; and ■ Management of quantum: to assist the REMCO in managing the range of outcomes.
Pension	<ul style="list-style-type: none"> ■ New Executive Directors who are members of a defined benefit pension arrangement will have their pensionable salary capped at the salary applicable immediately prior to appointment, with the exception of existing US base country participants who will have the bonus removed from the definition of pensionable base salary instead. The Executive Director will join a defined contribution scheme in their base country for contributions made in respect of salary above the defined benefit pensionable salary, or in exceptional circumstances, receive a cash allowance equivalent to the contribution above the cap; and ■ For recruitment: Explicit confirmation that new appointees, whether internally promoted or newly hired, will be provided with a pension in line with the wider workforce in their base country. 	<ul style="list-style-type: none"> ■ Management of quantum: to moderate the quantum of pay and assist the REMCO in managing the range of outcomes; and ■ Corporate governance: to adopt best practice in line with external guidelines.
Shareholding Requirement	<ul style="list-style-type: none"> ■ CFO requirement increased to 500% of base salary; and ■ Extended so it applies for a period of two years post-employment (at the lower of the shareholding requirement or the number of shares held at departure). 	<ul style="list-style-type: none"> ■ Alignment with shareholders: further aligns executives with the long-term interests of shareholders.

DIRECTORS' REMUNERATION POLICY continued

EXECUTIVE DIRECTORS

Executive Directors' remuneration policy table

Purpose and link to strategy	Maximum opportunity	Operation and performance management
Salary and pensionable base salary		
Provides a fixed level of earnings to attract and retain Executive Directors.	€2,000,000	<p>Reviewed annually with adjustments effective from January 1.</p> <p>In making salary determinations, the REMCO will consider:</p> <ul style="list-style-type: none"> ■ the market positioning of the compensation packages; ■ comparison with Senior Management salaries; ■ the employee context, and planned average salary increase for other employees across the Netherlands, the UK and the USA; ■ the experience, skills and performance of the Executive Director, or any change in the scope and responsibility of their role; ■ general economic conditions, Shell's financial performance, and governance trends; and ■ the impact of salary increases on pension benefits and other elements of the package. <p>For Executive Directors employed outside their base country, euro base salaries are translated into their home currency for pension purposes. Pensionable base salaries are maintained in line with euro base salaries taking into account exchange rate fluctuations and other factors as determined by the REMCO.</p>
Benefits		
Provides benefits, in line with those applicable to the wider workforce, in order to attract and retain Executive Directors.	<p>The maximum opportunity is the cost of providing the benefit under Shell's standard policy. These costs can vary.</p> <p>For certain benefits, for example, relocation and tax equalisation, the maximum opportunity will be the grossed-up cost of meeting the specific Executive Director's costs.</p>	<p>Typical benefits include car allowances and home-to-office transport, risk benefits (for example ill-health, disability or death-in-service), security provision, and employer contributions to insurance plans (such as medical). Precise benefits will depend on the Executive Director's specific circumstances. Post-retirement benefits such as healthcare and ongoing security provision may be applicable. Shell's mobility policies may apply, such as for relocation and tax return preparation support, as may tax equalisation related to expatriate employment prior to Board appointment, or in other limited circumstances to offset double taxation. The REMCO may adjust the range and scope of the benefits offered in the context of developments for other employees in relevant countries. Personal loans or guarantees are not provided to Executive Directors.</p>
Annual bonus		
<p>Rewards the delivery of short-term operational targets as derived from Shell's operating plan.</p> <p>To reinforce alignment with shareholder interests, 50% is delivered in cash and 50% is delivered in shares. The shares are subject to a three-year holding period, which applies beyond an Executive Director's tenure.</p>	<p>Maximum bonus (as a percentage of base salary):</p> <ul style="list-style-type: none"> ■ Chief Executive Officer (CEO): 250% ■ Chief Financial Officer (CFO): 240% <p>Target levels (as a percentage of base salary):</p> <ul style="list-style-type: none"> ■ CEO: 125% ■ CFO: 120% 	<ul style="list-style-type: none"> ■ The bonus is determined by reference to performance from January 1 to December 31 each year; ■ Annual bonus = base salary x target bonus % x scorecard result (0–2); ■ Taking the Shell operating plan into consideration, REMCO sets stretching scorecard targets and weightings which support the delivery of the strategy. Measures are related to financial performance, operational excellence and sustainable development. Indicative weightings are 30%, 50% and 20% respectively. This balance ensures that the achievement of short-term financial performance does not undermine future shareholder value creation; ■ Scorecard targets will be disclosed in a subsequent Directors' Remuneration Report when they are no longer deemed to be commercially sensitive; ■ There are no prescribed thresholds or minimum levels of performance that equate to a prescribed payment under the Policy and this structure can result in no bonus being awarded; ■ The annual bonus is subject to malus provisions before it is delivered and to clawback provisions thereafter; ■ The REMCO retains the ability to adjust performance measure targets and weightings year-by-year within the overall target and maximum payouts approved in the Policy; and ■ In the event that another Executive Director joins the Board, the REMCO will determine their target and maximum bonus, which will not exceed the target and maximum for the CEO.

Executive Directors' remuneration policy table *continued*

Purpose and link to strategy	Maximum opportunity	Operation and performance management
Long-term Incentive Plan (LTIP)		
<p>Rewards longer-term value creation linked to Shell's strategy. The measures predominantly focus on financial growth and increases in value compared with the other oil majors, supported by measures focused on the achievement of Shell's ambitions in the energy transition.</p> <p>To reinforce alignment with shareholder interests, shares delivered from vested LTIP awards are subject to a three-year holding period, which applies beyond an Executive Director's tenure.</p>	<p>Target award of 300% base salary.</p> <p>Awards may vest at up to 200% of the shares originally awarded, plus dividends.</p>	<ul style="list-style-type: none"> ■ Award levels are determined annually by the REMCO within the approved policy maximum; ■ Awards may vest between 0% and 200% of the initial award, depending on Shell's performance assessed on either an absolute basis against strategic targets or on a relative basis against the other oil majors; ■ Performance metrics and targets are set by the REMCO at the beginning of the relative performance period. When setting performance targets, the REMCO allocates weightings to each metric as it considers appropriate, taking into account strategic priorities; ■ For 2020, performance is assessed over three years based 90% on financial metrics (TSR, ROACE, FCF and CFFO) which support our strategic ambition to provide a world-class investment case and 10% on a measure focused on thriving in the energy transition; ■ Additional shares are released representing the value of dividends payable on the vested shares, as if these had been owned from the award date; ■ LTIP awards (net of tax) must be held for a further three years to align with Shell's longer-term time horizon and strategy; ■ The LTIP award is subject to malus provisions before it is delivered and to clawback provisions thereafter; ■ The REMCO may adjust or change the LTIP measures, targets and weightings to ensure continued alignment with Shell's strategy; and ■ In the event that another Executive Director joins the Board, the REMCO will determine their award level.
Discretion, Malus and Clawback		
<p>Enables the management of risks from behavioural-based incentive schemes and the REMCO to manage the range of pay outcomes.</p>	<p>Adjustment events exist for the purposes of applying malus and clawback.</p> <p>The REMCO retains discretion to adjust pay outcomes.</p>	<p>The REMCO retains the discretion to adjust mathematical outcomes of the annual bonus scorecard and / or LTIP vesting for any Executive Director if and to the extent that it considers this appropriate at their sole discretion.</p> <p>The use of any discretion will be disclosed and explained.</p> <p>The REMCO may adjust pay outcomes for the purposes of managing quantum. This would be done at the REMCO's discretion after considering single figure outcome for the year, taking into account Shell's performance, the operation of the remuneration structures and any other relevant considerations.</p> <p>Please refer to page 177 for a summary of the defined adjustment events.</p>
Pension		
<p>Provides a competitive retirement provision under the individual's base country benefits policy, to attract and retain Executive Directors.</p>	<p>Determined by the rules of the base country pension plan of which the Executive Director is a member.</p>	<p>Executive Directors' retirement benefits are maintained in line with those of the wider workforce in their base country. Only base salary is pensionable, unless country plan regulations specify otherwise and cannot legally be disappplied. The rules of the relevant plans detail the pension benefits which members can receive. The REMCO retains the right to amend the form of any Executive Director's pension arrangements where appropriate, for example in response to changes in legislation to ensure the original objective of this element of remuneration is preserved.</p> <p>New Executive Directors, whether internal appointees or external hires, will be provided with a retirement benefit in line with the wider workforce in their base country. For individuals who are members of a defined benefit pension arrangement:</p> <ul style="list-style-type: none"> ■ The pensionable salary will be capped at the salary applicable immediately prior to appointment, with the exception of existing US base country participants who will have the bonus removed from the definition of pensionable base salary instead; and ■ The Executive Director will join a defined contribution scheme in their base country for contributions made in respect of salary above the defined benefit pensionable salary, or in exceptional circumstances, receive a cash allowance equivalent to the contribution above the cap.
Shareholding requirement		
<p>Aligns interests of Executive Directors with those of shareholders by creating a connection between individual wealth and Shell's long-term performance.</p>	<p>Shareholding (% of base salary):</p> <ul style="list-style-type: none"> ■ CEO: 700% ■ CFO: 500% 	<p>Executive Directors are expected to build up their shareholding to the required level over a period of five years from appointment and, once reached, to maintain this level for the full period of their appointment. The intention is for the shareholding guideline to be reached through retention of vested shares from share plans. The REMCO will monitor individual progress and retains the ability to adjust the guideline in special circumstances on an individual basis.</p> <p>The Executive Director will be required to maintain their shareholding requirement (or existing shareholding if lower) for a period of two years from the date they cease to be an employee.</p> <p>In the event that another Executive Director joins the Board the REMCO will determine their Shareholding requirement level, which will not be less than 200% in line with corporate governance best practice.</p>

DIRECTORS' REMUNERATION POLICY continued

Notes to the Executive Directors' remuneration policy table

Comparator group

The benchmarking comparator group consists of the other oil majors (BP, Chevron, ExxonMobil, and Total) and a selection of major Europe-based companies.

The comparator companies are reviewed by the REMCO as part of the Remuneration Policy review every three years. The last review took place in 2019 in preparation for the 2020 Directors' Remuneration Policy vote. No changes to the comparator group are proposed.

The other oil majors are included in the comparator group as these represent our closest direct competitors operating in similar market conditions. The Europe-based companies are selected based on their size, complexity and global reach. The REMCO uses benchmark data from these companies only as a guide to the competitiveness of the remuneration packages. We do not seek to position our remuneration at any defined point against the benchmarked positions.

The REMCO retains the right to alter the comparator group as it sees fit in order to ensure it remains an appropriate and relevant benchmark.

2020 European comparator group

Allianz	Daimler	Rio Tinto
AstraZeneca	Diageo	Roche
BAT	GlaxoSmithKline	Siemens
Bayer	Nestle	Unilever
BHP Billiton	Novartis	Vodafone

Benefits

Benefits for Executive Directors deemed taxable in the UK are included as taxable benefits in the single total figure of remuneration table. These elements may include transport to and from home and office, the provision of home security, and occasional business-required partner travel, which are generally considered legitimate business expenses rather than components of remuneration.

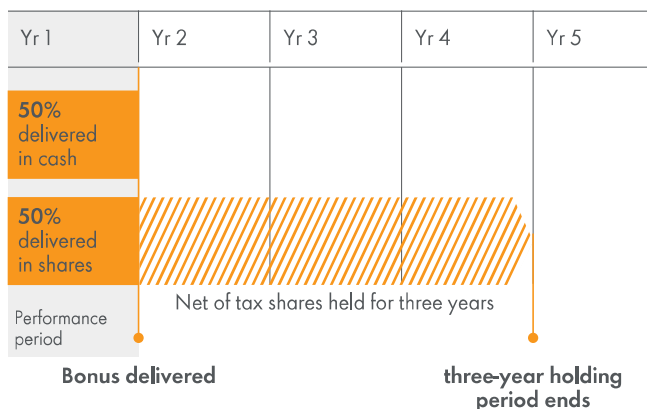
Annual bonus

For the 2020 performance year, the scorecard framework will consist of cash flow from operating activities (30% weight), operational excellence (50% weight) and sustainable development (20% weight). Targets are derived from the annual business plan. These measures are designed to drive focus on the financial and operational performance critical to our success as a world-class investment case and to maintain a strong licence to operate, underpinned by our commitment to safety and journey to thrive in the energy transition. The REMCO believes it is important for annual variable pay to remain balanced, with operational and environmental components, complementing the LTIP's focus on longer-term financial and strategic outcomes. The same annual bonus scorecard applies to the majority of group employees, supporting consistency of remuneration and alignment of objective across employees and senior management.

For future years, the specific measures and weightings for the annual bonus scorecard will be reviewed annually by the REMCO and adjusted accordingly to evolve with Shell's strategy and circumstances. The annual review will also consider the scorecard target and outcome history over a decade to ensure that the targets set remain stretching but realistic.

The REMCO retains the right to exercise its judgement to adjust the mathematical bonus scorecard outcome to ensure that the bonus scorecard outcome for Executive Directors reflects other aspects of Shell's performance which the REMCO deems appropriate for the reported year.

Annual bonus – time horizon



Long-term Incentive Plan

The LTIP rewards longer-term performance linked to Shell's strategy, which includes cash generation, capital discipline, value created for shareholders as well as progress towards meeting our ambition to thrive in the energy transition.

For 2020, the absolute measures will be FCF and energy transition, and relative growth compared with our peers will be based on: TSR, ROACE and CFFO. The relative measures, which focus on outperforming our closest competitors on key financial metrics, are supported by the absolute FCF metric which provides cash to service and repay debt, make shareholder distributions and fund capital investment. These are aligned with our strategic ambition to be a world-class investment case, and are supported by an energy transition measure focused on thriving in the energy transition and delivering our NCF target.

For the relative measures, 200% vests for first position, 150% for second, 80% for third and 0% for ranking fourth or fifth. The comparator group consists of four of the strongest companies in our industry (BP, Chevron, ExxonMobil and Total). Outperforming Shell's closest competitors on key financial metrics is challenging. A vesting outcome of 80% for median performance (40% of maximum) in a small comparator group is considered appropriate by the REMCO. The REMCO is aware that vesting for median performance is generally set at a limit of 25% of maximum for other UK companies. However, these are typically applied against a larger comparator group.

The REMCO will regularly review the measures, weightings and comparator group, and retains the right to adjust these to ensure that the LTIP continues to serve its intended purpose with a stretching level of challenge. If the REMCO was to propose any material changes to the LTIP performance metrics, it would consult with major shareholders.

TSR underpin

If the TSR ranking is fourth or fifth, the level of the award that can vest on the basis of the other measures will be capped at 50% of the maximum payout for the LTIP.

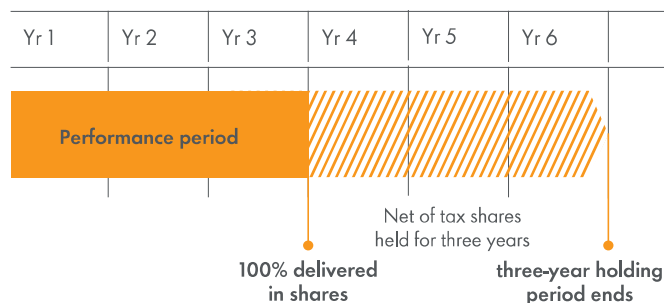
The detailed weightings and metrics applicable to the 2020 bonus scorecard are set out on page 160.

The detailed weightings and metrics applicable to the 2020 grant are set out on page 164.

Performance Period

LTIP performance is assessed over a three-year period. Vested shares from the LTIP are subject to a further three-year holding period post-vesting. This holding period commences on the date of vesting and remains in force beyond an Executive Director's tenure. This time horizon is deemed to be suitable for incentive purposes but is recognised as short relative to some of Shell's operations. However, the REMCO believes that it provides for broad alignment with shareholder interests when coupled with significant shareholding requirements.

LTIP time horizon



Discretion, malus and clawback

Variable pay awards may be made subject to adjustment events. At the discretion of REMCO, such an award may be adjusted before delivery (malus) or reclaimed after delivery (clawback) if an adjustment event occurs.

Adjustment events will be specified in award documentation and it is intended that they will, for example, relate to restatement of financial statements due to material non-compliance with a financial reporting requirement; misconduct by an Executive Director or misconduct through their direction or non-direction; any material breach of health and safety or environment regulations; serious reputational damage to Shell; material failure of risk management; corporate failure; or other exceptional events as determined at the discretion of the REMCO. The REMCO retains the right to alter the list of adjustment events in respect of future awards.

In addition, the REMCO retains the discretion to adjust mathematical outcomes if and to the extent that it considers this appropriate. This power to adjust the outcomes is broad and includes adjusting the outcomes to zero. For example, an adjustment might be made if the REMCO considers:

- The mathematical outcomes do not reflect the wider financial or non-financial performance of RDS or the participant over the performance period;
- The LTIP vesting percentage is not appropriate in the context of circumstances that were unexpected or unforeseen at award; and
- There is any other reason why an adjustment is appropriate.

It is not anticipated that discretion would be used for upwards adjustment. If, in exceptional circumstances, it was considered, this would be done only after consultation with major shareholders.

Performance outcomes and/or share price appreciation make it difficult to predict the final amounts delivered under the LTIP at the time of award. In years where the vesting outcome makes the total remuneration

inappropriate for any Executive Director, the REMCO will consider an adjustment to the annual bonus outcome or the LTIP vesting outcome for the purposes of managing remuneration quantum. In making any adjustment to the annual bonus or LTIP vesting outcome for this purpose REMCO will consider the overall level of remuneration for the Executive Director, the operation of the annual bonus, the operation of the LTIP, the wider performance of Shell over the performance periods, as well as the internal context for other employees.

An explanation of any discretionary adjustment would be set out in the relevant Directors' Remuneration Report.

Treatment of outstanding awards

Awards granted prior to the approval and implementation of this Policy and/or prior to an individual becoming an Executive Director will continue to vest and be delivered in accordance with the terms of the original award even if this is not consistent with the terms of this Policy.

As at March 10, 2020, this applies to Executive Directors Ben van Beurden and Jessica Uhl who each have outstanding awards under the LTIP.

Shareholding

The REMCO believes significant shareholding by Executive Directors is an important way of ensuring that shareholders and Executive Directors share the same priorities. Shareholding is one of Shell's core remuneration principles as it creates a balanced connection between individual wealth and Shell's long-term performance. This will support effective governance and an ownership mindset. Significant shareholding requirements reflect the performance timescales of Shell and are aligned with absolute shareholder return.

The CEO is expected to build up a shareholding of seven times their base salary over five years from appointment. The CFO is expected to build up a shareholding of five times their base salary over the same period. In the event of an increase to the guideline multiple of salary, for every additional multiple of salary required, the director will have one extra year to reach the increased guideline, subject to a maximum of five years from the date of the change.

Executive Directors will be required to maintain their shareholding requirement (or their existing shareholding if less than the guideline) for a period of two years post-employment.

The holding periods for LTIP vested shares and shares delivered as part of the annual bonus continue to apply after Executive Directors leave employment.

Differences for Executive Directors from other employees

The remuneration structure and approach to setting remuneration levels is consistent across Shell, with consideration given to location, seniority and responsibilities. However, a higher proportion of total remuneration is tied to variable pay for Executive Directors and members of Senior Management.

The salary for each Executive Director is determined based on the indicators in the "Executive Directors' remuneration policy table", which reflect the international nature of the Executive Directors' labour market. The salary for other employees is normally set on a country basis.

DIRECTORS' REMUNERATION POLICY continued

Executive Directors are eligible to receive the standard benefits and allowances provided to other employees. The provisions which are not generally available for other employees are described in "Benefits".

The methodology used for determining the annual bonus for Executive Directors is broadly consistent with the approach for Shell employees generally. However, bonuses for the majority of Shell employees are determined taking into account individual and business performance, whereas bonuses for Executive Directors are based solely on business performance. Although the makeup and weightings scorecard used for the majority of Shell employees is currently aligned with the scorecard, these scorecards may differ if required to support the achievement of business objectives. All Executive Directors and Executive Committee members receive 50% of their annual bonus in shares, which are subject to a three-year holding period.

Executive Directors are not eligible to receive new awards under employee share plans other than the LTIP, although awards previously granted will continue to vest in accordance with the terms of the original award. Selected employees participate in the Performance Share Plan (PSP). The operation of the PSP is similar to the LTIP, but currently differs, for example, in some performance measures and their relative weightings. As at March 2020, around 51,000 employees participate in one or more of Shell's global share plans and/or incentive plans, further supporting alignment with shareholder interests.

Executive Directors' retirement benefits are maintained in line with those of the wider workforce in their base country.

Illustration of potential remuneration outcomes

The charts on this page represent estimates under four performance scenarios ("Minimum", "On-target", "Maximum" and "Maximum assuming 50% share price appreciation") of the potential remuneration outcomes for each Executive Director resulting from the application of 2020 base salaries to awards made in accordance with the proposed Policy. The majority of Executive Directors' remuneration is delivered through variable pay elements, which are conditional on the achievement of stretching targets.

The REMCO will review the formulaic Single Figure outcome relative to the quality of performance outcomes and adjust these, taking into account Shell's performance, shareholder experience, the operation of the remuneration structures and any other relevant factors, to ensure that the highest variable pay outcomes are only achieved in years with the highest quality performance.

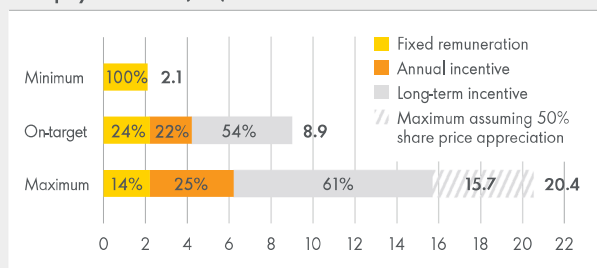
The scenario charts are based on future Policy award levels and are combined with projected single total figures of remuneration. The pay scenarios are forward-looking and only serve to illustrate the future Policy. For simplicity, the minimum, on-target and maximum scenarios assume no share price movement and exclude dividend accrual, for the portion of the bonus paid in shares and the LTIP, although dividend accrual during the performance and holding period applies. The scenarios are based on the current CEO (Ben van Beurden) and CFO (Jessica Uhl) roles.

Performance scenarios

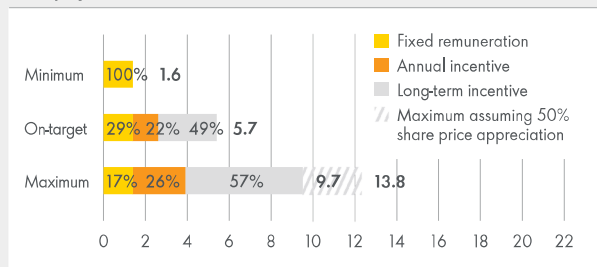
	Minimum	Target	Maximum[A]
Base salary (2020)	✓	✓	✓
Benefits (2019 actual)	✓	✓	✓
Pension (2020 estimate)	✓	✓	✓
Bonus	NIL	125% CEO 120% CFO	250% CEO 240% CFO
LTIP	NIL	300% CEO 270% CFO	600% CEO 540% CFO

[A] Maximum assuming 50% share price appreciation.

CEO pay scenarios (€m)



CFO pay scenarios (€m)



Recruitment

The REMCO determines the remuneration package for new Executive Director appointments. These appointments may involve external or internal recruitment or reflect a change in role of a current Executive Director.

When determining remuneration packages for new Executive Directors, the REMCO will seek a balanced outcome which allows Shell to:

- attract and motivate candidates of the right quality;
- take into account the individual's current remuneration package and other contractual entitlements;
- seek a competitive pay position relative to our comparator group, without overpaying;
- encourage relocation if required; and
- honour entitlements (for example, variable remuneration) of internal candidates before their promotion to the Board. The REMCO will follow the approach set out in the table below when determining the remuneration package for a new Executive Director.

Recruitment – Remuneration package

Component	Approach	Maximum
Ongoing remuneration	The salary, benefits, annual bonus, long-term incentives and pension benefits will be positioned and delivered within the framework of the Executive Directors' remuneration policy.	As stated in the "Executive Directors' remuneration policy table".
Compensation for the forfeiture of any awards under variable remuneration arrangements	To facilitate external recruitment, one-off compensation in consideration for forfeited awards under variable remuneration arrangements entered into with a previous employer may be required. The REMCO will use its judgement to determine the appropriate level of compensation by matching the value of any lost awards under variable remuneration arrangements with the candidate's previous employer. This compensation may take the form of a one-off cash payment or an additional award under the LTIP. The compensation can alternatively be based on a newly created long-term incentive plan arrangement where the only participant is the new director. The intention is that any such compensation would, as far as possible, align to the duration and structure of the award being forfeited.	An amount equal to the value of the forfeited variable remuneration awards, as assessed by the REMCO. Consideration will be given to appropriate performance conditions, performance periods and clawback arrangements.
Replacement of forfeited entitlements other than any awards under variable remuneration arrangements	There may also be a need to compensate a new Executive Director in respect of forfeited entitlements other than any awards under variable remuneration arrangements. This could include, for example, pension or contractual entitlements, or other benefits. On recruitment, these entitlements may be replicated within the Executive Directors' remuneration policy or valued by the REMCO and compensated in cash. In cases of internal promotion to the Board, any commitments made which cannot be effectively replaced within the Executive Directors' remuneration policy may, at the REMCO's discretion, continue to be honoured.	An amount equal to the value of the forfeited entitlements, as assessed by the REMCO.
Exceptional recruitment incentive	Apart from the ongoing annual remuneration package and any compensation in respect of the replacement of forfeited entitlements, there may be circumstances in which the REMCO needs to offer a one-off recruitment incentive in the form of cash or shares to ensure the right external candidate is attracted (e.g. to the industry). The REMCO recognises the importance of internal succession planning but it must also have the ability to compete for talent with other global companies. The necessity and level of this incentive will depend on the individual's circumstances. The intention will be that this is only used in genuinely exceptional circumstances.	Subject to the limits set out in the "Executive Directors' remuneration policy table".
Pension	New appointees will be provided with a pension in line with the wider workforce in their base country. For defined benefit members: <ul style="list-style-type: none"> ■ The pensionable salary is capped at executive committee level pay for defined benefit purposes (with the exception of participants in the US plan where the bonus is removed from the definition of pensionable pay; and ■ The member joins an appropriate base country defined contribution mechanism in excess of the cap, or exceptionally a pension cash allowance equivalent to the defined contribution level is payable in excess of the cap. 	In accordance with the pension provision applicable to the wider workforce in the base country.

Executive Directors' employment arrangements and letters of appointment

The Dutch Executive Directors are employed for an indefinite period. Executive Directors with the Netherlands as their base country will be employed on the basis of a contract of employment governed by Dutch employment law. For Executive Directors with a base country other than the Netherlands, REMCO will determine their employment arrangements based on a number of considerations, including Dutch immigration requirements and base country retirement benefits. Executive Directors' employment arrangements are available for inspection at the AGM or on request. For further details on appointment and re-appointment of Directors, see the "Governance Framework" on page 128 and "Other Regulatory and Statutory Information" on page 189.

End of employment Notice period

Employment arrangements of Executive Directors can generally end by either the employee or the employer providing one month's notice, or the applicable statutory notice period. For example, under Dutch law, the statutory notice period for the employer will vary in line with the length of service, with the maximum being four months' notice. Under Dutch law, termination payments are not linked to the contract's notice period.

The Netherlands statutory end-of-employment compensation

With effect from July 1, 2015, employment legislation in the Netherlands introduced statutory end-of-employment compensation. Under this legislation, every termination (other than following retirement or for cause) of a Dutch employment contract that has continued for a minimum of two years will give rise to an obligation to pay the departing employee transition compensation ("transitievergoeding"). The statutory compensation is capped at one times the annual salary, which is deemed to include variable pay such as the annual bonus. Executive Directors are expected not to claim transition compensation or any other applicable statutory compensation over and above the agreed compensation for loss of office as set out in the "End of employment" table on page 180.

Outstanding entitlements

In cases of resignation or dismissal for cause, fixed remuneration (base salary, benefits, and employer pension contributions) will cease on the last day of employment, variable remuneration elements will generally lapse and the Executive Director is not eligible for compensation for loss of office.

The information, on page 180, generally applies to termination of employment by Shell giving notice, by mutual agreement, or in situations where the employment terminates because of retirement with Shell consent at a date other than the normal retirement date, redundancy or in other similar circumstances at the REMCO's discretion.

DIRECTORS' REMUNERATION POLICY continued

End of employment

Provision	Policy
Compensation for loss of office	<p>For Executive Directors appointed between January 1, 2011 and December 31, 2016, employment contracts include a cap on termination payments of one times annual pay (base salary plus target bonus). Delivery of compensation is mitigated by a contractual obligation for the Executive Director to seek alternative employment and Shell's ability to implement phased payment terms.</p> <p>For Executive Directors appointed on or after January 1, 2017, the REMCO may offer a termination payment of up to one times base salary (target bonus will not be included). However, REMCO may be obligated to pay statutory compensation over and above the compensation for loss of office to a departing Executive Director who asserts a statutory claim thereto. Delivery of compensation is mitigated by a contractual obligation for the Executive Director to seek alternative employment and Shell's ability to implement phased payment terms.</p> <p>The provision of standard end-of-employment benefits such as repatriation costs, security provision and outplacement support may also be included, as deemed reasonable by the REMCO.</p> <p>The REMCO may adjust the termination payment for any situation where a full payment is inappropriate, taking into consideration applicable law, corporate governance provisions, the applicability of any statutory compensation and the best interests of Shell and shareholders as a whole.</p>
Annual bonus	<p>Any annual bonus in the year of departure is prorated based on service. Depending on the timing of the departure, the REMCO may consider the latest scorecard position or defer payment until the full-year scorecard result is known.</p> <p>Bonuses delivered in shares represent the bonus which a participant has already earned and carry no further performance conditions; therefore, these shares will be unrestricted at the conclusion of the normal deferral or holding period respectively and no proration will apply.</p>
LTIP	<p>Outstanding awards are prorated on a monthly basis, by reference to the Executive Director's service within the performance period. They will generally survive the end of employment and will remain subject to the same vesting performance conditions, and malus and clawback provisions, as if the Executive Director had remained in employment. The three-year holding period will also remain in force for any awards made on or after January 1, 2017. If the participant dies before the end of the performance period, the award will vest at the target level on the date of death. In case of death after the end of the performance period, the award will vest as described in this Policy.</p>

NON-EXECUTIVE DIRECTORS

Non-executive Directors' remuneration policy table

Fee structure	Approach to setting fees	Other remuneration
<p>Non-executive Directors (NEDs) receive a fixed annual fee for their directorship. The size of the fee will differ based on the position on the Board: Chair of the Board fee or standard Non-executive Director fee.</p> <p>Additional annual fee(s) are payable to any Director who serves as Senior Independent Director, a Board committee chair, or a Board committee member.</p> <p>A NED receives either a chair or member fee for each committee. This means that a chair of a committee does not receive both fees.</p> <p>NEDs receive an additional fee for any Board meeting involving intercontinental travel – except for one meeting a year held in a location other than The Hague.</p>	<p>The Chair's fee is determined by the REMCO. The Board determines the fees payable to NEDs. The maximum aggregate annual fees will be within the limit specified by the Articles of Association and in accordance with the NEDs' responsibilities and time commitments.</p> <p>The Board reviews NED fees periodically to ensure that they are aligned with those of other major listed companies.</p>	<p>Business expenses incurred in respect of the performance of their duties as a NED will be paid or reimbursed by Shell. Such expenses could include transport between home and office and occasional business-required partner travel. NEDs may receive a token of recognition on retirement from the board. The maximum value for this is €300. Where required, the Chair is offered Shell-provided accommodation in The Hague. The REMCO has the discretion to offer other benefits to the Chair as appropriate to their circumstances. Where business expenses or benefits create a personal tax liability to the Director, Shell may cover the associated tax.</p> <p>The Chair and the other NEDs cannot receive awards under any incentive or performance-based remuneration plans, and personal loans or guarantees are not granted to them.</p> <p>NEDs do not accrue any retirement benefits as a result of their non-executive directorships with Shell.</p> <p>NEDs are encouraged to hold shares with a value equivalent to 100% of their fixed annual fee and maintain that holding during their tenure.</p>

Non-executive Directors' letters of appointment

NEDs, including the Chair, have letters of appointment. NEDs' letters of appointment are available for inspection at the AGM or on request. For further details on appointment and re-appointment of Directors, see the "Governance Framework" on page 128 and "Other Regulatory and Statutory Information" on page 189.

Non-executive Director recruitment

The REMCO's approach to setting the remuneration package for NEDs is to offer fee levels and specific benefits (where appropriate) in line with the "Non-executive Directors' remuneration policy table" and subject to the Articles of Association. NEDs are not offered variable remuneration or retention awards.

When determining the benefits for a new Chair, the individual circumstances of the future Chair will be taken into account.

Non-executive Director termination of office

No payments for loss of office will be made to NEDs.

Consideration of overall pay and employment conditions

When setting the Policy, no specific employee groups were consulted. However, Shell seeks to promote and maintain good relations with employee representative bodies as part of its employee engagement performance as required.

When determining Executive Directors' remuneration structure and outcomes, the REMCO reviews a set of information, including relevant reference points and trends, which includes internal data on employee remuneration (for example, employee relations matters in respect of remuneration and average salary increases applying in the Netherlands, UK and the USA). During the Policy review, pay and employment conditions of the wider Shell employee population were taken into account by adhering to the same performance, rewards and benefits philosophy for the Executive Directors, as well as overall benchmarking principles. Furthermore, any potential differences from other employees (see "Differences for Executive Directors from other employees") were taken into account when providing the REMCO with advice in the formation of this Policy.

Dialogue between management and employees is important, with the annual Shell People Survey being one of the principal means of gathering employee views on a range of matters. The Shell People Survey includes questions inviting employees' views on their pay and benefit arrangements. Shell also encourages share ownership among employees, and many are shareholders who are able to participate in the vote on the Policy at the AGM.

The REMCO is kept informed by the CEO, the Chief Human Resources & Corporate Officer and the Executive Vice President Remuneration and HR Operations on the bonus scorecard and any relevant remuneration matters affecting other senior executives, extending to multiple levels below the Board and Executive Committee.

Consideration of shareholder views

The REMCO engages with major shareholders on a regular basis throughout the year and this allows it to hear views on Shell's remuneration approach and test proposals when developing or evolving the Policy. Recent examples of the REMCO responding to shareholder views include: considering the quantum of executive pay and the use of alternative reward structures; introducing the Energy Transition metric to the LTIP in line with our strategic ambitions; removing the individual performance modifier from the calculation of annual bonus outcomes to make remuneration structures simpler and more transparent to shareholders; reducing the CEO's target bonus from 150% to 125%; reducing the CEO's LTIP grant; and enabling the broader use of discretion to manage remuneration outcomes.

The REMCO will review the Policy regularly to ensure it continues to reinforce Shell's long-term strategy and remains closely aligned with shareholders' interests.

Additional policy statement

The REMCO reserves the right to make payments outside the Policy in limited exceptional circumstances, such as for regulatory, tax or administrative purposes or to take account of a change in legislation or exchange controls, and only where the REMCO considers such payments are necessary to give effect to the intent of the Policy.

Signed on behalf of the Board

/s/ Linda M. Coulter

LINDA M. COULTER

Company Secretary
March 10, 2021

OTHER REGULATORY AND STATUTORY INFORMATION

This section of the Annual Report contains the remaining information which the Directors are required to report on each year and for the year ended December 31, 2020. There are other matters that are required to be reported on and that have been disclosed in other sections of the Annual Report, as summarised below:

Management Report	<p>This Directors' Report, together with the Strategic Report, serves as the Management Report for the purpose of Disclosure Guidance and Transparency Rule 4.1.8R.</p> <p>Both the Directors' Report and Strategic Report have been presented in accordance with and reliance on English law, and the liabilities of the Directors in connection with those reports shall be subject to the limitations and restrictions provided by such law.</p>	<p>Directors' Report: pages 124-181</p> <p>Strategic Report: pages 4-111</p>
Corporate governance	The Company's statement on corporate governance, as required by DTR7.2.3R, is incorporated in this Directors' Report by way of reference.	Directors' Report: pages 124-181
Business relationships [A]	A statement, summarising the Directors' business relationships with suppliers, customers and others.	Strategic Report: pages 4-111
Employee engagement	Information on how Directors have engaged with employees.	Workforce Engagement: pages 138-139
Directors' interests [B]	<p>The interests (in shares of the Company or calculated equivalents) of the Directors in office at the end of the year, including any interests of a "connected person".</p> <p>Changes in Directors' share interests during the period from December 31, 2020, to March 10, 2021.</p>	Annual Report on Remuneration: pages 157
Likely future developments	Information relating to likely future developments.	Provided throughout the Strategic Report: pages 4-111
Research and development	Information relating to Shell's research and development, including expenditure.	Shell Story: pages 10-17
Diversity and inclusion	Information concerning diversity and inclusion. This includes information on the equal opportunities in recruitment, career development, promotion, training and rewards for all our people, including those with disabilities.	Our people: pages 108-111
Employee communication and involvement	Information concerning employee communication and involvement.	Our people: pages 108-111
Corporate social responsibility	<p>A summary of Shell's approach to corporate social responsibility.</p> <p>Further details will be available in the Shell Sustainability Report 2020.</p>	<p>Environment and society: pages 85-93</p> <p>Our people: pages 108-111</p>
Branches	<p>A list of our subsidiaries, joint ventures and associates.</p> <p>Our activities and interests are operated through subsidiaries, branches of subsidiaries, joint ventures and associates which are subject to the laws and regulations of many different jurisdictions.</p>	Additional Information, Appendix 1: pages 308-323
Greenhouse gas emissions	Information relating to greenhouse gas emissions.	Climate change and energy transition: pages 94-107
Risk management	<p>Detail on risk factors.</p> <p>Information on emerging risks.</p>	<p>Risk Factors: pages 28-37</p> <p>Other regulatory and statutory information: pages 182-189</p>
Financial risk management, objectives and policies	Descriptions of the use of financial instruments and Shell's financial risk management objectives and policies, and exposure to market risk (including price risk), credit risk and liquidity risk.	Consolidated Financial Statements: Note 19, pages 251-255
Listing rule information [C]	Information relating concerning the amount of interest capitalised by Shell.	Consolidated Financial Statements: Note 6, pages 233
Listing rule information [C]	The Remuneration Committee Report.	Directors' Remuneration Report: pages 153 - 181
Listing rule information [C]	Details of the Company's long-term incentive schemes as required by LR 9.4.3R	Directors' Remuneration Report: pages 153 - 181
Significant shareholdings	Information concerning significant shareholdings.	Shareholder information: pages 300-304

[A] This meets the purposes of Schedule 7 to The Companies (Miscellaneous Reporting) Regulations 2018.

[B] "Connected person" has the meaning given to "person closely associated" within the Market Abuse Regulation.

[C] This information is given in accordance with Listing Rule 9.8.4R. Further information in connection with Listing Rule 9.8.4R is contained in the remainder of "Other Statutory Information" which follows on 183-189.

MODERN SLAVERY ACT STATEMENT

We prioritise buying from and encouraging local providers by procuring goods and services from local suppliers who meet the standards we require. The standards include those relating to human rights, labour practices and business integrity and are governed by the Shell Supplier Principles. Monitoring is undertaken centrally in connection with the preparation of the Shell Group's Modern Slavery Act (MSA) Statement which is prepared by taking proposed inputs from Shell companies in scope of the MSA as to their steps taken to ensure modern slavery does not occur in their supply chain or organisation. The Shell Group Statement is approved by the Board of Royal Dutch Shell plc, after approval by the boards of Shell companies which are in scope of the MSA.

DISCLOSURE OF INFORMATION TO AUDITORS

In accordance with section 418 of the Act, each of the persons who is a Director at the date of approval of this Report confirms that, so far as the Director is aware, there is no relevant audit information of which the Company's auditor is unaware. The Director has taken all steps that he or she ought to have taken as a Director in order to make himself or herself aware of any relevant audit information and to establish that the Company's auditor is aware of that information.

FINANCIAL STATEMENTS, DIVIDENDS AND DIVIDEND POLICY

The "Consolidated Statement of Income" and "Consolidated Balance Sheet" can be found on pages 217 and 218 respectively.

Subject to Board approval, Shell aims to grow the dividend per share by around 4% every year, and once the Shell Group's net debt level has reached \$65 billion, Shell will target the distribution of 20-30% of its cash flow from operations to shareholders. The Board may choose to return cash to shareholders through a combination of dividends and share buybacks. When setting the level of shareholder remuneration, the Board looks at a range of factors, including the macro-environment, the underlying business earnings and cash flow of the Shell Group, the current balance sheet, future investment and divestment plans, and existing commitments.

Interim dividends are currently declared by the Board and paid on a quarterly basis. Shell does not currently pay a "final" dividend, which would need to be voted on by shareholders, requiring the introduction of a resolution at the AGM. This would delay the payment of the fourth quarter dividend (currently paid in late March) until after the AGM, which is towards the end of May, a delay of around seven weeks. Our approach to dividend payments is not uncommon for companies distributing returns to shareholders on a quarterly basis.

Shell pays its dividend in USD, EUR or GBP fully electronically either in CREST or via interbank transfers.

The Directors have announced a fourth quarter interim dividend as set out in the table below, payable on March 29, 2021, to shareholders on the Register of Members at the close of business on February 19, 2021. The closing date for dividend currency elections was March 5, 2021 [A] and the euro and sterling equivalents announcement date is March 15, 2021.

[A] A different dividend currency election date may apply to shareholders holding shares in a securities account with a bank or financial institution ultimately through Euroclear Nederland. This may also apply to other shareholders who do not hold their shares either directly on the Register of Members or in the corporate sponsored nominee arrangement. Such shareholders can contact their broker, financial intermediary, bank or financial institution for the election deadline that applies.

VIABILITY STATEMENT

The "Strategic Report" includes information about Shell's strategy, financial condition, cash flows and liquidity, as well as the factors, including the principal risks, likely to affect Shell's future development. It also describes Shell's business model, including competitive advantages and key strengths. The Directors assess Shell's prospects both at an operating and strategic level, each involving different time horizons. To this end, the Directors assess Shell's portfolio and strategy against a wide range of outlooks, including assessing the potential impacts of various possible energy transition pathways and scenarios for changes in societal expectations in relation to climate change. Shell recognises in its strategy that the world is transitioning to a lower-carbon energy system (see "Climate change and energy transition"). The Risk Factors section provides an overview of the principal risks Shell is exposed to in its operations.

On an annual basis, the Directors approve a detailed three-year operating plan, which forecasts Shell's cash flows and ability to service financing requirements, pay dividends and fund investing activities during the period. Shell's three-year operating plan contains assumptions in relation to internal and external parameters, including recovery from the impacts of the COVID-19 pandemic. Some of the key assumptions include the impact of commodity prices, exchange rates, future carbon costs, agreements like LNG contract renewals, production levels and product demand, and schedules of growth programmes. Considering the degree of change possible in these parameters, Shell has deemed a three-year period of assessment appropriate for the longer-term viability statement.

In making the going concern and longer term viability assessment, Shell has also considered the financial impact of each of the following severe but possible scenarios that could threaten Shell's viability. In reviewing these stress tests, the Directors have considered possible mitigation steps and have made certain assumptions regarding the availability of future funding options, including credit lines, debt facilities, possible asset disposals, changing levels of shareholder returns, and the ability to raise future financing in line with the operating plan window.

Scenario	Link to principal risks
A significant HSSE event	[A]
Unplanned shutdown of a major cash-generating asset for a year	[A]
A low oil and gas price environment (Brent at 2021: \$40, 2022: \$40, 2023: \$45 MOD)	[B] and [D]
A significant HSSE event in a low oil and gas price environment	[A], [B] and [D]
Sustained impact from politically adverse developments, lower growth in developing countries, as well as lower growth in Europe	[C]
Global macroeconomic uncertainties (including those from a pandemic) – low oil and gas price environment, negative impact on oil product and chemical margins, and long-term demand reduction	[B], [C] and [D]

OTHER REGULATORY AND STATUTORY INFORMATION continued

The list below is the sub-set of Group Principal Risks that may have an impact on viability and have been assessed in the above stress case scenarios.

- A. The nature of our operations exposes us, and the communities in which we work, to a wide range of health, safety, security and environment risks.
- B. We are exposed to macroeconomic risks including fluctuating prices of crude oil, natural gas, oil products and chemicals.
- C. We are exposed to treasury and trading risks, including liquidity risk, interest rate risk, foreign exchange risk, commodity price risk and credit risk. We are affected by the global macroeconomic environment and by financial and commodity market conditions.
- D. We seek to execute divestments in pursuing our strategy. We may be unable to divest these assets successfully in line with our strategy.

Furthermore, as a result of the events that have occurred in 2020, including the COVID-19 pandemic and significant fall in oil and gas prices during the first half of the year, the Board have received regular updates in relation to the financial framework. The short-term cash preservation measures, including opex and capex reduction, not to continue with the next tranche of the share buyback programme, lower dividend payments, and debt issuance, and the medium-term measures including the reshape of Shell's portfolio and organisation demonstrate the quantitative and qualitative actions being taken to support the viability of the Company.

Taking account of Shell's position and principal risks at December 31, 2020, the Directors have a reasonable expectation that Shell will be able to continue in operation and meet its liabilities as they fall due over its three-year operating plan period.

GOING CONCERN

In assessing the appropriateness of the going concern assumption over the period to 31 March 2022 (the 'going concern period'), management have stress tested Shell's most recent financial projections to incorporate a range of potential future outcomes by considering Shell's principal risks, further potential downside pressures on commodity prices and cash preservation measures, including reduced future operating costs, capital expenditure and dividend distributions. This assessment confirmed that Shell has adequate cash, other liquid resources and undrawn credit facilities to enable it to meet its obligations as they fall due in order to continue its operations during the going concern period. Therefore, the Directors consider it appropriate to continue to adopt the going concern basis of accounting in preparing these audited Condensed Consolidated Financial Statements.

NON-FINANCIAL INFORMATION STATEMENT

The Non-Financial Information Statement below forms part of the Strategic Report on pages 4-111.

Non-Financial Information Statement

Reporting requirement	Where to read more in this report	Page
Business Model	Shell story	10
Non-financial KPIs	Performance indicators	43
Environmental matters	Environment and society, Climate change and energy transition	85, 94
Employees	Our people and Directors' Report	108, 124
Social matters	Environment and society	85
Respect for human rights	Environment and society	85
Anti-corruption and anti-bribery matters	Our people	108

REPURCHASES OF SHARES

On July 26, 2018, the Company announced the start of a share buyback programme of at least \$25 billion, subject to further progress with debt reduction and oil price conditions. On March 23, 2020, the Company announced that in light of the economic and oil price environment, it had decided not to continue with the next tranche of the share buyback programme following the completion of the tranche announced on January 30, 2020. On April 14, 2020, the seventh tranche of the share buyback programme was completed, and no further tranches were undertaken in 2020. As announced on October 29, 2020, the Shell Group's cash allocation framework includes a target to reduce net debt to \$65 billion and following that an aim to increase distributions to shareholders through a combination of Shell's progressive dividend and share buybacks.

To ensure that the Company had the necessary authority to continue to buy back its shares when the time is considered appropriate, at the 2020 AGM, shareholders granted an authority for the Company to repurchase up to a maximum of 783 million of its shares (excluding purchases for employee share plans). This authority expires on the earlier of the close of business on August 19, 2021, or the end of the 2021 AGM.

As at December 31, 2020, 496 million A shares with a nominal value of €34.7 million (\$41.8 million) and 39 million B shares with a nominal value of €2.8 million (\$3.2 million) (6.85% of the Company's total issued share capital at December 31, 2020) had been cumulatively purchased and cancelled since the beginning of this programme, for a total cost of \$15.8 billion including expenses, at an average price of \$29.45 per share. The purpose of the shares repurchased in 2020 under the share buyback programme was to reduce the issued share capital of the Company. This is to offset the number of shares issued under the Scrip Dividend Programme and to reduce the equity issued in connection with the Company's combination with BG Group. The Scrip Dividend Programme was cancelled with effect from the fourth quarter 2017 interim dividend. More information can be found at www.shell.com/scrip. Since the completion of the tranche announced on January 30, 2020, no further shares have been bought back by the Company. This means that 783 million shares could still be repurchased under the current AGM authority.

The Board continues to regard the ability to repurchase issued shares in suitable circumstances as an important part of Shell's financial management. A new resolution will be proposed at the 2021 AGM to renew the authority for the Company to purchase its own share capital, up to specified limits, for a further year. This proposal will be described in more detail in the 2021 Notice of Annual General Meeting.

BOARD OF DIRECTORS

The names of the Directors who held office during the year can be found on pages 144-121. Information on the Directors who are seeking appointment or reappointment is included in the Notice of Annual General Meeting.

QUALIFYING THIRD-PARTY INDEMNITIES

The Company has entered into a Deed of Indemnity (Deed) with each Director of the Company who served during the year. The terms of each of these Deeds are identical and they reflect the statutory provisions on indemnities contained in the Companies Act 2006 (CA 2006). Under the terms of each Deed, the Company has agreed to indemnify the Director, to the widest extent permitted by the CA 2006, against any loss, liability or damage, howsoever caused (including in respect of a Director's own negligence), suffered or incurred by a Director in respect of their acts or omissions while or in the course of acting as a Director or employee of the Company, any associated company or affiliate (within the meaning of the CA 2006). In addition, the Company shall lend funds to Directors as required to meet reasonable costs and expenses incurred or to be incurred by them in defending any criminal or civil proceedings brought

against them in their capacity as a Director or employee of the Company, associated company or affiliate, or, in connection with certain applications brought under the CA 2006. The provisions in the Company's Articles relating to arbitration and exclusive jurisdiction are incorporated, mutatis mutandis, into the Deeds entered into by each Director and the Company.

The Company has provided both indemnities and Directors' and officers' insurance to the Directors in connection with the performance of their responsibilities. Copies of these indemnities and the Directors' and officers' insurance policies are open to inspection. A copy of the form of these indemnities has been previously filed with the US Securities and Exchange Commission.

RELATED PARTY TRANSACTIONS

Save as set out below and other than disclosures given in Notes 9 and 27 to the "Consolidated Financial Statements" on pages 238 and 262-263, there were no transactions or proposed transactions that were material to either the Company or any related party. Nor were there any transactions with any related party that were unusual in their nature or conditions.

On February 27, 2020 the fully-consolidated Shell Midstream Partners, L.P. (SHLX) signed an agreement with its Shell-controlled general partner to eliminate all incentive distribution rights and economic general partner interest in SHLX and convert the general partner's two per cent general partner interest in SHLX into a non-economic general partner interest in SHLX. SHLX also entered into a Purchase and Sale Agreement with Shell affiliates to acquire our 79% interest in the Mattox Pipeline Company LLC, which owns the Mattox Pipeline, and certain logistics assets at the Shell Norco Manufacturing Complex. Both transactions completed on April 1, 2020. As consideration for the assets and the elimination of incentive distribution rights, Shell received 160 million newly issued SHLX common units, plus \$1.2 billion of Series A perpetual convertible preferred units at a price of \$23.63 per unit.

POLITICAL CONTRIBUTIONS

No donations were made by the Company or any of its subsidiaries to political parties or organisations during the year. Shell Oil Company administers the non-partisan Shell Oil Company Employees' Political Awareness Committee (SEPAC), a political action committee registered with the US Federal Election Commission. Eligible employees may make voluntary personal contributions to the SEPAC. All employees' contributions comply with federal and state law and are publicly reported in accordance with US election laws. Shell Oil Company does not exercise control over SEPAC's funding decisions.

RECENT DEVELOPMENTS AND POST-BALANCE SHEET EVENTS

See Note 30 to the "Consolidated Financial Statements" on page 264.

SHARE CAPITAL

The Company's issued share capital at December 31, 2020, is set out in Note 8 to the "Parent Company Financial Statements" on pages 289-290. The percentage of the total issued share capital represented by each class of share is given below.

Share capital percentage

Share class	%
A	52.53
B	47.47
Sterling deferred	de minimis

TRANSFER OF SECURITIES

There are no restrictions on transfer or limitations on the holding of the ordinary shares other than under the Articles, under restrictions imposed by law or regulation (for example, insider trading laws) or pursuant to the Company's Share Dealing Code.

SHARE OWNERSHIP TRUSTS AND TRUST-LIKE ENTITIES

Shell has three primary employee share ownership trusts and trust-like entities: a Dutch foundation (stichting) and two US Rabbi Trusts. The shares held by the Dutch foundation are voted by its Board and the shares in the US Rabbi Trusts are voted by the Voting Trustee, Newport Trust Company. Both the Board of the Dutch foundation and the Voting Trustee are independent of Shell.

The UK Shell All Employee Share Ownership Plan has a separate related share ownership trust. Shares held by the trust are voted by its trustee, Computershare Trustees Limited, as directed by the participants.

AUDITOR

A resolution relating to the appointment of Ernst & Young LLP as auditor for the financial year 2021 will be proposed at the 2021 AGM.

ANNUAL GENERAL MEETING

The AGM will be held on May 19, 2021, at Carel van Bylandtlaan 16, 2596 HR, The Hague, The Netherlands. The Notice of Annual General Meeting will include details of the business to be put to shareholders at the AGM.

CONFLICTS OF INTEREST

In accordance with the Act and the Company's Articles, the Board may authorise any matter that otherwise may involve any Directors breaching their duty to avoid conflicts of interest. The Board has adopted a procedure to address these requirements. Detailed conflict of interest questionnaires are reviewed by the Board and, if considered appropriate, authorised. Conflicts of interest as well as any gifts and hospitality received by and provided by Directors are kept under review by the Board. Further information relating to conflicts of interest can be found in the Articles, available on the Shell website.

SIGNIFICANT COMMITMENTS OF THE CHAIR

The Chair's other significant commitments are given in his biography on page 114.

SHELL GENERAL BUSINESS PRINCIPLES

The Shell General Business Principles define how Shell subsidiaries are expected to conduct their affairs and are underpinned by the Shell core values of honesty, integrity and respect for people. These principles include, among other things, Shell's commitment to support fundamental human rights in line with the legitimate role of business and to contribute to sustainable development. They are designed to mitigate the risk of damage to our business reputation and to prevent violations of local and international legislation. They can be found at www.shell.com/sgbp. See "Risk factors" on pages 28-37.

OTHER REGULATORY AND STATUTORY INFORMATION continued

SHELL CODE OF CONDUCT

Directors, officers, employees and contract staff are required to comply with the Shell Code of Conduct, which instructs them on how to behave in line with the Shell General Business Principles. This Code clarifies the basic rules and standards they are expected to follow and the behaviour expected of them. These individuals must also complete mandatory Code of Conduct training.

Designated individuals are required to complete additional mandatory training on antitrust and competition laws, anti-bribery, anti-corruption and anti-money laundering laws, financial crime, data protection laws and trade compliance requirements (see “Risk factors” on page 28 - 37). The Shell Code of Conduct can be found at www.shell.com/codeofconduct.

CODE OF ETHICS

Executive Directors and Senior Financial Officers of Shell must also comply with the Code of Ethics. This Code is specifically intended to meet the requirements of Section 406 of the Sarbanes-Oxley Act. It can be found at www.shell.com/codeofethics.

INDEPENDENT PROFESSIONAL ADVICE

All Directors may seek independent professional advice in connection with their role as a Director. All Directors have access to the advice and services of the Company Secretary. The Company has provided both indemnities and Directors’ and officers’ insurance to the Directors in connection with the performance of their responsibilities. Copies of these indemnities and the Directors’ and officers’ insurance policies are open to inspection. A copy of the form of these indemnities has been previously filed with the US Securities and Exchange Commission.

RESULTS PRESENTATIONS AND ANALYSTS’ MEETINGS

The planned dates of the quarterly, half-yearly and annual results presentations, as well as all major analysts’ meetings, are announced in advance on the Shell website and through a regulatory release.

Generally, presentations are broadcast live via webcast and teleconference. Other meetings with analysts or investors are not normally announced in advance, nor can they be followed remotely by webcast or any other means. Procedures are in place to ensure that discussions in such meetings are always limited to non-material information or information already in the public domain.

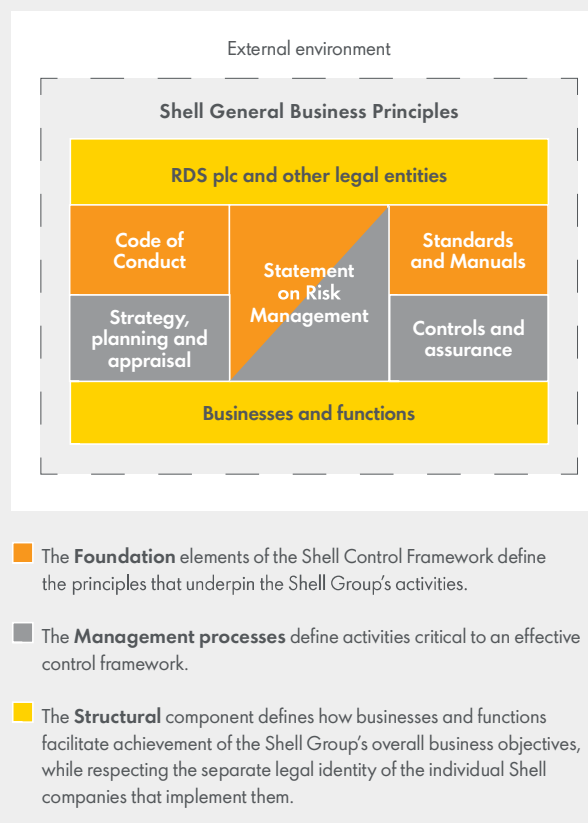
Results and meeting presentations can be found at www.shell.com/investor. This is in line with the requirement to ensure that all shareholders and other parties in the financial market have equal and simultaneous access to information that may influence the price of the Company’s securities.

RISK MANAGEMENT AND CONTROLS

The Board is responsible for maintaining a sound system of risk management and internal control, and for regularly reviewing its effectiveness.

A single overall control framework is in place for the Company and its subsidiaries that is designed to manage rather than eliminate the risk of failure to achieve business objectives. It therefore only provides reasonable and not absolute assurance against material misstatement or loss.

CONTROL FRAMEWORK



The Control Framework diagram illustrates the key components – “Foundations”, “Management processes” and “Structural” – that make up the Control Framework. “Foundations” comprises the objectives, principles and rules that underpin and establish boundaries for Shell activities. “Management processes” refers to the more significant management processes, including how strategy, planning and appraisal are used to improve performance and how risks are to be managed through effective controls and assurance. The “Structural” component defines how Businesses and Functions facilitate achievement of the Shell group’s overall business objectives.

Risk management

The “Statement on Risk Management” is a foundation element of Shell’s Control Framework and a key enabler of many of its management processes. We assess risks across the Shell Group in terms of three distinct categories:

- **Strategic risks:** we consider current and future portfolio considerations, examining parameters such as country concentration or exposure to higher-risk countries. We also consider long-range developments in order to test key assumptions or beliefs in relation to energy markets.
- **Operational risks:** we consider material operational exposures across Shell’s entire value chain, and promote a more granular assessment of key risks facing the organisation.
- **Conduct and culture risks:** we consider alignment of our policies, practices and behaviours against our purpose and core values.

To support risk assessment across each category, Shell has developed a risk appetite framework, which helps management establish and articulate the level of risk that they are willing to accept in pursuit of Shell's strategy and objectives, noting that there are also risks that Shell accepts or does not seek to fully mitigate. The financial framework sets an overarching boundary condition in the consideration of risk appetite, as the financial resilience of Shell should logically inform the aggregate level of risk appetite that could be sustained.

Shell's principal risks and the broad array of measures used to manage each risk are described on pages 28-37. During the year, management regularly reviews these principal risks and associated risk responses and implements further remedial actions as appropriate. The Executive Committee and the Board regularly consider Group-level risks, framed across the three categories above, together with the associated control mechanisms and risk responses. In 2020, specific attention was given to our response to the COVID-19 pandemic (see "Responding to the COVID-19 Pandemic" on page 188).

Management and the Board also consider emerging risks, defined as risks where the scope, impact and likelihood are still uncertain, but which could have a material effect on achieving Shell's strategy and objectives in the future. These risks are identified through, (among other procedures), the monitoring of external developments, scenario planning, the status of risk indicators, learnings from incidents and assurance findings, and the appraisal of Shell's forward-looking plans. Once identified, we undertake activities to monitor, prepare for and/or reduce the future impact, where possible, should such emerging risks materialise.

The system of risk management and internal control over financial reporting is an integral part of the Control Framework. Regular reviews are performed to identify the significant risks to financial reporting and the key controls designed to address them. These controls are documented, responsibility is assigned, and they are monitored for design and operating effectiveness. Controls found to be ineffective are remediated.

Shell has a climate change risk management structure which is supported by standards, policies and controls (see "Risk factors" on page 29 and "Climate change and energy transition" on pages 94-107). Climate change and risks resulting from greenhouse gas emissions have been identified as significant risk factors for Shell and are managed in accordance with other significant risks through the Board and Executive Committee.

Many of our major projects and operations are conducted in joint arrangements or associates, which may reduce the degree of control and ability to identify and manage risks (see "Risk Factors" on page 35). In each case, Shell appoints a representative to manage its interests who seeks to ensure that such projects operate under equivalent Shell standards to Shell.

We operate in more than 70 countries that have differing degrees of political, legal and fiscal stability. This exposes us to a wide range of political developments that could result in changes to contractual terms, laws and regulations. In addition, we and our joint arrangements and associates face the risk of litigation and disputes worldwide (see "Risk Factors" on page 30). We continuously monitor geopolitical developments and societal issues relevant to our interests. Employees who engage with government officials are subject to specific training programmes, procedures and regular communications, in addition to Shell General Business Principles and Shell Code of Conduct compliance. We are prepared to exit a country if we believe we can no longer operate in that country in accordance with our standards and applicable law, and we have done so in the past.

The Board confirms it has carried out a robust assessment of Shell's principal risks, including a robust process for identifying, evaluating and managing Shell's principal risks. The Board confirms it has carried out a robust assessment of Shell's emerging risks, the procedures in place to identify the emerging risks, and how risks are being managed or mitigated to help Shell achieve its strategy and objectives. This has been in place throughout 2020 and up to the date of this Report; is regularly reviewed by the Board; and accords with the FRC Guidance on risk management, internal control and related financial and business reporting.

Review of the effectiveness of risk management and internal control

The Board has delegated authority to the Audit Committee to assist it in fulfilling its responsibilities in relation to the effectiveness of the risk management framework and internal control system, the integrity of financial reporting as well as consideration of compliance matters. (see "Audit Committee Report" on pages 145-152).

The Audit Committee met six times this year and received regular reports from the Chief Internal Auditor on notable internal audits and those with a significant impact on control effectiveness. The Audit Committee also reviewed significant financial, business and compliance control incidents and received regular reports on business integrity issues. The Audit Committee also requested updates on specific financial, operational and compliance control issues throughout the year. The Audit Committee Chair provided an update to the Board after every Audit Committee meeting.

During and after such reports, the Board has an opportunity to request further information and/or ask clarifying questions, which it does to varying degrees depending on the issue. Similarly, the Chairs of the Safety, Environment and Sustainability Committee (SESCO) and the Nigeria Special Litigation Committee, an ad hoc Board committee, also provide regular updates after each of their respective meetings covering, among other matters, the respective aspects of controls that they monitor pursuant to their Terms of Reference. The Audit Committee and SESO minutes, once approved, are further provided to the Board and incorporated into Board minutes to ensure full access to and review by all Directors. These aspects, together with the 2020 Reports respectively produced by the Executive Vice President Taxation and Controller and Chief Internal Auditor, the External Auditors, the Chairs of the Disclosure Committee and the Financial Reporting Control Committee and the Chief Ethics & Compliance Officer, as well as summaries of the Annual Proved Reserves Disclosure and the Full Year HSSE & Social Performance Assurance Report, enable the Board's ongoing monitoring and annual review of material controls.

An annual review of the effectiveness of risk management and internal control was carried out by both the Executive Committee and the Audit Committee. This was based on their own insights and experience throughout the year as well as outcomes from the Group-level risk reviews and the Group Assurance Letter process, a structured internal assessment of compliance with legal and ethical requirements and the Shell Control Framework carried out by each Executive Director. As part of their annual review, the Executive Committee and Audit Committee also considered input from the Chief Internal Auditor, Chief Ethics & Compliance Officer and the External Auditor. The insights and conclusions from this annual assessment were reviewed and discussed by the Board.

The Board confirms that it has conducted its annual review of the effectiveness of Shell's system of risk management and internal control in respect of 2020, such review covering all material controls, including financial, operational and compliance controls.

OTHER REGULATORY AND STATUTORY INFORMATION continued

Responding to the COVID-19 pandemic

The COVID-19 pandemic has transformed economies, government policies, markets and businesses globally. Shell has been responding to the pandemic with a broad, structured approach to ensure we support our colleagues, suppliers, customers and the communities where we work, while ensuring resilience in our day-to-day operations and overall financial framework. A dedicated Group Coordination Team, under the direct supervision of the Executive Committee, has been in place to oversee Shell's risk response plans globally.

We have taken many steps to protect the health of our colleagues, including requiring or encouraging office-based staff to work from home, depending on the advice of local authorities. We are providing the technology support to ensure up to 70,000 colleagues can work remotely each day. We have developed comprehensive COVID-safe return to site approaches across Shell's offices with small-scale proof-of-concept tests.

For people working on our platforms offshore, or our facilities onshore, we enforce social distancing, carry out health screening and have procedures in place to allow the safe evacuation of any suspected cases of COVID-19.

To keep our customers safe at our retail sites we launched Clean+, a global initiative to provide enhanced cleaning, regular sanitation of common touchpoints, free sanitiser and/or wipes, protection for staff and reminders to maintain safe distancing.

Management at all levels continue to engage extensively with staff to understand and respond to the stresses placed on them as a result of the pandemic. A confidential counselling service is available to help colleagues experiencing the psychological impact of the pandemic,

and we continue to provide extra online resources to help people manage their physical and mental well-being.

To sustain our operations and supply chains, which in turn support our suppliers and customers, we have business continuity plans in place across all our businesses, functions and operating sites. These plans are adjusted as needed by considering short- and medium-term "likely" and "worst case" scenarios developed by the Group Coordination Team. Examples of specific enhanced controls include the strengthening of our global web content filtering capability in response to the switch from office to remote working and additional measures to improve cyber-awareness. We have reiterated and emphasised adherence to Shell's compliance rules (including the Code of Conduct). Shell's Crisis Management Standard is also being used to guide our operational risk responses, and our country chair network has been strengthened to address specific challenges that arise at local levels.

Throughout the pandemic, we have maintained a strong focus on our cash allocation framework, using a bespoke COVID-19 risk register to monitor the effectiveness of our risk responses to ensure the financial resilience of our portfolio. These responses included the implementation of certain cash preservation measures. More details are provided on pages 81 - 84.

We expect many of our risk response measures to stay in place in 2021. We continue to adjust and apply our learnings from this experience to ensure we remain resilient in this new macroeconomic environment. Detailed information about the impact of the pandemic on Shell's principal risks and our responses to these impacts is provided on pages 28-37.

MANAGEMENT'S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES OF SHELL

Shell's CEO and CFO have evaluated the effectiveness of Shell's disclosure controls and procedures at December 31, 2020. Based on that evaluation, they concluded that Shell's disclosure controls and procedures are effective.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING OF SHELL

Management, including the CEO and CFO, is responsible for establishing and maintaining adequate internal control over Shell's financial reporting and the preparation of the "Consolidated Financial Statements". It conducted an evaluation of the effectiveness of Shell's internal control over financial reporting and the preparation of the "Consolidated Financial Statements" based on the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). On the basis of this evaluation, management concluded that, at December 31, 2020, the Company's internal control over financial reporting and the preparation of the "Consolidated Financial Statements" was effective.

THE TRUSTEE'S AND MANAGEMENT'S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES FOR THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST

The Trustee of the Royal Dutch Shell Dividend Access Trust (the Trustee) and Shell's CEO and CFO have evaluated the effectiveness of the disclosure controls and procedures in respect of the Dividend Access Trust (the Trust) at December 31, 2020. On the basis of this evaluation, these officers have concluded that the disclosure controls and procedures of the Trust are effective.

THE TRUSTEE'S AND MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING OF THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST

The Trustee and the Company's management are responsible for establishing and maintaining adequate internal control over the Trust's

financial reporting. The Trustee and the Company's management conducted an evaluation of the effectiveness of internal control over financial reporting based on the Internal Control - Integrated Framework (2013) issued by COSO. On the basis of this evaluation, the Trustee and management concluded that, at December 31, 2020, the Trust's internal control over financial reporting was effective.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There has not been any change in the internal control over financial reporting of Shell or the Trust that occurred during the period covered by this Report that has materially affected, or is reasonably likely to materially affect, the internal control over financial reporting of Shell or the Trust. Material financial information of the Trust is included in the "Consolidated Financial Statements" and is therefore subject to the same disclosure controls and procedures as Shell. See the "Royal Dutch Shell Dividend Access Trust Financial Statements" on pages 294-297 for additional information.

ARTICLES OF ASSOCIATION

The Company's Articles of Association (Articles) were adopted at the 2019 AGM. The Articles may only be amended by a special resolution of the shareholders in a general meeting. A full version of the Company's Articles can be found at www.shell.com/investors.

MANAGEMENT AND DIRECTORS

The Company has a single-tier Board of Directors headed by a Chair, with management led by a CEO. See "The Board of Royal Dutch Shell plc" on page 114 and Senior Management on page 122.

DIRECTORS' SHAREHOLDING QUALIFICATION

While the Articles do not require Directors to hold shares in the Company, the Remuneration Committee believes that Executive Directors should align their interests with those of shareholders by holding shares in the Company.

The CEO is expected to build up a shareholding of seven times base salary over five years from appointment and the CFO is expected to build up a shareholding of five times base salary over the same period. In the event that another Executive Director joins the Board, the Remuneration Committee will determine their shareholding requirement, which will not be less than 200% of their base salary.

Executive Directors will be required to maintain their requirement (or existing shareholding if less than the guideline) for a period of two years post-employment. Non-executive Directors are encouraged to hold shares with a value equivalent to 100% of their fixed annual fee and to maintain that holding during their tenure. Information on the Directors with shares in the Company can be found in the "Directors' Remuneration Report" on pages 153-156,

APPOINTMENT AND RETIREMENT OF DIRECTORS

The Company's Articles, the Corporate Governance Code and the Companies Act 2006 govern the appointment and retirement of Directors. Board membership and biographical details of the Directors are provided on pages 114-121. However, Directors follow the direction laid out in the Code and stand for re-election annually.

During the year, Dick Boer and Martina Hund-Mejean (effective May 20, 2020), Sir Andrew Mackenzie and Bram Schot (effective October 1, 2020) were appointed to the Board. Further, Gerard Kleisterlee, Linda Stuntz and Roberto Setubal stood down from the Board at the 2020 AGM held on May 19, 2020.

On March 11, 2021, the Company announced the appointment of Sir Andrew Mackenzie as Chair of the Board of Royal Dutch Shell plc, with effect from the conclusion of the 2021 AGM. Andrew replaces Chad Holliday, who stands down following the 2021 AGM after more than 10 years' service. Sir Nigel Sheinwald will also stand down following the 2021 AGM, after serving nine years on the Board. Jane Lute will be proposed to shareholders for appointment as a Non-executive Director, effective May 19, 2021. The 2021 AGM is currently scheduled for May 18, 2021.

RIGHTS ATTACHING TO SHARES

The full rights attaching to shares are set out in the Company's Articles of Association. The Company can issue shares with any rights or restrictions attached to them as long as this is not restricted by any rights attached to existing shares. These rights or restrictions can be decided either by an ordinary resolution passed by the shareholders or by the Board as long as there is no conflict with any resolution passed by the shareholders.

VOTING

Currently, only the A and B shares have voting rights. The voting rights of each A share and each B share are equal and carry one vote at a general meeting of the Company.

The sterling deferred shares are not ordinary shares and therefore have different rights and restrictions attached to them.

CHANGE OF CONTROL

There are no provisions in the Articles that would delay, defer or prevent a change of control.

DIRECTORS' RESPONSIBILITIES IN RESPECT OF THE PREPARATION OF THE ANNUAL REPORT AND ACCOUNTS

The Directors are responsible for preparing the Annual Report, including the financial statements, in accordance with applicable laws and regulations. These require the Directors to prepare financial statements for each financial year. As such, the Directors have prepared the (i) Consolidated Financial Statements in accordance with international accounting standards in conformity with the requirements of the UK Companies Act 2006, and therefore in accordance with International Financial Reporting Standards adopted pursuant to Regulation (EC) No 1606/2002 as it applies in the European Union; and (ii) Parent Company Financial Statements in accordance with international accounting standards in conformity with the

requirements of the UK Companies Act 2006. In preparing these financial statements, the Directors have also elected to comply with IFRS as issued by the International Accounting Standards Board (IASB). The Directors must not approve the financial statements unless they are satisfied that they give a true and fair view of the state of affairs of Shell and the Company and of the profit or loss of Shell and the Company for that period. In preparing these financial statements, the Directors are required to:

- adopt the going concern basis unless it is inappropriate to do so;
- select suitable accounting policies and then apply them consistently;
- make judgements and accounting estimates that are reasonable and prudent; and
- state whether international accounting standards in conformity with the requirements of the UK Companies Act 2006, International Financial Reporting Standards adopted pursuant to Regulation (EC) No 1606/2002 as it applies in the European Union and International Financial Reporting Standards as issued by the IASB have been followed.

The Directors are responsible for keeping adequate accounting records that are sufficient to show and explain the transactions of Shell and the Company and disclose with reasonable accuracy, at any time, the financial position of Shell and the Company and to enable them to ensure that the financial statements comply with the Companies Act 2006 (the Act) and, as regards the Consolidated Financial Statements, with Article 4 of the IAS Regulation and therefore are in accordance with IFRS as adopted by the EU. The Directors are also responsible for safeguarding the assets of Shell and the Company and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

Each of the Directors, whose names and functions can be found on pages 114-121, confirms that, to the best of their knowledge:

- the financial statements, which have been prepared in accordance with international accounting standards in conformity with the requirements of the UK Companies Act 2006, International Financial Reporting Standards adopted pursuant to Regulation (EC) No 1606/2002 as it applies in the European Union and International Financial Reporting Standards as issued by the IASB, give a true and fair view of the assets, liabilities, financial position and profit of Shell and the Company; and
- the Management Report includes a fair review of the development and performance of the business and the position of Shell, together with a description of the principal risks and uncertainties that it faces.

Furthermore, so far as each of the Directors is aware, there is no relevant audit information of which the auditors are unaware, and each of the Directors has taken all the steps that ought to have been taken in order to become aware of any relevant audit information and to establish that the auditors are aware of that information.

The Directors consider that the Annual Report, including the financial statements, taken as a whole, is fair, balanced and understandable and provides the information necessary for shareholders to assess Shell's position and performance, business model and strategy.

The Directors consider it appropriate to continue to adopt the going concern basis of accounting in preparing the financial statements.

The Directors are responsible for the maintenance and integrity of the Shell website (www.shell.com). Legislation in the UK governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

Signed on behalf of the Board

/s/ Linda M. Coulter

LINDA M. COULTER

Company Secretary
March 10, 2021

FINANCIAL STATEMENTS AND SUPPLEMENTS

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GENERATING **SHAREHOLDER VALUE**

Financial Statements and Supplements

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC

1. OUR OPINIONS AND CONCLUSIONS ARISING FROM OUR AUDIT

1.1 Our unmodified opinion on the financial statements

In our opinion, the financial statements of Royal Dutch Shell plc (the Parent Company) and its subsidiaries (collectively, Shell or Group):

- give a true and fair view of the state of Shell's and of the Parent Company's affairs as at December 31, 2020 and of Shell's loss and the Parent Company's income for the year then ended;
- have been properly prepared in accordance with International Accounting Standards in conformity with the requirements of the Companies Act 2006 and, as regards the Group financial statements, both International Financial Reporting Standards (IFRS) adopted pursuant to Regulation (EC) No. 1606/2002 as it applies in the European Union (EU) and IFRS as issued by the international Accounting Standards Board (IASB); and
- have been prepared in accordance with the requirements of the Companies Act 2006.

1.2 What we have audited

We have audited the financial statements of Royal Dutch Shell plc and its subsidiaries for the year ended December 31, 2020, which are included in the Annual Report and comprise:

Shell	Parent Company
Consolidated Balance Sheet as at December 31, 2020	Balance Sheet as at December 31, 2020
Consolidated Statement of Income for the year then ended	Statement of Income for the year then ended
Consolidated Statement of Comprehensive Income for the year then ended	Statement of Comprehensive Income for the year then ended
Consolidated Statement of Changes in Equity for the year then ended	Statement of Changes in Equity for the year then ended
Consolidated Statement of Cash Flows for the year then ended	Statement of Cash Flows for the year then ended
Related Notes 1 to 30 to the Consolidated Financial Statements, including a summary of significant accounting policies	Related Notes 1 to 14 to the Parent Company Financial Statements

The financial reporting framework that has been applied in the preparation of the financial statements is applicable law and International Accounting Standards in conformity with the requirements of the Companies Act 2006 and, as regards the Group financial statements, both IFRS adopted pursuant to Regulation (EC) No. 1606/2002 as it applies in the European Union and IFRS as issued by the IASB.

2. BASIS FOR OUR OPINION

We conducted our audit in accordance with International Standards on Auditing (UK) (ISA (UK)) and applicable law. Our responsibilities under those standards are further described in the 'Our responsibilities for the audit of the financial statements' section of our report below. We are independent of Shell and the Parent Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in the UK, including the Financial Reporting Council's Ethical Standard as applied to listed public interest entities, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained during the planning, execution and conclusion of our audit is sufficient and appropriate to provide a suitable basis for our opinion.

3. CONCLUSIONS RELATING TO GOING CONCERN

In auditing the financial statements, we have concluded that the directors' use of the going concern basis of accounting in the preparation of the financial statements of the Group is appropriate. Our evaluation of the directors' assessment of the Shell Group and Parent Company's ability to continue to adopt the going concern basis of accounting included the following:

- we obtained an understanding of the controls over management's going concern evaluation. We then evaluated the design of these controls and tested their operating effectiveness. We tested management's controls over the review and approval of the business operating plan and the underlying economic assumptions;
- we assessed the information used in the going concern assessment for consistency with the operating plan and information obtained through auditing other areas of the business, obtained an understanding of the business planning process and challenged the central assumptions, including those relating to climate risk and the energy transition. We involved our economist to review Shell's global economic scenarios as well as their economic projections in 10 major countries;
- given that management prepare forecasts for other business purposes that go beyond March 31, 2022 (the going concern period), we have used such forecasts in our management challenge process and considered events and conditions beyond the period of management's assessment that may cast significant doubt over the entities' ability to continue as going concerns; and
- we conducted severe but plausible independent stress testing and a reverse stress test to determine the conditions under which Shell could potentially experience a liquidity shortfall. This included assuming lower Brent prices of \$20/bbl for 2021 and 2022 and overlaying the assumptions that Shell will not achieve any further asset sales over this period, will not have access to new capital raising and no access to commercial paper programmes. Under this stress testing, we concluded that there would still be sufficient facilities available for Shell to continue as a going concern.

Based on the work we have performed, we have not identified any material uncertainties relating to events or conditions that, individually or collectively, may cast significant doubt on the Group's and Parent Company's ability to continue as going concerns until 31 March 2022.

In relation to the Group and Parent Company's reporting on how they have applied the UK Corporate Governance Code, we have nothing material to add or draw attention to in relation to the directors' statement in the financial statements about whether the directors considered it appropriate to adopt the going concern basis of accounting.

Our responsibilities and the responsibilities of the directors with respect to going concern are described in the relevant section of this report. However, because not all future events or conditions can be predicted, this statement is not a guarantee as to the Company's or Group's ability to continue as a going concern.

4. OVERVIEW OF OUR AUDIT APPROACH

<p>UPDATING OUR UNDERSTANDING OF SHELL'S BUSINESS AND ITS ENVIRONMENT</p>	<p>Our global audit team has deep industry experience through working for many years on the audits of large integrated international oil and gas companies and commodity trading organisations. Our audit planning starts with updating our view on external market factors, for example geopolitical risk, the potential impact of climate change and the energy transition, commodity price risk and major trends in the industry. In 2020, the oil and gas industry suffered severe macro-economic shocks due to factors such as the impact of COVID-19 on the global economy and on GDP growth, the pace of decarbonisation and the energy transition and the volatility in the oil price, refining margins and in demand for petroleum products.</p> <p>In planning our 2020 audit, we were mindful that there is increased importance on companies providing stakeholders with information on significant judgements applied in the preparation of the financial statements, including the sources of estimation uncertainty and other key assumptions in light of economic and market uncertainty, climate risk and the energy transition. Shell has focused on cost control, capital spending, cash flow management, tackling climate change and is undertaking a fundamental restructuring. As part of our audit, we understood Shell's energy transition strategy and how this is reflected in setting oil and gas commodity price assumptions, refining margin assumptions, the estimation of oil and gas reserves, the recoverable amounts of assets and the recognition and measurement of provisions. This assessment was conducted in light of the commitments that Shell has made with respect to decarbonisation in order to be a net-zero emissions energy business by 2050.</p> <p>Our updated understanding of Shell's business and the environment in which it operates informed our risk assessment procedures.</p>
<p>IDENTIFYING AND ASSESSING THE RISKS OF MATERIAL MISSTATEMENT</p>	<p>The current macro-economic environment has created heightened estimation uncertainty and an elevated risk of material misstatement of Shell's asset and liability carrying values. These factors had a pervasive impact on Shell's financial statements and increased the risk around key areas of accounting judgement, such as impairment, inventory valuation and provisioning. We also faced additional audit risk due to the fact that the entire 2020 audit was conducted under remote working conditions. We have therefore clarified, and shown as a separate risk, the risk of employee and management fraud as a result of remote working and the potential implications of the restructuring announcement on the stability of the control environment.</p> <p>The risks we identified were as follows:</p> <ul style="list-style-type: none"> ■ impairment of PP&E (including exploration and production assets and refineries) and joint ventures and associates (JVA); ■ the risk of unrealised trading gains and losses being recognised as a result of errors, unauthorised trading activity or deliberate misstatement of Shell's trading position; ■ risk of fraud through management override within other significant revenue streams; and ■ the risk of both employee and management fraud, including financial statement fraud to overstate financial results or position, misappropriation of assets and illegal acts in responding to the current environment. <p>Our additional areas of audit focus were:</p> <ul style="list-style-type: none"> ■ the estimation of decommissioning and restoration provisions; ■ legal proceedings and other contingencies, with specific emphasis on OPL 245; ■ uncertain tax positions; ■ trading valuation (including mark-to-market, hedging, impairment and credit losses); ■ identification of onerous regasification contracts in the LNG portfolio; ■ inventory valuation (in relation to net realisable value); ■ recognition and measurement of deferred tax assets; ■ pension asset and liability valuations; ■ recoverability of government receivables; ■ the impact of climate change and the energy transition on the financial statements; ■ the dividend distribution process, including the determination of realised profits and losses for the purposes of making distributions under the Companies Act 2006 (this area of audit focus relates to the parent company only); and ■ the recoverable amount of investments held by the parent company (this area of audit focus relates to the parent company only). <p>In conducting our audit procedures, we changed the nature of our testing compared to the prior year through developing alternative means of obtaining sufficient and appropriate audit evidence, including through our enhanced use of technology and digital audit techniques.</p> <p>The use of these digital audit tools provided us with an integrated view of risk, thus enabling us to focus our audit effort on operating units with higher risk profiles. They also enabled us to perform risk-led analyses of entire populations of data.</p>

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

4. OVERVIEW OF OUR AUDIT APPROACH continued

<p>ASSESSING MATERIALITY (SECTION 5)</p>	<p>Our determination of materiality in uncertain times</p> <p>For the purposes of determining whether the financial statements are free from material misstatement due to fraud or error, we define materiality as the magnitude of misstatement that, either individually or in the aggregate, could reasonably be expected to influence the economic decisions of the users of these financial statements. In determining this year's materiality, we have considered both Shell's changing risk landscape and the unique combination of macro-economic factors, including current market volatility, disruption in demand and production and global supply chain oversupplies in 2020.</p> <p>The world is in an uncertain place and will be so for some time. However, we believed that it was important that, in setting materiality in these uncertain times, we did not overreact to what is expected to be a relatively temporary phenomenon – especially when Shell continues to be the same company structurally. In the 4th Quarter of 2020 and post year-end, the oil price has more than recovered to the levels it was before the pandemic and oil price collapse in March 2020. Our key criterion in determining materiality remained our perception of the needs of Shell's investors. We considered which earnings, activity or capital-based measure aligned best with the expectations of the Audit Committee and users of Shell's financial statements. In so doing, we applied a 'reasonable investor perspective', which reflected our understanding of the common financial information needs of the members of Shell as a group.</p> <p>For the previous four years, we believed that investor needs were best met by basing materiality on normalised adjusted earnings, which excludes identified items and are adjusted for tax (adjusted earnings). However, for 2020, in light of the extraordinary circumstances under which Shell was operating, we undertook a fundamental review of the possible alternative bases on which to determine materiality. We considered alternative benchmarks to adjusted earnings, including revenue, EBITDA, total assets and equity. These indicated a range for materiality of \$1.1 billion to \$2.0 billion, with the capital-based measures being at the top end of this range.</p> <p>We believed that an adjusted earnings approach remained appropriate, despite the fact that the difficult trading environment would distort short-term earnings-based measures. Although this was an unprecedented time for Shell and the industry and there was uncertainty around how long negative price impacts would last, views of economists and market participants were that demand would return and that the supply/demand balance would be re-addressed over time. By applying an adjusted earnings approach, the materiality range narrowed to \$1.0 billion to \$1.3 billion. We planned our 2020 audit using the bottom end of this range, which resulted in the following materiality measures for 2020:</p> <ul style="list-style-type: none"> ■ planning materiality: \$1,000 million (2019: \$1,200 million); ■ performance materiality: \$500 million (2019: \$900 million); and ■ reporting differences threshold: \$50 million (2019: \$60 million). <p>Our determination of performance materiality was underpinned by our assessment of the potential impact of remote working on Shell throughout the year and the potential impact on Shell's control environment of the restructuring programme (Project Reshape). We confirmed with the Audit Committee that they were satisfied that these levels of materiality were appropriate. We kept our assessment of materiality under review throughout the year.</p>
<p>DETERMINING THE SCOPE OF OUR AUDIT (SECTION 6)</p>	<p>Our scope was tailored to the circumstances of our audit of Shell and was influenced by our determination of materiality and our assessed risks of material misstatement.</p> <p>We reassessed our 2020 audit scope following the completion of our 2019 audit. Our starting point was the consolidated 2019 financial reporting data by Area of Operation (AoO). We identified those AoOs that were significant by virtue of their contribution to Shell's results or significant by virtue of their associated risk or complexity. In doing this we considered the history or expectation of unusual or complex transactions, potential for or history of material misstatements, the previous effectiveness of controls, our assessment in relation to fraud, bribery or corruption; and internal audit findings. We then considered the adequacy of account coverage and remaining audit risk of AoOs not directly covered by audit procedures. Finally, we sense checked our scope to the prior year, ensured that there was appropriate unpredictability and made the necessary changes where appropriate.</p> <p>By following this approach, our audit effort focused on higher risk areas, such as management judgements. Our group wide procedures enabled us to obtain audit evidence over the AoOs that were not full, specific or specified procedure scope.</p>

IDENTIFYING KEY AUDIT MATTERS (SECTION 7)

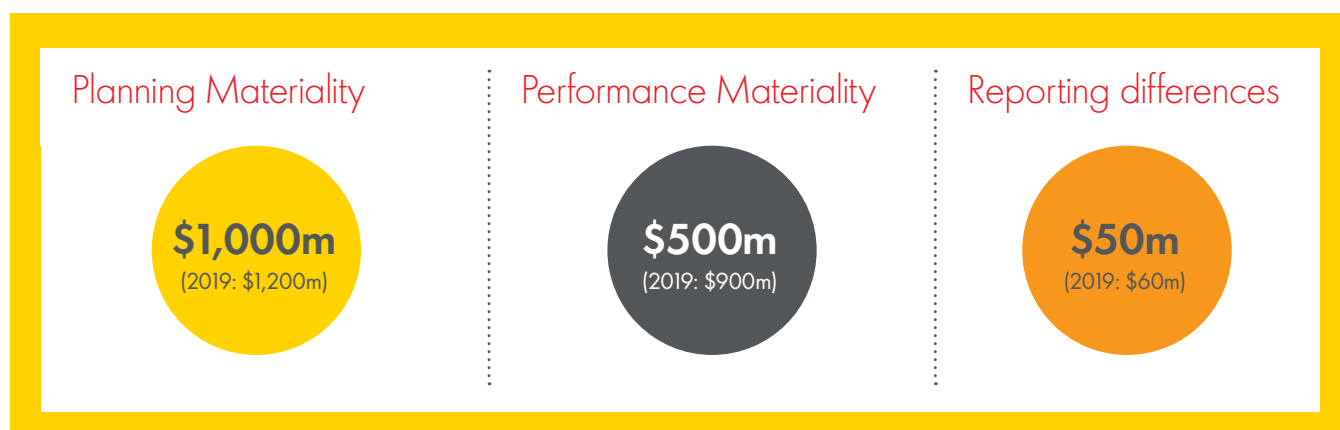
We have identified the following key audit matters that, in our professional judgement, had the greatest effect on our overall audit strategy, the allocation of resources in the audit and in directing the global audit team's efforts:

- the impact of climate risk and the energy transition on the financial statements;
- the estimation of oil and gas reserves, including reserves used in the calculation of depreciation, depletion and amortisation (DD&A), impairment testing to evaluate the recoverable amounts of production assets and in the estimation of decommissioning and restoration provisions;
- the recoverable amounts of exploration and production assets, and investments in joint ventures and associates;
- the estimation of future refining margins to evaluate the recoverability of manufacturing assets;
- the estimation of decommissioning and restoration (D&R) provisions;
- the recognition and measurement of deferred tax assets;
- revenue recognition: the risk of unrealised trading gains and losses being recognised as a result of errors, unauthorised trading activity or deliberate misstatement of the group's trading positions;
- the dividend distribution process, including the determination of realised profits and losses for the purposes of making distributions under the Companies Act 2006 (this key audit matter relates to the Parent Company only); and
- the recoverable amount of investments held by the Parent Company (this key audit matter relates to the Parent Company only).

In the current year, in response to the changes in the economic environment, we have added two key audit matters that were not reported as key audit matters in our 2019 report. These relate to: (1) the impact of climate risk and the energy transition on the financial statements; and (2) impairment of investments held by the Parent Company.

5. OUR ASSESSMENT OF MATERIALITY

The scope of our work is influenced by our view of materiality and our assessed risks of material misstatement. As we develop our audit strategy, we determine materiality at the overall level and at the individual account level (referred to as our 'performance materiality' (see below).



INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

5. OUR APPLICATION OF MATERIALITY continued

Overall materiality

What we mean

We apply the concept of materiality both in planning and performing our audit, as well as in evaluating the effect of identified misstatements (including omissions) on our audit and in forming our audit opinion. For the purposes of determining whether or not Shell's financial statements are free from material misstatement (whether due to fraud or error), we define materiality as the magnitude of misstatements that, individually or in the aggregate, could reasonably be expected to influence the economic decisions of the users of these financial statements. We are required to establish a materiality level for the financial statements as a whole that is appropriate in light of Shell's particular circumstances.

Our overall materiality provides a basis for identifying and assessing the risk of material misstatement and determining the nature and extent of our audit procedures. Our evaluation of materiality requires professional judgement and necessarily takes into account qualitative as well as quantitative considerations. It also considers our assessment of the expectations of those charged with governance at Shell and users of Shell's financial statements. As required by auditing standards, we reassess materiality throughout the duration of the audit.

Level set

Group materiality

We set our preliminary overall materiality for Shell's Consolidated Financial Statements at \$1,000 million (2019: \$1,200 million). We kept this under review throughout the year and reassessed the appropriateness of our original assessment in light of Shell's results and external market conditions. Based on these reviews and reassessments, we did not find it necessary to revise our level of overall materiality.

Parent Company materiality:

We determined materiality for the Parent Company to be \$1.0 billion (2019: \$2.6 billion), which is 0.4% of equity (2019: 1% of equity). We concluded that equity remains an appropriate basis to determine materiality for an investment holding company. However, we identified an indicator of impairment in the carrying value of the Parent Company's investments, which represent the majority of the equity value of the Parent Company. As a result, we concluded it was appropriate to align the Parent Company materiality with the lower materiality of the Group. Any balances in the Parent Company financial statements that were relevant to our audit of the consolidated group were audited using an allocation of group performance materiality.

Our basis of determining materiality in uncertain times

Our assessment of overall materiality was \$1,000 million. This was derived from an average of Shell's earnings for 2018 and 2019 and the estimated result for 2020 on an adjusted earnings basis reported by Shell in its quarterly results announcements, and adjusted for an effective tax rate.

In determining materiality, auditing standards require us to use benchmark measures, such as pre-tax income, total revenue, total assets and equity. Nevertheless, we have to exercise considerable judgement, including which earnings, activity or capital-based measure aligns best with the expectations of users of Shell's financial statements and the Audit Committee.

In determining this year's materiality, we have considered both Shell's changing risk landscape and various macro-economic factors, such as the impact of the pandemic on the global economy and on GDP growth, the pace of decarbonisation and the energy transition and volatility in oil and gas prices and in demand for petroleum products.

The world is in an uncertain place and will be so for some time. However, we believed that it was important that, in setting materiality in these uncertain times, we did not overreact to what is expected to be a relatively temporary phenomenon – especially when Shell continues to be the same company structurally. In the 4th Quarter of 2020 and post year-end, the oil price has more than recovered to the levels it was before the pandemic and oil price collapse in March 2020. Our key criterion in determining materiality remained our perception of the needs of Shell's investors.

We considered which earnings, activity or capital-based measure aligned best with the expectations of the Audit Committee and users of Shell's financial statements. In so doing, we applied a 'reasonable investor perspective', which reflected our understanding of the common financial information needs of the members of Shell as a group.

For the previous four years, we believed that investor needs were best met by basing materiality on adjusted earnings. However, for 2020, in light of the extraordinary circumstances under which Shell was operating, we undertook a fundamental review of the possible alternative bases on which to determine materiality. We considered alternative benchmarks to adjusted earnings, including revenue, EBITDA, total assets and equity. These indicated a range for materiality of \$1.1 billion to \$2.0 billion, with the capital-based measures being at the top end of this range.

In light of this analysis, we re-considered whether or not an adjusted earnings approach remained appropriate, despite the fact that the difficult trading environment would distort short-term earnings-based measures. In so doing, we reflected on the following factors:

- the use of adjusted earnings allows investors to understand how management has performed despite the commodity price environment, as opposed to because of it;
- analyst forecasts predominately feature adjusted earnings, which exclude identified items, as the basis for their forecasts. The analyst consensus data supports our judgement that adjusted earnings, excluding identified items, remains the key indicator of performance from a reasonable investor perspective;
- although this is an unprecedented time for Shell and the industry and there is uncertainty around how long negative price impacts will last, views of economists and market participants are that demand will return and that the supply/demand balance will be re-addressed over time; and
- Shell were not forecasting a significant drop in volumes in 2020 (although there would be some impacts as capital expenditure reductions flowed through later in the year). This provided further support to this being a price driven impact on earnings rather than one relating to Shell's fundamental business model, underlying activities and produced and manufactured volumes.

On the basis of our analysis of these factors, we concluded that we should continue to focus on Shell's adjusted earnings reported by Shell in its quarterly results announcements and adjusted for an effective tax rate.

By applying an adjusted earnings approach, the materiality range narrowed from our initial range of \$1.1 billion to \$2.0 billion to \$1.0 billion to \$1.3 billion. We planned our 2020 audit using the bottom end of this range.

The identified items excluded in 2020 were: net divestment gains (\$0.3 billion), net impairments (\$28.1 billion charge), fair value accounting of commodity derivatives and certain gas contracts (\$1.2 billion charge), onerous contract provisions (\$1.4 billion charge), redundancy and restructuring (\$0.9 billion charge), and the aggregate of other individually small items (net \$0.7 billion charge).

The identified items excluded in 2019 were: net divestment gains (\$2.6 billion), net impairments (\$4.2 billion charge), fair value accounting of commodity derivatives and certain gas contracts (\$0.6 billion gain), redundancy and restructuring (\$0.1 billion charge), and the aggregate of other individually small items (net \$0.8 billion charge).

The identified items excluded in 2018 were: net divestment gains (\$3.3 billion), net impairments (\$1.0 billion charge), fair value accounting of commodity derivatives and certain gas contracts (\$1.1 billion gain), redundancy and restructuring (\$0.2 billion charge), and the aggregate of other individually small items (net \$0.1 billion charge).

Performance materiality

What we mean

Having established overall materiality, we determined 'performance materiality', which represents our tolerance for misstatement in an individual account. It is calculated as a percentage of overall materiality in order to reduce to an appropriately low level the probability that the aggregate of uncorrected and undetected misstatements exceeds overall materiality of \$1,000 million for Shell's financial statements as a whole.

Once we had determined our audit scope, we then assigned performance materiality to our various in-scope operating units. Our in-scope operating unit audit teams used this assigned performance materiality in performing their group audit procedures. The performance materiality allocation is dependent on the size of the operating unit, measured by its contribution of earnings to Shell, or other appropriate metric, and the risk associated with the operating unit.

Level set

In assessing the appropriate level of performance materiality, we consider the nature, the number and impact of the audit differences identified in 2019 as well as the overall control environment.

At the planning stage of the audit, which was at the very start of the pandemic, we set our performance materiality at 75% (2019: 75%) of planning materiality, namely \$750 million (2019: \$900 million). However, we noted that the developing macro-economic environment was creating heightened estimation uncertainty and an elevated risk of material misstatement of Shell's asset and liability carrying values. These factors had a pervasive impact on Shell's financial statements and increased the risk around key areas of accounting judgement. We also faced additional audit risk due to the fact that the entire 2020 audit was conducted under remote working conditions.

Consequently, we kept our planning and performance materiality under ongoing review. Whilst we confirmed that the overall materiality level of \$1,000 million remained appropriate, in the second half of 2020, we revised performance materiality downwards to be 50% of planning materiality (\$500 million). This decision was based on the following considerations:

- the potential impacts of remote working through the year-end close;
- the heightened estimation uncertainty;
- the potential impact on Shell's control environment of the restructuring programme (Project Reshape); and
- corrected and uncorrected errors.

The primary impact of reducing our performance materiality was a reduction in the testing thresholds that were assigned to our component teams, which led to larger sample sizes for the purposes of our substantive audit testing.

In 2020, the range of performance materiality allocated to operating units was \$75 million to \$325 million (2019: \$135 million to \$450 million). This is set out in more detail in section 6 below.

Audit difference reporting threshold

What we mean

This is the amount below which identified misstatements are considered to be clearly trivial.

The threshold is the level above which we collate and report audit differences to the Audit Committee.

We also report differences below that threshold that, in our view, warrant reporting on qualitative grounds. We evaluate any uncorrected misstatements against both the quantitative measures of materiality discussed above and in light of other relevant qualitative considerations in forming our opinion.

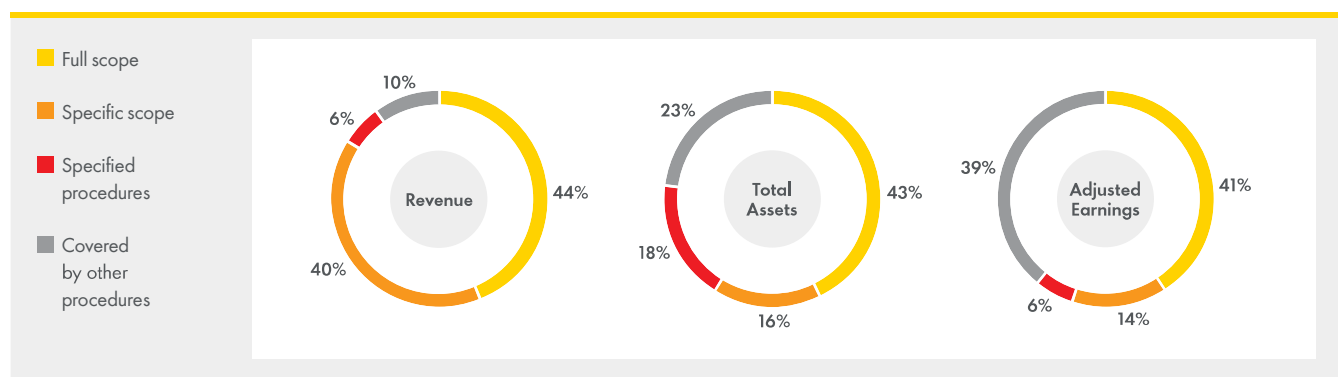
Level set

We agreed with the Audit Committee that we would report to the Committee all audit differences more than \$50 million (2019: \$60 million), as well as differences below that threshold that, in our view, warranted reporting on qualitative grounds.

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

6. OUR SCOPE OF THE AUDIT OF SHELL'S FINANCIAL STATEMENTS

What we mean	<p>We are required to establish an overall audit strategy that sets the scope, timing and direction of our audit, and that guides the development of our audit plan. Audit scope comprises the physical locations, operating units, activities and processes to be audited that, in aggregate, are expected to provide sufficient coverage of the financial statements for us to express an audit opinion.</p>
Criteria for determining our audit scope and selection of in-scope operating units	<p>Our assessment of audit risk and our evaluation of materiality determined our audit scope for each operating unit within Shell which, when taken together, enabled us to form an opinion on the financial statements under ISA (UK). Our audit effort was focused towards higher risk areas, such as management judgements, and on operating units that we considered significant based upon size, complexity or risk.</p> <p>We reassessed our 2020 audit scope following the completion of our 2019 audit. Our starting point was the consolidated 2019 financial reporting data by Area of Operation (AoO). We identified those AoOs that were significant by virtue of their contribution to Shell's results or significant by virtue of their associated risk or complexity. In doing this we considered the history or expectation of unusual or complex transactions, potential for or history of material misstatements, the previous effectiveness of controls, our forensic assessment in relation to fraud, bribery or corruption, and internal audit findings. We then considered the adequacy of account coverage and remaining audit risk of AoOs not directly covered by audit procedures. Finally, we sense checked our scope to the prior year and also ensured that there was appropriate unpredictability in our scope and made the necessary changes where appropriate.</p> <p>By following this approach, our audit effort focused on higher risk areas, such as management judgements. Our group wide procedures enabled us to obtain audit evidence over the AoOs that were not full, specific or specified procedure scope.</p> <p>The reduction in our 2020 (\$1,000 million) planning materiality compared to 2019 (\$1,200 million) did not increase the number of components in our audit scope. However, what did change was the nature of our testing, where we developed alternative means of obtaining sufficient and appropriate audit evidence, including through our enhanced use of technology and digital audit techniques.</p> <p>We kept our audit scope under review throughout the year to reflect changes in Shell's underlying business and risks; however no significant changes were required.</p>
Full and specific scope	<p>We selected 48 operating units (2019: 49) across 14 countries (2019: 11) based on their size or risk characteristics. We performed full scope audits of the complete financial information of 17 operating units (2019: 17). For 31 operating units (2019: 32) we performed specific scope audit procedures on individual account balances within the operating unit based on their size and risk profiles.</p>
Specified procedures	<p>In addition to the 48 operating units (2019: 49) discussed above, we selected a further 45 operating units (2019: 41) where we performed procedures at the operating unit level that were specified by the group engagement team in response to specific risk factors and in order to ensure that, at the overall group level, we reduced and appropriately covered the residual risk of error.</p> <p>In addition, specified procedures were performed at the group level on a further 90 operating units. These procedures included the testing of Shell's centralised activities addressing the implications of significant and complex accounting matters across all operating units, testing controls for the revenue and purchase to pay processes, including IT general and IT application controls, segment level impairment reviews, procedures over the forecasts as they relate to deferred tax asset recoverability and review of pension scheme assumptions and procedures over unusual accounting transactions including acquisitions, divestments and redundancies.</p>
Group procedures	<p>For the remaining 607 operating units (2019: 614), we performed supplementary audit procedures in relation to Shell's centralised group accounting and reporting processes. These included, but were not limited to, Shell's activities addressing the appropriate elimination of intercompany balances and the completeness of provisions for litigation and other claims. We performed testing of both manual and consolidation journal entries throughout the year, homogenous processes and controls at the Business Service Centres (BSCs) and testing of group wide IT systems. We performed a disaggregated analytical review on each financial statement line item and also tested Shell's analytical procedures performed at a group, segment and function level.</p> <p>In addition to this testing, we applied our Risk Scan analytics techniques, which consolidate internal and external data to inform us of higher risk components to be included in scope. This allowed us to risk rate each of the 742 operating units whereby we identified 230 operating units where we believed that it was appropriate to carry out targeted testing. This included the audit of manual journal entries and/or the testing of payments to third party vendors to ensure that these had been approved in line with Shell's policies and had an appropriate business rationale.</p> <p>Our coverage by full, specific, specified and group procedures is illustrated below. The summary is by Total assets, adjusted earnings and Revenue. Overall, our full, specific and specified procedures accounted for 61% of Shell's absolute adjusted earnings reported by Shell in its quarterly results announcements and adjusted for an effective tax rate. The remaining adjusted earnings were covered by Group wide procedures.</p> <p>The Parent Company is located in the United Kingdom and audited directly by the Group engagement team.</p>



Allocation of performance materiality to the in-scope operating units

The level of materiality that we applied in undertaking our audit work at the operating unit level was determined by applying a percentage of our total performance materiality. This percentage is based on the significance of the operating unit relative to Shell as a whole and our assessment of the risk of material misstatement at that operating unit. In 2020 the range of materiality applied at the operating unit level was \$75 million to \$325 million (2019: \$135 million to \$450 million). The operating units selected, together with the ranges of materiality applied, were:

Location	Segment / Function	No. of operating units	Range of materiality applied \$ million
Full scope operating units:			
Australia, Qatar	Integrated Gas	4	100-150
Brazil, Nigeria, USA	Upstream	4	100-150
USA	Oil Products and Chemicals	2	100
Bahamas, Singapore, The Netherlands, UAE, UK, USA	Trading and Supply	7	187-325
Total full scope operating units		17	
Specific scope operating units:			
Malaysia, UK, Indonesia	Upstream	3	100
Singapore, USA	Oil Products and Chemicals	5	100
Singapore, The Netherlands, UK, USA	Corporate	12	100-150
Canada, Singapore, UAE, UK, USA, South Korea	Trading and Supply	11	75
Total specific scope operating units		31	
Total full and specific scope operating units		48	

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

6. OUR SCOPE OF THE AUDIT OF SHELL'S FINANCIAL STATEMENTS continued

Group evaluation, review and oversight of component teams

The group engagement partner and Senior Statutory Auditor, Allister Wilson, has overall responsibility for the direction, supervision and performance of the Shell audit engagement in compliance with professional standards and applicable legal and regulatory requirements. He is supported by 14 segment and function partners and associate partners, who are based in the Netherlands and the UK, and who together with related staff, comprise the integrated group engagement team. This group engagement team established the overall group audit strategy, communicated with component auditors, performed work on the consolidation process and evaluated the conclusions drawn from the audit evidence as the basis for forming EY's opinion on the group financial statements.

For the purpose of the group audit, the group engagement team is responsible for directing, supervising, evaluating and reviewing the work of EY global network firms operating under their instruction (local EY teams) to assess whether:

- the work was performed and documented to a sufficiently high standard;
- the local EY audit team demonstrated that they had challenged management sufficiently and had executed their audit procedures with a sufficient level of scepticism; and
- there is sufficient appropriate audit evidence to support the conclusions reached.

The group engagement team provided detailed instructions to our BSC and in-country teams to drive the audit strategy and execution in a coordinated manner. However, travel restrictions presented challenges to us exercising sufficient and appropriate direction, supervision, oversight and review of overseas EY audit teams such that we had adequate involvement in their work.

Under normal circumstances, Allister Wilson and other group audit partners and directors would visit in-scope operating units and Shell's BSCs. The purpose of these visits would be to discuss the audit approach with the local EY teams and any issues arising from their work, meet with local management, attend planning and closing meetings and review key audit working papers on risk areas. However, in planning our audit, we assumed a worst-case scenario where travel restrictions and lockdowns would persist throughout the period of the audit. As a result, we developed an audit strategy that enabled the group engagement team to fulfil its responsibilities under auditing standards to evaluate, review and oversee the work of component teams on a remote basis.

In the absence of group team members being able to travel to visit local EY teams at component locations, this process included maintaining a continuous and open dialogue with our component teams, as well as holding formal closing meetings quarterly, to ensure that we were fully aware of their progress and results of their procedures. Between quarters, and during critical periods of the audit, we increased the use of online collaboration tools to facilitate team meetings, information sharing and the evaluation, review and oversight of component teams. We requested more detailed deliverables from component teams and we utilised fully the interactive capability of EY Canvas, our global audit workflow tool, to review remotely the underlying work performed. Our experience of this way of working – with both Shell and our teams – was positive. The technology proved to be robust and resilient in supporting the new way of working.

Involvement with local EY teams

Shell has centralised processes and controls over key areas within its BSCs. Members of the group engagement team provide direct oversight, review and coordination of our BSC audit teams. Our BSC teams performed centralised testing in the BSCs for certain accounts, including revenue, cash and payroll. In establishing our overall approach to the group audit, we determined the type of work that needed to be undertaken at each of the operating units or BSCs by the group engagement team or by auditors from other local EY teams.

The group engagement team performed procedures directly on 90 of the in-scope operating units. For the operating units where the work was performed by local EY auditors, we determined the appropriate level of involvement of the group engagement team to enable us to conclude that sufficient appropriate audit evidence had been obtained.

During 2020, the group team were unable to carry out physical site visits. However, we performed virtual site visits at those locations that we would normally have visited in person. We also joined the virtual site visits at 3 locations carried out by the Audit Committee.

The Senior Statutory Auditor and other group audit partners, associate partners and directors conducted virtual site visits of operating units across 7 countries as well as each of Shell's four BSCs. The countries and the BSC locations visited were as follows:

Countries visited	BSCs
Australia	India [A]
Brazil [A]	Malaysia [A]
Nigeria [A]	Philippines [A]
Singapore	Poland [A]
Qatar	
UK [A]	
USA [A]	

[A] These were visited multiple times on a virtual basis

7. OUR ASSESSMENT OF KEY AUDIT MATTERS

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial statements of the current period and include the most significant assessed risks of material misstatement (whether or not due to fraud) that we identified. As Shell's auditors, we are required to determine – from the matters communicated by us to the Audit Committee during the year – those matters that required significant attention from us in performing our audit of Shell's 2020 Consolidated and Parent Company Financial Statements. In making this determination we took the following into account:

- the risks that we believed were significant to our audit and therefore required special audit consideration;
- areas of higher assessed risk of material misstatement that influenced our audit focus;
- significant audit judgements relating to areas in Shell's Consolidated and Parent Company Financial Statements, including accounting estimates that we identified as having high estimation uncertainty;
- the effect on our audit of significant events or transactions that occurred during the period; and
- those assessed risks of material misstatement that had the greatest effect on the allocation of resources in the audit and directing the efforts of the audit team.

On this basis, we identified the following key audit matters that, in our professional judgement, were of most significance in our audit of Shell's 2020 Consolidated and Parent Company Financial Statements. These matters included those that had the greatest effect on:

- our overall strategy;
- the allocation of resources in the audit; and
- directing the efforts of our audit team.

The key audit matters have been addressed in the context of the audit of Shell's Consolidated and Parent Company Financial Statements as a whole, and in forming our opinions thereon, and we do not provide a separate opinion on these matters. The table below describes the key audit matters, a summary of our procedures carried out and our key observations that we communicated to the Audit Committee.

In the current year, we have added two key audit matters that were not reported as key audit matters in our 2019 report. These relate to: (1) the impact of climate risk and the energy transition on the financial statements; and (2) the recoverable amount of investments held by the Parent Company (this key audit matter relates to the Parent Company only).

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

7. OUR ASSESSMENT OF KEY AUDIT MATTERS continued

THE IMPACT OF CLIMATE RISK AND THE ENERGY TRANSITION ON THE FINANCIAL STATEMENTS

Description of the key audit matter	Our response to the risk
<p>The financial impacts of climate change and the energy transition remain an area of audit focus, as they have a pervasive impact on many areas of accounting judgement and estimate and, therefore, our audit. Risk is elevated compared to 2019 due to the increased focus on climate change of investors and regulators.</p> <p>Climate change presents financial risk both to business and to the global economy. The Financial Stability Board established the Task Force on Climate-related Financial Disclosures (TCFD) to develop recommendations for more effective climate-related disclosures that could promote more informed investment, credit and insurance underwriting decisions and, in turn, enable stakeholders to understand better the concentrations of carbon-related assets in the financial sector and the financial system's exposures to climate-related risks.</p> <p>Shell has incorporated climate-related risks and opportunities into their risk management and strategic planning processes and is focused on increasing transparency and promoting investors' understanding of its strategies to respond to the risks and opportunities presented by climate change (see page 94).</p> <p>Shell states that its Energy Transition Report is aligned with the TCFD recommendations and sets out how Shell plans to be resilient to expected changes in the energy system and how its strategy helps it to thrive as the world transitions to lower-carbon energy page 162.</p> <p>The audit risk is that critical accounting estimates or judgements do not reflect material climate risks and could, as a result, mislead investors. For example, forecast assumptions that underpin management's operating plan used in assessing the recoverable amount of assets, particularly oil and gas price assumptions relevant to upstream oil and gas PP&E assets, and refining margins relevant to manufacturing assets, may not appropriately reflect the macro-economic impacts of the pandemic, combined with changes in supply and demand due to climate risk and the energy transition.</p> <p>Similarly, there is an audit risk that the narrative disclosures around material climate risk in the Annual Report and the financial statements are not aligned.</p> <p>The critical accounting judgements and estimates that are impacted by climate risk and the energy transition include the following:</p> <ul style="list-style-type: none"> ■ the estimation of oil and gas reserves and resources; ■ the useful economic lives of PP&E and the estimation of depreciation, depletion and amortisation (DD&A); ■ impairment assessments for goodwill, PP&E and joint ventures and associates, including the recovery of exploration and evaluation assets that may no longer be considered to be economic due to the impact of climate risk and the energy transition on oil and gas prices; ■ the recognition and measurement of decommissioning and restoration (D&R) provisions, including operations that historically have been assumed to have indefinite lives; ■ the recognition and measurement of Deferred Tax Assets; and ■ climate change-related litigation brought against Shell that may lead to an outflow of resources or otherwise impact Shell's business. 	<p>Our audit procedures took account of the content of a letter dated 5 November 2020 sent by Sarasin and Partners to the Audit Committee Chair regarding their call for "Paris-aligned" accounts, as well as the document published on the same date by the Institutional Investors Group on Climate Change (IIGCC) entitled "Investor Expectations for Paris-aligned Accounts" and the FRC's climate change thematic review.</p> <p>The procedures we carried out included the following:</p> <ul style="list-style-type: none"> ■ understanding Shell's processes around the climate change and energy transition-related disclosures in the Annual Report, including risk assessment, viability and greenhouse gas emissions' reporting; ■ assessing the reasonableness of Shell's carbon prices included as part of the forecast operating plan, going concern and viability assessments with assistance of EY auditors with expertise in climate change; ■ assessing the consistency of Shell's public statements on energy transition and climate change with significant judgements and estimates reflected in the financial statements (for example oil and gas reserve estimates, future capital and operating expenses assumptions and assumed refining margins); ■ assessing the historical accuracy of disclosures made in the Annual Report. This included considering the disclosure recommendations of the TCFD and the appropriateness of Shell's disclosures in respect thereof; ■ we made inquiries of management relating to Shell's assessment of its resilience to the energy transition; ■ we evaluated Shell's long-term pricing assumptions against the IEA outlook; ■ we assessed the energy transition assumptions within the estimation of oil and gas reserves; ■ we assessed the reasonableness of Shell's refining margin estimation methodology, particularly in light of the expected impacts of a lower carbon world. For example, we read reports from independent, third-party sources in order to identify potential contrary evidence and to assess the reasonableness of key inputs and assumptions used in Shell's refining margin model. These inputs included refining capacity additions, expected refinery closures, carbon dioxide costs and the strategic and political behaviour of National Oil Companies; ■ we mapped the climate change and energy transition risks to key audit areas; and ■ with the assistance of EY auditors with expertise in climate change, we assessed and challenged the reasonableness of Shell's narrative disclosures around material climate risk. In addition, we evaluated the consistency between these narrative disclosures and the financial statements. <p>The audit procedures were performed principally by the group engagement team.</p>

Key observations communicated to the Shell Audit Committee Critical accounting judgements and estimates

In January 2021, we reported to the Audit Committee that we did not see any evidence that Shell's balance sheet overstated assets or understated liabilities. For Upstream and Integrated Gas assets, we were satisfied that the reserves used in the DD&A calculation do not extend to an unrealistic period in the future based on our current understanding of expected future developments. For Oil Products and Chemicals assets, we considered the fundamental shift in the refining market driven by overcapacity in the mid-term, energy transition in the long-term, and further exacerbated by the impacts of COVID-19 in the short to medium term. Given the headroom that supports the carrying amount of goodwill that is allocated to CGUs at the segment level, we were satisfied that the carrying amount of goodwill was appropriately recorded.

Also, based on our assessment of the relevant facts and circumstances as well as the audit evidence obtained from legal counsel, we were satisfied with management's assertion that no provision should currently be made in respect of climate change-related litigation.

Key observations in relation to the other financial impacts of climate change and the energy transition are included in the other key audit matters below.

Investor expectations for 'Paris-aligned Accounts'

The IIGCC expect auditors to provide reassurance that the accounts incorporate material climate risks, and whether or not the accounts can be considered 'Paris-aligned'. In order to meet this expectation, the IIGCC's paper outlines the following four steps auditors should take to 'encourage Paris-aligned financial statements':

Key steps investors expect auditors to take

Our response communicated to the Audit Committee

Consideration of material climate risks:

Confirmation that critical accounting estimates or judgements reflect material climate risks, in line with accounting standards.

The other key audit matters below include details of the audit procedures performed in considering climate risk and the energy transition in the execution of our audit, together with the conclusions that we reached.

Paris-alignment: Confirmation as to whether or not these critical assumptions and estimates can be considered consistent with a 2050 net zero emissions pathway and, if not, whether Paris-aligned assumptions have been adequately considered in the Notes to the Financial Statements. If not, the auditor should indicate what reasonable Paris-aligned assumptions would be.

Meeting the goals of the Paris agreement is a global aspiration that must be cemented in reality. It requires the world economy to transform in a number of complex and connected ways. Shell's financial statements reflect the world as it currently exists and what management reasonably expects based on current facts and evidence. It does not reflect what management and the world wishes and desires – a Paris-compliant world. Shell's pathway to Paris alignment is reflected in the Group's strategy. Like the rest of society, Shell is at the beginning of a journey, the speed and direction of which will change as facts and circumstances change and as management reflect these changes in the Group's evolving strategy.

There is significant uncertainty surrounding the ways in which society and the world economy will change over the next 30 years and the extent to which such changes will meet the aspirations of the Paris Agreement. Whilst companies can commit to these aspirations, financial reporting under IFRS is based on reasonable and supportable assumptions that represent management's current best estimate of the range of economic conditions that will exist in the foreseeable future.

To fulfil the aspirations of the Paris Agreement, Shell's strategy will need continuously to evolve as the world economy transforms itself. For example, for Shell to reach net-zero emissions by 2050, it would also be necessary for Shell's customers to de-carbonise. Importantly also, Shell has reported in Note 2 to the Consolidated Financial Statements that their operating plan and pricing assumptions do not yet reflect Shell's 2050 net-zero emissions target. For these reasons, it is neither possible nor appropriate for EY, as Shell's auditor, to attempt to provide in our audit opinion Paris-aligned assumptions that are not in our remit to determine, and the impact that any such assumptions might be expected to have on the financial statements.

We are satisfied that the disclosure in relation to the Board's current view on the ways in which Shell's critical accounting judgements and estimates are impacted by climate risk and the energy transition are sufficient and appropriate. However, it is not within our professional remit, responsibility or expertise to disclose in our audit opinion what we would consider to be reasonable assumptions taking the net-zero transition into account, and the impact such assumptions might have on Shell's financial statements.

These are the board's financial statements, and it is up to the board to provide appropriate disclosures and for us to audit them and to express our professional opinion thereon. We have reported in this unqualified independent auditor's report to the members of Royal Dutch Shell plc that, in our opinion, Shell's financial statements as a whole provide a true and fair view of the group's state of affairs and loss for the year.

Pathway to consistency: Alert shareholders to any inconsistency between the narrative disclosures around climate risks, the company's strategy and the financial statements.

As part of reviewing the Annual Report and Accounts, with the assistance of EY auditors with expertise in climate change, we assessed and challenged the reasonableness of Shell's narrative disclosures around material climate risk and their consistency with the financial statements. We are not aware of any inconsistency between the narrative disclosures around climate risks, the company's strategy, the financial statements and our understanding of the business.

Dividend resilience: Confirm that capital maintenance/solvency tests have appropriately considered climate risks, such as dividend legality. In many jurisdictions these rules are additional to following accounting standards, and often they demand greater prudence when dealing with foreseeable losses and liabilities.

See the key audit matter below on 'The dividend distribution process, including the determination of realised profits and losses for the purposes of making distributions under the Companies Act 2006'.

Cross-reference: See the Audit Committee Report on page 150 for details on how the Audit Committee reviewed the potential impact of climate change and energy transition. Also, see Notes 2, 8 and 25 to the Consolidated Financial Statements.

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

7. OUR ASSESSMENT OF KEY AUDIT MATTERS continued

THE ESTIMATION OF OIL AND GAS RESERVES, INCLUDING RESERVES USED IN THE CALCULATION OF DEPRECIATION, DEPLETION AND AMORTISATION (DD&A), IMPAIRMENT TESTING TO EVALUATE THE RECOVERABLE AMOUNTS OF EXPLORATION AND OF PRODUCTION ASSETS AND IN THE ESTIMATION OF DECOMMISSIONING AND RESTORATION (D&R) PROVISIONS

Description of the key audit matter

This is a forecast-based valuation. Risk is unchanged compared to 2019.

As described in Note 8 to the Consolidated Financial Statements, Exploration and evaluation assets amounted to \$9,226 million, and Production assets amounted to \$131,763 million. Production assets had an associated DD&A charge of \$33,806 million. The accounting for these financial statement amounts relies on management's estimation of oil and gas reserves. As further described in Note 8, impairment charges of \$20,155 million of Exploration and Production assets were recorded during the year. As described in Note 18, D&R provisions amounted to \$23,175 million.

Auditing the estimation of oil and gas reserves is complex as there is significant estimation uncertainty in assessing the quantities of Shell's reserves and resources. The estimates are based on a central group of experts' assessments of petroleum initially in place, production curves and certain other inputs, including future capital and operating cost assumptions and future carbon costs.

In-year movements are driven by revisions of previous estimates resulting from reclassifications, improved recovery assumptions, extensions and discoveries and purchases and sales of reserves in place. Revisions generally arise from new information, for example additional drilling results, changes in production patterns and changes to development plans, which are an input to the cash flows used in the measurement of Exploration and Production assets and D&R provisions.

Auditing these financial statement areas is complex because we are required to evaluate the work of reservoir engineers and assess the appropriateness of the inputs selected by management described above. These inputs are used by reservoir engineers in estimating oil and gas reserves.

Our response to the risk

Our reserves audit team includes auditors with substantial oil and gas reserves expertise, valuation experience and relevant qualifications in energy economics.

The procedures we carried out included the following:

- we obtained an understanding of the controls over Shell's oil and gas reserves estimation process. We then evaluated the design of these controls and tested their operating effectiveness. For example, we tested management's controls over completeness and accuracy of the financial data provided to the reservoir engineers for use in estimating oil and gas reserves;
- we tested whether significant additions or reductions in reserves had been made in the period in which the new information became available;
- we evaluated the professional qualifications and objectivity of Shell's internal reservoir engineers who:
 - provide the detailed preparation of the reserve estimates; and
 - are primarily responsible for providing independent review and challenge, and ultimately endorsement of, the reserve estimates;
- we evaluated the completeness and accuracy of the inputs used by the internal reservoir engineers in estimating the economic limit test for the determination of oil and gas reserves by agreeing the inputs to source documentation. The economic limit of a project is reached when the operating cash flow from a project becomes negative. The economic limit test has a direct impact on DD&A and impairment. Where relevant, we assessed whether the economic limit test incorporated Shell's estimate of future carbon costs to reflect the potential impact of climate change and the energy transition. We also identified and evaluated corroborative and contrary evidence by comparing actual to prior year forecasts;
- for undeveloped reserves, we evaluated management's development plan for compliance with the SEC rule that undrilled locations must be scheduled to be drilled within five years, unless specific circumstances justify a longer period. This evaluation was made by assessing consistency of the development projections with Shell's drilling, development and capital expenditure plans;
- we tested the existence and completeness of the undeveloped reserves recognised. Where volumes recognised remained undeveloped for more than five years from the date they were booked, or where development was not expected for at least five years, we assessed whether or not Shell was still working towards development by comparing with future development plans, including capital expenditure plans. Also, where reserves are recognised beyond current licence terms, we obtained evidence to support the assumption that the licence would be renewed; and
- we assessed whether or not the energy transition assumptions used in the asset plans reflected the commitments that Shell has made with respect to decarbonisation in order to be a net-zero emissions energy business by 2050, specifically considering reserve volumes expected to be lifted beyond 2030.

Our procedures were led by the group engagement team, with input from our teams in Australia, Brazil, Canada, Kazakhstan, Norway, Nigeria, Qatar, Russia and the USA.

Key observations communicated to the Shell Audit Committee

We reported that our reserves audit team included a partner with significant oil and gas reserves expertise and valuation experience. He is a graduate of the 'Ecole Polytechnique', the industrial and engineering school in France, holds a post graduate diploma from the French Petroleum School (Institut Français du Pétrole) and lectures on oil and gas reserves. Other audit team members had relevant industry experience through working for many years on the audits of oil and gas companies.

Based on our testing, we did not identify any significant errors in the oil and gas reserves and resources and concluded that the inputs and assumptions used to estimate reserves and resources were reasonable. We reported that we had verified that significant additions to or reductions in reserves had been recorded in the appropriate period, and that they were in compliance with Shell's reserves and resources guidance.

We reported to the Audit Committee that, in light of the commitments that Shell has made to be a net-zero emissions energy company by 2050, we saw no evidence that the recognition of the reserve volumes expected to be lifted beyond 2030 results in the overstatement of Shell's balance sheet by overstating the recoverable amounts of Shell's assets or understatement of D&R provisions.

Cross-reference: See the Audit Committee Report on page 147 for details on how the Audit Committee reviewed assurances for oil and gas reserves. Also, see Notes 2, 8 and 18 to the Consolidated Financial Statements, and Supplementary information – oil and gas (unaudited) on page 265.

IMPAIRMENT OF PP&E (INCLUDING EXPLORATION AND PRODUCTION ASSETS AND REFINERIES) AND JOINT VENTURES AND ASSOCIATES (JVA)

Description of the key audit matter

This is a forecast-based estimate. Risk is elevated compared to 2019 due to the increased uncertainty in future commodity prices, refining margins and demand for petroleum products, as well as the impact of the energy transition.

As described in Notes 8 and 9 to the Consolidated Financial Statements, Shell recognised \$141 billion of Exploration and Production assets, \$50 billion of manufacturing, supply and distribution assets (refineries), as well as investments in joint ventures and associates of \$22 billion. As disclosed in Note 8 and Note 9, Shell recorded impairment charges of \$27 billion and \$0.6 billion of PP&E and JVAs respectively.

Auditing the recoverable amounts of PP&E and investments in JVAs is complex and subjective due to the significant amount of judgement involved. The most complex judgements in forecasting future cash flows relate to management's view on the long-term oil and gas price outlook and refining margins appropriate to local markets. These judgements are particularly difficult because of increased demand uncertainty due to factors such as the macro-economic impacts of the pandemic and the pace of decarbonisation and the energy transition.

Other judgements relate to oil and gas reserve estimates, future expected production volumes, the risk of cash flows and the expected useful lives of the assets.

Further, given the long timeframes involved, the recoverable amounts of assets are often sensitive to the extent of the risk of the future cash flows. There is a risk of material misstatement in the event that the future cash flows do not reflect appropriately the risks specific to the asset.

Production assets, including JVAs

Producing assets' operational performance and the impact of external factors have a significant bearing on the estimate of the recoverable amounts of Shell's Upstream and Integrated Gas assets.

The most complex judgement in determining the recoverable amount of Production assets within Upstream and Integrated Gas is the estimation of future oil and gas price, both in the short term and the long term. The estimation of future oil and gas prices is subject to increased uncertainty, given climate change, the energy transition and the impact of the pandemic on the demand for petroleum products. There is a risk that management's oil and gas price assumptions are not appropriate, potentially leading to a material misstatement.

A further management judgement relates to the estimation of oil and gas reserves as there is significant estimation uncertainty in the process of assessing the quantities of Shell's reserves and resources. We have described the risk within the Estimation of oil and gas reserves key audit matter above.

Our response to the risk

Overall

We obtained an understanding of the controls over Shell's asset impairment process for: (1) production assets, including joint ventures and associates; (2) exploration and evaluation assets; and (3) manufacturing, supply and distribution assets. We then evaluated the design of these controls and tested their operating effectiveness. For example, we tested controls over the identification of cash generating units, of indicators of impairment and reversals of impairment and the approval of key inputs to impairment assessments, including oil and gas prices and refining margins, discount rates and oil and gas reserves.

We evaluated Shell's asset impairment methodology and where impairment assessments were carried out, we tested the mathematical accuracy and completeness of the models used. For those assets or investments impaired previously, we evaluated the actual results versus the assumptions made and considered if reversals were required.

In order to evaluate the cash flow inputs of the impairment models, our procedures included the following:

- tested whether operating expenditure profiles, capital costs to complete construction and refinery turnaround costs, agreed to approved operator budgets and management forecasts;
- tested whether carbon pricing was included in cash flows, where applicable;
- reconciled reserves volumes in the impairment models and tested whether the life-of-field assumptions were consistent with those applied in the decommissioning and restoration provision models; and
- performed sensitivity analyses on key variables in the base case cash flow models to understand the impact of changes in certain assumptions (including oil and gas prices, refining margins, production and the risk of cashflows).

Where impairment tests were undertaken, we performed sensitivity analyses of the models using different price scenarios and asset specific risks taking into account the nature of the asset, its location, its stage of development and associated risks.

Oil and gas price assumptions

To test price assumptions, we compared future short and long-term commodity prices to consensus analysts' forecasts and those adopted by other international oil companies; we evaluated whether prices were used consistently across Shell, including pricing differentials, and evaluated whether Shell's long-term price assumptions incorporated the potential impact of climate change and the energy transition by comparing the assumptions to the International Energy Agency price outlook in the Energy Outlook scenarios.

Risk of cash flows

We assessed the basis for adjusting the cash flows to reflect the risks of each individual asset that were not reflected in the impairment discount rate. In so doing, we considered, for Upstream and Integrated Gas, the stage of the life of the asset, the nature of the asset and tested the consistency across similar fields. In respect of refineries, we considered refining margins, refinery availability and estimated unplanned maintenance costs.

Oil and gas reserves estimates

The procedures we performed in relation to oil and gas estimates are described above within the Estimation of oil and gas reserves key audit matter.

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

7. OUR ASSESSMENT OF KEY AUDIT MATTERS continued

IMPAIRMENT OF PP&E (INCLUDING EXPLORATION AND PRODUCTION ASSETS AND REFINERIES) AND JOINT VENTURES AND ASSOCIATES (JVA) continued

Description of the key audit matter

Exploration and evaluation assets

Exploration and evaluation (E&E) expenditures are capitalised on a project-by-project basis. E&E activity is inherently risky given the level of uncertainty considered in the run up to Final Investment Decision (FID). Where FID is not achieved, there is a significant judgement relating to the risk that certain E&E costs are not written off in the appropriate reporting period. Given the current environment, there is a heightened risk that projects will no longer proceed, in which case they may need to be written off. It is possible that a greater than usual number of projects will not proceed in the current environment.

Manufacturing, supply and distribution assets

In the event that there is a prolonged period of low refining margins, there may be a need to assess refineries for impairment. Auditing future refining margins is inherently complex as the margins are influenced by regional factors and there is limited external refining margin forecast data available.

Our response to the risk

Exploration and evaluation assets

We performed a licence-by-licence risk assessment of Shell's E&E assets to identify assets with a significant risk of impairment. We assessed each significant licence area against the impairment criteria within IFRS 6, with a particular focus on those assets that were expected to be developed over the medium and long term, or those assets where the dominant commodity that will be produced is oil.

We considered whether the development of E&E projects would be inconsistent with Shell's current strategy and may no longer be considered to be economic due to the impact of climate risk and the energy transition on oil and gas prices.

Manufacturing, supply and distribution

In addition to the procedures described above, the procedures we performed are described within the *Estimation of future refining margins to evaluate the recoverability of manufacturing assets* key audit matter below.

The audit procedures were performed by our group engagement teams as well as our local audit teams in Australia, Brazil, Malaysia, Nigeria, Qatar, the UK and the USA, which covered 49% of PP&E and investments in joint ventures and associates across the Group.

We also performed specified procedures over the recoverability of PP&E balances in Argentina, Australia, Brunei, Canada, Cyprus, Denmark, Egypt, Germany, Indonesia, Iraq, Italy, Kazakhstan, Malaysia, Mexico, the Netherlands, Nigeria, Philippines, Qatar, Russia, South Africa, Tanzania, Tunisia, Trinidad and Tobago and the USA which covered an additional 17% of PP&E and investments in joint ventures and associates across the Group.

Key observations communicated to the Shell Audit Committee

Oil and gas price assumptions

We obtained external evidence, including price forecasts by banks, brokers, consultants and published data from Shell's peer group, to support the reasonableness of Shell's price assumptions. Overall, Shell's assumptions for both Brent and Henry Hub lie comfortably within the benchmarks that we had identified. In the short-term, Shell's Brent price assumption is the most conservative compared to our sector benchmarks and Shell's forecast aligns broadly with the sector averages from 2023 onwards.

For Henry Hub, compared to the sector, Shell's forecast is below the average in the short-term, converging with the bank/broker, consultant and peer group averages by 2024.

Refining margins

Key observations in relation to refining margins are set out in the key audit matter below.

Impairment discount rates

Shell applied a discount rate of 6% to estimate the recoverable amount in impairment tests, with additional risking included in the cashflows. Whilst the risking of cashflows is highly judgemental, we were satisfied that the cash flows had been risked appropriately.

Production assets, including Joint ventures and associates

We reported that management's review to determine whether or not any indicators of impairment were present had considered all relevant information available at the end of each reporting period, including: the reserves and resources review process, the output of Shell's operating plan and strategic changes in Shell's intended future use of assets, including the refining portfolio, some of which were driven by the energy transition.

For the assets where management's impairment assessment resulted in an impairment charge, the charges were within an acceptable range. Also, we were satisfied that the impairment charges were recorded in the appropriate period.

Exploration and evaluation (E&E) assets

The E&E assets that were being carried were consistent with Shell's strategy and operating plan, including the impacts of the energy transition. We were satisfied that it remained appropriate to continue to carry the E&E assets whilst the technical feasibility and commercial viability of extracting commercial reserves were being assessed.

Manufacturing, supply and distribution assets

The significant reduction in future margin assumptions represents an impairment trigger, which resulted in Shell's entire refinery portfolio being tested for impairment. We reported that, in our view, management had performed extensive and rigorous impairment assessments covering 14 refineries. Management's forecasts included appropriate risking covering margin, availability and cost downside risks. We were satisfied that the risking had been applied appropriately across the portfolio of refineries. We reported that the outcome of the impairment assessments was consistent with our analysis of expected future refining margins, based on the configuration of each individual refinery, including the fact that refineries that are able to produce the most beneficial mix of products, in particular low density products, are expected to fare more favourably and therefore have a higher recoverable amount.

A pre-tax impairment charge of \$4.8 billion was recorded. The impairment models were most sensitive to refining margins. A +/-10% change in the long-term refining gross margin across the portfolio would have had an impact of approximately \$1.5-\$2.5 billion of additional impairment or \$1.7-\$2.7 billion of impairment reversal.

Impairment disclosures

We agreed that the disclosure of the impairments recorded during the year, including sensitivity analysis, performed by the company was appropriate.

Cross-reference: See the Audit Committee Report on page 150 for details on how the Audit Committee considered impairments. Also, see Notes 2, 8 and 9 to the Consolidated Financial Statements.

THE ESTIMATION OF FUTURE REFINING MARGINS TO EVALUATE THE RECOVERABILITY OF REFINERIES

Description of the key audit matter

This is a forecast-based valuation. Risk is elevated compared to 2019 due to Shell reshaping its refining portfolio and refocusing its downstream strategy.

As described in Note 8 to the Consolidated Financial Statements, manufacturing, supply and distribution assets were \$50 billion. As further described in Note 8, an impairment charge of \$6,859 million was recorded in respect of manufacturing, supply and distribution assets. As described in Note 2, forecast refining margins are a key input to:

- assessing whether or not there are indicators that refining assets might be impaired;
- estimating the recoverable amount of refining assets; and
- whether or not there is a need for D&R provisions.

Auditing future refining margins is inherently complex as the margins are influenced by regional factors and there is limited external refining margin forecast data available. In prior years, Shell's estimation of long-term refining margins focused on the concept of reversion to mean, as opposed to attempting to forecast refining cycles. The previous approach was, by nature, backward looking and assumed that the refining margin will revert to the mean over time, unless a fundamental shift in markets had been identified.

Shell viewed the expected increase in supply of refined products with new refineries being constructed, as well as the ongoing impact of energy transition on the demand side as a fundamental shift in markets. Consequently, Shell revised its approach to estimating refining margins. The revised estimation process represented a significant shift in terms of margin methodology, reflecting energy market demand and supply fundamentals, including the energy transition, as well as the shorter-term impacts of the pandemic.

The approach incorporates long-run demand forecasts, including the impacts of the energy transition, and supply dynamics, including the speed of the industry's response to changing demand through either constructing new refineries or closing older refineries.

Under Shell's new estimation methodology, forecast average gross refining margins between 2020 and 2030 have decreased compared to the historic reversion to mean approach. As a result of over-capacity in the market, a significant decrease in refining margins is estimated between 2021 and 2025. As market rationalisation occurs, margins are forecast to recover between 2025 and 2030. The refineries that remain in operation are forecast to generate stronger margins from 2030.

Our response to the risk

We obtained an understanding of the controls over Shell's process for the estimation of refining margins. We then evaluated the design of these controls and tested their operating effectiveness. For example, we tested controls over the approval of refining margins.

Our other procedures included the following:

- we read Shell's documentation with respect to their methodology for determining refining margins and held discussions with the Shell individuals responsible for the analysis and design and implementation of Shell's new methodology and the resulting model;
- we involved our oil and gas valuations specialists to assess the reasonableness of Shell's refining margin estimation methodology and reasonableness of their assumptions;
- we read reports from independent, third-party sources in order to identify potential contrary evidence and to assess the reasonableness of key inputs and assumptions used in the model. These inputs included refining capacity additions, expected refinery closures, carbon dioxide costs and the strategic and political behaviour of National Oil Companies;
- we undertook numerical analysis of the indicative refining margins for the three key refining hubs (US Gulf Coast, North West Europe and Singapore) and compared these to market and consultant forecasts;
- we reviewed analysts' views of refining margins for each of the three refining hubs;
- we recreated refining margins from Shell's price forecasts and benchmarked these to the refining margins derived from traded futures; and
- we reperformed management's calculations for taking the forecast margins at the three regional hubs and turning them into localised margin forecasts on a refinery-by-refinery basis.

The audit procedures were performed principally by the group engagement team.

Key observations communicated to the Shell Audit Committee

We reported to the Audit Committee in July 2020 that the more significant assumptions in the new estimation methodology related to demand change, primarily as a result of the energy transition and, on the supply side, non-economic behaviour, such as investment in refineries for strategic rather than economic reasons. The structural shifts in energy markets were likely to result in more volatile future margins, as well as prolonged periods of abnormally high or low margins. This means that in an uncertain future, the risk of operating a refinery would increase and therefore a reversion to mean methodology may no longer be appropriate; this was particularly the case in an environment where the outlook was unstable and refinery owners begin to act in a manner driven by different economic fundamentals.

We confirmed to the Audit Committee that we involved our oil and gas valuations specialists in assisting us in concluding on the appropriateness of management's revised methodology and reasonableness of their assumptions. We also confirmed that we used external broker reports to support our expectations with respect to future refining margins and assessed whether or not management's projections were consistent with our independent analysis. Based on our benchmarking against these external sources, we satisfied ourselves that Shell's demand forecast assumptions and refining margins were consistent with industry forecasts; however, we noted that Shell's view was at the conservative end of the industry.

Shell's revised refining assumptions were conservative compared to other market benchmarks and represented approximately a 30% decrease compared to previous views on refining margins. We benchmarked Shell's key assumptions in estimating future refining margins to external data, where possible, and concluded that the assumptions used were reasonable and supportable, albeit conservative. The company followed a rigorous and robust process to determine the revised assumptions.

The significant reduction in future margin assumptions represented an impairment indicator (see key audit matter above).

Cross-reference: See the Audit Committee Report on page 150 for details on how the Audit Committee reviewed refining margins. Also, see Notes 2 and 8 to the Consolidated Financial Statements.

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

7. OUR ASSESSMENT OF KEY AUDIT MATTERS continued

THE ESTIMATION OF DECOMMISSIONING AND RESTORATION (D&R) PROVISIONS

Description of the key audit matter	Our response to the risk
<p>This is an estimation based on uncertain outcomes. Risk is elevated compared to 2019 due to the rationalisation of Shell's manufacturing portfolio.</p> <p>As described in Note 18 of the Consolidated Financial Statements, at December 31, 2020, Shell recognised \$23 billion of D&R provisions.</p> <p>D&R provisions are a highly judgemental area. They are based on a number of estimates and assumptions that are impacted by future activities, economic factors and the legislative environments in which Shell operates.</p> <p>D&R provisions are also affected by changes in the oil and gas reserve estimates and price assumptions, which determine the date on which production will cease.</p> <p>The main judgements in determining the D&R provisions include the appropriateness of the cost, inflation, capital cost outlook escalation rates, estimated asset lives, discount rate, cessation of production (COP), the number of days to decommission an asset and contingency rate assumptions used in the models and the consistency of their application across the portfolio.</p> <p>Industry practice has been not to recognise D&R provisions associated with refineries and petrochemicals facilities. This was on the basis that the assets were considered to have indefinite lives and, therefore, that it was considered remote that an outflow of economic benefit would be required. This was driven by the assumption that demand for oil products would continue to grow and there would be a need for more, rather than less, refining capacity; hence it was not expected that existing refineries would be shut down and decommissioned for the foreseeable future.</p> <p>During the second quarter of 2020, Shell revised downwards its discount rate for D&R provisions from 3% to 1.75%. The reduction in the rate was driven by unprecedented macroeconomic conditions due to COVID-19, which resulted in a significant drop in US treasury bond rates. The impact of the change in discount rate was to increase Shell's decommissioning liabilities by \$3.6 billion as at June 30, 2020.</p>	<p>The procedures we performed included the following:</p> <ul style="list-style-type: none"> ■ we obtained an understanding of the controls over Shell's D&R estimation process. We then evaluated the design of these controls and tested their operating effectiveness. For example, we tested controls over the review of the estimation and completeness of costs in accordance with Shell's internal guidelines; ■ we considered the increasing expectation that demand for oil products will fall, particularly in developed economies, together with Shell's plans to rationalise their manufacturing portfolio. In so doing, we challenged management's assessment of whether or not the expected useful lives of manufacturing assets remained appropriate. In particular, we challenged management's conclusion that manufacturing assets could no longer be considered to have indefinite lives, and that therefore D&R provisions were required for certain refineries. We also challenged management's assessment of the need for contingent liability disclosure in respect of certain other assets; ■ we obtained an understanding of the procedures performed by management to estimate the D&R provisions. This included understanding the processes to establish whether or not a legal or constructive obligation existed; ■ we understood changes in D&R cost estimates, and assessed whether they reflected the latest regulatory requirements and technical developments; ■ we read case studies relating to previously decommissioned sites and compared the cost of those decommissioning activities to management's assumptions; ■ we agreed key inputs such as site acreage and distillation capacity to publicly available sources; ■ we evaluated changes in assumptions for labour rates, rig type and rates, number of wells, well durations and any contingency applied; ■ we assessed changes in assumptions for the anticipated date of decommissioning; ■ in the case of non-operated assets, we understood and challenged whether management applied their own assumptions to the D&R estimate or used the operator-provided estimates; ■ we tested the D&R accounting models and assumptions therein, including discount rates, equity percentages and inflation rates. We involved our valuation specialists in testing these assumptions, including the change in Shell's discount rate assumption from 3% to 1.75% during the year; ■ we challenged the timing of recognition of D&R provisions related to projects in development; ■ we evaluated contingent liabilities and D&R provisions arising from assets previously disposed of; ■ we ensured key assumptions used were aligned with the assumptions used in other areas of measurement, such as impairment; ■ we assessed the counterparty risk of prior disposals to ascertain the risk of the related D&R provision becoming a liability of Shell; and ■ we reviewed and challenged the disclosures in the financial statements. <p>The audit procedures were performed principally by the group engagement team and our component teams in Australia, Brazil, Trinidad and Tobago, the UK and the USA.</p>

Key observations communicated to the Shell Audit Committee

Upstream and Integrated Gas

In January 2021, we reported that the Upstream and Integrated Gas D&R provisions recorded as at December 31, 2020 were fairly stated and that changes in D&R provisions during the year, including the application of the revised discount rate and capital cost outlook escalation rates, had been reflected appropriately in the financial statements.

Refineries

In January 2021, we confirmed to the Audit Committee that:

- we agreed with management's conclusion that it was no longer appropriate to consider refineries to have indefinite lives and that for manufacturing assets either D&R provisions or contingent liability disclosures were required;
- for those provisions recorded, that the amounts recorded fell within a reasonable range and that the provisions were supported by appropriate evidence;
- estimating refinery useful lives is highly judgemental, particularly when considering time periods of 50 to 100 years. In our view, management had appropriately stratified the refining portfolio and, in doing so, had made reasonable judgements as to which refineries required a provision and which required contingent liability disclosure;
- we considered Shell's risk-free rate assumption to be reasonable and supported by our analysis, based on data from the US Department of Treasury and Oxford Economics. We also concluded that changes in D&R provisions as a result of the revised discount rate, were reflected appropriately in the financial statements; and
- we agreed that the disclosure of contingent liabilities was appropriate.

Cross-reference: See the Audit Committee Report on page 147 on how the Audit Committee reviewed D&R provisions. Also, see Notes 18 and 25 to the Consolidated Financial Statements.

RECOGNITION AND MEASUREMENT OF DEFERRED TAX ASSETS

Description of the key audit matter

This is an estimation based on uncertain outcomes. The realisation of these assets is largely dependent on generating substantial future profits. Risk is elevated compared to 2019 due to the increased uncertainty in forecasting future profits in the current macro-economic environment.

As described in Note 16 of the Consolidated Financial Statements, at December 31, 2020 Shell recognised gross deferred tax assets (DTAs) totalling \$33 billion, which are recognised within two balance sheet line items, DTAs and as an offset against deferred tax liabilities (DTLs), depending on the overall tax position in a particular jurisdiction.

The recognition of material DTA balances is supported by the unwinding of DTLs and forecast future taxable profits, which are underpinned by Shell's assumptions, including commodity price assumptions and the timing of the unwinding of DTAs.

Auditing the recognition and measurement of DTAs is complex because the estimation requires significant judgement, including the timing of reversals of DTLs and the availability of future profits against which tax deductions represented by the DTAs can be offset.

A key judgement applied by management in assessing whether it is appropriate to recognise certain DTAs includes the expectation of probable taxable profits arising beyond Shell's 10-year planning horizon. There is greater uncertainty regarding future taxable profits that exist outside the 10-year planning period.

Our response to the risk

We obtained an understanding of the controls over Shell's processes for the recognition and measurement of DTAs. We then evaluated the design of these controls and tested their operating effectiveness. For example, we tested controls over projected sources of taxable income and the calculations that support the recognition of DTAs.

We considered the expected timing of utilisation of the DTA, including the relevant country tax laws that apply to the utilisation of tax losses and deductible temporary differences. This included the ability to carry tax losses forward or back and any restrictions arising from ring fencing losses for tax purposes.

We tested the forecast timing of the unwinding of taxable temporary differences by evaluating the projected sources of taxable income and considering the nature of the temporary differences and the relevant tax law.

For DTAs that are supported by forecast taxable profits or tax planning strategies, our procedures included the following:

- we performed sensitivity analyses over the commodity price and/or other key assumptions, including the risk of forecast profit, that underpin Shell's assessment of forecast probable taxable profits;
- we evaluated the extent to which sufficient probable taxable profits would arise in the period within which the related losses and/or deductible temporary differences would be available for utilisation, considering for example, limits on the length of time that losses can be carried forward, if applicable, or if losses are ring fenced for tax purposes;
- we evaluated management's negative stress test to enable us to understand the tolerance of the estimation uncertainty to further risk; and
- we confirmed that the tax balances were calculated using substantively enacted tax laws and rates.

For the tax planning strategies necessary to justify the recognition of the relevant DTAs, we involved our tax professionals to evaluate whether the Company's proposed tax planning strategies were achievable.

Our audit procedures over the recognition and valuation of DTAs were performed by our tax specialist teams in Australia, Brazil, Canada, the Netherlands, Malaysia, Nigeria, Singapore, Qatar, the UK and the USA, which covered 77% of the gross DTA balance. We also performed specified procedures over the recognition and valuation of DTAs in Albania, Austria, China, Egypt, France, Germany, Kazakhstan, Norway, Oman, Philippines, South Africa, Spain, Switzerland, Tanzania, Trinidad and Tobago and Tunisia, which covered an additional 14% of the gross DTA balance.

Key observations communicated to the Shell Audit Committee

In January 2021, we reported to the Audit Committee that the majority of the DTAs are either offset against DTLs or are expected to be recovered from forecast profits within the operating planning horizon. In aggregate, these factors supported 97% of the recognised DTAs. The remaining 3% relied on estimated future profits between 2031 and 2040. Whilst the application of risk is judgemental, we satisfied ourselves that management's risk of forecast profit was appropriate to reflect the uncertainty throughout the forecast period.

The COVID-19 impact on the global economy and on GDP growth, together with the dramatic fall in the oil price and in demand for petroleum products, had increased the level of pressure on the recoverability of DTAs that were supported by estimated future taxable profits. However, we have concluded that there is sufficient evidence to support Shell's recognition of DTAs, although there is a greater degree of judgement required when profits beyond Shell's operating planning horizon are necessary to support the asset recognition.

Cross-reference: See the Audit Committee Report on page 150 for details on how the Audit Committee reviewed certain tax matters, in particular the recoverability of deferred tax assets. Also, see Notes 2 and 16 to the Consolidated Financial Statements.

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

7. OUR ASSESSMENT OF KEY AUDIT MATTERS continued

REVENUE RECOGNITION: THE RISK OF UNREALISED TRADING GAINS AND LOSSES BEING RECOGNISED AS A RESULT OF ERRORS, UNAUTHORISED TRADING ACTIVITY OR DELIBERATE MISSTATEMENT OF SHELL'S TRADING POSITIONS

Description of the key audit matter

This is a risk of error in revenue due to the complexity of Shell's trading and supply function. Risk is unchanged compared to 2019.

As described in Note 4 of the Consolidated Financial Statements, at December 31, 2020 Shell recognised \$181 billion of revenue. As described in Note 19, Shell recognised derivative financial instrument assets of \$9 billion and derivative financial instrument liabilities of \$6 billion.

The recognition of unrealised trading gains and losses is a complex audit area. There is an inherently higher risk of error, of unauthorised trading activity or of deliberate misstatement of the group's overall trading positions.

Shell's trading and supply function is integrated within the Oil Products, Chemicals, Integrated Gas and Upstream segments and is spread across multiple regions. The trading and supply function is inherently complex due to, amongst other things, the fact that trading is not always carried out in active markets where prices are readily available. This exposes Shell to risks that are not normally associated with core oil and gas activities. Further, in 2020, trading margins have been under pressure due to the volatility of commodity prices and demand since the start of the pandemic.

Auditing unrealised trading gains and losses is complex because of the significant judgement used in determining the key assumptions used in valuing the trades, the risk of error, of unauthorised trading activity or of deliberate misstatement of Shell's trading positions.

The deliberate misstatement of Shell's trading positions or mismarking of positions could result in understated trading losses, overstated trading profits and/or individual bonuses being manipulated through inappropriate inter-period profit or loss allocations.

Our response to the risk

We obtained an understanding of the controls over Shell's process for the recognition of revenue relating to unrealised trading gains and losses. We then evaluated the design of these controls and tested their operating effectiveness. For example, we tested controls within the front-to-end deal lifecycle across the trading and supply function and controls around the review of valuation models.

Our trading audit professionals comprise individuals who have significant experience of auditing both large commodity trading organisations and financial institutions.

To audit the existence, completeness and valuation of open positions, we focused specifically on over-the-counter (OTC) physical and financial transactions. Our audit procedures included the following:

Existence:

- we obtained external confirmations for a sample of open trading positions with brokers and counterparties and, where necessary, we evaluated the existence of the position by agreement to signed contracts.

Completeness:

- we performed additional confirmation testing by obtaining confirmations from a sample of counterparties who had open positions in the prior trading year, but no reported trading positions in the current year; and
- we performed procedures to identify unrecorded liabilities by comparing sales to trade receivables and purchases to trade payables that occurred near the end of the financial year to evaluate whether or not transactions were recorded in the correct period.

Valuation:

- we analysed the key valuation inputs to the valuation models;
- we assessed Shell's valuation methodology against market practice. This included comparing the price curves and volatility assumptions adopted by Shell to external broker quotes, market consensus providers, and our independent assessments;
- for a sample of non-complex derivatives (Level 1 and 2), we performed an independent recalculation of their fair value at the end of the year; and
- we involved EY valuation specialists to assist us in performing independent testing of the valuation models of Level 3 contracts. We evaluated the contract terms and key assumptions against independent market information.

The other audit procedures we performed included:

- we enquired of management whether or not there were any breakdowns of trading controls or instances of rogue trading reported or known or suspected frauds;
- we assessed the design of key controls and performed independent testing of key trading controls throughout the financial year;
- we assessed the relevant accounting policies against IFRS and considered their appropriateness under current market conditions; and
- we evaluated the appropriateness of presentation on both the income statement and balance sheet based on the standards required by IFRS.

The audit procedures were performed principally by the group engagement team and the UK and US component teams.

Key observations communicated to the Shell Audit Committee

In March 2021, we reported to the Audit Committee that:

- the valuation of derivative contracts as at December 31, 2020 was appropriate;
- our testing satisfied us that the models used to value contracts were appropriate for the purposes of the valuations included in Shell's Consolidated Financial Statements;
- the unrealised gains and losses had been recorded appropriately;
- our completeness testing did not identify any unrecorded liabilities or significant cut-off issues; and
- our testing did not identify any indications of unauthorised trading activity or deliberate misstatement of Shell's trading positions.

Cross-reference: See the Audit Committee Report on page 147 for details on how the Audit Committee reviewed the Trading and Supply's control framework. Also, see Note 4 to the Consolidated Financial Statements.

THE DIVIDEND DISTRIBUTION PROCESS, INCLUDING THE DETERMINATION OF REALISED PROFITS AND LOSSES FOR THE PURPOSES OF MAKING DISTRIBUTIONS UNDER THE COMPANIES ACT 2006

Description of the key audit matter	Our response to the risk
<p>This is a risk of non-compliance with laws and regulations. This key audit matter relates to the Parent Company only. Risk is unchanged compared to 2019.</p> <p>Royal Dutch Shell plc has \$19.2 billion of distributable profits at December 31, 2020. In 2020, Shell distributed \$7.3 billion of dividends and repurchased \$1.2 billion of shares.</p> <p>There is considerable public interest in ensuring that companies pay dividends and buy back shares out of profits available for distribution. Although Shell has reduced quarterly dividends and the share buyback programme was paused during 2020, shareholders' returns are a fundamental part of Shell's financial framework and it remains a major dividend-paying company. Given the uncertainty surrounding a prolonged period of economic crisis, volatility, weaker commodity prices and demand outlook, this remains a key matter of interest to stakeholders.</p> <p>The legal framework applicable to UK companies for determining profits available for distribution is contained in both the Companies Act 2006 and complementary technical guidance. Under this framework, distributions are made by individual companies and not by groups. The Shell Consolidated Financial Statements are therefore not relevant for the purpose of determining Shell's profits available for distribution. Whether or not a distribution may be made by Shell is determined by reference to Shell's 'relevant accounts', which are the Parent Company financial statements.</p>	<p>The procedures we performed included the following:</p> <ul style="list-style-type: none"> ■ we obtained an understanding of the procedures performed by management to monitor the profits available for distribution of the Parent Company. This included understanding the processes to monitor profits available for distribution of the subsidiary entities paying significant dividends to the Parent Company; ■ we tested management's distributable reserve controls at both the Parent Company and subsidiary entities that pay significant dividends, which are designed to ensure that there are sufficient profits available for distribution prior to a dividend being proposed and approved. Our testing included a review of management's analysis of non-distributable profits or losses. We also assessed the completeness of the non-distributable profits or losses identified; ■ we analysed transactions that impacted significantly the retained earnings of the Parent Company and subsidiary entities paying significant dividends and considered whether any of these transactions do not meet the criteria of distributable profits or losses. We considered whether operating and financial circumstances existed that could result in a dividend block within the group structure; ■ we reviewed management's analysis of profits available for distribution in the Parent Company and compared this to the expected future distributions. We also reperformed the calculation of distributable profits available for distribution of the Parent Company by reference to the relevant accounts; ■ we confirmed that, as at December 31, 2020, the Parent Company had a merger reserve of \$234 billion and that, in the event that the investment in Shell Petroleum N.V. held by RDS plc were to be impaired (see the key audit matter below), this would have no impact on Shell's distributable profits. We confirmed further that this is because, under the Companies Act 2006, any such impairments would first be charged to the income statement and then transferred to the merger reserve, as opposed to impacting distributable reserves; and ■ we satisfied ourselves that distributions made in 2020 were allowable, by reference to the most recent relevant accounts, for the purposes of making distributions under the Companies Act 2006. <p>The audit procedures were performed principally by the group engagement team and the UK component team.</p>

Key observations communicated to the Shell Audit Committee

In March 2021, we reported to the Audit Committee that:

- the procedures performed by management to monitor the profits available for distribution of the Parent Company and subsidiary entities paying significant dividends to the Parent Company were appropriate;
- the analysis performed by management to identify non-distributable profits or losses and expected future commitments or operating and financial circumstances that could result in a dividend block is appropriate; and
- we were satisfied that the profits available for distribution, by reference to the relevant accounts, were sufficient to support the distributions made by the Parent Company.

Cross-reference: See Note 23 to the Consolidated Financial Statements and Note 8 to the Parent Company Financial Statements.

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

7. OUR ASSESSMENT OF KEY AUDIT MATTERS continued

THE RECOVERABLE AMOUNT OF INVESTMENTS HELD BY THE PARENT COMPANY

Description of the key audit matter	Our response to the risk
<p>This is a forecast-based valuation. The risk is elevated compared to 2019 due to the impact of the pandemic on the Global economy and on Shell's profitability. This key audit matter relates to the Parent Company only.</p> <p>As described in Note 4 to the Parent Company Financial Statements, at December 31, 2020, RDS plc held investments in subsidiaries of \$257 billion, mainly related to its investment in Shell Petroleum N.V. (SPNV).</p> <p>The weak macro-economic environment and the impact of the pandemic have led to a shortfall of the market capitalisation of the group versus the carrying value of the investment held in SPNV of around \$100 billion at year end. This is an indicator of impairment and management have tested SPNV for impairment as a result.</p> <p>SPNV holds directly and indirectly the entire Shell group. Therefore, both the operational performance of the group's assets and external factors have a significant impact on the estimate of the recoverable amount of SPNV.</p> <p>Accounting standards require the recoverable amount to be determined at the higher of fair value less cost of disposal and value in use (VIU). Management have estimated the recoverable amount of SPNV on the basis of an aggregation of the VIU of the group's CGUs discounted at a pre-tax nominal discount rate of 6%.</p> <p>The most significant judgement applied in determining the VIU of SPNV is the projection of cashflows from Shell's business plan. A further significant judgement applied is in the risking of the projected cashflows. In order to assess how sensitive the VIU is to fluctuations in assumptions, management performed a reverse stress test to determine the level at which an impairment would be recorded.</p>	<p>We tested the controls over the management approval of key inputs, metrics and adjustments made to Shell's Operating Plan which supports the recoverable value of the investment, including oil and gas prices, oil and gas reserves and future refining margins.</p> <p>In order to evaluate the cash flow inputs of the impairment model, we gained an understanding of the methodology behind the model and verified its mathematical accuracy and completeness.</p> <p>We assessed the conclusions reached in the asset impairment tests performed during the year and Shell's impairment assessment of the goodwill allocated at the Upstream and IG segment level and whether any contrary evidence existed from those tests that would call into question the validity of management's SPNV VIU methodology.</p> <p>We challenged the appropriateness of the extent to which the cashflows had been risked and considered the sensitivity of the impairment assessment to further risking. We reviewed management's reverse stress test, which adjusted the extent to which cashflows were risked until the headroom was removed entirely; we also evaluated corroborative and contrary evidence to assess whether this level of risking of the cashflows was within a range of reasonably possible outcomes.</p> <p>We engaged our EY valuations specialists to assist in the review and challenge of the appropriateness of the VIU approach applied by management. Our specialists applied alternative approaches to calculate the VIU of SPNV at December 31, 2020. We also carried out sensitivity analyses by applying further adjustments and risking and determined a reasonable range for the recoverable amount of SPNV. We considered whether the outcome of these analyses supported the carrying value of SPNV.</p> <p>Our valuation specialists also estimated the fair value of SPNV at December 31, 2020 on the basis of data observed in historic market transactions. This confirmed that the VIU of SPNV was higher than its fair value and that, therefore, it was appropriate to estimate the recoverable amount of SPNV at its VIU.</p> <p>The audit procedures were performed by the group engagement team and local audit teams through a combination of substantive and control procedures.</p>

Key observations communicated to the Shell Audit Committee

In March 2021, we reported to the Audit Committee that:

- we were satisfied that the overall VIU methodology was appropriately applied by management and was consistent with the impairment assessments performed at an asset level and provided a reasonable basis for estimating the VIU of SPNV;
- we did not identify any contrary evidence from the goodwill and asset impairment tests performed by management during the year and we were satisfied that the conclusions reached in those impairment tests did not contradict the results of management's SPNV impairment assessment;
- the VIU of SPNV was higher than its fair value and that, therefore, it was appropriate to estimate the recoverable amount of SPNV at its VIU;
- based on our analysis, we determined a reasonable range for the recoverable amount of SPNV and confirmed that the carrying value of the investment lies within our range; and
- we were satisfied that, whilst the recoverable amount has decreased significantly in 2020, no impairment was required.

Cross-reference: See Note 23 to the Consolidated Financial Statements and Note 4 to the Parent Company Financial Statements.

8. OTHER INFORMATION AND MATTERS ON WHICH WE ARE REQUIRED TO REPORT BY EXCEPTION

The other information comprises the information included in the Annual Report set out on pages 1 to 189 and 298 to 327 including the Strategic Report, Governance and Additional Information sections, other than the financial statements and our auditor's report thereon. The Directors are responsible for the other information contained within the Annual Report.

Our opinion on the financial statements does not cover the other information and, except to the extent otherwise explicitly stated in this report, we do not express any form of assurance conclusion thereon. In the table below, we have outlined our responsibility for the other information in the Annual Report and the matters on which we are required to report by exception.

OTHER INFORMATION

Our responsibility

In connection with our audit of the financial statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated. If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether there is a material misstatement in the financial statements or a material misstatement of the other information. If, based on the work we have performed, we conclude that there is a material misstatement of the other information, we are required to report that fact.

Our reporting

We have nothing to report in this regard.

STRATEGIC REPORT AND THE DIRECTORS' REPORT

Our responsibility

We are required to report whether, based on the work undertaken in the course of the audit:

- the information given in the strategic report and the directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements; and
- the strategic report and the directors' report have been prepared in accordance with applicable legal requirements.

We are required to report by exception whether, in light of the knowledge and understanding of the Group and the Parent Company and its environment obtained in the course of the audit, we have identified material misstatements in the strategic report or the directors' report.

Our reporting

In our opinion, based on the work undertaken in the course of the audit, the information given in the strategic report and the directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements and they have been prepared in accordance with applicable legal requirements.

We have nothing to report by exception.

DIRECTORS' REMUNERATION REPORT

Our responsibility

We are required to report whether the part of the Directors' Remuneration Report to be audited has been properly prepared in accordance with the Companies Act 2006.

Under the Companies Act 2006, we are also required to report by exception whether certain disclosures of directors' remuneration specified by law are not made.

Our reporting

In our opinion, the part of the Directors' Remuneration Report to be audited has been properly prepared in accordance with the Companies Act 2006.

We have nothing to report by exception.

CORPORATE GOVERNANCE STATEMENT

Our responsibility

The Listing Rules require us to review the directors' statement in relation to going concern, longer-term viability and that part of the Corporate Governance Statement relating to the group and company's compliance with the provisions of the UK Corporate Governance Code specified for our review.

Based on the work undertaken as part of our audit, we are required to consider whether each of the following elements of the Corporate Governance Statement is materially consistent with the financial statements or our knowledge obtained during the audit:

- Directors' statement with regards to the appropriateness of adopting the going concern basis of accounting and any material uncertainties identified set out on page 184;
- Directors' explanation as to its assessment of the company's prospects, the period this assessment covers and why the period is appropriate set out on page 183;
- Directors' statement on fair, balanced and understandable set out on page 189;
- Board's confirmation that it has carried out a robust assessment of the emerging and principal risks set out on page 28;
- the section of the annual report that describes the review of effectiveness of risk management and internal control systems set out on page 186; and;
- the section describing the work of the Audit Committee set out on page 145.

Our reporting

Based on the work undertaken as part of our audit, we have concluded that each of these elements of the Corporate Governance Statement is materially consistent with the financial statements or our knowledge obtained during the audit.

OTHER REPORTING

Our responsibility

Under the Companies Act 2006, we are required to report to you by exception if, in our opinion:

- adequate accounting records have not been kept by the Parent Company, or returns adequate for our audit have not been received from branches not visited by us; or
- the Parent Company financial statements and the part of the Directors' Remuneration Report to be audited are not in agreement with the accounting records and returns; or
- we have not received all the information and explanations we require for our audit.

Our reporting

We have nothing to report by exception.

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF ROYAL DUTCH SHELL PLC continued

9. RESPONSIBILITIES OF THE DIRECTORS

As explained more fully in the statement of Directors' responsibilities set out on page 22, the Directors are responsible for the preparation of the Consolidated Financial Statements and for being satisfied that they give a true and fair view, and for such internal control as the Directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the Directors are responsible for assessing Shell's and the Parent Company's ability to continue as going concerns, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors either intend to liquidate Shell or the Parent Company or to cease operations, or have no realistic alternative but to do so.

10. OUR RESPONSIBILITIES FOR THE AUDIT OF THE FINANCIAL STATEMENTS

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISA (UK) will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

11. EXPLANATION AS TO WHAT EXTENT OUR AUDIT WAS CONSIDERED CAPABLE OF DETECTING IRREGULARITIES, INCLUDING FRAUD

Irregularities, including fraud, are instances of non-compliance with laws and regulations. We design procedures in line with our responsibilities, outlined above, to detect irregularities, including fraud.

The risk of not detecting a material misstatement due to fraud is higher than the risk of not detecting one resulting from error, as fraud may involve deliberate concealment by, for example, forgery or intentional misrepresentations, or through collusion.

The extent to which our procedures are capable of detecting irregularities, including fraud, is detailed below. However, the primary responsibility for the prevention and detection of fraud rests with both those charged with governance of the entity and management.

Our approach was as follows:

- We obtained an understanding of the legal and regulatory frameworks that are applicable to Shell and determined that the most significant are those that relate to the reporting framework (IFRS, Companies Act 2006, the UK Corporate Governance Code, the US Securities Exchange Act of 1934 and the Listing Rules of the UK Listing Authority) and the relevant tax compliance regulations in the jurisdictions in which Shell operates. In addition, we concluded that there are certain significant laws and regulations that may have an effect on the determination of the amounts and disclosures in the financial statements and those laws and regulations relating to health and safety, employee matters, environmental and bribery and corruption practices.
- We understood how Shell is complying with those frameworks by making enquiries of management, internal audit, those responsible for legal and compliance procedures and the Company Secretary. We corroborated our enquiries through our review of Board minutes, papers provided to the Audit Committee and correspondence received from regulatory bodies and noted that there was no contradictory evidence.
- We assessed the susceptibility of Shell's Consolidated Financial Statements to material misstatement, including how fraud might occur, by embedding forensic specialists into our group engagement team. Our forensic specialists worked with the group engagement team to identify the fraud risks across various parts of the business. In addition, we utilised internal and external information to perform a fraud risk assessment for each of the countries of operation. We considered the risk of fraud through management override and, in response, we incorporated data analytics across manual journal entries into our audit approach. We also considered the possibility of fraudulent or corrupt payments made through third parties and conducted detailed analytical testing on third party vendors in high risk jurisdictions. Where instances of risk behaviour patterns were identified through our data analytics, we performed additional audit procedures to address each identified risk. These procedures included the testing of transactions back to source information and were designed to provide reasonable assurance that the financial statements were free from fraud or error. We also conducted specific audit procedures in relation to the risk of bribery and corruption across various countries of operation determined on a risk-based approach.

- Based on the results of our risk assessment we designed our audit procedures to identify non-compliance with such laws and regulations identified above. Our procedures involved journal entry testing, with a focus on journals meeting our defined risk criteria based on our understanding of the business; enquiries of legal counsel, group management, internal audit and all full and specific scope management; review of the volume and nature of complaints received by the whistleblowing hotline during the year; and
- If any instances of non-compliance with laws and regulations were identified, these were communicated to the relevant local EY teams who performed sufficient and appropriate audit procedures, supplemented by audit procedures performed at the group level.

A further description of our responsibilities for the audit of the financial statements is located on the Financial Reporting Council's website at <https://www.frc.org.uk/auditorsresponsibilities>. This description forms part of our auditor's report.

12. OTHER MATTERS WE ARE REQUIRED TO ADDRESS

Following the recommendation of the Audit Committee, we were re-appointed by Royal Dutch Shell plc's Annual General Meeting (AGM) on May 19, 2020, as auditors of Royal Dutch Shell to hold office until the conclusion of the next AGM of the Company, and signed an engagement letter on July 16, 2020. Our total uninterrupted period of engagement is five years covering periods from our appointment through to the period ending December 31, 2020.

The non-audit services prohibited by the FRC's Ethical Standard were not provided to Shell or the Parent Company and we remain independent of Shell and the Parent Company in conducting the audit.

Our audit opinion is consistent with our additional report to the Audit Committee explaining the results of our audit.

13. USE OF OUR REPORT

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the Company and the company's members as a body for our audit work for this report or for the opinions we have formed.

/s/ Allister Wilson (Senior Statutory Auditor)

ALLISTER WILSON

Senior Statutory Auditor
for and on behalf of Ernst & Young LLP
London
March 10, 2021

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CONSOLIDATED STATEMENT OF INCOME

				\$ million
	Notes	2020	2019	2018
Revenue	4	180,543	344,877	388,379
Share of profit of joint ventures and associates	9	1,783	3,604	4,106
Interest and other income	5	869	3,625	4,071
Total revenue and other income		183,195	352,106	396,556
Purchases		117,093	252,983	294,399
Production and manufacturing expenses	4	24,001	26,438	26,970
Selling, distribution and administrative expenses	4	9,881	10,493	11,360
Research and development	4	907	962	986
Exploration	4	1,747	2,354	1,340
Depreciation, depletion and amortisation	4	52,444	28,701	22,135
Interest expense	6	4,089	4,690	3,745
Total expenditure		210,162	326,621	360,935
(Loss)/income before taxation		(26,967)	25,485	35,621
Taxation (credit)/charge	16	(5,433)	9,053	11,715
(Loss)/income for the period	4	(21,534)	16,432	23,906
Income attributable to non-controlling interest	4	146	590	554
(Loss)/income attributable to Royal Dutch Shell plc shareholders	4	(21,680)	15,842	23,352
Basic earnings per share (\$)	24	(2.78)	1.97	2.82
Diluted earnings per share (\$)	24	(2.78)	1.95	2.80

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

				\$ million
	Notes	2020	2019	2018
(Loss)/income for the period	4	(21,534)	16,432	23,906
Other comprehensive income/(loss) net of tax				
Items that may be reclassified to income in later periods:				
Currency translation differences	22	1,179	344	(3,171)
Debt instruments remeasurements	22	23	29	(15)
Cash flow hedging (losses)/gains [A]	22	(160)	(276)	730
Net investment hedging (losses)/gains [A]	22	(423)	9	(1)
Deferred cost of hedging	22	100	66	(209)
Share of other comprehensive loss of joint ventures and associates	9	(42)	(76)	(10)
Total		677	96	(2,676)
Items that are not reclassified to income in later periods:				
Retirement benefits remeasurements		(2,702)	(2,102)	3,588
Equity instruments remeasurements		64	(30)	(153)
Share of other comprehensive income of joint ventures and associates	9	119	2	193
Total		(2,519)	(2,130)	3,628
Other comprehensive (loss)/income for the period		(1,842)	(2,034)	952
Comprehensive (loss)/income for the period		(23,376)	14,398	24,858
Comprehensive income attributable to non-controlling interest		136	625	383
Comprehensive (loss)/income attributable to Royal Dutch Shell plc shareholders		(23,512)	13,773	24,475

[A] As from 2020, 'Cash flow hedging (losses)/gains' and 'Net investment hedging (losses)/gains' have been separately disclosed. Prior period comparatives for these items have been revised to conform with current year presentation (see Note 22).

CONSOLIDATED FINANCIAL STATEMENTS continued**CONSOLIDATED BALANCE SHEET**

		\$ million	
	Notes	Dec 31, 2020	Dec 31, 2019
Assets			
Non-current assets			
Intangible assets	7	22,822	23,486
Property, plant and equipment	8	210,847	238,349
Joint ventures and associates	9	22,451	22,808
Investments in securities	10	3,222	2,989
Deferred tax	16	16,311	10,524
Retirement benefits	17	2,474	4,717
Trade and other receivables	11	7,641	8,085
Derivative financial instruments	19	2,805	689
		288,573	311,647
Current assets			
Inventories	12	19,457	24,071
Trade and other receivables	11	33,625	43,414
Derivative financial instruments	19	5,783	7,149
Cash and cash equivalents	13	31,830	18,055
		90,695	92,689
Total assets		379,268	404,336
Liabilities			
Non-current liabilities			
Debt	14	91,115	81,360
Trade and other payables	15	2,304	2,342
Derivative financial instruments	19	420	1,209
Deferred tax	16	10,463	14,522
Retirement benefits	17	15,168	13,017
Decommissioning and other provisions	18	27,310	21,799
		146,780	134,249
Current liabilities			
Debt	14	16,899	15,064
Trade and other payables	15	41,677	49,208
Derivative financial instruments	19	5,308	5,429
Taxes payable	16	6,006	6,693
Retirement benefits	17	437	419
Decommissioning and other provisions	18	3,624	2,811
		73,951	79,624
Total liabilities		220,731	213,873
Equity			
Share capital	20	651	657
Shares held in trust		(709)	(1,063)
Other reserves	22	12,752	14,451
Retained earnings		142,616	172,431
Equity attributable to Royal Dutch Shell plc shareholders		155,310	186,476
Non-controlling interest		3,227	3,987
Total equity		158,537	190,463
Total liabilities and equity		379,268	404,336

Signed on behalf of the Board

/s/ Jessica Uhl

JESSICA UHL

Chief Financial Officer

March 10, 2021

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

\$ million

	Equity attributable to Royal Dutch Shell plc shareholders					Non-controlling interest	Total equity
	Share capital (see Note 20)	Shares held in trust	Other reserves (see Note 22)	Retained earnings	Total		
At January 1, 2020	657	(1,063)	14,451	172,431	186,476	3,987	190,463
Comprehensive (loss)/income for the period	—	—	(1,832)	(21,397) [A]	(23,229)	136	(23,093)
Transfer from other comprehensive income	—	—	270	(270)	—	—	—
Dividends (see Note 23)	—	—	—	(7,270)	(7,270)	(311)	(7,581)
Repurchases of shares	(6)	—	6	(1,214)	(1,214)	—	(1,214)
Share-based compensation	—	354	(143)	(230)	(19)	—	(19)
Other changes in non-controlling interest	—	—	—	566	566	(585) [B]	(19)
At December 31, 2020	651	(709)	12,752	142,616	155,310	3,227	158,537
At January 1, 2019 (as previously published)	685	(1,260)	16,615	182,606	198,646	3,888	202,534
Impact of IFRS 16	—	—	—	4	4	—	4
At January 1, 2019 (as revised)	685	(1,260)	16,615	182,610	198,650	3,888	202,538
Comprehensive income/(loss) for the period	—	—	(2,069)	15,842	13,773	625	14,398
Transfer from other comprehensive income	—	—	(74)	74	—	—	—
Dividends (see Note 23)	—	—	—	(15,198)	(15,198)	(537)	(15,735)
Repurchases of shares [C]	(28)	—	28	(10,286)	(10,286)	—	(10,286)
Share-based compensation	—	197	(49)	(613)	(465)	—	(465)
Other changes in non-controlling interest	—	—	—	2	2	11	13
At December 31, 2019	657	(1,063)	14,451	172,431	186,476	3,987	190,463
At January 1, 2018	696	(917)	16,794	177,733	194,306	3,456	197,762
Comprehensive income for the period	—	—	1,123	23,352	24,475	383	24,858
Transfer from other comprehensive income	—	—	(971)	971	—	—	—
Dividends (see Note 23)	—	—	—	(15,675)	(15,675)	(586)	(16,261)
Repurchases of shares [C]	(11)	—	11	(4,519)	(4,519)	—	(4,519)
Share-based compensation	—	(343)	(342)	693	8	—	8
Other changes in non-controlling interest	—	—	—	51	51	635	686
At December 31, 2018	685	(1,260)	16,615	182,606	198,646	3,888	202,534

[A] Comprehensive loss for the period of \$21,397 million recognised in retained earnings includes a gain of \$283 million, recognised in equity, that relates to remeasurement of a share of interest in a joint venture in respect of prior years.

[B] The change is mainly related to the non-controlling interest in Shell Midstream Partners, L.P. (SHLX) following the completion of the sale of Shell's 79% interest in the Mattox Pipeline Company LLC and certain logistics assets at the Shell Norco Manufacturing Complex to SHLX.

[C] The repurchase of shares recognised through retained earnings includes the aggregate maximum consideration to which Shell was contractually bound to under the tranches of the buyback programme, plus associated stamp duty (see Note 20).

CONSOLIDATED FINANCIAL STATEMENTS continued**CONSOLIDATED STATEMENT OF CASH FLOWS**

	Notes	2020	2019	\$ million 2018
(Loss)/income before taxation for the period		(26,967)	25,485	35,621
Adjustment for:				
Interest expense (net)		3,316	3,705	2,878
Depreciation, depletion and amortisation		52,444	28,701	22,135
Exploration well write-offs	8	815	1,218	449
Net gains on sale and revaluation of non-current assets and businesses		(286)	(2,519)	(3,265)
Share of profit of joint ventures and associates		(1,783)	(3,604)	(4,106)
Dividends received from joint ventures and associates		2,591	4,139	4,903
Decrease/(increase) in inventories		4,477	(2,635)	2,823
Decrease/(increase) in current receivables		9,625	(921)	1,955
Decrease in current payables		(9,494)	(1,223)	(1,336)
Derivative financial instruments		977	(1,484)	799
Retirement benefits		568	(365)	390
Decommissioning and other provisions		1,104	(686)	(1,754)
Other		8	(28)	1,264
Tax paid		(3,290)	(7,605)	(9,671)
Cash flow from operating activities		34,105	42,178	53,085
Capital expenditure		(16,585)	(22,971)	(23,011)
Investments in joint ventures and associates		(1,024)	(743)	(880)
Investment in equity securities		(218)	(205)	(187)
Proceeds from sale of property, plant and equipment and businesses		2,489	4,803	4,366
Proceeds from sale of joint ventures and associates		1,240	2,599	1,594
Proceeds from sale of equity securities		281	469	4,505
Interest received		532	911	823
Other investing cash inflows		3,239	2,921	1,373
Other investing cash outflows		(3,232)	(3,563)	(2,242)
Cash flow from investing activities		(13,278)	(15,779)	(13,659)
Net decrease in debt with maturity period within three months		(63)	(308)	(396)
Other debt:				
New borrowings		23,033	11,185	3,977
Repayments		(17,385)	(14,292)	(11,912)
Interest paid		(4,105)	(4,649)	(3,574)
Derivative financial instruments [A]		1,157	(48)	
Change in non-controlling interest		(42)	—	678
Cash dividends paid to:				
Royal Dutch Shell plc shareholders		(7,424) [B]	(15,198)	(15,675)
Non-controlling interest		(311)	(537)	(584)
Repurchases of shares		(1,702)	(10,188)	(3,947)
Shares held in trust: net purchases and dividends received		(382)	(1,174)	(1,115)
Cash flow from financing activities		(7,224)	(35,209)	(32,548)
Currency translation differences relating to cash and cash equivalents		172	124	(449)
Increase/(decrease) in cash and cash equivalents		13,775	(8,686)	6,429
Cash and cash equivalents at beginning of year		18,055	26,741	20,312
Cash and cash equivalents at end of year	13	31,830	18,055	26,741

[A] As from 2019, a new line item 'Derivative financial instruments' has been introduced for derivatives related to debt.

[B] Cash dividends paid represents the payment of net dividends (after deduction of withholding taxes where applicable) and payment of withholding taxes on dividends paid in the previous quarter.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1 – BASIS OF PREPARATION

The Consolidated Financial Statements of Royal Dutch Shell plc (the “Company”) and its subsidiaries (collectively referred to as “Shell”) have been prepared in accordance with international accounting standards in conformity with the requirements of the UK Companies Act 2006 (the “Act”), and therefore in accordance with International Financial Reporting Standards (IFRS) adopted pursuant to Regulation (EC) No 1606/2002 as it applies in the European Union. As applied to Shell, there are no material differences from IFRS as issued by the International Accounting Standards Board (IASB); therefore, the Consolidated Financial Statements have been prepared in accordance with IFRS as issued by the IASB.

As described in the accounting policies in Note 2, the Consolidated Financial Statements have been prepared under the historical cost convention except for certain items measured at fair value. Those accounting policies have been applied consistently in all periods, except for the accounting for lease contracts following the prospective adoption of IFRS 16 Leases from January 1, 2019.

The Consolidated Financial Statements were approved and authorised for issue by the Board of Directors on March 10, 2021.

2 – SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS AND ESTIMATES

This Note describes Shell’s significant accounting policies, which are those relevant to an understanding of the Consolidated Financial Statements. It includes the measurement bases used in preparing the Consolidated Financial Statements. It allows an understanding as to how transactions, other events and conditions are reported. It also describes: (a) judgements, apart from those involving estimations, that management makes in applying the policies that have the most significant effect on the amounts recognised in the Consolidated Financial Statements; and (b) estimations, including assumptions about the future, that management makes in applying the policies. The sources of estimation uncertainty that have a significant risk of a material adjustment to the carrying amounts of assets and liabilities within the next financial year are specifically identified as a significant estimate.

The accounting policies applied are consistent with those of the previous financial year except for the adoption as from January 1, 2020 of amendments to IFRS 9 *Financial Instruments* (IFRS 9) and IFRS 7 *Financial Instruments: Disclosures* (IFRS 7), and IFRS 3 *Business Combinations* (IFRS 3).

The transition to the accounting pronouncements as listed below has no or no material impact.

IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures*

Inter-Bank Offered Rate (IBOR) Reform – Phase 1

IFRS 9 and IFRS 7 contain a temporary targeted exception from applying specific hedge accounting requirements pre-IBOR reform.

By applying the exception, Shell anticipates that the interest rate benchmark on which the hedged risk is based is not altered as a result of the IBOR reform. However, any hedge ineffectiveness continues to be recorded in the income statement. The exception ceases to apply when the uncertainty arising from interest rate benchmark reform is no longer present.

IFRS 3 *Business Combinations*

The amendment to IFRS 3 resolves the difficulties that arose when an entity determined whether it acquired a business or a group of assets. Under the amended definition of a business, an acquisition qualifies as a business combination when the assets and liabilities acquired include an input and a substantive process that together significantly contribute to the ability to create outputs. The amended definition of a business is applied prospectively.

Nature of the Consolidated Financial Statements

The Consolidated Financial Statements are presented in US dollars (dollars) and comprise the financial statements of the Company and its subsidiaries, being those entities over which the Company has control, either directly or indirectly, through exposure or rights to their variable returns and the ability to affect those returns through its power over the entities. Information about subsidiaries at December 31, 2020, can be found in ‘Appendix 1: Significant Subsidiaries and Other Related Undertakings’.

Subsidiaries are consolidated from the date on which control is obtained until the date that such control ceases, using consistent accounting policies. All inter-company balances and transactions, including unrealised profits arising from such transactions, are eliminated. Unrealised losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. Non-controlling interest represents the proportion of income, other comprehensive income and net assets in subsidiaries that is not attributable to the Company’s shareholders.

Climate change and energy transition

Meeting the goals of the Paris Agreement is a global and Shell target. Shell’s pathway to Paris alignment is reflected in the Group’s strategy and in 2020 we announced a long-term target to become a net-zero emissions energy business by 2050, in step with society.

It is important to note that the world needs to transform in a number of complex and interconnected ways. While the world has made some movement towards the goals of Paris, unfortunately, society is not yet on a path to meet Paris. Getting the energy system on a path to net-zero emissions will require coordinated action between energy providers, energy users and governments.

One of the key aspects that underpin Shell’s financial statements are the oil and gas price and refining margin assumptions. These price assumptions are developed with input from our scenarios and other factors. The mid-price is our reasonable best estimate and the basis for our operating plans, outlooks and impairment testing.

Shell’s operating plan and outlook (including portfolio changes) are forecasted for a 10-year period and include significant actions to reduce its greenhouse gas (GHG) emissions in its journey towards its net-zero emissions target by 2050 as outlined in this report. However, our plan and pricing assumptions do not yet reflect Shell’s 2050 net-zero emissions target, because our planning timeframe is 10 years and there is significant uncertainty on how society will transition to net-zero emissions. Instead these reflect the current economic environment, the pace of the world’s energy transition and Shell’s reasonable expectation of how the next 10 years will evolve. As society moves towards net-zero emissions, Shell expects its operating plan, outlook and assumptions to be revised accordingly.

Long term, it is expected that the current Shell portfolio will change and evolve with the energy transition. Decision-making on the future portfolio is guided by the pace of society’s progress and the aim of being in step with society as it moves towards the goal of the Paris Agreement. Shell has set out its strategy of how it will achieve its target to be a net-zero emissions energy business by 2050, in step with society’s progress towards achieving net-zero emissions.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

2 – SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS AND ESTIMATES continued

Currency translation

Foreign currency transactions are translated using the exchange rate at the dates of the transactions or valuation where items are remeasured. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at quarter-end exchange rates of monetary assets and liabilities denominated in foreign currencies (including those in respect of inter-company balances, unless related to loans of a long-term investment nature) are recognised in income unless when recognised in other comprehensive income in respect of cash flow or net investment hedges. Foreign exchange gains and losses in income are presented within interest and other income or within purchases where not related to financing. Share capital issued in currencies other than the dollar is translated at the exchange rate at the date of issue.

On consolidation, assets and liabilities of non-dollar entities are translated to dollars at year-end rates of exchange, while their statements of income, other comprehensive income and cash flows are translated at quarterly average rates. The resulting translation differences are recognised as currency translation differences within other comprehensive income. Upon sale of all or part of an interest in, or upon liquidation of, an entity, the appropriate portion of cumulative currency translation differences related to that entity is generally recognised in income.

Revenue recognition

Revenue from sales of oil, natural gas, chemicals and other products is recognised at the transaction price to which Shell expects to be entitled, after deducting sales taxes, excise duties and similar levies. For contracts that contain separate performance obligations, the transaction price is allocated to those separate performance obligations by reference to their relative stand-alone selling prices.

Revenue is recognised when control of the products has been transferred to the customer. For sales by Integrated Gas and Upstream operations, this generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism; for sales by refining operations, it is either when the product is placed onboard a vessel or offloaded from the vessel, depending on the contractually agreed terms; and for sales of oil products and chemicals, it is either at the point of delivery or the point of receipt, depending on contractual conditions.

Revenue resulting from hydrocarbon production from properties in which Shell has an interest with partners in joint arrangements is recognised on the basis of Shell's volumes lifted and sold. Revenue resulting from the production of oil and natural gas under production-sharing contracts (PSCs) is recognised for those amounts relating to Shell's cost recoveries and Shell's share of the remaining production. Gains and losses on derivative contracts and the revenue and costs associated with other contracts that are classified as held primarily for the purpose of being traded are reported on a net basis in the Consolidated Statement of Income. Purchases and sales of hydrocarbons under exchange contracts that are necessary to obtain or reposition feedstocks for refinery operations are presented net in the Consolidated Statement of Income.

Revenue resulting from arrangements that are not considered contracts with customers is presented as revenue from other sources.

Research and development

Development costs that are expected to generate probable future economic benefits are capitalised as intangible assets. All other research and development expenditure is recognised in income as incurred.

Exploration costs

Hydrocarbon exploration costs are accounted for under the successful efforts method: exploration costs are recognised in income when incurred, except that exploratory drilling costs, including in respect of the recapitalisation of the depreciation, are included in property, plant and equipment pending determination of proved reserves. Exploration costs capitalised in respect of exploration wells that are more than 12 months old are written off unless: (a) proved reserves are booked; or (b) (i) they have found commercially producible quantities of reserves and (ii) they are subject to further exploration or appraisal activity in that either drilling of additional exploratory wells is under way or firmly planned for the near future or other activities are being undertaken to sufficiently progress the assessing of reserves and the economic and operating viability of the project.

Property, plant and equipment and intangible assets Recognition

Property, plant and equipment comprise assets owned by Shell, assets held by Shell under lease contracts, and assets operated by Shell as contractor in PSCs. They include rights and concessions in respect of properties with proved reserves ("proved properties") and with no proved reserves ("unproved properties"). Property, plant and equipment, including expenditure on major inspections, and intangible assets are initially recognised in the Consolidated Balance Sheet at cost where it is probable that they will generate future economic benefits. This includes capitalisation of decommissioning and restoration costs associated with provisions for asset retirement (see "provisions"), certain development costs (see "research and development") and the effects of associated cash flow hedges (see "financial instruments") as applicable. The accounting for exploration costs is described separately (see "exploration costs"). Intangible assets include goodwill, liquefied natural gas (LNG) off-take and sales contracts obtained through acquisition, emission certificates, software costs and trademarks. Interest is capitalised as an increase in property, plant and equipment, on major capital projects during construction.

Property, plant and equipment and intangible assets are subsequently carried at cost less accumulated depreciation, depletion and amortisation (including any impairment). Gains and losses on sale are determined by comparing the proceeds with the carrying amounts of assets sold and are recognised in income, within interest and other income.

An asset is classified as held for sale if its carrying amount will be recovered principally through sale rather than through continuing use, which is when the sale is highly probable, and it is available for immediate sale. Assets classified as held for sale are measured at the lower of the carrying amount upon classification and the fair value less costs to sell.

Depreciation, depletion and amortisation

Property, plant and equipment related to hydrocarbon production activities are in principle depreciated on a unit-of-production basis over the proved developed reserves of the field concerned, other than assets whose useful lives differ from the lifetime of the field which are depreciated applying the straight-line method. However, for certain Integrated Gas and Upstream assets, the use for this purpose of proved developed reserves, which are determined using the SEC-mandated yearly average oil and gas prices, would result in depreciation charges for these assets which do not reflect the pattern in which their future economic benefits are expected to be consumed as, for example, it may result in assets with long-term expected lives being depreciated in full within one year. Therefore, in these instances, other approaches are applied to determine the reserves base for the purpose of calculating depreciation, such as using management's expectations of future oil and gas prices rather than yearly average prices, to provide a phasing of periodic depreciation charges that more appropriately reflects the expected utilisation of the assets concerned. (See Note 8)

Rights and concessions in respect of proved properties are depleted on the unit-of-production basis over the total proved reserves of the relevant area. Where individually insignificant, unproved properties may be grouped and depreciated based on factors such as the average concession term and past experience of recognising proved reserves.

Property, plant and equipment held under lease contracts and capitalised LNG off-take and sales contracts are depreciated or amortised over the term of the respective contract. Other property, plant and equipment and intangible assets are depreciated or amortised on a straight-line basis over their estimated useful lives, except for goodwill, which is not amortised. They include refineries and chemical plants (for which the useful life is generally 20 years), retail service stations (15 years), upgraders (30 years) and major inspection costs, which are depreciated over the estimated period before the next planned major inspection (three to five years).

On classification of an asset as held for sale, depreciation ceases.

Estimates of the useful lives and residual values of property, plant and equipment and intangible assets are reviewed annually and adjusted if appropriate.

Impairment

The carrying amount of goodwill is tested for impairment annually; in addition, assets other than unproved properties (see "exploration costs") are tested for impairment whenever events or changes in circumstances indicate that the carrying amounts for those assets may not be recoverable. On classification as held for sale, the carrying amounts of property, plant and equipment and intangible assets are also reviewed. If assets are determined to be impaired, the carrying amounts of those assets are written down to their recoverable amount, which is the higher of fair value less costs of disposal (see "fair value measurements") and value in use.

Value in use is determined as the amount of estimated risk-adjusted discounted future cash flows. For this purpose, assets are grouped into cash-generating units based on separately identifiable and largely independent cash inflows. Estimates of future cash flows used in the evaluation of impairment of assets are made using management's forecasts of commodity prices, market supply and demand, potential costs associated with operational GHG emissions, mainly related to CO₂,

and forecast product and refining margins. In addition, management takes into consideration the expected useful lives of the manufacturing facilities, exploration and production assets, and expected production volumes. The latter takes into account assessments of field and reservoir performance and includes expectations about both proved reserves and volumes that are expected to constitute proved reserves in the future (unproved volumes), which are risk-weighted utilising geological, production, recovery and economic projections. Cash flow estimates are risk-adjusted to reflect local conditions as appropriate and discounted at a rate based on Shell's marginal cost of debt.

Impairments, except those related to goodwill, are reversed as applicable to the extent that the events or circumstances that triggered the original impairment have changed.

Impairment losses and reversals are reported within depreciation, depletion and amortisation.

Judgements and estimates

Proved oil and gas reserves

Unit-of-production depreciation, depletion and amortisation charges are principally measured based on management's estimates of proved developed oil and gas reserves. Also, exploration drilling costs are capitalised pending the results of further exploration or appraisal activity, which may take several years to complete and before any related proved reserves can be booked.

Proved reserves are estimated by a central group of reserves experts. The estimated proved reserves are determined by reference to available geological and engineering data and only include volumes for which access to market is assured with reasonable certainty. Yearly average oil and gas prices are applied in the determination of proved reserves. Estimates of proved reserves are inherently imprecise, require the application of judgement and are subject to regular revision, either upward or downward, based on new information such as from the drilling of additional wells, observation of long-term reservoir performance under producing conditions and changes in economic factors, including product prices, contract terms, legislation or development plans.

Changes to estimates of proved developed reserves affect prospectively the amounts of depreciation, depletion and amortisation charged and, consequently, the carrying amounts of exploration and production assets. Generally, in the normal course of business the diversity of the asset portfolio will limit the net effect of such revisions. The outcome of, or assessment of plans for, exploration or appraisal activity may result in the related capitalised exploration drilling costs being recognised in income in that period.

Judgement is involved in determining when to use an alternative reserves base in order to appropriately reflect the expected utilisation of the assets concerned (see "depreciation, depletion and amortisation").

Information about the carrying amounts of exploration and production assets and the amounts charged to income, including depreciation, depletion and amortisation and the quantitative impact of the use of an alternative reserves base, is presented in Note 8.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

2 – SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS AND ESTIMATES continued

Judgements and estimates continued

Impairment

For the purposes of determining whether impairment of assets has occurred, and the extent of any impairment loss or its reversal, the key assumptions management uses in estimating risk-adjusted future cash flows for value in use measures are future oil and gas prices and refining margins. In addition, management uses other assumptions such as potential costs associated with operational GHG emissions and expected production volumes appropriate to the local circumstances and environment. These assumptions and the judgements of management that are based on them are subject to change as new information becomes available. Changes in assumptions could affect the carrying amounts of assets, and any impairment losses and reversals will affect income. Changes in economic conditions can affect the rate used to discount future cash flow estimates or the risk-adjustment in the future cash flows.

Expected production volumes, which comprise proved reserves and unproved volumes, are used for impairment testing because management believes this to be the most appropriate indicator of expected future cash flows. As discussed in “Proved oil and gas reserves” above, reserves estimates are inherently imprecise. Furthermore, projections about unproved volumes are based on information that is necessarily less robust than that available for mature reservoirs.

Estimation is involved with respect to the expected life of refineries and chemicals sites, and also including management’s view on the future development of refining margins.

The determination of cash-generating units requires judgement. Changes in this determination could impact the calculation of value in use and therefore the conclusion on the recoverability of assets’ carrying amounts when performing an impairment test.

Judgement, which is subject to change as new information becomes available, can be required in determining when an asset is classified as held for sale. A change in that judgement could result in impairment charges affecting income, depending on whether classification requires a write-down of the asset to its fair value less costs to sell.

In assessing the value in use, the estimated risk adjusted future cash flows are discounted to their present value using a pre-tax discount rate that reflects Shell’s marginal cost of debt, current market assessments of the time value of money and residual risks (e.g. normal operational and other generic uncertainties). The discount rate applied does not reflect risks for which future cash flow estimates have been adjusted.

Significant estimates

Future commodity price assumptions used in the impairment testing in Integrated Gas and Upstream, presented in Note 8, tend to be stable because management does not consider short-term increases or decreases in prices as being indicative of long-term levels, but they are nonetheless subject to change.

Until 2019 management’s estimate of longer-term refining margins used in the impairment testing in Oil Products was based on the reversion to mean methodology, unless a fundamental shift in markets had been identified, over the life of the refineries. Under this approach, it was assumed that refining margins would revert to historical averages over time. As from 2020, a different price methodology applies, based on Shell management’s understanding and interpretation of demand and supply fundamentals in the near term and taking into account various other factors such as industry rationalisation and energy transition in the long term.

Future commodity prices and refining margins used in impairment testing provide a source of estimation uncertainty as referred to in paragraph 125 of IAS 1 *Presentation of Financial Statements* (IAS 1.125).

Information about the carrying amounts of assets and impairments and their sensitivity to changes in significant estimates are presented in Notes 7 and 8.

Leases (from January 1, 2019)

A contract, or part of a contract, that conveys the right to control the use of an identified asset for a period of time in exchange for payments to be made to the owners (lessors) is accounted for as a lease. Contracts are assessed to determine whether a contract is, or contains, a lease at the inception of a contract or when the terms and conditions of a contract are significantly changed. The lease term is the non-cancellable period of a lease, together with contractual options to extend or to terminate the lease early, where it is reasonably certain that an extension option will be exercised or a termination option will not be exercised.

At the commencement of a lease contract, a right-of-use asset and a corresponding lease liability are recognised, unless the lease term is 12 months or less. The commencement date of a lease is the date on which the underlying asset is made available for use. The lease liability is measured at an amount equal to the present value of the lease payments during the lease term that are not paid at that date. The lease liability includes contingent rentals and variable lease payments that depend on an index, rate, or where they are fixed payments in substance. The lease liability is remeasured when the contractual cash flows of variable lease payments change due to a change in an index or rate when the lease term changes following a reassessment.

Lease payments are discounted using the interest rate implicit in the lease. If that rate is not readily available, the incremental borrowing rate is applied. The incremental borrowing rate reflects the rate of interest that the lessee would have to pay to borrow over a similar term, with a similar security, the funds necessary to obtain an asset of a similar nature and value to the right-of-use asset in a similar economic environment.

In general, a corresponding right-of-use asset is recognised for an amount equal to each lease liability, adjusted by the amount of any pre-paid lease payment relating to the specific lease contract. The depreciation on right-of-use assets is recognised in income unless capitalised as exploration drilling cost (see “exploration cost”) or capitalised when the right-of-use asset is used to construct another asset.

Where Shell is the lessor in a lease arrangement at inception, the lease arrangement will be classified as a finance lease or an operating lease. Classification is based on the extent to which the risks and rewards incidental to ownership of the underlying asset lie with the lessor or the lessee.

Where Shell, usually in its capacity as operator, has entered into a lease contract on behalf of a joint arrangement, a lease liability is recognised to the extent that Shell has primary responsibility for the lease liability. A finance sub-lease is subsequently recognised if the related right-of-use asset is subleased to the joint arrangement. This is usually the case when the joint arrangement has the right to direct the use and obtains substantially all of the economic benefits from using the asset.

Impairment of the right-of-use asset

Right-of-use assets are subject to existing impairment requirements as set out in “property, plant and equipment” (see Note 8).

Judgements and estimates

A lease term includes optional lease periods where it is reasonably certain Shell will exercise the option to extend or not to exercise the option to terminate the lease. Determination of the lease term is subject to judgement and has an impact on the measurement of the lease liability and related right-of-use asset. When assessing the lease term at the commencement date, Shell takes into consideration the broader economics of the contract. Reassessment of the lease term is performed upon changes in circumstances that may affect the probability that an option to extend or to terminate the lease will be exercised.

Where the rate implicit in the lease is not readily available, an incremental borrowing rate is applied. This incremental borrowing rate reflects the rate of interest that the lessee would have to pay to borrow over a similar term, with a similar security, the funds necessary to obtain an asset of a similar nature and value to the right-of-use asset in a similar economic environment. Determination of the incremental borrowing rate requires estimation.

Leases (prior to January 1, 2019)

Agreements under which payments are made to owners in return for the right to use an asset for a period are accounted for as leases. Leases that transfer substantially all the risks and rewards of ownership are recognised at the commencement of the lease term as finance leases within property, plant and equipment and debt at the fair value of the leased asset or, if lower, at the present value of the minimum lease payments. Finance lease payments are apportioned between interest expense and repayments of debt. All other leases are classified as operating leases and the cost is recognised in income on a straight-line basis, except where capitalised as exploration drilling costs (see “exploration costs”).

Joint arrangements and associates

Arrangements under which Shell has contractually agreed to share control (see “Nature of the Consolidated Financial Statements” for the definition of control) with another party or parties are joint ventures where the parties have rights to the net assets of the arrangement, or joint operations where the parties have rights to the assets and obligations for the liabilities relating to the arrangement. Investments in entities over which Shell has the right to exercise significant influence but neither control nor joint control are classified as associates. Information about incorporated joint arrangements and associates at December 31, 2020, can be found in “Appendix I: Significant Subsidiaries and Other Related Undertakings”.

Investments in joint ventures and associates are accounted for using the equity method, under which the investment is initially recognised at cost and subsequently adjusted for the Shell share of post-acquisition income

less dividends received and the Shell share of other comprehensive income and other movements in equity, together with any loans of a long-term investment nature. Where necessary, adjustments are made to the financial statements of joint ventures and associates to bring the accounting policies used into line with those of Shell. In an exchange of assets and liabilities for an interest in a joint venture, the non-Shell share of any excess of the fair value of the assets and liabilities transferred over the pre-exchange carrying amounts is recognised in income. Unrealised gains on other transactions between Shell and its joint ventures and associates are eliminated to the extent of Shell’s interest in them; unrealised losses are treated similarly but may also result in an assessment of whether the asset transferred is impaired.

Shell recognises its assets and liabilities relating to its interests in joint operations, including its share of assets held jointly and liabilities incurred jointly with other partners.

Inventories

Inventories are stated at cost or net realisable value, whichever is lower. Cost comprises direct purchase costs (including transportation), and associated costs incurred in bringing inventories to their present condition and location, and is determined using the first-in, first-out (FIFO) method for oil, gas and chemicals and by the weighted average cost method for materials.

Taxation

The charge for current tax is calculated based on the income reported by the Company and its subsidiaries, as adjusted for items that are non-taxable or disallowed and using rates that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is determined, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the Consolidated Balance Sheet and on unused tax losses and credits carried forward.

Deferred tax assets and liabilities are calculated using the enacted or substantively enacted rates that are expected to apply when an asset is realised or a liability is settled. They are not recognised where they arise on the initial recognition of goodwill or of an asset or liability in a transaction (other than in a business combination) that, at the time of the transaction, affects neither accounting nor taxable profit, or in respect of taxable temporary differences associated with subsidiaries, joint ventures and associates where the reversal of the respective temporary difference can be controlled by Shell and it is probable that it will not reverse in the foreseeable future.

Deferred tax assets are recognised to the extent that it is probable that future taxable profits will be available against which the deductible temporary differences, unused tax losses and credits carried forward can be utilised.

Income tax receivables and payables as well as deferred tax assets and liabilities include provisions for uncertain income tax positions/treatments.

Income taxes are recognised in income except when they relate to items recognised in other comprehensive income, in which case the tax is recognised in other comprehensive income. Income tax assets and liabilities are presented separately in the Consolidated Balance Sheet except where there is a right of offset within fiscal jurisdictions and an intention to settle such balances on a net basis.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

2 – SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS AND ESTIMATES continued

Judgements and estimates

Tax liabilities are recognised when it is considered probable that there will be a future outflow of funds to a taxing authority. In such cases, provision is made for the amount that is expected to be settled, where this can be reasonably estimated. Provisions for uncertain income tax positions/treatments are measured at the most likely amount or the expected value, whichever method is more appropriate. Generally, uncertain tax treatments are assessed on an individual basis, except where they are expected to be settled collectively. It is assumed that taxing authorities will examine positions taken if they have the right to do so and that they have full knowledge of the relevant information. A change in estimate of the likelihood of a future outflow and/or in the expected amount to be settled would be recognised in income in the period in which the change occurs. This requires the application of judgement as to the ultimate outcome, which can change over time depending on facts and circumstances. Judgements mainly relate to transfer pricing, including inter-company financing, interpretation of PSCs, expenditure deductible for tax purposes and taxation arising on disposal.

Deferred tax assets are recognised only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those assets are likely to reverse, and a judgement as to whether or not there will be sufficient taxable profits available to offset the assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognised in respect of deferred tax assets as well as in the amounts recognised in income in the period in which the change occurs.

Taxation information, including charges and deferred tax assets and liabilities, is presented in Note 16. Income taxes include taxes at higher rates levied on income from certain Integrated Gas and Upstream activities.

Retirement benefits

Benefits in the form of retirement pensions and health care and life insurance are provided to certain employees and retirees under defined benefit and defined contribution plans.

Obligations under defined benefit plans are calculated annually by independent actuaries using the projected unit credit method, which takes into account employees' years of service and, for pensions, average or final pensionable remuneration, and are discounted to their present value using interest rates of high-quality corporate bonds denominated in the currency in which the benefits will be paid and of a duration consistent with the plan obligations. Where plans are funded, payments are made to independently managed trusts; assets held by those trusts are measured at fair value. Defined benefit plan surpluses are recognised as assets to the extent that they are considered recoverable, which is generally by way of a refund or lower future employer contributions.

The amounts recognised in income in respect of defined benefit plans mainly comprise service cost and net interest. Service cost comprises principally the increase in the present value of the obligation for benefits resulting from employee service during the period (current service cost) and also amounts relating to past service and settlements or amendments of plans. Plan amendments are changes to benefits and are generally recognised when all legal and regulatory approvals have been received and the effects have been communicated to members. Net interest is

calculated using the net defined benefit liability or asset matched against the discount rate yield curve at the beginning of each year for each plan. Remeasurements of the net defined benefit liability or asset resulting from actuarial gains and losses, and the return on plan assets excluding the amount recognised in income, are recognised in other comprehensive income.

For defined contribution plans, pension expense represents the amount of employer contributions payable for the period.

Significant judgements and estimates

Defined benefit obligations and plan assets, and the resulting liabilities and assets that are recognised, require significant estimation as these are subject to volatility as (actuarial) assumptions regarding future outcomes and market values change. Substantial judgement is required in determining the actuarial assumptions, which vary for the different plans to reflect local conditions but are determined under a common process in consultation with independent actuaries. The assumptions applied in respect of each plan are reviewed annually and adjusted where necessary to reflect changes in experience and actuarial recommendations.

Actuarial assumptions applied in determining defined benefit obligations provide a source of estimation uncertainty as referred to in IAS 1.125.

Information about the amounts reported in respect of defined benefit pension plans, assumptions applicable to the principal plans and their sensitivity to changes in significant estimates are presented in Note 17.

Provisions

Provisions are recognised at the balance sheet date at management's best estimate of the expenditure required to settle the present obligation. Non-current amounts are discounted at a rate intended to reflect the time value of money. The carrying amounts of provisions and the discount rate applied are regularly reviewed and adjusted for new facts or changes in law, technology or financial markets.

Provisions for decommissioning and restoration costs, which arise principally in connection with hydrocarbon production facilities, oil products manufacturing facilities and pipelines, are measured on the basis of current requirements, technology and price levels; the present value is calculated using amounts discounted over the useful economic life of the assets. The liability is recognised (together with a corresponding amount as part of the related property, plant and equipment) once a legal or constructive obligation arises to dismantle an item of property, plant and equipment and to restore the site on which it is located and when a reasonable estimate can be made. The effects of changes resulting from revisions to the timing or the amount of the original estimate of the provision are reflected on a prospective basis, generally by adjustment to the carrying amount of the related property, plant and equipment. However, where there is no related asset, or the change reduces the carrying amount to nil, the effect, or the amount in excess of the reduction in the related asset to nil, is recognised in income.

Shell reviews its refinery and chemical sites on a regular basis to determine whether any changes in assumptions, including expected life, trigger the need to recognise a provision for decommissioning and restoration.

Redundancy provisions are recognised when a detailed formal plan identifies the business or part of the business concerned, the location and number of employees affected, a detailed estimate of the associated cost and an appropriate timeline, and the employees affected have been notified of the plan's main features.

An onerous contract provision is recognised when the unavoidable cost of meeting the obligations under the contract exceed the economic benefits expected to be received under it. The unavoidable cost under a contract is the lower of the cost of fulfilling the contract and any compensation or penalties arising from failure to fulfil it. The cost of fulfilling a contract comprises the costs that relate directly to the contract. Before an onerous provision is recognised Shell first recognises any impairment loss that has occurred on assets dedicated to that contract.

Other provisions are recognised in income in the period in which an obligation arises and the amount can be reasonably estimated. Provisions are measured based on current legal requirements and existing technology where applicable. Recognition of any joint and several liability is based on management's best estimate of the final pro rata share of the liability. Provisions are determined independently of expected insurance recoveries. Recoveries are recognised when virtually certain of realisation.

Estimates

Estimates of provisions for future decommissioning and restoration costs are recognised and based on current legal and constructive requirements, technology and price levels. Because actual cash outflows can differ from estimates due to changes in laws, regulations, public expectations, technology, prices and conditions, and can take place many years in the future, the carrying amounts of provisions are regularly reviewed and adjusted to take account of such changes.

Significant estimate

The discount rate applied to reflect the time value of money in the carrying amount of provisions requires estimation. The discount rate applied is reviewed regularly and adjusted following changes in market rates.

The discount rate applied to determine the carrying amount of provisions provides a source of estimation uncertainty as referred to in IAS 1.125.

Information about decommissioning and restoration provisions and their sensitivity to changes in estimates are presented in Note 18.

Financial instruments

Financial assets and liabilities are presented separately in the Consolidated Balance Sheet except where there is a legally enforceable right of offset and Shell has the intention to settle on a net basis or realise the asset and settle the liability simultaneously.

Financial Assets

Financial assets are classified at initial recognition and subsequently measured at amortised cost, fair value through other comprehensive income or fair value through profit or loss. The classification of financial assets is determined by the contractual cash flows and where applicable the business model for managing the financial assets.

Debt instruments are measured at amortised cost, if the objective of the business model is to hold the financial asset in order to collect contractual cash flows and the contractual terms give rise to cash flows that are solely payments of principal and interest. It is initially recognised at fair value plus or minus transaction costs that are directly attributable to the acquisition or issue of the financial asset. Subsequently the financial asset is measured using the effective interest method less any impairment. Gains and losses are recognised in profit or loss when the asset is derecognised, modified or impaired.

All equity instruments and other debt instruments are recognised at fair value. For equity instruments, on initial recognition, an irrevocable election (on an instrument-by-instrument basis) can be made to designate these as at fair value through other comprehensive income instead of fair value through profit or loss. Dividends received on equity instruments are recognised as other income in profit or loss when the right of payment has been established, except when Shell benefits from such proceeds as a recovery of part of the cost of the financial asset, in which case, such gains are recorded in other comprehensive income.

Investments in securities

Investments in securities ("securities") comprise equity and debt securities. Equity securities are carried at fair value. Generally, unrealised holding gains and losses are recognised in other comprehensive income. On sale, net gains and losses previously accumulated in other comprehensive income are transferred to retained earnings. Debt securities are generally carried at fair value with unrealised holding gains and losses recognised in other comprehensive income. On sale, net gains and losses previously accumulated in other comprehensive income are recognised in income.

Impairment of financial assets

The expected credit loss model is applied for recognition and measurement of impairments in financial assets measured at amortised cost or at fair value through other comprehensive income. The expected credit loss model is also applied for financial guarantee contracts to which IFRS 9 applies and which are not accounted for at fair value through profit or loss. The loss allowance for the financial asset is measured at an amount equal to the 12-month expected credit losses. If the credit risk on the financial asset has increased significantly since initial recognition, the loss allowance for the financial asset is measured at an amount equal to the lifetime expected credit losses. Changes in loss allowances are recognised in profit or loss. For trade receivables, a simplified impairment approach is applied recognising expected lifetime losses from initial recognition.

Cash and cash equivalents

Cash and cash equivalents comprise cash at bank and in hand, including offsetting bank overdrafts, short-term bank deposits, money market funds, reverse repos and similar instruments that generally have a maturity of three months or less at the date of purchase.

Financial Liabilities

Financial liabilities are measured at amortised cost, unless they are required to be measured at fair value through profit or loss, such as instruments held for trading, or Shell has opted to measure them at fair value through profit or loss. Debt and trade payables are recognised initially at fair value based on amounts exchanged, net of transaction costs, and subsequently at amortised cost except for fixed rate debt subject to fair value hedging which is remeasured for the hedged risk (see below). Interest expense on debt is accounted for using the effective interest method, and other than interest capitalised, is recognised in income. For financial liabilities that are measured under the fair value option, the change in the fair value related to own credit risk is recognised in other comprehensive income. The remaining fair value change is recognised at fair value through profit or loss.

Derivative contracts and hedges

Derivative contracts are used in the management of interest rate risk, foreign exchange risk, commodity price risk, and foreign currency cash balances. Derivatives that are not closely related to the host contract in terms of economic characteristics and risks and the host contract of which is not a financial asset are separated from their host contract and recognised at fair value with the associated gains and losses recognised in income.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

2 – SIGNIFICANT ACCOUNTING POLICIES, JUDGEMENTS AND ESTIMATES continued

Contracts to buy or sell a non-financial item that can be settled net in cash are accounted for as financial instruments, with the exception of those contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with Shell's expected purchase, sale or usage requirements. Gains or losses arising from changes in the fair value of derivatives that are not designated as effective hedging instruments are recognised in income.

Certain derivative contracts qualify and are designated either: as a fair value hedge of the change in *fair value* of a recognised asset or liability or an unrecognised firm commitment; or as a *cash flow* hedge for the change in cash flows to be received or paid relating to a recognised asset or liability or a highly probable forecast transaction; or as a *net investment* hedge of the change in foreign exchange rates associated with net investments in foreign operations with a different functional currency than Shell's functional currency.

A change in the fair value of a hedging instrument designated as a fair value hedge is recognised in income, together with the consequential adjustment to the carrying amount of the hedged item. The effective portion of a change in fair value of a derivative contract designated as a cash flow hedge is recognised in other comprehensive income until the hedged transaction occurs; any ineffective portion is recognised in income. Where the hedged item is a non-financial asset or liability, the amount in accumulated other comprehensive income is transferred to the initial carrying amount of the asset or liability (reclassified to the balance sheet); a net investment hedge is accounted for similarly to a cash flow hedge. Gains or losses on the hedging instrument relating to the effective portion of the hedge are recognised in other comprehensive income while any gains or losses relating to the ineffective portion are recognised in the income statements. On disposal of the foreign operation, the cumulative value of any such gains or losses recorded in other comprehensive income is reclassified to the income statement.

The effective portion of a change due to retranslation at quarter-end exchange rates in the carrying amount of debt and the principal amount of derivative contracts used to hedge net investments in foreign operations is recognised in other comprehensive income until the related investment is sold or liquidated; any ineffective portion is recognised in income.

All relationships between hedging instruments and hedged items are documented, as well as risk management objectives and strategies for undertaking hedge transactions. The effectiveness of hedges is also continually assessed and hedge accounting is discontinued when there is a change in the risk management strategy.

Unless designated as hedging instruments, contracts to sell or purchase non-financial items that can be settled net as if the contracts were financial instruments and that do not meet expected own use requirements (typically, forward sale and purchase contracts for commodities in trading operations), and contracts that are or contain written options, are recognised at fair value; associated gains and losses are recognised in income.

Derivatives that are held primarily for the purpose of trading are presented as current in the Consolidated Balance Sheet.

Fair value measurements

Fair value measurements are estimates of the amounts for which assets or liabilities could be transferred at the measurement date, based on the assumption that such transfers take place between participants in principal markets and, where applicable, taking highest and best use into account.

Estimates

Where available, fair value measurements are derived from prices quoted in active markets for identical assets or liabilities. In the absence of such information, other observable inputs are used to estimate fair value. Inputs derived from external sources are corroborated or otherwise verified, as appropriate. In the absence of publicly available information, fair value is determined using estimation techniques that take into account market perspectives relevant to the asset or liability, in as far as they can reasonably be ascertained, based on predominantly unobservable inputs. For derivative contracts where publicly available information is not available, fair value estimations are generally determined using models and other valuation methods, the key inputs for which include future prices, volatility, price correlation, counterparty credit risk and market liquidity, as appropriate; for other assets and liabilities, fair value estimations are generally based on the net present value of expected future cash flows.

Share-based compensation plans

The fair value of share-based compensation expense arising from the Performance Share Plan (PSP) and the Long-term Incentive Plan (LTIP) – Shell's main equity-settled plans – is estimated using a Monte Carlo option pricing model and is recognised in income from the date of grant over the vesting period with a corresponding increase directly in equity. The model projects and averages the results for a range of potential outcomes for the vesting conditions, the principal assumptions for which are the share price volatility and dividend yields for Shell and four of its main competitors over the last three years and the last 10 years.

Shares held in trust

Shares in the Company, which are held by employee share ownership trusts and trust-like entities, are not included in assets but are reflected at cost as a deduction from equity as shares held in trust.

Acquisitions and sales of interests in a business

Assets acquired and liabilities assumed when control is obtained over a business, and when an interest or an additional interest is acquired in a joint operation which is a business, are recognised at their fair value at the date of the acquisition; the amount of the purchase consideration above this value is recognised as goodwill. When control is obtained, any non-controlling interest is recognised as the proportionate share of the identifiable net assets. The acquisition of a non-controlling interest in a subsidiary and the sale of an interest while retaining control are accounted for as transactions within equity. The difference between the purchase consideration or sale proceeds after tax and the relevant proportion of the non-controlling interest, measured by reference to the carrying amount of the interest's net assets at the date of acquisition or sale, is recognised in retained earnings as a movement in equity attributable to Royal Dutch Shell plc shareholders.

Environmental schemes and related environmental plans Emission trading schemes

Emission certificates acquired for compliance purposes are initially recognised at cost and classified under intangible assets. In the schemes where a cap is set for emissions, the associated emission certificates granted are recognised at cost, which may be zero. Emission certificates held for trading purposes are recognised at cost or net realisable value, whichever is lower, and classified under inventory. An emission liability is recognised under other liabilities when actual emissions occur that give rise to an obligation. To the extent the liability is covered by emission certificates held for compliance purposes, the liability is measured with reference to the value of these emission certificates held and for the

remaining uncovered portion at fair market value. The associated expense is presented under “production and manufacturing expenses”. Both the emission certificates and the emission liability are derecognised upon settling the liability with the respective regulator.

Biofuels certificates

Self-generated biofuel certificates are recognised at nil value, as they primarily offset the obligation. Biofuel certificates acquired that are held for compliance purposes are recognised at cost under intangible assets. A biofuel liability is recognised under other liabilities when the number of biofuel certificates available from own activities is less than required. To the extent covered by biofuel certificates held for compliance purposes, the liability is measured with reference to the value of these certificates held and for the remaining uncovered portion at market value. Biofuel certificates and the biofuel liability are both derecognised upon settling the liability with the respective regulator.

Renewable power schemes

Renewable power certificates acquired for compliance purposes are recognised at cost as an intangible asset. Self-generated renewable power certificates are generally transferred to the customer upon sales of electricity. A renewable power liability is recognised under other liabilities when electricity sales take place that give rise to an obligation to retire renewable power certificates. The associated cost is recognised in “Purchases” in the income statement. If the obligation relates to power consumed in business operations, it is presented in other liabilities with cost reflected in “Production and manufacturing expenses”. To the extent covered by renewable power certificates held for compliance purposes, the liability is measured with reference to the value of these renewable power certificates and for the remaining uncovered portion at market value. Renewable power certificates and the renewable power liability are derecognised upon settling the liability with the respective regulator.

Consolidated Statement of Income presentation

Purchases reflect all costs related to the acquisition of inventories and the effects of the changes therein, and include associated costs incurred in conversion into finished or intermediate products. Production and manufacturing expenses are the costs of operating, maintaining and managing production and manufacturing assets. Selling, distribution and administrative expenses include direct and indirect costs of marketing and selling products.

3 – CHANGES TO IFRS NOT YET ADOPTED

Inter-Bank Offered Rate (IBOR) Reform – Phase 2

Amendments to IFRS 9 *Financial Instruments* (IFRS 9), IFRS 7 *Financial Instruments: Disclosures* (IFRS 7) and IFRS 16 *Leases* (IFRS 16) were issued in August 2020 that complement those amendments issued in 2019 (IBOR Reform – Phase 1) and focus on the effects of IBOR reform on a company's financial statements that arise when, for example, an IBOR used to calculate interest on a financial asset is replaced with an alternative benchmark rate.

In Phase 2 the IASB amended requirements relating to: changes in the basis for determining contractual cash flows of financial assets, financial liabilities and lease liabilities; hedge accounting; and disclosures. These amendments apply only to changes required by the IBOR reform to financial instruments and hedging relationships.

The amendments are effective for periods beginning on or after January 1, 2021 and are to be applied retrospectively. Early application is permitted.

Shell's fixed-rate debt hedged to floating rate will be affected by the market-wide replacement of London Inter-Bank Offered Rate (LIBOR) by alternative risk-free reference rates, most significantly by reform of dollar LIBOR.

The majority of Shell's debt-related interest rate and currency swaps were designated in fair value hedge relationships at December 31, 2020.

The notional amount of hedging instruments designated in hedge relationships affected by the reform, at December 31, 2020, was \$23,010 million. Furthermore, Shell has one floating rate note of \$500 million tied to LIBOR, maturing in 2023, which will be affected.

A Group-wide project is in progress to manage the transition to alternative benchmark rates disclosures.

UK-adopted international accounting standards

On December 31, 2020 at 11pm BST, legislation made under the European Union (Withdrawal) Act 2018 brought into UK law IFRS adopted pursuant to Regulation (EC) No 1606/2002 as it applies in the European Union (EU) (previously referred to as “IFRS as adopted by the EU”) to provide continuity. These standards are referred to as UK-adopted international accounting standards.

For reporting periods beginning on or after January 1, 2021, Shell's filing of the Annual Report to the Registrar of Companies for England and Wales (“Companies House”) and other UK regulatory filings will be prepared in accordance with these UK-adopted international accounting standards.

The IFRS endorsement powers for the UK have been transferred from the European Commission to the Secretary of State for Business, Energy and Industrial Strategy (BEIS).

There are currently no material differences between the UK-adopted international accounting standards and IFRS adopted pursuant to Regulation (EC) No 1606/2002 as it applies in the EU. But if divergence occurs between the two accounting frameworks this may result in the need to report against both accounting frameworks to meet the UK and Dutch reporting requirements. However, if the EU determines that UK-adopted international accounting standards are equivalent to IFRS adopted pursuant to Regulation (EC) No 1606/2002 as it applies in the EU, any divergence between the two accounting frameworks would have no impact on Shell's future reporting. The EU has not yet accepted the UK-adopted international accounting standards at the time of publishing this Report.

It is expected that in the short term there will be no material differences between IFRS as issued by the IASB, UK-adopted international accounting standards and IFRS adopted pursuant to Regulation (EC) No 1606/2002 as it applies in the EU.

IFRS 17 Insurance contracts (IFRS 17)

IFRS 17 was issued in 2017, and is required to be adopted for annual reporting periods beginning on or after January 1, 2023. The IFRS 17 model combines a current balance sheet measurement of insurance contracts with recognition of profit over the period that services are provided. The general model in the standard requires insurance contract liabilities to be measured using probability-weighted current estimates of future cash flows, an adjustment for risk, and a contractual service margin representing the profit expected from fulfilling the contracts. Effects of changes in the estimates of future cash flows and the risk adjustment relating to future services are recognised over the period services are provided rather than immediately in profit or loss. Shell is in the process of evaluating the initial impact of this standard.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

4 – SEGMENT INFORMATION

General information

Shell is an international energy company engaged in the principal aspects of the oil and gas industry and reports its business through segments. With effect from 2020, Shell's reporting segments consist of Integrated Gas, Upstream, Oil Products, Chemicals and Corporate, reflecting the way Shell reviews and assesses its performance. The Oil Products and Chemicals businesses were previously reported under the Downstream segment. Oil sands mining activities, previously included in the Upstream segment, are reported under Oil Products. Comparative information has been reclassified.

The Integrated Gas segment manages liquefied natural gas (LNG) activities and the conversion of natural gas into gas-to-liquids (GTL) fuels and other products, as well as the New Energies portfolio. It includes natural gas and liquids exploration and extraction, and the operation of the upstream and midstream infrastructure necessary to deliver gas and liquids to market. It markets and trades natural gas, LNG, electricity and carbon-emission rights, and also markets and sells LNG as a fuel for heavy-duty vehicles and marine vessels.

The Upstream segment explores for and extracts crude oil, natural gas and natural gas liquids. It also markets and transports oil and gas, and operates the infrastructure necessary to deliver them to market.

The Oil Products segment comprises the Refining and Trading, and Marketing classes of business. The Refining and Trading class of business turns crude oil and other feedstocks into a range of oil products which are moved and marketed around the world for domestic, industrial and transport use. With effect from 2020, this class of business includes the oil sands mining activities which were previously reported under the

Upstream segment. The Marketing class of business includes the Retail, Lubricants, Business-to-Business (B2B), Pipelines and Biofuels businesses.

The Chemicals segment operates manufacturing plants and its own marketing network.

The Corporate segment covers the non-operating activities supporting Shell, comprising Shell's holdings and treasury organisation, its self-insurance activities and its headquarters and central functions.

Basis of Segmental Reporting

Sales between segments are based on prices generally equivalent to commercially available prices. Third-party revenue and non-current assets information by geographical area are based on the country of operation of the Group subsidiaries that report this information. Separate disclosure is provided for the UK as this is the Company's country of domicile.

Segment earnings are presented on a current cost of supplies basis (CCS earnings). On this basis, the purchase price of volumes sold during the period is based on the current cost of supplies during the same period after making allowance for the tax effect. CCS earnings therefore exclude the effect of changes in the oil price on inventory carrying amounts. CCS earnings attributable to RDS plc shareholders is the earnings measure used by the Chief Executive Officer for the purposes of making decisions about allocating resources and assessing performance.

Finance expense and income related to core financing activities, as well as related taxes, are included in the Corporate segment earnings rather than in the earnings of the business segments.

Information by segment on a current cost of supplies basis is as follows:

2020

	Integrated Gas	Upstream	Oil Products	Chemicals	Corporate	Total	\$ million
Revenue:							
Third-party	33,287	6,767	128,717	11,721	51	180,543	[A] [B]
Inter-segment	3,410	21,564	6,213	2,850	–	34,037	
Share of profit/(loss) of joint ventures and associates (CCS basis)	562	(7)	988	567	(268)	1,842	
Interest and other income, of which:	14	542	(93)	–	406	869	
Interest income	6	56	28	–	589	679	
Net gains on sale and revaluation of non-current assets and businesses	218	55	(9)	(2)	24	286	
Other	(210)	431	(112)	2	(207)	(96)	
Third-party and inter-segment purchases (CCS basis)	21,112	4,505	113,177	9,969	8	148,771	
Production and manufacturing expenses	5,723	10,521	5,942	1,787	28	24,001	
Selling, distribution and administrative expenses	729	(23)	7,360	1,339	476	9,881	
Research and development expenses	103	486	209	109	–	907	
Exploration expenses	611	1,136	–	–	–	1,747	
Depreciation, depletion and amortisation charge, of which:	17,704	23,119	10,473	1,116	32	52,444	
Impairment losses	12,221	8,697	6,531	5	9	27,463	[C]
Interest expense	76	374	56	3	3,580	4,089	
Taxation (credit)/charge (CCS basis)	(2,507)	(467)	(898)	7	(983)	(4,848)	
CCS earnings	(6,278)	(10,785)	(494)	808	(2,952)	(19,701)	

[A] Includes \$10,008 million of revenue from sources other than from contracts with customers, which mainly comprises the impact of fair value accounting of commodity derivatives. This amount includes both the reversal of prior gains of \$1,136 million related to sales contracts and prior losses of \$539 million related to purchase contracts that were previously recognised and where physical settlement has taken place during 2020.

[B] With effect from 2020, additional contracts are classified as held for trading purposes and consequently revenue is reported on a net rather than gross basis. The effect on revenue for the full year was a reduction of \$46,289 million.

[C] Impairment losses comprise Property, plant and equipment (\$26,676 million) and Intangible assets (\$787 million).

2019

	Integrated Gas	Upstream [A]	Oil Products [A]	Chemicals [A]	Corporate	\$ million Total
Revenue:						
Third-party	41,322	9,482	280,460	13,568	45	344,877 [B]
Inter-segment	4,280	35,735	7,819	3,917	–	51,751
Share of profit/(loss) of joint ventures and associates (CCS basis)	1,791	379	1,179	546	(307)	3,588
Interest and other income, of which:	263	2,180	273	(7)	916	3,625
Interest income	–	–	–	–	899	899
Net gains on sale and revaluation of non-current assets and businesses	282	1,888	305	(8)	52	2,519
Other	(19)	292	(32)	1	(35)	207
Third-party and inter-segment purchases (CCS basis)	23,498	6,982	262,004	13,039	(6)	305,517
Production and manufacturing expenses	5,768	11,102	7,536	1,995	37	26,438
Selling, distribution and administrative expenses	716	29	7,976	1,323	449	10,493
Research and development expenses	181	450	219	112	–	962
Exploration expenses	281	2,073	–	–	–	2,354
Depreciation, depletion and amortisation charge, of which:	6,238	16,881	4,461	1,074	47	28,701
Impairment losses	579	2,576	622	5	–	3,782 [C]
Impairment reversals	–	–	(190)	–	–	(190) [D]
Interest expense	104	526	77	5	3,978	4,690
Taxation charge/(credit) (CCS basis)	2,242	5,878	1,319	(2)	(578)	8,859
CCS earnings	8,628	3,855	6,139	478	(3,273)	15,827

[A] Revised to conform with reporting segment changes applicable from 2020.

[B] Includes \$3,760 million of revenue from sources other than from contracts with customers, which mainly comprises the impact of fair value accounting of commodity derivatives.

[C] Impairment losses comprise Property, plant and equipment (\$3,639 million) and Intangible assets (\$143 million).

[D] See Note 8.

2018

	Integrated Gas	Upstream [A]	Oil Products [A]	Chemicals [A]	Corporate	\$ million Total
Revenue:						
Third-party	43,764	9,459	316,409	18,704	43	388,379 [B]
Inter-segment	5,031	37,125	10,613	4,864	–	57,633
Share of profit/(loss) of joint ventures and associates (CCS basis)	2,273	285	1,101	684	(222)	4,121
Interest and other income, of which:	2,230	605	393	(53)	896	4,071
Interest income	–	–	–	–	772	772
Net gains on sale and revaluation of non-current assets and businesses	2,231	717	350	(53)	20	3,265
Other	(1)	(112)	43	–	104	34
Third-party and inter-segment purchases (CCS basis)	27,775	5,948	300,417	17,332	1	351,473
Production and manufacturing expenses	5,370	11,169	8,226	2,362	(157)	26,970
Selling, distribution and administrative expenses	458	29	9,183	1,130	560	11,360
Research and development expenses	186	493	205	102	–	986
Exploration expenses	208	1,132	–	–	–	1,340
Depreciation, depletion and amortisation charge, of which:	4,850	12,871	3,165	1,034	215	22,135
Impairment losses	200	1,065	346	78	7	1,696 [C]
Impairment reversals	–	(1,265)	–	–	–	(1,265) [D]
Interest expense	212	586	84	16	2,847	3,745
Taxation charge/(credit) (CCS basis)	2,795	8,756	1,211	339	(1,270)	11,831
CCS earnings	11,444	6,490	6,025	1,884	(1,479)	24,364

[A] Revised to conform with reporting segment changes applicable from 2020.

[B] Includes \$3,348 million of revenue from sources other than from contracts with customers, which mainly comprises the impact of fair value accounting of commodity derivatives.

[C] Impairment losses comprise Property, plant and equipment (\$1,515 million) and Intangible assets (\$181 million).

[D] See Note 8.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

4 – SEGMENT INFORMATION continued

Reconciliation of CCS earnings to income for the period

	\$ million		
	2020	2019	2018
(Loss)/income attributable to Royal Dutch Shell plc shareholders	(21,680)	15,842	23,352
Income attributable to non-controlling interest	146	590	554
(Loss)/income for the period	(21,534)	16,432	23,906
Current cost of supplies adjustment:			
Purchases	2,359	(784)	559
Taxation	(585)	194	(116)
Share of profit of joint ventures and associates	59	(15)	15
Current cost of supplies adjustment	1,833	(605)	458
Of which:			
Attributable to Royal Dutch Shell plc shareholders	1,759	(572)	481
Attributable to non-controlling interest	74	(33)	(23)
CCS earnings	(19,701)	15,827	24,364
Of which:			
CCS earnings attributable to Royal Dutch Shell plc shareholders	(19,921)	15,270	23,833
CCS earnings attributable to non-controlling interest	220	557	531

Information by geographical area is as follows:

2020

	\$ million				
	Europe	Asia, Oceania, Africa	USA	Other Americas	Total
Third-party revenue, by origin	50,138 [A]	65,139	50,856	14,410	180,543
Intangible assets, property, plant and equipment, joint ventures and associates at December 31	38,785 [B]	104,450	62,976	49,909	256,120

[A] Includes \$12,958 million that originated from the UK.

[B] Includes \$23,302 million located in the UK.

2019

	\$ million				
	Europe	Asia, Oceania, Africa	USA	Other Americas	Total
Third-party revenue, by origin	98,455 [A]	139,916	83,212	23,294	344,877
Intangible assets, property, plant and equipment, joint ventures and associates at December 31	43,262 [B]	119,732	67,105	54,544	284,643

[A] Includes \$41,094 million that originated from the UK.

[B] Includes \$24,696 million located in the UK.

2018

	\$ million				
	Europe	Asia, Oceania, Africa	USA	Other Americas	Total
Third-party revenue, by origin	118,960 [A]	153,716	89,876	25,827	388,379
Intangible assets, property, plant and equipment, joint ventures and associates at December 31	38,617 [B]	117,127	59,625	56,721	272,090

[A] Includes \$54,659 million that originated from the UK.

[B] Includes \$21,863 million located in the UK.

5 – INTEREST AND OTHER INCOME

	2020	2019	\$ million 2018
Interest income	679	899	772
Dividend income (from investments in equity securities)	22	23	104
Net gains on sale and revaluation of non-current assets and businesses	286	2,519	3,265
Net foreign exchange (losses)/gains on financing activities	(391)	5	(174)
Other	273	179	104
Total	869	3,625	4,071

In 2020, 'Other' income mainly related to amounts recognised in respect of sublease income from partners in joint operations.

In 2019, net gains on sale of non-current assets and businesses arose mainly in respect of gains on the sale of Integrated Gas assets in Australia, Upstream assets in the USA and Denmark, as well as Oil Products assets in Saudi Arabia and China.

In 2018, net gains on sale of non-current assets and businesses arose mainly in respect of gains on the sale of Integrated Gas assets in Thailand, Malaysia, Oman and New Zealand, as well as Upstream assets in Iraq and Malaysia and an Oil Products divestment in Argentina, partly offset by a charge related to the disposal of our Upstream assets in Ireland.

6 – INTEREST EXPENSE

	2020	2019	\$ million 2018
Interest incurred and similar charges	4,359 [A]	4,592 [A]	3,550
Less: interest capitalised	(799)	(752)	(876)
Other net losses on fair value and cash flow hedges of debt	32	132	169
Accretion expense	497	718	902
Total	4,089	4,690	3,745

[A] Includes \$2,185 million (2019: \$2,186 million) of interest expense related to leases, of which \$1,031 million (2019: \$1,137 million) related to those leases which before January 1, 2019 were classified as operating leases.

The rate applied in determining the amount of interest capitalised in 2020 was 4.5% (2019: 4.5%; 2018: 4.0%).

7 – INTANGIBLE ASSETS

2020

	Goodwill	LNG off-take and sales contracts	Software	Other	\$ million Total
Cost					
At January 1	14,973	10,211	2,958	3,908	32,050
Additions	247	–	133	1,448	1,828
Sales, retirements and other movements	(64)	(181)	(77)	(637)	(959)
Currency translation differences	57	–	100	94	251
At December 31	15,213	10,030	3,114	4,813	33,170
Depreciation, depletion and amortisation, including impairments					
At January 1	768	4,014	2,524	1,258	8,564
Charge for the year [A]	276	835	156	695	1,962
Sales, retirements and other movements	–	(181)	(129)	9	(301)
Currency translation differences	18	–	76	29	123
At December 31	1,062	4,668	2,627	1,991	10,348
Carrying amount at December 31	14,151	5,362	487	2,822 [B]	22,822

[A] Includes \$787 million related to impairments, of which \$472 million in 'Other' related to Integrated Gas. (See Note 8)

[B] Includes \$1,013 million related to emission certificates held for compliance purposes. (See Note 29)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

7 – INTANGIBLE ASSETS continued

2019

\$ million

	Goodwill	LNG off-take and sales contracts	Software	Other	Total
Cost					
At January 1	14,338	10,365	2,910	3,482	31,095
Additions	674	—	137	449	1,260
Sales, retirements and other movements	(46)	(154)	(100)	(22)	(322)
Currency translation differences	7	—	11	(1)	17
At December 31	14,973	10,211	2,958	3,908	32,050
Depreciation, depletion and amortisation, including impairments					
At January 1	622	3,293	2,425	1,169	7,509
Charge for the year [A]	135	876	176	178	1,365
Sales, retirements and other movements	(1)	(155)	(87)	(85)	(328)
Currency translation differences	12	—	10	(4)	18
At December 31	768	4,014	2,524	1,258	8,564
Carrying amount at December 31	14,205	6,197	434	2,650	23,486

[A] Includes \$143 million related to impairments.

Goodwill at December 31, 2020, principally related to the acquisition of BG Group plc in 2016, allocated to Integrated Gas (\$4,800 million) and Upstream (\$5,946 million) at the operating segment level, and to Pennzoil-Quaker State Company (\$1,609 million), a lubricants business in the Oil Products segment based largely in North America.

8 – PROPERTY, PLANT AND EQUIPMENT

2020

\$ million

	Exploration and production		Manufacturing, supply and distribution	Other	Total
	Exploration and evaluation	Production			
Cost					
At January 1	18,596	286,666	104,817	29,081	439,160
Additions	1,728	9,659	6,287	3,460	21,134
Sales, retirements and other movements	(5,928)	600	(5,510)	(1,109)	(11,947)
Currency translation differences	92	3,632	2,282	970	6,976
At December 31	14,488	300,557	107,876	32,402	455,323
Depreciation, depletion and amortisation, including impairments					
At January 1	4,010	136,300	48,872	11,629	200,811
Charge for the year [A]	3,336	34,209	11,680	1,693	50,918
Sales, retirements and other movements	(2,148)	(5,075)	(4,129)	(1,091)	(12,443)
Currency translation differences	64	2,805	1,819	502	5,190
At December 31	5,262	168,239	58,242	12,733	244,476
Carrying amount at December 31	9,226	132,318	49,634	19,669	210,847

[A] Includes \$26,676 million relating to impairment losses (see table 'Impairments' below).

2019

\$ million

	Exploration and production		Manufacturing, supply and distribution	Other	Total
	Exploration and evaluation	Production			
Cost					
At January 1	21,181	285,252	97,694	26,268	430,395
Additions	2,659	11,374	10,945	3,145	28,123
Sales, retirements and other movements	(5,442)	(11,253)	(3,683)	(456)	(20,834)
Currency translation differences	198	1,293	(139)	124	1,476
At December 31	18,596	286,666	104,817	29,081	439,160
Depreciation, depletion and amortisation, including impairments					
At January 1	3,287	131,692	46,218	10,465	191,662
Charge for the year	1,096	19,346	5,742	1,573	27,757
Sales, retirements and other movements	(440)	(15,567)	(2,981)	(437)	(19,425)
Currency translation differences	67	829	(107)	28	817
At December 31	4,010	136,300	48,872	11,629	200,811
Carrying amount at December 31	14,586	150,366	55,945	17,452	238,349

Sales, retirements and other movements in 2020 includes to sales of the Appalachia shale gas position and the Martinez refinery, both in the USA.

The carrying amount of property, plant and equipment at December 31, 2020, included \$31,611 million (2019: \$27,779 million) of assets under construction. This amount excludes exploration and evaluation assets. The carrying amount at December 31, 2020, included \$1,159 million of assets classified as held for sale (2019: \$1,401 million).

The carrying amount of exploration and production assets at December 31, 2020, included rights and concessions in respect of proved and unproved properties of \$11,485 million (2019: \$14,355 million). Exploration and evaluation assets principally comprise rights and concessions in respect of unproved properties and capitalised exploration drilling costs.

The carrying amount of assets at December 31, 2020, for which an alternative reserves base was applied in the calculation of the depreciation charge (see Note 2), was \$1,707 million (2019: \$173 million). If no alternative reserves base had been used, the pre-tax depreciation charge for the year ended December 31, 2020, would have been \$1,012 million higher (2019: \$77 million, 2018: \$1,003 million).

Contractual commitments for the purchase and lease of property, plant and equipment at December 31, 2020, amounted to \$5,699 million (2019: \$4,599 million (as revised)).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

8 – PROPERTY, PLANT AND EQUIPMENT continued

Right-of-use assets

Within property, plant and equipment the following amounts relate to leases:

2020

	Exploration and production		Manufacturing, supply and distribution	Other	Total
	Exploration and evaluation	Production			
\$ million					
Cost					
At January 1	5	15,213	13,574	5,759	34,551
Additions	–	502	1,570	1,580	3,652
Sales, retirements and other movements	–	(1,370)	(675)	(75)	(2,120)
Currency translation differences	–	95	57	120	272
At December 31	5	14,440	14,526	7,384	36,355
Depreciation, depletion and amortisation, including impairments					
At January 1	–	5,761	2,936	1,164	9,861
Charge for the year	–	1,898	2,675	760	5,333
Sales, retirements and other movements	–	(712)	(627)	(158)	(1,497)
Currency translation differences	–	50	29	27	106
At December 31	–	6,997	5,013	1,793	13,803
Carrying amount at December 31	5	7,443	9,513	5,591	22,552

2019

	Exploration and production		Manufacturing, supply and distribution	Other	Total
	Exploration and evaluation	Production			
\$ million					
Cost					
At January 1	–	16,379	10,718	5,017	32,114
Additions	5	664	3,124	917	4,710
Sales, retirements and other movements	–	(1,867)	(268)	(157)	(2,292)
Currency translation differences	–	37	–	(18)	19
At December 31	5	15,213	13,574	5,759	34,551
Depreciation, depletion and amortisation, including impairments					
At January 1	–	5,209	1,110	589	6,908
Charge for the year	–	1,632	1,855	703	4,190
Sales, retirements and other movements	–	(1,091)	(30)	(128)	(1,249)
Currency translation differences	–	11	1	–	12
At December 31	–	5,761	2,936	1,164	9,861
Carrying amount at December 31	5	9,452	10,638	4,595	24,690

Impairments

	2020	2019	Total
\$ million			
Impairment losses [A]			
Exploration and production	20,155	2,983	1,066
Manufacturing, supply and distribution	6,490	654	441
Other	31	2	8
Total	26,676	3,639	1,515
Impairment reversals [A]			
Exploration and production	–	–	1,265
Manufacturing, supply and distribution	–	190	–
Total	–	190	1,265

[A] See Note 4.

Impairment losses in 2020 were mainly triggered by Shell's revision of the mid- and long-term commodity price and refining margin outlook reflecting the expected effects of the macroeconomic environment and the COVID-19 pandemic as well as energy market demand and supply fundamentals. The impairment losses for exploration and production assets related primarily to Integrated Gas (\$11,539 million), including the Queensland Curtis LNG and Prelude floating LNG operations, and Upstream (\$8,629 million), including assets in the Gulf of Mexico, unconventional assets in North America, offshore assets in Brazil and Europe and a project in Nigeria (OPL 245). The impairment losses for manufacturing, supply and distribution related primarily to Oil Products (\$6,493 million), including assets in Europe and the shutdown of the Convent refinery in the USA.

Impairment losses in 2019 were mainly triggered by the revision to Shell's long-term oil and gas price outlook and change to future capital expenditure plans. The impairment losses related primarily to Upstream shale and deep-water properties in North and South America, in Integrated Gas to properties in Australia and in Oil Products to the refining portfolio. Impairment losses in 2018 were mainly in Upstream, and principally related to the disposal of Shell's interests in Norway and Ireland and related to assets in the Gulf of Mexico. Impairment reversals in 2018 were mainly related to assets in North America.

For impairment testing purposes, the respective carrying amounts of property, plant and equipment and intangible assets were compared with their value in use. Cash flow projections used in the determination of value in use were made using management's forecasts of commodity prices, market supply and demand, potential costs associated with operational GHG emissions, product margins including forecast refining margins and expected production volumes (see Note 2). These cash flows were adjusted for the risks specific to the assets, and therefore these risks were not included in the determination of the discount rate applied. The nominal pre-tax rate applied in 2020 was 6% (2019: 6%; 2018: 6%).

Oil and gas price assumptions applied for impairment testing are reviewed and, where necessary, adjusted on a periodic basis. Reviews include comparison with available market data and forecasts that reflect developments in demand such as global economic growth, technology efficiency, policy measures and, in supply, consideration of investment and resource potential, cost of development of new supply, and behaviour of major resource holders. The near-term commodity price assumptions applied in impairment testing in 2020 were as follows:

Commodity price assumptions [A]

	2021	2022	2023	2024
Brent crude oil (\$/b)	40	50	60	63
Henry Hub natural gas (\$/MMBtu)	2.50	2.50	2.75	3.03

[A] Money of the day.

For periods after 2024, the real-terms long-term price assumptions applied were \$60 per barrel (/b) (2019: \$60/b) for Brent crude oil and \$3.00 per million British thermal units (/MMBtu) (2019: \$3.00/MMBtu) for Henry Hub natural gas, both at real-terms 2020.

Until 2019 management's estimate of longer-term refining margins in Oil Products was based on the reversion to mean methodology, unless a fundamental shift in markets had been identified, over the life of the refineries. Under this approach, it was assumed that refining margins will revert to historical averages over time. As from 2020, a different price methodology has been applied, based on management's understanding and interpretation of demand and supply fundamentals in the near term and taking into account various other factors such as industry rationalisation and energy transition in the long term. This resulted in a downward revision of average long-term refining margins by around 30% from previous assumptions applied.

Some 53% of the Group's combined "Property, plant and equipment", "Investments in Joint Ventures and Associates" and "Intangible assets" were tested for impairment in 2020. Of the assets tested, some 56% were subject to either partial or full impairments. At December 31, 2020, the recoverable amounts principally determined through value in use of assets subject to impairment were \$17.2 billion for Integrated Gas, \$39.1 billion for Upstream and \$1.8 billion for Oil Products respectively.

The main sensitivities in relation to impairment are the commodity price assumptions in Integrated Gas and Upstream and refining margins in Oil Products. A change of -10% or +10% of the commodity price assumptions would ceteris paribus result in some \$6.0-\$8.0 billion impairment or of some \$6.0-\$9.0 billion impairment reversal respectively in Integrated Gas and Upstream. A change of -10% or +10% in long-term refining margins would ceteris paribus result in some \$1.5-\$2.5 billion impairment or some \$1.7-\$2.7 billion impairment reversal respectively in Oil Products.

Capitalised exploration drilling costs

	\$ million		
	2020	2019	2018
At January 1	5,668	6,629	6,981
Additions pending determination of proved reserves	1,016	2,036	2,588
Amounts charged to expense	(815)	(1,218)	(449)
Reclassifications to productive wells on determination of proved reserves	(1,385)	(1,655)	(2,461)
Other movements [A]	(830)	(124)	(30)
At December 31	3,654	5,668	6,629

[A] Includes \$750 million impairment of capitalised exploration drilling costs.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued**8 – PROPERTY, PLANT AND EQUIPMENT** continued

	Projects		Wells	
	Number	\$ million	Number	\$ million
Between 1 and 5 years	33	1,666	80	1,275
Between 6 and 10 years	12	975	47	1,309
Between 11 and 15 years	7	213	21	217
Between 16 and 20 years	–	–	3	53
Total	52	2,854	151	2,854

Exploration drilling costs capitalised for periods greater than one year at December 31, 2020, analysed according to the most recent year of activity, are presented in the table above. These comprise \$82 million relating to two projects where drilling activities were under way or firmly planned for the future, and \$2,772 million relating to 50 projects awaiting development concepts.

9 – JOINT VENTURES AND ASSOCIATES**Shell share of comprehensive income of joint ventures and associates**

	2020			2019			\$ million 2018		
	Joint ventures	Associates	Total	Joint ventures	Associates	Total	Joint ventures	Associates	Total
Income for the period	629 [A]	1,154	1,783	1,121	2,483	3,604	1,307	2,799	4,106
Other comprehensive income/(loss) for the period	76	1	77	(82)	8	(74)	172	11	183
Comprehensive income for the period	705	1,155	1,860	1,039	2,491	3,530	1,479	2,810	4,289

[A] Includes \$599 million impairment losses recognised in share of profit of joint ventures and associates.

Carrying amount of interests in joint ventures and associates

	Dec 31, 2020			\$ million Dec 31, 2019		
	Joint ventures	Associates	Total	Joint ventures	Associates	Total
Net assets	14,406	8,045	22,451	13,426	9,382	22,808

Transactions with joint ventures and associates

	\$ million		
	2020	2019	2018
Sales and charges to joint ventures and associates	5,426	7,748	8,270
Purchases and charges from joint ventures and associates	8,262	11,581 [A]	13,758 [A]

[A] As revised, following the reassessment of contractual relationships, by \$2,008 million (2019) and \$2,546 million (2018).

These transactions principally comprise sales and purchases of goods and services in the ordinary course of business. Related balances outstanding at December 31, 2020, and 2019, are presented in Notes 11 and 15.

Other arrangements in respect of joint ventures and associates

	\$ million	
	Dec 31, 2020	Dec 31, 2019
Commitments to make purchases from joint ventures and associates [A]	1,674	2,177
Commitments to provide debt or equity funding to joint ventures and associates	900	897

[A] Commitments to make purchases from joint ventures and associates mainly relate to contracts associated with LNG processing fees and transportation capacity. Shell has other purchase obligations related to joint ventures and associates that are not fixed or determinable and are principally intended to be resold in a short period of time through sales agreements with third parties. These include long-term LNG and natural gas purchase commitments and commitments to purchase refined products or crude oil at market prices.

10 – INVESTMENTS IN SECURITIES

Investments in securities

	\$ million	
	Dec 31, 2020	Dec 31, 2019
Equity securities:	1,396	1,437
Equity securities at fair value through other comprehensive income	1,396	1,437
Debt securities:	1,826	1,552
Debt securities at amortised cost	12	11
Debt securities at fair value through other comprehensive income	1,165	1,086
Debt securities at fair value through profit or loss	649	455
Total	3,222	2,989
At fair value		
Measured by reference to prices in active markets for identical assets	1,637	1,669
Measured by reference to other observable inputs	68	56
Measured using predominantly unobservable inputs	1,505	1,253
Total	3,210	2,978
At cost	12	11
Total	3,222	2,989

Equity securities at December 31, 2020, principally comprised interests below 5% in various investments. Debt securities principally comprised a portfolio required to be held by the Company's internal insurance entities as security for their activities.

Investments in securities measured using predominantly unobservable inputs [A]

	\$ million	
	2020	2019
At January 1	1,253	1,193
Gains/(losses) recognised in other comprehensive income	45	(42)
Purchases	329	340
Sales	(60)	(237)
Other movements	(62)	(1)
At December 31	1,505	1,253

[A] Based on expected dividend flows, adjusted for country and other risks as appropriate and discounted to their present value.

11 – TRADE AND OTHER RECEIVABLES

	Dec 31, 2020		Dec 31, 2019	
	Current	Non-current	Current	Non-current
Trade receivables	21,781	–	30,216	–
Lease receivables	186	1,380	213	1,528
Other receivables	7,251	4,109	7,791	4,039
Amounts due from joint ventures and associates	726	829	912	1,078
Prepayments and deferred charges	3,681	1,323	4,282	1,440
Total	33,625	7,641	43,414	8,085

The fair value of financial assets included above approximates the carrying amount and was determined from predominantly unobservable inputs.

Other receivables at December 31, 2020, include receivables from certain governments in their capacity as joint arrangement partners of \$1,357 million (2019: \$1,209 million), after provisions for impairments, that are overdue in part or in full. Recoverability and timing thereof are subject to uncertainty, however, the ultimate risk of default on the carrying amount is considered to be low. Other receivables also include income tax and other tax receivables (see Note 16).

Provisions for impairments deducted from trade and other receivables amounted to \$968 million at December 31, 2020 (2019: \$649 million).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued**11 – TRADE AND OTHER RECEIVABLES** continued**Allowance for expected credit losses – trade receivables**

Shell uses a provision matrix to calculate expected credit losses (ECLs) for trade receivables. The provision matrix is initially based on Shell's historical observed default rates. Shell calculates the ECL to adjust the historical credit loss experienced with forward-looking information. The ECL at December 31, 2020 is \$112 million (2019: \$83 million), which represents 0.27%-0.51% (2019: 0.08%-0.27%) of all trade receivables. The increase compared with prior year is mainly due to changes in the macroeconomic environment and the COVID-19 pandemic.

A loss allowance provision of \$349 million (2019: \$193 million) was established, in addition to all other impairments to trade receivables as at December 31, 2020, that are outside of the provision matrix calculations.

Lease receivables

Lease contracts where Shell is the lessor are classified as finance leases or operating leases. Receivables for lease contracts classified as finance leases are as follows:

	\$ million	
	Dec 31, 2020	Dec 31, 2019
Less than one year	262	305
Between 1 and 5 years	859	953
5 years and later	852	1,019
Total undiscounted lease payments receivable	1,973	2,277
Unearned finance income	407	536
Net investment in leases	1,566	1,741

In addition at December 31, 2020, Shell is entitled to contractual payments under operating leases of \$248 million (2019: \$344 million).

12 – INVENTORIES

	\$ million	
	Dec 31, 2020	Dec 31, 2019
Oil, gas and chemicals	16,949	21,653 [A]
Other including materials	2,508	2,418 [A]
Total	19,457	24,071

[A] As revised, following the reclassification of non-physical trading inventories of \$1,001 million from 'Oil, gas and chemicals' to 'Other including materials'.

Inventories at December 31, 2020, include write-downs to net realisable value of \$239 million (2019: \$546 million).

13 – CASH AND CASH EQUIVALENTS

	\$ million	
	Dec 31, 2020	Dec 31, 2019
Cash	4,831	4,168
Short-term bank deposits	2,220	2,665
Money market funds, reverse repos and other cash equivalents	24,779	11,222
Total	31,830	18,055

Included in cash and cash equivalents at December 31, 2020, were amounts totalling \$65 million (2019: \$431 million) subject to currency controls or other legal restrictions. Money market funds and reverse repos used in cash management provided higher yields compared with other cash equivalents available in 2020. Information about credit risk is presented in Note 19.

14 – DEBT AND LEASE ARRANGEMENTS

Debt

	Dec 31, 2020			\$ million Dec 31, 2019		
	Debt (excluding lease liabilities)	Lease liabilities	Total	Debt (excluding lease liabilities)	Lease liabilities	Total
Short-term debt	7,535	—	7,535	3,962	—	3,962
Long-term debt due within 1 year	5,221	4,143	9,364	6,146	4,956	11,102
Current debt	12,756	4,143	16,899	10,108	4,956	15,064
Non-current debt	66,838	24,277	91,115	55,779	25,581	81,360
Total	79,594	28,420	108,014	65,887	30,537	96,424

Net debt

	\$ million Asset/(liability)				
	Current debt	Non-current debt	Derivative financial instruments	Cash and cash equivalents (see Note 13)	Net debt
At January 1, 2020	(15,064)	(81,360)	(724)	18,055	(79,093)
Cash flow	7,536	(13,121)	(1,157)	13,603	6,861
Lease additions	(870)	(2,268)			(3,138)
Other movements	(8,380)	8,354	524	—	498
Currency translation differences and foreign exchange gains/(losses)	(121)	(2,720)	2,155	172	(514)
At December 31, 2020	(16,899)	(91,115)	798	31,830	(75,386)
At January 1, 2019	(13,046)	(79,815)	(1,345)	26,741	(67,465)
Cash flow	10,333	(7,269)	351	(8,810)	(5,395)
Lease additions	(971)	(3,547)			(4,518)
Other movements	(11,453)	9,179	453	—	(1,821)
Currency translation differences and foreign exchange gains/(losses)	73	92	(183)	124	106
At December 31, 2019	(15,064)	(81,360)	(724)	18,055	(79,093)

Management's priorities for applying Shell's cash are first the reduction of net debt to \$65 billion and, on achieving this milestone, distribution of a total of 20%–30% of cash flow from operations to shareholders. Remaining cash will be allocated to disciplined and measured capital expenditure growth and further debt reduction.

Gearing

	\$ million, except where indicated	
	Dec 31, 2020	Dec 31, 2019
Net debt	75,386	79,093
Total equity	158,537	190,463
Total capital	233,923	269,556
Gearing	32.2%	29.3%

Gearing is a measure of Shell's capital structure and is defined as net debt (total debt less cash and cash equivalents) as a percentage of total capital (net debt plus total equity).

Shell has access to international debt capital markets via two commercial paper (CP) programmes, a Euro medium-term note (EMTN) programme and a US universal shelf (US shelf) registration. Issuances under the CP programmes are supported by a committed credit facility and cash.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued**14 – DEBT AND LEASE ARRANGEMENTS** continued**Borrowing facilities and amounts undrawn**

	Facility		Amount undrawn	
	Dec 31, 2020	Dec 31, 2019	Dec 31, 2020	Dec 31, 2019
CP programmes	20,000	20,000	13,254	16,610
EMTN programme	unlimited	unlimited	N/A	N/A
US shelf registration	–	unlimited	N/A	N/A
Committed credit facilities	22,651	10,000	22,651	10,000

Under the CP programmes, Shell can issue debt of up to \$10 billion with maturities not exceeding 270 days and \$10 billion with maturities not exceeding 397 days.

The EMTN programme is updated each year, most recently in August 2020. In 2020, debt issued under this programme amounted to \$6,734 million (2019: \$3,322 million).

The US shelf registration provides Shell with the flexibility to issue debt securities, ordinary shares, preferred shares and warrants. The registration is updated every three years. The US shelf registration expired in December 2020. Concurrent with the filing of our Annual Report on Form 20-F with the Securities and Exchange Commission (SEC) on March 11, 2021, a new US shelf registration statement will be filed with the SEC and be effective upon filing. During 2020, debt totalling \$6,250 million (2019: \$4,000 million) was issued under the registration.

On December 13, 2019, Shell entered into \$10 billion revolving credit facilities, which in anticipation of the LIBOR reform (see Notes 2 and 3), were linked to the new Secured Overnight Financing Rate (SOFR). Under the terms of the facilities, the LIBOR interest rate was replaced by SOFR on the first anniversary of the signing date of these revolving credit facilities. The committed credit facilities are available at pre-agreed margins, with \$2 billion expiring in 2021 and \$8 billion expiring in 2025. Each facility includes a remaining one-year extension option at the discretion of each lender. The terms and availability are not conditional on Shell's financial ratios nor its financial credit ratings. The interest and fees paid on both facilities are linked to Shell's progress towards reaching its short-term Net Carbon Footprint intensity target. In April 2020, Shell entered into a dual currency \$7,200 million and €4,432 million revolving credit facility expiring in April 2021, with two 6 month extension options at the discretion of Shell. The extension options have not been exercised, and the facility will expire in April 2021.

In addition, other subsidiaries have access to undrawn short-term bank facilities totalling \$3,115 million at December 31, 2020 (2019: \$2,784 million).

The following tables compare contractual cash flows for debt excluding lease liabilities at December 31 with the carrying amount in the Consolidated Balance Sheet. Contractual amounts reflect the effects of changes in foreign exchange rates; differences from carrying amounts reflect the effects of discounting, premiums and, where fair value hedge accounting is applied, fair value adjustments. Interest is estimated assuming interest rates applicable to variable rate debt remain constant and there is no change in aggregate principal amounts of debt other than repayment at scheduled maturity, as reflected in the table.

2020

	Contractual payments							Difference from carrying amount	Carrying amount
	Less than 1 year	Between 1 and 2 years	Between 2 and 3 years	Between 3 and 4 years	Between 4 and 5 years	5 years and later	Total		
Commercial paper	6,746	–	–	–	–	–	6,746	(15)	6,731
Bonds	5,080	4,720	5,408	4,633	8,043	41,853	69,737	1,308	71,045
Bank and other borrowings	944	162	33	215	47	417	1,818	–	1,818
Total (excluding interest)	12,770	4,882	5,441	4,848	8,090	42,270	78,301	1,293	79,594
Interest	1,834	1,707	1,630	1,527	1,412	15,985	24,095		

2019

	Contractual payments								\$ million
	Less than 1 year	Between 1 and 2 years	Between 2 and 3 years	Between 3 and 4 years	Between 4 and 5 years	5 years and later	Total	Difference from carrying amount	Carrying amount
Commercial paper	3,390	—	—	—	—	—	3,390	(38)	3,352
Bonds	5,900	4,971	4,392	4,326	2,091	38,323	60,003	694	60,697
Bank and other borrowings	859	425	56	71	15	412	1,838	—	1,838
Total (excluding interest)	10,149	5,396	4,448	4,397	2,106	38,735	65,231	656	65,887
Interest	1,665	1,559	1,430	1,357	1,263	14,618	21,892		

Interest rate swaps have been entered into against certain fixed rate debt affecting the effective interest rate on these balances (see Note 19). The fair value of debt excluding lease liabilities at December 31, 2020, was \$88,294 million (2019: \$71,163 million), mainly determined from the prices quoted for those securities.

Lease arrangements

Lease liabilities are secured on the leased assets. Shell has lease contracts in Integrated Gas and Upstream, principally for floating production storage and offloading units, subsea equipment, power generation, for drilling and ancillary equipment, service vessels, LNG vessels and land and buildings; in Oil Products, principally for tankers, storage capacity and retail sites; in Chemicals, principally for plant pipeline and machinery and in Corporate, principally for land and buildings.

Lease expenses not included in the measurement of lease liability

	2020	2019
Expense relating to short-term leases	1,156	834
Expense relating to variable lease payments not included in the lease liabilities	1,209	1,091

The total cash outflow in respect of leases representing repayment of principal and payment of interest in 2020 was \$6,891 million (2019: \$7,866 million), recognised in the Consolidated Statement of Cash Flows from financing activities.

The future lease payments under lease contracts and the carrying amounts at December 31, by payment date are as follows:

2020

	Contractual lease payments	Interest	Lease liabilities
Less than 1 year	6,059	1,916	4,143
Between 1 and 5 years	16,681	5,617	11,064
5 years and later	19,999	6,786	13,213
Total	42,739 [A]	14,319	28,420

[A] Future cash outflows in respect of leases may differ from lease liabilities recognised due to future decisions that may be taken by Shell in respect of the use of leased assets. These decisions may result in variable lease payments being made. In addition, Shell may reconsider whether it will exercise extension options or termination options, where future reconsideration is not reflected in the lease liabilities. There is no exposure to these potential additional payments in excess of the recognised lease liabilities until these decisions have been taken by Shell.

2019

	Contractual lease payments	Interest	Lease liabilities
Less than 1 year	7,337	2,381	4,956
Between 1 and 5 years	17,435	6,141	11,294
5 years and later	21,340	7,053	14,287
Total	46,112	15,575	30,537

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued**15 – TRADE AND OTHER PAYABLES**

	Dec 31, 2020		Dec 31, 2019	
	Current	Non-current	Current	Non-current
Trade payables	22,664	—	29,497	—
Other payables [A]	6,941	1,843	6,356	2,060
Amounts due to joint ventures and associates	3,281	39	3,312	40
Accruals and deferred income	8,791	422	10,043	242
Total	41,677	2,304	49,208	2,342

[A] Includes obligations under environmental schemes for compliance purposes of \$2,053 million as at December 31, 2020. (See Note 29)

The fair value of financial liabilities included above approximates the carrying amount and was determined from predominantly unobservable inputs.

Other payables include amounts due to joint arrangement partners and in respect of other project-related items.

Information about offsetting, collateral and liquidity risk is presented in Note 19.

16 – TAXATION**Taxation charge**

	2020	2019	\$ million 2018
Current tax:			
Charge in respect of current period	3,272	7,597	10,415
Adjustments in respect of prior periods	(56)	(1)	60
Total	3,216	7,596	10,475
Deferred tax:			
Relating to the origination and reversal of temporary differences, tax losses and credits	(9,063)	1,377	1,438
Relating to changes in tax rates and legislation	(16)	(67)	(157)
Adjustments in respect of prior periods	430	147	(41)
Total	(8,649)	1,457	1,240
Total taxation (credit)/charge	(5,433)	9,053	11,715

Adjustments in respect of prior periods relate to events in the current period and reflect the effects of changes in rules, facts or other factors compared with those used in establishing the current tax position or deferred tax balance in prior periods.

Reconciliation of applicable tax charge at statutory tax rates to taxation charge

	2020	2019	\$ million 2018
(Loss)/income before taxation	(26,967)	25,485	35,621
Less: share of profit of joint ventures and associates	(1,783)	(3,604)	(4,106)
(Loss)/income before taxation and share of profit of joint ventures and associates	(28,750)	21,881	31,515
Applicable tax (credit)/charge at standard statutory tax rates	(8,330)	7,214	11,641
Adjustments in respect of prior periods	374	146	19
Tax effects of:			
Derecognition/(recognition) of deferred tax assets	1,458	846	(381)
Expenses not deductible for tax purposes	1,239	1,493	1,176
Incentives for investment and development	(557)	(757)	(557)
Exchange rate differences	339	(34)	623
Disposals	(34)	(235)	(524)
Changes in tax rates and legislation	(16)	(67)	(157)
Income/(loss) not subject to tax at standard statutory rates	6	159	(286)
Other reconciling items	88	288	161
Taxation (credit)/charge	(5,433)	9,053	11,715

The weighted average of statutory tax rates was 29% in 2020 (2019: 33%; 2018: 37%). The loss before taxation was significantly impacted by asset impairments which occurred in jurisdictions subject to relatively lower tax rates, resulting in a lower weighted average statutory tax rate as compared with 2019.

Taxes payable

	\$ million	
	Dec 31, 2020	Dec 31, 2019
Income taxes	3,111	3,478
Sales taxes, excise duties and similar levies	2,895	3,215
Total	6,006	6,693

Included in other receivables at December 31, 2020 was income tax receivable of \$1,293 million (2019: \$1,328 million) (see Note 11).

2020 – Deferred tax

	\$ million					
	Decommissioning and other provisions	Property, plant and equipment	Tax losses and credits carried forward	Retirement benefits	Other	Total
Deferred tax asset						
At January 1, 2020	5,380	3,014	11,629	3,660	4,361	28,044
Credit/(charge) to income	1,057	1,975	685	(250)	605	4,072
Currency translation differences	140	163	286	122	58	769
Other	(10)	80	(104)	242	60	268
At December 31, 2020	6,567	5,232	12,496	3,774	5,084	33,153
Deferred tax liability						
At January 1, 2020		(28,040)		(1,093)	(2,909)	(32,042)
Credit to income		4,355		4	218	4,577
Currency translation differences		(143)		(2)	(39)	(184)
Other		27		418	(101)	344
At December 31, 2020		(23,801)		(673)	(2,831)	(27,305)
Net deferred tax asset at December 31, 2020						5,848
Deferred tax asset/liability as presented in the balance sheet at December 31, 2020						
Deferred tax asset						16,311
Deferred tax liability						(10,463)

2019 – Deferred tax

	\$ million					
	Decommissioning and other provisions	Property, plant and equipment	Tax losses and credits carried forward	Retirement benefits	Other	Total
Deferred tax asset						
At January 1, 2019	5,859	3,718	12,167	3,310	4,276	29,330
Credit/(charge) to income	15	(521)	(647)	(76)	10	(1,219)
Currency translation differences	56	6	57	(8)	(2)	109
Other	(550)	(189)	52	434	77	(176)
At December 31, 2019	5,380	3,014	11,629	3,660	4,361	28,044
Deferred tax liability						
At January 1, 2019		(27,627)		(1,674)	(2,769)	(32,070)
(Charge)/credit to income		(227)		46	(57)	(238)
Currency translation differences		(129)		(6)	(5)	(140)
Other		(57)		541	(78)	406
At December 31, 2019		(28,040)		(1,093)	(2,909)	(32,042)
Net deferred tax liability at December 31, 2019						(3,998)
Deferred tax asset/liability as presented in the balance sheet at December 31, 2019						
Deferred tax asset						10,524
Deferred tax liability						(14,522)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

16 – TAXATION continued

The presentation in the balance sheet takes into consideration the offsetting of deferred tax assets and deferred tax liabilities within the same tax jurisdiction, where this is permitted. The overall deferred tax position in a particular tax jurisdiction determines if a deferred tax balance related to that jurisdiction is presented within deferred tax assets or deferred tax liabilities.

Other movements in deferred tax assets and liabilities principally relate to acquisitions, sales of non-current assets and businesses, and amounts recognised in other comprehensive income.

The deferred tax category 'Other' primarily includes deferred tax positions in respect of leases, financial assets and liabilities, inventories, intangible assets and investments in subsidiaries, joint ventures and associates.

Deferred tax assets of \$16,311 million (2019: \$10,524 million) are recognised only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those assets are likely to be recovered, and a judgement as to whether or not there will be sufficient taxable profits available to offset the assets. It is considered probable based on business forecasts that such taxable profits will be available. For Oil Products additional judgement is required; in some European jurisdictions the assessment of forecasted taxable profits resulting in deferred tax asset recognition of \$778 million (2019: \$1,194 million) extends for an additional 10 years beyond Shell's regular 10 years planning horizon. In those situations, additional risking has been applied to the forecast of taxable profits.

The amount of deferred tax assets which are dependent on future taxable profits not arising from the reversal of existing deferred tax liabilities, and which relate to tax jurisdictions where Shell has suffered a loss in the current or preceding year, was \$12,759 million at December 31, 2020 (2019: \$8,773 million). The increase of the amount compared with 2019 is primarily due to the reduction in deferred tax liabilities or increase in deferred tax assets resulting from impairments recorded in 2020, as well as a greater number of entities having incurred a loss in 2020.

Unrecognised taxable temporary differences associated with undistributed retained earnings of investments in subsidiaries, joint ventures and associates amounted to \$6,705 million at December 31, 2020 (2019: \$6,356 million). These retained earnings are subject to withholding tax upon distribution.

Unrecognised deductible temporary differences, unused tax losses and credits carried forward amounted to \$42,836 million at December 31, 2020 (2019: \$33,068 million), including amounts of \$31,873 million (2019: \$24,295 million) that are subject to time limits for utilisation of five years or later, or are not time limited.

Furthermore, there are unrecognised losses for Petroleum Resource Rent Tax (PRRT) in Australia, amounting to \$39,402 million as at the end of the most recent PRRT fiscal year, June 30, 2020 (June 30, 2019: \$36,905 million). Based on business forecasts at existing commodity price levels, and the annual augmentation of the unused PRRT losses, this amount is expected to increase in the near future.

17 – RETIREMENT BENEFITS

Retirement benefits are provided through a number of funded and unfunded defined benefit plans and defined contribution plans, the most significant of which are in the Netherlands, UK and USA. Benefits comprise principally pensions; retirement health care and life insurance are also provided in certain countries.

Financial position

	\$ million	
	Dec 31, 2020	Dec 31, 2019
Obligations	(115,792)	(103,545)
Plan assets	102,678	94,826
Asset ceilings	(17)	
Deficit	(13,131)	(8,719)
Retirement benefits in the Consolidated Balance Sheet:		
Non-current assets	2,474	4,717
Non-current liabilities	(15,168)	(13,017)
Current liabilities	(437)	(419)
Total	(13,131)	(8,719)

Retirement benefit expense

	\$ million		
	2020	2019	2018
Defined benefit plans:			
Interest expense on obligations	1,828	2,364	2,282
Interest income on plan assets	(1,657)	(2,253)	(2,087)
Current service cost, net of plan participants' contributions	1,431	1,188	1,494
Other	(174)	26	(221)
Total	1,428	1,325	1,468
Defined contribution plans	423	428	410
Total retirement benefit expense	1,851	1,753	1,878

Retirement benefit expense is presented principally within production and manufacturing expenses and selling, distribution and administrative expenses in the Consolidated Statement of Income. Interest income on plan assets is calculated using the same rate as that applied to the related defined benefit obligations for each plan to determine interest expense.

Remeasurements

	\$ million		
	2020	2019	2018
Actuarial (losses)/gains on obligations:			
Due to changes in financial assumptions [A]	(10,150)	(11,711)	8,186
Due to experience adjustments [B]	804	232	(268)
Due to changes in demographic assumptions [C]	1,375	(75)	(459)
Total	(7,971)	(11,554)	7,459
Return on plan assets in excess/(shortage) of interest income	4,509	8,460	(2,312)
Other movements	7	(12)	66
Total remeasurements	(3,455)	(3,106)	5,213

[A] Mainly relates to changes in the discount rate assumptions.

[B] Experience adjustments arise from differences between the actuarial assumptions made in respect of the year and actual outcomes.

[C] Mainly relates to updates in mortality assumptions.

Defined benefit plan obligations

	\$ million, except where indicated	
	2020	2019
At January 1	103,545	91,856
Current service cost	1,435	1,186
Interest expense	1,828	2,364
Actuarial losses	7,971	11,554
Benefit payments	(4,059)	(3,961)
Other movements	(444)	194
Currency translation differences	5,516	352
At December 31	115,792	103,545
Comprising:		
Funded pension plans	105,338	93,727
Weighted average duration	18 years	17 years
Unfunded pension plans	5,086	4,793
Weighted average duration	13 years	13 years
Unfunded OPEB plans [A]	5,368	5,025
Weighted average duration	15 years	14 years

[A] Mainly related to post-retirement medical benefits in the USA.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

17 – RETIREMENT BENEFITS continued

Defined benefit plan assets

	\$ million, except where indicated	
	2020	2019
At January 1	94,826	85,803
Return on plan assets in excess of interest income	4,509	8,460
Interest income	1,657	2,253
Employer contributions	614	1,462
Plan participants' contributions	42	42
Benefit payments	(3,843)	(3,741)
Other movements	(281)	160
Currency translation differences	5,154	387
At December 31	102,678	94,826
Comprising:		
Quoted in active markets:		
Equities	25%	26%
Debt securities	52%	51%
Real estate	0%	1%
Other:		
Equities	8%	8%
Debt securities	5%	4%
Real estate	6%	6%
Investment funds	3%	3%
Cash	1%	1%

Employer contributions to defined benefit pension plans are based on actuarial valuations in accordance with local regulations and are estimated to be \$1.6 billion in 2021.

Characteristics of significant defined benefit and defined contribution plans and regulatory framework The Netherlands

The principal defined benefit pension plan in the Netherlands is a funded career-averaged pension arrangement with retired employees drawing benefits as an annuity. The duration of the related Dutch defined benefit obligation is 19 years (2019: 19 years). Whilst the plan was closed to employees hired or rehired after July 1, 2013, it currently remains open for ongoing accrual for existing active members. 31% (2019: 34%) of the overall defined benefit liability in the Netherlands relates to active members. From July 1, 2013 onwards new employees in the Netherlands are entitled to membership of a defined contribution pension plan.

In line with Dutch regulations, the defined benefit pension plan has a joint Trustee Board with trustee representatives nominated by the company, the Central Staff Council and retired members. The defined benefit pension plan also has an Accountability Council comprised of members nominated by the company, the Central Staff Council and retired members. Furthermore, there is a Supervisory Committee which includes external experts from the pension industry to oversee management, compliance and operations of the fund. The defined contribution pension plan has a one-tier Trustee Board with an independent chairperson, and trustee representatives nominated by the company and the Central Staff Council (currently no retired members in the fund to act as trustee) as well as two executive board members. The defined contribution fund also has an Accountability Council comprised of members nominated by the company and the Central Staff Council.

The Dutch government is currently drafting a new regulatory framework for pensions in the Netherlands. The government aims to complete development of new regulations by January 2022 with subsequent implementation by January 2026. It is expected that these regulatory changes will have an impact on both the defined benefit pension plan and the defined contribution pension plan with anticipated changes currently being discussed with the Central Staff Council.

UK

The principal defined benefit pension plan in the UK is a funded final salary pension arrangement with retired employees mainly drawing benefits as an annuity with the option to take a portion as a lump sum. The duration of the related UK defined benefit obligation is 19 years (2019: 18 years). Whilst the plan was closed to employees hired or rehired on or after March 1, 2013, it currently remains open for ongoing accrual for existing active members. 21% (2019: 21%) of the overall defined liability in the UK relates to active members. From March 1, 2013 onwards new employees in the UK are entitled to membership of a defined contribution pension plan.

In line with UK regulations, the defined benefit pension plan is governed by a corporate trustee whose board is comprised of four trustee directors nominated by the company including the chair and four member-nominated trustee directors. The defined contribution pension plan is governed by a corporate trustee whose board is comprised of three company nominated directors including the chair and two member-nominated trustee directors. The trustees are responsible for administering the plans in line with the Trust Deed and Regulations, including setting the investment strategy for the pension plans' assets and paying member benefits, and are required to act in the best interests of the members of the pension plans.

USA

The principal defined benefit pension plan in the USA is a funded average final pay pension plan. At retirement, all retirees can choose to draw their benefit as an annuity, whereas some also have the choice to take their benefit as a lump sum. The duration of the related US defined benefit obligation is 13 years (2019: 13 years). In addition, the company provides a defined contribution plan. Each of these plans is subject to the provisions of the Employee Retirement Income Security Act (ERISA). 25% (2019: 31%) of the overall defined liability of the funded defined benefit plan in the USA relates to active members.

Both the defined benefit pension plan and the defined contribution pension plan are governed by trustees who are appointed by the Plan Sponsor and are named fiduciaries with respect to the plans. The trustees are generally responsible for investment-related matters, appointing the Plan Administrator, maintaining general oversight and deciding appeals of participants.

The company also sponsors "other post-retirement employee benefit" (OPEB) plans in the USA that provide medical, dental, and vision benefits as well as life insurance benefits to eligible retired employees. The plans are unfunded, and the company and retirees share the costs. The plan that provides post-retirement medical benefits is closed to employees hired or rehired on or after January 1, 2017. Certain life insurance benefits are paid by the company.

Significant funding requirements:

- Additional contributions to the Dutch defined benefit pension plan would be required if the 12-month rolling average local funding percentage falls below 105% for six months or more. At the most recent (2020) funding valuation the local funding percentage was above this level;
- There are no set minimum statutory funding requirements for the UK plans. A professional qualified independent actuary, appointed by the trustee board, undertakes a local funding valuation typically every three years. The most recent completed funding valuation for the principal defined benefit plan was undertaken as at December 31, 2017. A funding valuation as at December 31, 2020 is currently under way. The most recent completed funding valuation (2017) revealed a funding ratio of 108% and the resulting Schedule of Contributions was for no Sponsor contribution (except for salary sacrifice contributions); and
- Under the Pension Protection Act, US pension plans are subject to minimum required contribution levels based on the funding position. No contributions are required based on the most recent funding valuation.

Associated risks to which retirement benefits are exposed

There are inherent risks associated with defined benefit pension and OPEB plans. These risks are related to various assumptions made on valuation of the liabilities and the cash funding requirement of the underlying plans. Volatility in capital markets or government policies, and the resulting consequences for investment performance, interest and inflation rates, as well as changes in assumptions for mortality, retirement age or pensionable remuneration at retirement, could result in significant changes to the funding level of future liabilities, and in case of a shortfall, there could be a requirement to make substantial cash contributions (depending on the applicable local regulations).

These inherent risks are managed by a pension forum, chaired by the Chief Financial Officer, which oversees Shell's pension strategy, policy and operations. The forum is supported by a risk committee in reviewing the results of the assurance process with respect to the pension risk.

Investment strategies

Long-term investment strategies of plans are generally determined by the relevant pension plan trustees using a structured asset/liability modelling approach to define the asset mix that best meets the objectives of optimising returns within agreed risk levels while maintaining adequate funding levels.

Principal and actuarial assumptions

The principal assumptions applied in determining the present value of defined benefit obligations and their bases were as follows:

- rates of increase in pensionable remuneration, pensions in payment and health-care costs: historical experience and management's long-term expectation;
- discount rates: prevailing long-term AA corporate bond yields, chosen to match the currency and duration of the relevant obligation; and
- mortality rates: published standard mortality tables for the individual countries concerned adjusted for Shell experience where statistically significant.

The weighted averages for those assumptions and related sensitivity information at December 31 are presented below. Sensitivity information indicates by how much the defined benefit obligations would increase or decrease if a given assumption were to increase or decrease with no change in other assumptions.

							\$ million, except where indicated
	Assumptions used at nominal rates		Effect of using alternative assumptions				
	December 31, 2020 [A]	December 31, 2019	Range of assumptions	Increase/(decrease) in defined benefit obligations			
				December 31, 2020		December 31, 2019	
Rate of increase in pensionable remuneration	3.8%	4.1%	-1% to +1%	(1,780) to	1,948	(1,975) to	2,266
Rate of increase in pensions in payment	1.6%	1.6%	-1% to +1%	(10,937) to	13,523	(9,541) to	11,757
Rate of increase in health-care costs [B]	6.0%	6.1%	-1% to +1%	(605) to	751	(546) to	675
Discount rate for pension plans	1.5%	2.1%	-1% to +1%	21,463 to	(16,382)	18,431 to	(14,155)
Discount rate for health-care plans [B]	2.6%	3.2%	-1% to +1%	791 to	(624)	704 to	(558)
Expected age at death for persons aged 60:							
Men	87 years	87 years	-1 year to +1 year	(2,022) to	2,112	(1,717) to	1,782
Women	88 years	89 years	-1 year to +1 year	(1,985) to	2,070	(1,631) to	1,694

[A] The weighted average inflation rate used in the calculation of the defined benefit obligation is 1.7%.

[B] Mainly related to post-retirement medical benefits in the USA.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

18 – DECOMMISSIONING AND OTHER PROVISIONS

\$ million

	Decommissioning and restoration	Legal	Environmental	Redundancy	Other	Total
At January 1, 2020						
Current	755	626	263	295	872	2,811
Non-current	18,264	1,185	934	220	1,196	21,799
	19,019	1,811	1,197	515	2,068	24,610
Additions	1,697 [A]	502	199	986	2,386	5,770
Amounts charged against provisions	(433)	(522)	(138)	(375)	(388)	(1,856)
Accretion expense	448	17	21	1	10	497
Disposals	(154)	–	(7)	–	(18)	(179)
Remeasurements and other movements	2,090	(59)	(73)	(241)	(265)	1,452
Currency translation differences	508	1	26	52	53	640
	4,156	(61)	28	423	1,778	6,324
At December 31, 2020						
Current	900	521	273	673	1,257	3,624
Non-current	22,275	1,229	952	265	2,589	27,310
	23,175	1,750	1,225	938	3,846	30,934
At January 1, 2019						
Current	876	213	264	441	1,547	3,341
Non-current	17,057	1,247	1,074	280	1,528	21,186
	17,933	1,460	1,338	721	3,075	24,527
Additions	625	585	229	290	535	2,264
Amounts charged against provisions	(797)	(216)	(223)	(304)	(562)	(2,102)
Accretion expense	644	28	16	3	25	716
Disposals	(1,238)	–	(8)	–	(14)	(1,260)
Remeasurements and other movements	1,696	(45)	(155)	(192)	(988)	316
Currency translation differences	156	(1)	–	(3)	(3)	149
	1,086	351	(141)	(206)	(1,007)	83
At December 31, 2019						
Current	755	626	263	295	872	2,811
Non-current	18,264	1,185	934	220	1,196	21,799
	19,019	1,811	1,197	515	2,068	24,610

[A] Includes \$798 million additions for the recognition of decommissioning and restoration provisions in Integrated Gas and Upstream and \$899 million for the recognition of decommissioning and restoration provisions for manufacturing facilities in Oil Products.

The amount and timing of settlement in respect of these provisions are uncertain and dependent on various factors that are not always within management's control. Reviews of estimated future decommissioning and restoration costs and the discount rate applied are carried out regularly. The discount rate applied at December 31, 2020 was 1.75% (2019: 3%). This decrease resulted from the significant decrease in capital markets rates in 2020. An increase of 0.5% or a decrease of 0.5% in the discount rate could result in a decrease of \$1.7 billion or an increase of \$2.2 billion of decommissioning and restoration provisions, respectively. Such increase/decrease will be reflected in the carrying amount of the related asset. Where applicable that carrying amount is tested for impairment.

In 2020, there was an increase of \$3,999 million (2019: \$2,241 million) in the decommissioning and restoration provision as a result of the change in the discount rate, partly offset by a decrease in the provision resulting from changes in cost estimates of \$1,909 million (2019: \$545 million), reported within remeasurements and other movements.

Of the decommissioning and restoration provision at December 31, 2020, an estimated \$3,921 million is expected to be utilised within one to five years, \$2,206 million within six to 10 years, and the remainder in later periods.

Other provisions include amounts recognised in respect of onerous contracts (\$1,739 million) and employee benefits. At December 31, 2020, the onerous contract provision includes onerous contracts that relate to Lake Charles terminals and the closure of the Convent refinery, both in the USA.

19 – FINANCIAL INSTRUMENTS

Financial instruments in the Consolidated Balance Sheet include investments in securities (see Note 10), cash and cash equivalents (see Note 13), debt (see Note 14) and derivative contracts.

Risks

In the normal course of business, financial instruments of various kinds are used for the purposes of managing exposure to interest rate, foreign exchange and commodity price movements.

Treasury standards are applicable to all subsidiaries and each subsidiary is required to adopt a treasury policy consistent with these standards. These policies cover: financing structure; interest rate and foreign exchange risk management; insurance; counterparty risk management; and use of derivative contracts. Wherever possible, treasury operations are carried out through specialist regional organisations without removing from each subsidiary the responsibility to formulate and implement appropriate treasury policies.

Apart from forward foreign exchange contracts to meet known commitments, the use of derivative contracts by most subsidiaries is not permitted by their treasury policy.

Other than in exceptional cases, the use of external derivative contracts is confined to specialist trading and central treasury organisations that have appropriate skills, experience, supervision, control and reporting systems.

Shell's operations expose it to market, credit and liquidity risk, as described below.

Market risk

Market risk is the possibility that changes in interest rates, foreign exchange rates or the prices of crude oil, natural gas, LNG, refined products, chemical feedstocks, power and carbon-emission rights will adversely affect the value of assets, liabilities or expected future cash flows.

Interest rate risk

Most debt is raised from central borrowing programmes. Shell's policy continues to be to have debt principally denominated in dollars and to maintain a largely floating interest rate exposure profile; however, Shell has issued a significant amount of fixed rate debt in recent years, taking advantage of historically low interest rates available in debt markets. As a result, the majority of the debt portfolio at December 31, 2020, is at fixed rates and this reduces Shell's adverse exposure to rising floating dollar interest rates (see Notes 2 and 3).

The financing of most subsidiaries is structured on a floating-rate basis, and any further interest rate risk management is only applied under exceptional circumstances.

On the basis of the floating-rate net cash position at December 31, 2020 (both issued and hedged), and assuming other factors (principally foreign exchange rates and commodity prices) remained constant and that no further interest rate management action was taken, an increase in interest rates of 1% would have increased 2020 income before taxation by \$62 million (2019: \$98 million decrease, based on the floating rate net debt position at December 31, 2019).

The carrying amounts and maturities of debt and borrowing facilities are presented in Note 14. Interest expense is presented in Note 6.

Foreign exchange risk

Many of the markets in which Shell operates are priced, directly or indirectly, in dollars. As a result, the functional currency of most Integrated Gas and Upstream entities and those with significant cross-border business is the dollar. For Oil Products and Chemicals entities, the functional currency is typically the local currency. Consequently, Shell is exposed to varying levels of foreign exchange risk when an entity enters into transactions that are not denominated in its functional currency, when foreign currency monetary assets and liabilities are translated at the balance sheet date and as a result of holding net investments in operations that are not dollar-functional. Each entity is required to adopt treasury policies that are designed to measure and manage its foreign exchange exposures by reference to its functional currency.

Foreign exchange gains and losses arise in the normal course of business from the recognition of receivables and payables and other monetary items in currencies other than an entity's functional currency. Foreign exchange risk may also arise in connection with capital expenditure. For major projects, an assessment is made at the final investment decision stage whether to hedge any resulting exposure.

Assuming other factors (principally interest rates and commodity prices) remained constant and that no further foreign exchange risk management action were taken, a 10% appreciation against the dollar at December 31 of the main currencies to which Shell is exposed would have the following effects:

	\$ million			
	Increase/(decrease) in income before taxation		Increase in net assets	
	2020	2019	2020	2019
10% appreciation against the dollar of:				
Euro	(263)	36	451	1,227
Malaysian ringgit	255	243	270	290
Australian dollar	179	(55)	598	835
Sterling	(166)	(58)	328	581
Canadian dollar	1	(97)	1,299	1,380

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

19 – FINANCIAL INSTRUMENTS continued

The above sensitivity information was calculated by reference to carrying amounts of assets and liabilities at December 31 only. The effect on income before taxation arises in connection with monetary balances denominated in currencies other than an entity's functional currency; the effect on net assets arises principally from the translation of assets and liabilities of entities that are not dollar-functional.

Foreign exchange gains and losses included in income are presented in Note 5.

Commodity price risk

Certain subsidiaries have a mandate to trade crude oil, natural gas, LNG, refined products, chemical feedstocks, power and carbon-emission rights, and to use commodity derivative contracts (forwards, futures, swaps and options) as a means of managing price and timing risks arising from this trading activity. In effecting these transactions, the entities concerned operate within procedures and policies designed to ensure that risks, including those relating to the default of counterparties, are managed within authorised limits.

Value-at-risk (VAR) techniques based on variance/covariance or Monte Carlo simulation models are used to make a statistical assessment of the market risk arising from possible future changes in market values over a 1-day holding period and within a 95% confidence level. The calculation of potential changes in fair value takes into account positions, the history of price movements and the correlation of these price movements. Models are regularly reviewed against actual fair value movements to ensure integrity is maintained. The VAR year-end positions in respect of commodities traded in active markets, which are presented in the table below, are calculated on a diversified basis in order to reflect the effect of offsetting risk within combined portfolios.

Value-at-risk (pre-tax)

	\$ million	
	December 31, 2020	December 31, 2019
Global oil	24	22
North America gas and power	14	12
Europe gas and power	11	5
Carbon-emission rights	7	4

Credit risk

Policies are in place to ensure that sales of products are made to customers with appropriate creditworthiness. These policies include detailed credit analysis and monitoring of trading partners against counterparty credit limits. Credit information is regularly shared between business and finance functions, with dedicated teams in place to quickly identify and respond to cases of credit deterioration. Mitigation measures are defined and implemented for higher-risk business partners and customers, and include shortened payment terms, collateral or other security posting and vigorous collections. In addition, policies limit the amount of credit exposure to any individual financial institution. There are no material concentrations of credit risk, with individual customers or geographically, and there has been no significant level of counterparty default in recent years.

Surplus cash is invested in a range of short-dated, secure and liquid instruments including short-term bank deposits, money market funds, reverse repos and similar instruments. The portfolio of these investments is diversified to avoid concentrating risk in any one instrument, country or counterparty. Management monitors the investments regularly and adjusts the investment portfolio in light of new market information where necessary to ensure credit risk is effectively diversified.

In commodity trading, counterparty credit risk is managed within a framework of credit limits with utilisation being regularly reviewed. Credit risk exposure is monitored and the acceptable level of credit exposure is determined by a credit committee. Credit checks are performed by a department independent of traders, and are undertaken before contractual commitment. Where appropriate, netting arrangements, credit insurance, prepayments and collateral are used to manage specific risks.

Shell routinely enters into offsetting, master netting and similar arrangements with trading and other counterparties to manage credit risk. Where there is a legally enforceable right of offset under such arrangements and Shell has the intention to settle on a net basis or realise the asset and settle the liability simultaneously, the net asset or liability is recognised in the Consolidated Balance Sheet, otherwise assets and liabilities are presented gross. These amounts, as presented net and gross within trade and other receivables, trade and other payables and derivative financial instruments in the Consolidated Balance Sheet at December 31, were as follows:

2020

	\$ million					
	Amounts offset		Amounts not offset			
	Gross amounts before offset	Amounts offset	Net amounts as presented	Cash collateral received/pledged	Other offsetting instruments	Net amounts
Assets:						
Within trade receivables	10,658	6,470	4,188	14	79	4,095
Within derivative financial instruments	12,798	6,125	6,673	1,573	1,750	3,350
Liabilities:						
Within trade payables	10,580	6,467	4,113	1	79	4,033
Within derivative financial instruments	10,502	5,893	4,609	797	1,761	2,051

2019

\$ million

	Amounts offset			Amounts not offset		Net amounts
	Gross amounts before offset	Amounts offset	Net amounts as presented	Cash collateral received/pledged	Other offsetting instruments	
Assets:						
Within trade receivables	13,821	8,975	4,846	54	101	4,691
Within derivative financial instruments	12,995	7,310	5,685	531	2,262	2,892
Liabilities:						
Within trade payables	13,335	9,029	4,306	11	101	4,194
Within derivative financial instruments	12,355	7,253	5,102	706	2,262	2,134

Amounts not offset principally relate to contracts where the intention to settle on a net basis was not clearly established at December 31.

The carrying amount of financial assets pledged as collateral for liabilities or contingent liabilities at December 31, 2020, presented within trade and other receivables, was \$1,909 million (2019: \$1,948 million). The carrying amount of collateral held at December 31, 2020, presented within trade and other payables, was \$1,675 million (2019: \$718 million). Collateral mainly relates to initial margins held with commodity exchanges and over-the-counter counterparty variation margins. Some derivative contracts are fully cash collateralised, thereby eliminating both counterparty risk and the Group's own non-performance risk.

Liquidity risk

Liquidity risk is the risk that suitable sources of funding for Shell's business activities may not be available. Management believes that it has access to sufficient debt funding sources (capital markets) and to undrawn committed borrowing facilities to meet foreseeable requirements. Information about borrowing facilities is presented in Note 14.

Derivative contracts and hedges

Derivative contracts are used principally as hedging instruments, however, because hedge accounting is not always applied, movements in the carrying amounts of derivative contracts that are recognised in income are not always matched in the same period by the recognition of the income effects of the related hedged items.

Carrying amounts, maturities and hedges

The carrying amounts of derivative contracts at December 31, designated and not designated as hedging instruments for hedge accounting purposes, were as follows:

2020

\$ million

	Assets			Liabilities			Net
	Designated	Not designated	Total	Designated	Not designated	Total	
Interest rate swaps	451	—	451	26	22	48	403
Forward foreign exchange contracts	—	276	276	—	651	651	(375)
Currency swaps and options	1,890	13	1,903	280	63	343	1,560
Commodity derivatives	—	5,534	5,534	92	4,565	4,657	877
Other contracts	—	424	424	—	29	29	395
Total	2,341	6,247	8,588	398	5,330	5,728	2,860

2019

\$ million

	Assets			Liabilities			Net
	Designated	Not designated	Total	Designated	Not designated	Total	
Interest rate swaps	227	8	235	34	24	58	177
Forward foreign exchange contracts	7	236	243	2	309	311	(68)
Currency swaps and options	90	15	105	932	56	988	(883)
Commodity derivatives	—	6,914	6,914	—	5,281	5,281	1,633
Other contracts	—	341	341	—	—	—	341
Total	324	7,514	7,838	968	5,670	6,638	1,200

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

19 – FINANCIAL INSTRUMENTS continued

Net gains before tax on derivative contracts, excluding realised commodity contracts and those accounted for as hedges, were \$1,676 million in 2020 (2019: \$2,004 million losses; 2018: \$1,818 million losses). The International Financial Reporting Interpretation Committee (IFRIC) guidance concerning the physical settlement of a contract to buy or sell a non-financial item has been applied prospectively as from 2020. The result of this decision is that \$597 million of prior gains that would have previously reversed at the time of trade delivery, have been excluded from the amount disclosed in 2020.

Certain contracts, mainly to hedge price risk relating to forecast commodity transactions, were designated in cash flow hedging relationships and are presented after the offset of related margin balances with exchanges. Contracts to hedge foreign exchange risks were also designated in cash flow hedging relationships and the net carrying amount of these contracts at December 31, 2020, was an asset of \$556 million (2019: \$167 million liability). See Note 22 for the accumulated balance recognised within other comprehensive income.

Certain interest rate and currency swaps were designated in fair value hedges, principally in respect of debt for which the net carrying amount of the related derivative contracts, net of accrued interest, at December 31, 2020, was an asset of \$1,422 million (2019: \$518 million liability).

In 2020, €3 billion of debt instruments were designated as hedges of net investments in foreign operations, relating to the foreign exchange risk arising between certain intermediate holding companies and their subsidiaries. See Note 22 for the accumulated balance recognised within other comprehensive income.

In the course of trading operations, certain contracts are entered into for delivery of commodities that are accounted for as derivatives. The resulting price exposures are managed by entering into related derivative contracts. These contracts are managed on a fair value basis and the maximum exposure to liquidity risk is the undiscounted fair value of derivative liabilities.

For a minority of commodity derivatives contracts, carrying amounts cannot be derived from quoted market prices or other observable inputs, in which case fair value is estimated using valuation techniques such as Black-Scholes, option spread models and extrapolation using quoted spreads with assumptions developed internally based on observable market activity.

Other contracts include certain contracts that are held to sell or purchase commodities and others containing embedded derivatives, which are required to be recognised at fair value because of pricing or delivery conditions, even though they were entered into to meet operational requirements. These contracts are expected to mature in 2021-2025, with certain contracts having early termination rights (for either party). Valuations are derived from quoted market prices.

The contractual maturities of derivative liabilities at December 31 compare with their carrying amounts in the Consolidated Balance Sheet as follows:

2020

	Contractual maturities							Difference from carrying amount [A]	Carrying amount
	Less than 1 year	Between 1 and 2 years	Between 2 and 3 years	Between 3 and 4 years	Between 4 and 5 years	5 years and later	Total		
Interest rate swaps	12	10	9	7	5	6	49	(1)	48
Forward foreign exchange contracts	504	56	22	38	—	—	620	31	651
Currency swaps and options	174	13	28	—	159	—	374	(31)	343
Commodity derivatives	2,990	743	265	174	115	391	4,678	(21)	4,657
Other contracts	15	15	—	—	—	—	30	(1)	29
Total	3,695	837	324	219	279	397	5,751	(23)	5,728

[A] Mainly related to the effect of discounting.

2019

	Contractual maturities							Difference from carrying amount [A]	Carrying amount
	Less than 1 year	Between 1 and 2 years	Between 2 and 3 years	Between 3 and 4 years	Between 4 and 5 years	5 years and later	Total		
Interest rate swaps	35	8	4	4	5	4	60	(2)	58
Forward foreign exchange contracts	214	40	8	—	118	—	380	(69)	311
Currency swaps and options	255	475	444	201	204	1,777	3,356	(2,368)	988
Commodity derivatives	3,472	756	349	189	123	511	5,400	(119)	5,281
Other contracts	—	—	—	—	—	—	—	—	—
Total	3,976	1,279	805	394	450	2,292	9,196	(2,558)	6,638

[A] Mainly related to the effect of discounting.

Fair value measurements

The net carrying amounts of derivative contracts held at December 31, categorised according to the predominant source and nature of inputs used in determining the fair value of each contract, were as follows:

2020

	Prices in active markets for identical assets/liabilities	Other observable inputs	Unobservable inputs	Total
				\$ million
Interest rate swaps	—	403	—	403
Forward foreign exchange contracts	—	(375)	—	(375)
Currency swaps and options	—	1,560	—	1,560
Commodity derivatives	37	(237)	1,077	877
Other contracts	20	375	—	395
Total	57	1,726	1,077	2,860

2019

	Prices in active markets for identical assets/liabilities	Other observable inputs	Unobservable inputs	Total
				\$ million
Interest rate swaps	—	177	—	177
Forward foreign exchange contracts	—	(68)	—	(68)
Currency swaps and options	—	(883)	—	(883)
Commodity derivatives	(6)	895	744	1,633
Other contracts	27	304	10	341
Total	21	425	754	1,200

Net carrying amounts of derivative contracts measured using predominantly unobservable inputs

	2020	2019
		\$ million
At January 1	754	(27)
Net gains recognised in revenue	564	1,085
Purchases	217	453
Sales	(450)	(633)
Settlements	(9)	—
Recategorisations (net)	(12)	(125)
Currency translation differences	13	1
At December 31	1,077	754

Included in net gains recognised in revenue in 2020 were unrealised net gains totalling \$743 million relating to assets and liabilities held at December 31, 2020 (2019: \$612 million gains).

Unrecognised day one gains or losses

Certain long-term commodity purchase contracts extend to periods where observable pricing data are limited and so their value may include estimates for a portion of the value. Where this is more than an insignificant part of the overall contract valuation, any gains or losses will be deferred. Valuation techniques are further described in Note 2. The unrecognised gains on these derivative contracts at December 31, 2020 were as follows:

	2020	2019
		\$ million
At January 1	929	388
Movements	39	541
At December 31	968	929

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued**20 – SHARE CAPITAL****Issued and fully paid ordinary shares of €0.07 each [A]**

	Number of shares		Nominal value (\$ million)		
	A	B	A	B	Total
At January 1, 2020	4,151,787,517	3,729,407,107	349	308	657
Repurchases of shares	(50,548,018)	(23,223,271)	(4)	(2)	(6)
At December 31, 2020	4,101,239,499	3,706,183,836	345	306	651
At January 1, 2019	4,471,889,296	3,745,486,731	376	309	685
Repurchases of shares	(320,101,779)	(16,079,624)	(27)	(1)	(28)
At December 31, 2019	4,151,787,517	3,729,407,107	349	308	657

[A] Share capital at December 31, 2020, and 2019, also included 50,000 issued and fully paid sterling deferred shares of £1 each.

At the Company's Annual General Meeting (AGM) on May 19, 2020, the Board was authorised to allot ordinary shares in the Company, and to grant rights to subscribe for or to convert any security into ordinary shares in the Company, up to an aggregate nominal amount of €182.7 million (representing 2,611 million ordinary shares of €0.07 each), and to list such shares or rights on any stock exchange. This authority expires at the earlier of the close of business on August 19, 2021, and the end of the AGM to be held in 2021, unless previously renewed, revoked or varied by the Company in a general meeting.

At the May 19, 2020 AGM, shareholders granted the Company the authority to repurchase up to 783 million ordinary shares (excluding any treasury shares), renewing the authority granted by the shareholders at previous AGMs. The authority will expire at the earlier of the close of business on August 19, 2021, and the end of the AGM of the Company to be held in 2021. Ordinary shares purchased by the Company pursuant to this authority will either be cancelled or held in treasury. Treasury shares are shares in the Company which are owned by the Company itself. The minimum price, exclusive of expenses, which may be paid for an ordinary share is €0.07. The maximum price, exclusive of expenses, which may be paid for an ordinary share is the higher of: (i) an amount equal to 5% above the average market value for an ordinary share for the five business days immediately preceding the date of the purchase; and (ii) the higher of the price of the last independent trade and the highest current independent bid on the trading venues where the purchase is carried out.

On March 23, 2020, in light of the economic and oil price environment, the Board decided not to continue with the next tranche of the share buyback programme following the completion of the tranche announced on January 30, 2020.

21 – SHARE-BASED COMPENSATION PLANS AND SHARES HELD IN TRUST**Share-based compensation expense**

	\$ million		
	2020	2019	2018
Equity-settled [A]	359	537	531
Total	359	537	531

[A] On an incidental basis awards may be cash-settled, where an equity settlement is not possible under local regulations.

The principal share-based employee compensation plans are the PSP and LTIP. Awards of shares and American Depositary Shares (ADS) of the Company under the PSP and LTIP are granted upon certain conditions to eligible employees. The actual amount of shares that may vest ranges from 0% to 200% of the awards, depending on the outcomes of prescribed performance conditions over a three-year period beginning on January 1 of the award year. Shares and ADSs vest for nil consideration.

Share awards under the PSP and LTIP

	Number of A shares (million)	Number of B shares (million)	Number of A ADSs (million)	Weighted Average remaining contractual life (years)
At January 1, 2020	29	10	8	1.0
Granted	10	4	3	
Vested	(9)	(4)	(3)	
Forfeited	(1)	—	—	
At December 31, 2020	29	10	8	1.0
At January 1, 2019	30	12	8	1.0
Granted	11	3	3	
Vested	(11)	(5)	(3)	
Forfeited	(1)	—	—	
At December 31, 2019	29	10	8	1.0

Other plans offer eligible employees opportunities to acquire shares and ADSs of the Company or receive cash benefits measured by reference to the Company's share price.

Shell employee share ownership trusts and trust-like entities purchase the Company's shares in the open market to meet delivery commitments under employee share plans. At December 31, 2020, they held 14.3 million A shares (2019: 17.4 million), 5.2 million B shares (2019: 6.5 million) and 5.1 million A ADSs (2019: 5.3 million).

22 – OTHER RESERVES

Other reserves attributable to Royal Dutch Shell plc shareholders

	Merger reserve	Share premium reserve	Capital redemption reserve	Share plan reserve	Accumulated other comprehensive income	Total
	\$ million					
At January 1, 2020	37,298	154	123	1,049	(24,173)	14,451
Other comprehensive loss attributable to Royal Dutch Shell plc shareholders	—	—	—	—	(1,832)	(1,832)
Transfer from other comprehensive income	—	—	—	—	270	270
Repurchases of shares	—	—	6	—	—	6
Share-based compensation	—	—	—	(143)	—	(143)
At December 31, 2020	37,298	154	129	906	(25,735)	12,752
At January 1, 2019	37,298	154	95	1,098	(22,030)	16,615
Other comprehensive loss attributable to Royal Dutch Shell plc shareholders	—	—	—	—	(2,069)	(2,069)
Transfer from other comprehensive income	—	—	—	—	(74)	(74)
Repurchases of shares	—	—	28	—	—	28
Share-based compensation	—	—	—	(49)	—	(49)
At December 31, 2019	37,298	154	123	1,049	(24,173)	14,451
At January 1, 2018	37,298	154	84	1,440	(22,182)	16,794
Other comprehensive income attributable to Royal Dutch Shell plc shareholders	—	—	—	—	1,123	1,123
Transfer from other comprehensive income	—	—	—	—	(971)	(971)
Repurchases of shares	—	—	11	—	—	11
Share-based compensation	—	—	—	(342)	—	(342)
At December 31, 2018	37,298	154	95	1,098	(22,030)	16,615

The merger reserve and share premium reserve were established as a consequence of the Company becoming the single parent company of Royal Dutch Petroleum Company and The "Shell" Transport and Trading Company, plc, now The Shell Transport and Trading Company Limited, in 2005. The merger reserve increased in 2016 following the issuance of shares for the acquisition of BG Group plc. The capital redemption reserve was established in connection with repurchases of shares of Royal Dutch Shell plc. The share plan reserve is in respect of equity-settled share-based compensation plans.

The capital redemption reserve was established in connection with repurchases of shares of the Company.

The share plan reserve is in respect of equity-settled share-based compensation plans (see Note 21). The movement comprises the net of the charge for the year and the release as a result of vested awards and is after deduction of tax of \$4 million in 2020 (2019: \$45 million; 2018: \$71 million).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

22 – OTHER RESERVES continued

Accumulated other comprehensive income comprises the following:

Accumulated other comprehensive income attributable to Royal Dutch Shell plc shareholders

\$ million

	Currency translation differences [A]	Equity instruments remeasurements	Debt instruments remeasurements	Cash flow hedging (losses)/ gains [A]	Net investment hedging (losses)/ gains [A]	Deferred cost of hedging	Retirement benefits remeasurements	Total
At January 1, 2020	(9,415)	793	8	(233)	(2,016)	(287)	(13,023)	(24,173)
Recognised in other comprehensive income	1,204	68	31	(9)	(423)	17	(3,455)	(2,567)
Reclassified to income	(28)	–	(8)	(173)	–	94	–	(115)
Reclassified to the balance sheet	–	–	–	16	–	–	–	16
Reclassified to retained earnings	–	169	–	–	–	–	101	270
Tax on amounts recognised/reclassified	3	(4)	–	6	–	(11)	753	747
Total, net of tax	1,179	233	23	(160)	(423)	100	(2,601)	(1,649)
Share of joint ventures and associates	51	118	–	(92)	–	–	–	77
Other comprehensive income/(loss) for the period	1,230	351	23	(252)	(423)	100	(2,601)	(1,572)
Less: non-controlling interest	10	–	–	–	–	–	–	10
Attributable to Royal Dutch Shell plc shareholders	1,240	351	23	(252)	(423)	100	(2,601)	(1,562)
At December 31, 2020	(8,175)	1,144	31	(485)	(2,439)	(187)	(15,624)	(25,735)
At January 1, 2019	(9,722)	906	(21)	117	(2,025)	(353)	(10,932)	(22,030)
Recognised in other comprehensive income	302	(17)	24	(592)	13	9	(3,106)	(3,367)
Reclassified to income	38	–	5	268	–	86	–	397
Reclassified to the balance sheet	–	–	–	11	–	–	–	11
Reclassified to retained earnings	–	(85)	–	–	–	–	11	(74)
Tax on amounts recognised/reclassified	4	(13)	–	37	(4)	(29)	1,004	999
Total, net of tax	344	(115)	29	(276)	9	66	(2,091)	(2,034)
Share of joint ventures and associates	(2)	2	–	(74)	–	–	–	(74)
Other comprehensive loss for the period	342	(113)	29	(350)	9	66	(2,091)	(2,108)
Less: non-controlling interest	(35)	–	–	–	–	–	–	(35)
Attributable to Royal Dutch Shell plc shareholders	307	(113)	29	(350)	9	66	(2,091)	(2,143)
At December 31, 2019	(9,415)	793	8	(233)	(2,016)	(287)	(13,023)	(24,173)
At January 1, 2018	(6,711)	1,975	(6)	(627)	(2,024)	(144)	(14,645)	(22,182)
Recognised in other comprehensive income	(3,793)	(147)	(15)	50	(1)	(362)	5,213	945
Reclassified to income	651	–	–	722	–	95	–	1,468
Reclassified to the balance sheet	–	–	–	(30)	–	–	–	(30)
Reclassified to retained earnings	–	(1,108)	–	–	–	–	137	(971)
Tax on amounts recognised/reclassified	(29)	(6)	–	(12)	–	58	(1,625)	(1,614)
Total, net of tax	(3,171)	(1,261)	(15)	730	(1)	(209)	3,725	(202)
Share of joint ventures and associates	(25)	193	–	14	–	–	1	183
Other comprehensive loss/income for the period	(3,196)	(1,068)	(15)	744	(1)	(209)	3,726	(19)
Less: non-controlling interest	185	(1)	–	–	–	–	(13)	171
Attributable to Royal Dutch Shell plc shareholders	(3,011)	(1,069)	(15)	744	(1)	(209)	3,713	152
At December 31, 2018	(9,722)	906	(21)	117	(2,025)	(353)	(10,932)	(22,030)

[A] As from 2020, 'Net investment hedging (losses)/gains' are presented separately. Prior to 2020, these were aggregated within 'Currency translation differences' and 'Cash flow hedging (losses)/gains'. Prior period comparatives for these categories have been revised to conform with current year presentation.

23 – DIVIDENDS

Interim dividends

	\$ per share			\$ million		
	2020	2019	2018	2020	2019	2018
A shares:						
Cash:						
March	0.47	0.47	0.47	1,862	2,100	2,176
June	0.16	0.47	0.47	653	2,062	2,140
September	0.16	0.47	0.47	654	2,007	2,165
December	0.1665	0.47	0.47	691	1,978	2,124
Total – A shares	0.9565	1.88	1.88	3,860	8,147	8,605
B shares:						
Cash:						
March	0.47	0.47	0.47	1,620	1,775	1,794
June	0.16	0.47	0.47	586	1,762	1,746
September	0.16	0.47	0.47	582	1,765	1,784
December	0.1665	0.47	0.47	622	1,749	1,746
Total – B shares	0.9565	1.88	1.88	3,410	7,051	7,070
Total				7,270	15,198	15,675

In addition, on February 4, 2021, the Directors announced a further interim dividend in respect of 2020 of \$0.1665 per A share and \$0.1665 per B share. The total dividend is estimated to be \$1,300 million and is payable on March 29, 2021, to shareholders on the register at February 19, 2021.

Dividends on A shares are by default paid in euros, although holders may elect to receive dividends in US dollars or in sterling. Dividends on B shares are by default paid in sterling, although holders may elect to receive dividends in US dollars or in euros. Dividends on ADSs are paid in dollars.

24 – EARNINGS PER SHARE

	2020	2019	2018
(Loss)/income attributable to Royal Dutch Shell plc shareholders (\$ million)	(21,680)	15,842	23,352
Weighted average number of A and B shares used as the basis for determining:			
Basic earnings per share (million of shares)	7,795.6	8,058.3	8,282.8
Diluted earnings per share (million of shares)	7,795.6	8,112.5	8,348.7

Basic earnings per share are calculated by dividing the income attributable to Royal Dutch Shell plc shareholders for the year by the weighted average number of A and B shares outstanding during the year. The weighted average number of shares outstanding excludes shares held in trust.

Diluted earnings per share are based on the same income/(loss) figures. The weighted average number of shares outstanding during the year is increased by dilutive shares related to share-based compensation plans. If the inclusion of potentially issuable shares could decrease diluted loss per share, the potentially issuable shares are excluded from the weighted average number of shares outstanding used to calculate diluted earnings per share. The number of potentially issuable shares that has been excluded from the calculation for 2020 is 36.0 million shares.

Earnings per share are identical for A and B shares.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued

25 – LEGAL PROCEEDINGS AND OTHER CONTINGENCIES General

In the ordinary course of business, Shell subsidiaries are subject to a number of contingencies arising from litigation and claims brought by governmental authorities, including tax authorities, and private parties. The operations and earnings of Shell subsidiaries continue, from time to time, to be affected to varying degrees by political, legislative, fiscal and regulatory developments, including those relating to the protection of the environment and indigenous groups in the countries in which they operate. The industries in which Shell subsidiaries are engaged are also subject to physical risks of various types.

The amounts claimed in relation to such events and, if such claims against Shell were successful, the costs of implementing the remedies sought in the various cases could be substantial. Based on information available to date and taking into account that in some cases it is not practicable to estimate the possible magnitude or timing of any resultant payments, management believes that the foregoing are not expected to have a material adverse impact on Shell's Consolidated Financial Statements. However, there remains a high degree of uncertainty around these contingencies, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition.

In certain divestment transactions, liabilities related to decommissioning and restoration are de-recognised upon transfer of these obligations to the buyer. For certain of these obligations Shell has issued guarantees to third parties and continues to be liable in case the primary obligor is not able to meet its obligation. These potential obligations arising from issuance of these guarantees are assessed to be remote.

Decommissioning and restoration of manufacturing facilities

Industry practice has been not to recognise decommissioning and restoration provisions associated with manufacturing facilities in Oil Products and Chemicals. This was on the basis that these assets were considered to have indefinite lives and, therefore, that it was considered remote that an outflow of economic benefits would be required.

In 2020, the changed macroeconomic fundamentals were considered, together with Shell's plans to rationalise the Group's manufacturing portfolio. It was also reconsidered whether it remained appropriate not to recognise decommissioning and restoration provisions for manufacturing facilities.

It was concluded that the assumption of indefinite lives for manufacturing facilities is no longer appropriate, and the need for either recognition of decommissioning and restoration provisions or contingent liability disclosure was reviewed. In 2020, provisions have been recognised for certain shorter-lived manufacturing facilities (See Note 18). For the remaining longer-lived facilities, where decommissioning would generally be more than 50 years away, it was concluded that, while there is a present obligation that has arisen from past events, the amount of the obligation cannot be measured with sufficient reliability. This conclusion was reached on the basis that the settlement dates are indeterminate; and that other estimates, such as extremely long-term discount rates for which there is no observable measure, are not reliable. Consequently, a decommissioning and restoration obligation exists that cannot be recognised or quantified and that is disclosed as a contingent liability.

Pesticide litigation

Shell Oil Company (SOC), along with another agricultural chemical pesticide manufacturer and several distributors, has been sued by public and quasi-public water purveyors, water storage districts, and private landowners alleging responsibility for groundwater contamination caused by applications of chemical pesticides. There are approximately 60 such cases currently pending. These suits assert various theories of strict liability and negligence, and seek to recover actual damages, including drinking well treatment and remediation costs. Most assert claims for punitive damages. While the Company continues to vigorously defend these lawsuits, a new environmental regulatory standard became effective in the State of California, where a majority of the suits are pending. Effective January 2018, the new standard requires public water systems state-wide to perform quarterly or monthly sampling of their drinking water sources for a chemical contained in certain pesticides. Water systems deemed out of compliance with the five parts per trillion regulatory standard must take corrective action to resolve the exceedance or take the potable water source out of service. In response to this new regulatory standard, the Company is monitoring the sampling results to determine the number of wells potentially impacted. Based on the claims asserted and SOC's track record, with regard to amounts paid to resolve varying claims, management does not expect the outcome of these lawsuits pending at December 31, 2020, to have a material adverse impact on Shell. However, there remains a high degree of uncertainty regarding the potential outcome of some of these pending lawsuits, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition.

Climate change litigation

In the USA, 18 lawsuits have been filed by several municipalities and/or states against oil and gas companies, including Royal Dutch Shell plc. The plaintiffs seek damages for a variety of claims including harm to their public and private infrastructure from rising sea levels and other alleged impacts of climate change caused by the defendants' fossil fuel products. A similar suit has been filed by a crab-fishing industry group claiming harm to their fisheries as a result of alleged ocean-related impacts of climate change. In the Netherlands a case has been filed against Shell by a group of environmental non-governmental organisations (eNGOs) and individual claimants seeking a court order that emission levels from Shell's activities and sold energy products are unlawful and that by 2030 it should reduce those emissions by least (net) 45%, alternatively 35% or 25% (as compared with 2019 levels). Management believes the outcome of these matters should be resolved in a manner favourable to Shell, but there remains a high degree of uncertainty regarding the ultimate outcome of these lawsuits, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition.

Brazil tax

Pursuant to Law 7.183/2015 issued by the State of Rio de Janeiro (RJ State) and effective March 2016, a value-added levy has been imposed on oil extraction in the RJ State. The Company understands that the obligations arising from this law are not legally sustainable and Shell obtained favourable injunctions suspending the enforcement of the law in two separate lawsuits, one filed to cover year 2016 and the other covering year 2017 onwards. The injunctions remain in effect and Shell received favourable decisions on the subject matter from the RJ State Court. The RJ State has appealed against both decisions and one is pending.

confirmation by the State Court while the other is pending final decisions by the Brazilian Superior and Supreme Courts. In addition, and as this is an industry-wide issue, the Brazilian Association of Oil and Gas Exploration and Production Companies, of which Shell is a member, filed a suit in February 2016 before the Brazilian Supreme Court, challenging the constitutionality of the law. This matter is currently pending with the Supreme Court. Should Shell be required to pay such a levy, it could result in a potential total liability of approximately \$5,473 million as of end 2020.

Louisiana coast litigation

The State of Louisiana and multiple local governments have initiated 43 lawsuits against 200 oil and gas companies, claiming either current or historical oil and gas operations caused or contributed to contamination, land loss and the erosion of the Louisiana coastline. Shell entities are named in 14 of the suits. Although the State and local parishes fail to claim specified amounts, these claims represent potentially material matters. The cases are of first impression, arise out of an untested 1980 Louisiana statute and represent a novel attempt to render illegal operations that federal and state agencies permitted and authorised at the time. Management believes the outcome of these matters should ultimately be resolved in a manner favourable to Shell; there remains a high degree of uncertainty, however, concerning the scope of the claims and the ultimate outcomes, as well as their potential effects on future operations, earnings, cash flows, reputation and Shell's financial condition.

NAM (Groningen gas field) litigation

Since 1963 NAM – a joint venture between Shell and ExxonMobil (50%–50%) – has been producing gas from the Groningen field, the largest gas field in Western Europe. After smaller tremors in the 1990s and the late 2000s, an earthquake measuring 3.6 on the Richter scale occurred in 2012, causing damage to properties in the affected area, and the area continues to experience tremor/earthquake-type events. NAM has received more than 100,000 claims for physical damage to property – the majority of which have been successfully settled. The Dutch State has taken over the damage-claim-handling from NAM for all claim categories (physical damage to property, housing value loss, emotional damages and loss of living enjoyment) while NAM remains financially responsible. NAM still faces claims in civil litigation from claimants who elect not to use the government arrangement or from claims pre-dating the governmental arrangements. These claims include, but are not limited to:

- housing claims where NAM was found liable for value loss;
- emotional damages and loss of living enjoyment ~5,000 claimants; and
- other civil litigation matters.

There remains a high degree of uncertainty concerning the ultimate outcomes and their potential effects on future operations, earnings, cash flows, reputation and Shell's financial condition.

Nigerian litigation

Shell subsidiaries and associates operating in Nigeria are parties to various environmental and contractual disputes brought in the courts of Nigeria, England and the Netherlands. These disputes are at different stages in litigation, including at the appellate stage, where judgements have been rendered against Shell entities. If taken at face value, the aggregate amount of these judgements could be seen as material. Management, however, believes that the outcomes of these matters will ultimately be resolved in a manner favourable to Shell. However, there remains a high degree of uncertainty regarding these cases, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition.

OPL 245

Authorities are investigating Shell Nigeria Exploration and Production Company Ltd.'s (SNEPCO's) investment in Nigerian oil block OPL 245 and the 2011 settlement of litigation pertaining to that block with regard to potential anti-bribery and anti-corruption laws.

On January 27, 2017, the Nigeria Federal High Court issued an Interim Order of Attachment for Oil Prospecting Licence 245 (OPL 245), pending the conclusion of the investigation. SNEPCO applied for and was granted a discharge of this order on constitutional and procedural grounds. Also in Nigeria, in March 2017 criminal charges alleging official corruption and conspiracy to commit official corruption were filed against SNEPCO, one current Shell employee and third parties including ENI SpA and one of its subsidiaries. Those proceedings are ongoing. In January 2020, criminal charges alleging disobeying direction of law were filed in Nigeria against Shell Nigeria Ultra Deep Ltd., SNEPCO, and third parties including Nigeria Agip Exploration Limited (NAE). Those proceedings are ongoing. In March 2017, parties alleging to be shareholders of Malabu Oil and Gas Company Ltd. (Malabu) filed two actions to challenge the 2011 settlement and the award of OPL 245 to SNEPCO and an ENI SpA subsidiary by the Federal Government of Nigeria. Those proceedings are also ongoing. On May 8, 2018, Human Environmental Development Agenda (HEDA) sought permission from the Federal High Court of Nigeria to apply for an order to direct the Attorney General of the Federation to revoke OPL 245 on grounds that the entire Malabu transaction in relation to the OPL is unconstitutional, illegal and void as it was obtained through fraudulent and corrupt practice. On October 4, 2018, SNEPCO was joined as a defendant in the HEDA action. Those proceedings are ongoing. On July 3, 2019, the Nigerian Federal High Court upheld objections from SNEPCO and NAE and struck the lawsuit filed by HEDA. The suit was struck because of the statute of limitations and the determination by the court that it lacked jurisdiction to hear the matter. HEDA has appealed the judgement.

On December 12, 2018, the Federal Republic of Nigeria (FRN) issued a claim form in the UK against Shell and six of its subsidiaries, ENI SpA and two of its subsidiaries, Malabu as well as two other entities for the amount of \$1,092 million plus damages for having participated in a fraudulent and corrupt scheme leading to the acquisition by Shell and ENI corporate defendants in 2011 of OPL 245. The Shell entities were served with proceedings in April and May 2019, following which they, and other defendants, challenged the jurisdiction of the English courts. Following a hearing in April 2020, the English High Court rendered judgement in May 2020, dismissing the claims in England and refusing the FRN's request for permission to appeal. In September 2020, the UK Court of Appeal also refused the FRN's permission to appeal, meaning the case is now concluded.

On February 14, 2017, Royal Dutch Shell plc received a notice of request for indictment from the Milan public prosecutor with respect to this matter. On December 20, 2017, Royal Dutch Shell plc and four former Shell employees including one former executive were remanded to trial in Milan. On May 14, 2018, a trial commenced in the Court of Milan. The FRN was admitted as a civil claimant by a court decision on July 20, 2018. On September 18, 2018, Shell was joined to the proceedings as the civilly responsible party for the damages caused by the alleged illegal acts of the four former Shell employees. Three other Shell entities (Shell UK Ltd, Shell Petroleum Development Company of Nigeria Ltd. and Shell Exploration and Production Africa Ltd.) also joined the proceedings as responsible civile for their respective former employees at that phase of the proceedings. The trial is ongoing with closing arguments completed in January and rebuttals scheduled for February. Based on Shell's review of the Milan public prosecutor's file and the information and facts currently available to Shell, management does not believe there is a basis to convict Shell or the four former Shell employees.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued**25 – LEGAL PROCEEDINGS AND OTHER CONTINGENCIES** continued

On September 20, 2018, a guilty judgement was filed by the Milan Judge of the Preliminary Hearing in a separate OPL 245 fast-track trial of two individuals, neither of whom worked for or on behalf of Shell. That decision is under appeal. Separate OPL 245 pre-trial criminal proceedings are pending against another individual who also did not work for or on behalf of Shell.

In February 2019, we were informed by the Dutch Public Prosecutor's Office (DPP) that they were nearing the conclusion of their investigation and preparing to prosecute Royal Dutch Shell plc for criminal charges directly or indirectly related to the 2011 settlement of disputes over OPL 245 in Nigeria. On October 2, 2019, the US Department of Justice (DOJ) informed Shell that it was closing its inquiry into Shell in relation to OPL 245. We understand that the decision was based on the facts available to the DOJ, including ongoing legal proceedings in Europe. On April 22, 2020, the United States Securities and Exchange Commission notified us that it had also closed its inquiry into Shell in relation to OPL 245. There remains a high degree of uncertainty around the OPL 245 matters and contingencies discussed above, as well as their potential effect on future operations, earnings, cash flows and Shell's financial condition. Accordingly, at this time, it is not practicable to estimate the magnitude and timing of any possible obligations or payments. Any violation of anti-bribery, anti-corruption or anti-money laundering legislation could have a material adverse effect on Royal Dutch Shell plc's earnings, cash flows and financial condition.

26 – EMPLOYEES**Employee costs**

	2020	2019	\$ million 2018
Remuneration	9,128	10,075	10,167
Social security contributions	793	844	810
Retirement benefits (see Note 17)	1,851	1,753	1,878
Share-based compensation (see Note 21)	359	537	531
Total [A]	12,131	13,209	13,386

[A] Excludes employees seconded to joint ventures and associates.

Average employee numbers

	2020	2019	Thousand 2018
Integrated Gas	11	10	9
Upstream [A]	14	14	14
Oil Products [A]	34	32	35
Chemicals [A]	2	4	4
Corporate [B]	25	23	20
Total [C]	86	83	82

[A] Due to the resegmentations. (See Note 4)

[B] Includes all employees working in business service centres irrespective of the segment they support.

[C] Excludes employees seconded to joint ventures and associates (2020: 2,000 employees; 2019: 3,000 employees; 2018: 3,000 employees).

27 – DIRECTORS AND SENIOR MANAGEMENT**Remuneration of Directors of the Company**

	2020	2019	\$ million 2018
Emoluments	6	8	12
Value of released awards under long-term incentive plans	6	12	20
Employer contributions to pension plans	1	1	1

Emoluments comprise salaries and fees, annual bonuses (for the period for which performance is assessed) and other benefits. The value of released awards under long-term incentive plans for the period is in respect of the performance period ending in that year. In 2020 retirement benefits were accrued in respect of qualifying services under defined benefit plans by two Directors.

Further information on the remuneration of the Directors can be found in the Directors' Remuneration Report on pages 153-156.

Directors and Senior Management expense

	2020	2019	\$ million 2018
Short-term benefits	14	18	26
Retirement benefits	3	3	3
Share-based compensation	17	15	14
Termination and related amounts	2	2	–
Total	36	38	43

Directors and Senior Management comprise members of the Executive Committee and the Non-executive Directors of the Company.

Short-term benefits comprise salaries and fees, annual bonuses delivered in cash and shares (for the period for which performance is assessed), other benefits and employer social security contributions.

28 – AUDITOR'S REMUNERATION

	2020	2019	\$ million 2018
Fees in respect of the audit of the Consolidated and Parent Company Financial Statements, including audit of consolidation returns	36	32	31
Other audit fees, principally in respect of audits of accounts of subsidiaries	17	18	16
Total audit fees	53	50	47
Audit-related fees	3	4	5
Fees in respect of other non-audit services [A]	2	–	1
Total	58	54	53

[A] Various services that were classified as 'Audit-related' in the past are classified as 'Other non-audit services' under the revised UK auditor rules that apply since March 15, 2020.

In addition, the auditor provided audit services to retirement benefit plans for employees of subsidiaries. Remuneration paid by those benefit plans amounted to \$1 million in 2020 (2019: \$1 million; 2018: \$1 million).

29 – EMISSION SCHEMES AND RELATED ENVIRONMENTAL PLANS

Emission trading schemes

Generally, emission trading schemes (ETS) are mandated governmental schemes to control emission levels and enhance clean energy transition, allowing for the trading of emission certificates. In most ETS, governments set an emission cap for one or more sectors. Generally, entities in scope of the scheme are allowed to buy emission certificates to cover shortages or sell surplus emission certificates. In certain countries emissions are priced through a carbon tax. For Shell, the most significant carbon pricing mechanisms are established in the EU, Canada, Singapore and the USA.

Biofuel schemes

Biofuel schemes are mandated schemes that set binding national targets on the share of renewables in fuel consumption or measures on reducing GHG emissions by fuel suppliers. Biofuels are blended with existing fuels such as gasoline and diesel to reduce net emissions. The share of biofuel in the total sales mix of fuel is used to comply with regulatory requirements. This can be achieved by biofuel production through 'selfblending' in jurisdictions that grant the biofuel certificates at blending stage or through purchase of renewable, certified feedstock like ethanol used subsequently in the manufacturing process.

Renewable power schemes

Renewable power schemes create a financial incentive to consume power that is sourced from renewable origins or requires that a minimum percentage of power sold meets the green definition of the relevant standard. These regulations are typically accompanied by schemes supporting investments in the renewable technology. Renewable power schemes generally use certificates to monitor compliance, where renewable power credits are granted for each MWh of energy generated that meets the predefined renewable criteria. Shell's compliance obligation under renewable power schemes comes primarily from energy supply and results from regulations applying in Europe, North America and Australia.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS continued**29 – EMISSION SCHEMES AND RELATED ENVIRONMENTAL PLANS** continued**2020**

	ETS and related schemes	Biofuels	Renewable power	Total
				\$ million
Emission and related cost recognised in the Income Statement	150 [A]	1,137 [B]	364	1,651
Purchased certificates presented under intangible assets	157	780	76	1,013
Obligation at the end of the period presented under other liabilities	(154) [C]	(1,603)	(296)	(2,053)
Of which:				
Short term	(154)	(1,549)	(290)	(1,993)
Long term	—	(54)	(6)	(60)
Net asset/(liability) at the end of the period	3	(823)	(220)	(1,040)

[A] Includes cost of emission certificates that were allocated free of charge, with an equivalent fair value at grant date of \$377 million.

[B] Represents the cost of biofuel certificates required in addition to own blending activities performed.

[C] Includes emission certificates that were allocated free of charge with a carrying amount of zero and an equivalent fair value at grant date of \$398 million.

Emission certificates acquired that are held for compliance purposes are recognised at cost under intangible assets. In addition, a portfolio of emission certificates is held for trading purposes and classified under inventory (see Notes 2 and Note 12).

Cost recognised in the Consolidated Statement of Income represents the compliance cost associated with emissions or with products sold during the year. The liability at year-end represents the compliance cost recognised over current and past compliance periods to the extent not settled to date. Liabilities are settled in line with compliance periods, which depend on the scheme and may not coincide with the calendar year.

Due to the increasing importance of emission schemes and related environmental plans, this Note is newly included in 2020 and comparatives are not provided. The figures present compliance schemes only, excluding voluntary activities.

30 – POST-BALANCE SHEET EVENTS

A restructuring plan named Reshape was announced in the third quarter 2020. Under Reshape, between 7,000 and 9,000 job reductions are expected by the end of 2022, including around 1,500 people who have already elected to take selective voluntary severance in 2020. In January 2021 the impact of Reshape was communicated to employees, establishing for some employees, a constructive obligation that satisfies the IFRS criteria for recognising a provision. This represents a non-adjusting post-balance sheet event under IFRS. The costs for this phase of the plan, and where the IFRS recognition criteria have been satisfied, are in the range of \$650 million to \$850 million (Shell share pre-tax) and will be recognised in the first quarter of 2021. Further redundancy costs will be recognised once the IFRS recognition criteria are met during 2021 and 2022.

On February 17, 2021, an agreement was reached with publicly listed Canadian energy company Crescent Point Energy Corp. to sell the Duvernay shale light oil position in Alberta, Canada, for a total consideration of \$707 million (C\$900 million). The transaction has an effective date of January 1, 2021. The consideration is comprised of \$550 million in cash and 50 million shares (valued at \$157 million) in Crescent Point Energy common stock (TSX: CPG). Subject to regulatory approvals, the transaction is expected to close in April 2021.

On March 9, 2021, we announced that Shell Egypt and one of its affiliates have signed an agreement with a consortium made up of subsidiaries of Cheiron Petroleum Corporation and Cairn Energy plc to acquire Shell's upstream assets in Egypt's Western Desert for a base consideration of \$646 million and additional payments of up to \$280 million between 2021 and 2024, contingent on the oil price and the results of further exploration. The transaction is subject to government and regulatory approvals and is expected to complete in the second half of 2021.

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED)

ABOUT THIS SECTION

The purpose of this section is to comply with the requirements of the Financial Accounting Standards Board (FASB) “Extractive Activities – Oil and Gas (Topic 932)”. Extractive activities for this purpose include exploration and production activities to extract oil, condensates, natural gas liquids, oil sands and natural gas from their natural reservoirs.

In Shell, extractive activities, or oil and gas exploration and production activities, are undertaken within the Upstream segment, Integrated Gas segment and Oil Products segment (oil sands). Shell’s extractive activities do not represent the full extent of the Upstream, Integrated Gas and Oil Products activities and exclude downstream GTL, some LNG activities, Marketing business in Oil Products, Power and New Energies, trading and optimisation, as well as other non-extractive activities. The information in this “extractive activities” section is therefore not suitable for modelling Shell’s integrated businesses for which we refer to the segment information. Full segment information to the Consolidated Financial Statements is available on pages 230-232.

The information set out on pages 265-282 is referred to as “unaudited” as a means of clarifying that it is not covered by the audit opinion of the independent registered public accounting firm that has audited and reported on the Consolidated Financial Statements.

PROVED RESERVES

Proved reserves estimates are calculated pursuant to the US Securities and Exchange Commission (SEC) Rules and the FASB’s Topic 932. Proved reserves can be either developed or undeveloped. The definitions used are in accordance with the SEC Rule 4-10 (a) of Regulation S-X. We include proved reserves associated with future production that will be consumed in operations.

Proved reserves shown are net of any quantities of crude oil or natural gas that are expected to be (or could be) taken as royalties in kind. Proved reserves outside North America include quantities that will be settled as royalties in cash. Proved reserves include certain quantities of crude oil or natural gas that will be produced under arrangements that involve Shell subsidiaries, joint ventures and associates in risks and rewards but do not transfer title of the product to those entities.

Subsidiaries’ proved reserves at December 31, 2020, were divided into 85% developed and 15% undeveloped on a barrel of oil equivalent basis. For the Shell share of joint ventures and associates, the proved reserves at December 31, 2020, were divided into 88% developed and 12% undeveloped on a barrel of oil equivalent basis.

Proved reserves are recognised under various forms of contractual agreements. Shell’s proved reserves volumes at December 31, 2020, present in agreements such as production-sharing contracts (PSC), tax/variable royalty contracts or other forms of economic entitlement contracts, where the Shell share of reserves can vary with commodity prices, were 2,044 million barrels of crude oil and natural gas liquids, and 12,133 thousand million standard cubic feet (scf) of natural gas.

Proved reserves cannot be measured exactly because estimation of reserves involves subjective judgement (see “Risk factors” on page 31 and our “Proved reserves assurance process” below). These estimates remain subject to revision and are unaudited supplementary information.

PROVED RESERVES ASSURANCE PROCESS

A central group of reserves experts, who on average have around 25 years’ experience in the oil and gas industry, undertake the primary assurance of the proved reserves bookings. This group of experts is part of the Resources Assurance and Reporting (RAR) organisation within Shell. A Vice President with 35 years’ experience in the oil and gas industry currently heads the RAR organisation. He is a member of the Society of

Petroleum Engineers, Society of Petroleum Evaluation Engineers and holds a BA in mathematics from Oxford University and an MEng in Petroleum Engineering from Heriot-Watt University. The RAR organisation reports directly to an Executive Vice President of Finance, who is a member of the Upstream Reserves Committee (URC). The URC is a multidisciplinary committee consisting of senior representatives from the Finance, Legal, Projects & Technology and Upstream organisations. The URC reviews and endorses all major (larger than 20 million barrels of oil equivalent) proved reserves bookings and de-bookings and endorses the total aggregated proved reserves. Final approval of all proved reserves bookings remains with Shell’s Executive Committee, and all proved reserves bookings are reviewed by Shell’s Audit Committee. The Internal Audit function also provides secondary assurance through audits of the control framework.

CRUDE OIL, NATURAL GAS LIQUIDS, SYNTHETIC CRUDE OIL AND BITUMEN

Shell subsidiaries’ proved reserves of crude oil, natural gas liquids (NGLs), synthetic crude oil and bitumen at the end of the year; their share of the proved reserves of joint ventures and associates at the end of the year; and the changes in such reserves during the year are set out on pages 266-268. Significant changes in these proved reserves are discussed below, where “revisions and reclassifications” are changes based on new information that resulted from development drilling, production history, and changes in economic factors.

PROVED RESERVES 2020–2019

Shell subsidiaries

Asia

The net increase of 181 million barrels in revisions and reclassifications was mainly in Kazakhstan and Oman.

USA

The net decrease of 116 million barrels in revisions and reclassifications of which half was mainly in Permian and Belridge Light Oil.

Canada

The net increase of 55 million barrels in revisions and reclassifications was mainly in Jackpine Mine and Muskeg River mine.

South America

The net decrease of 82 million barrels in revisions and reclassifications was mainly in Brazil.

PROVED RESERVES 2019–2018

Shell subsidiaries

Europe

The net decrease of 65 million barrels in sales and purchases resulted from divestments carried out in Denmark.

Asia

The net increase of 226 million barrels in revisions and reclassifications was mainly in Oman and Kazakhstan.

USA

The increase of 86 million barrels in revisions and reclassifications mainly resulted from field performance studies and development activities in the Permian Basin and in the Mars and Ursa fields in the Gulf of Mexico. The increase of 74 million barrels in extensions and discoveries was in the Permian Basin and PowerNap.

South America

The increase of 72 million barrels in revisions and reclassifications mainly resulted from field performance studies and development activities in the Lula (recently renamed Tupi) and Lapa fields (Brazil). The net increase of 60 million barrels in extensions and discoveries was mainly in Mero (Brazil).

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**Proved developed and undeveloped reserves 2020**

	Million barrels												
	Europe	Asia	Oceania	Africa	North America			South America	Total				
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	All products
Shell subsidiaries													
At January 1	274	1,551	121	395	982	18	607	–	1,033	4,374	607	–	4,981
Revisions and reclassifications	(46)	181	(41)	42	(116)	(2)	57	–	(82)	(63)	57	–	(6)
Improved recovery	–	–	–	–	–	–	–	–	–	–	–	–	0
Extensions and discoveries	–	14	–	–	27	7	–	–	–	48	–	–	48
Purchases of minerals in place	–	9	–	–	–	–	–	–	–	9	–	–	9
Sales of minerals in place	(1)	–	–	–	–	–	–	–	–	(1)	–	–	(1)
Production [A]	(49)	(182)	(7)	(58)	(165)	(9)	(20)	–	(136)	(606)	(20)	–	(626)
At December 31	178	1,573	73	379	728	15	644	–	815	3,761	644	–	4,405
Shell share of joint ventures and associates													
At January 1	12	271	–	–	–	–	–	–	–	283	–	–	283
Revisions and reclassifications	(5)	(27)	–	–	–	–	–	–	–	(32)	–	–	(32)
Improved recovery	–	–	–	–	–	–	–	–	–	–	–	–	–
Extensions and discoveries	–	–	–	–	–	–	–	–	1	1	–	–	1
Purchases of minerals in place	–	–	–	–	–	–	–	–	–	–	–	–	–
Sales of minerals in place	–	–	–	–	–	–	–	–	–	–	–	–	–
Production	(1)	(34)	–	–	–	–	–	–	(1)	(36)	–	–	(36)
At December 31	6	210	–	–	–	–	–	–	–	216	–	–	216
Total	184	1,783	73	379	728	15	644	–	815	3,977	644	–	4,621
Reserves attributable to noncontrolling interest in Shell subsidiaries at December 31	0	0	0	0	0	0	322	0	0	0	322	0	322

[A] Includes 1 million barrels consumed in operations for synthetic crude oil.

Proved developed reserves 2020

	Million barrels												
					North America				South America				
	Europe	Asia	Oceania	Africa	USA		Canada		Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Total
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	All products
Shell subsidiaries													
At January 1	156	1,403	106	314	641	15	607	–	675	3,310	607	–	3,917
At December 31	103	1,417	69	316	539	12	644	–	674	3,130	644	–	3,774
Shell share of joint ventures and associates													
At January 1	11	240	–	–	–	–	–	–	–	251	–	–	251
At December 31	6	192	–	–	–	–	–	–	1	199	–	–	199

Proved undeveloped reserves 2020

	Million barrels												
					North America				South America				Total
	Europe	Asia	Oceania	Africa	USA		Canada		Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	All products
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	All products
Shell subsidiaries													
At January 1	118	149	15	80	341	3	–	–	358	1,064	–	–	1,064
At December 31	76	156	5	63	189	3	–	–	141	633	–	–	633
Shell share of joint ventures and associates													
At January 1	1	31	–	–	–	–	–	–	–	32	–	–	32
At December 31	–	18	–	–	–	–	–	–	–	18	–	–	18

Proved developed and undeveloped reserves 2019

Million barrels

					North America				South America				Total	
	Europe	Asia	Oceania	Africa	USA		Canada							
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen		All products
Shell subsidiaries														
At January 1	368	1,502	129	420	1,017	23	661	—	1,027	4,486	661	—	5,147	
Revisions and reclassifications	27	226	2	33	86	(2)	(34)	—	72	444	(34)	—	410	
Improved recovery	—	—	—	—	—	—	—	—	4	4	—	—	4	
Extensions and discoveries	—	7	—	6	74	11	—	—	60	158	—	—	158	
Purchases of minerals in place	—	—	—	—	5	—	—	—	—	5	—	—	5	
Sales of minerals in place	(65)	—	—	—	(29)	(2)	—	—	—	(96)	—	—	(96)	
Production [A]	(56)	(184)	(10)	(64)	(171)	(12)	(20)	—	(130)	(627)	(20)	—	(647)	
At December 31	274	1,551	121	395	982	18	607	—	1,033	4,374	607	—	4,981	
Shell share of joint ventures and associates														
At January 1	9	281	—	—	—	—	—	—	—	290	—	—	290	
Revisions and reclassifications	4	21	—	—	—	—	—	—	—	25	—	—	25	
Improved recovery	—	4	—	—	—	—	—	—	—	4	—	—	4	
Extensions and discoveries	—	2	—	—	—	—	—	—	—	2	—	—	2	
Purchases of minerals in place	—	—	—	—	—	—	—	—	—	—	—	—	—	
Sales of minerals in place	—	—	—	—	—	—	—	—	—	—	—	—	—	
Production	(1)	(37)	—	—	—	—	—	—	—	(38)	—	—	(38)	
At December 31	12	271	—	—	—	—	—	—	—	283	—	—	283	
Total	286	1,822	121	395	982	18	607	—	1,033	4,657	607	—	5,264	
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31														
	—	—	—	—	—	—	304	—	—	—	304	—	304	

[A] Includes 1 million barrels consumed in operations for synthetic crude oil.

Proved developed reserves 2019

Million barrels

	North America												South America	Total
	Europe	Asia	Oceania	Africa	USA		Canada		Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen		
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen						
Shell subsidiaries														
At January 1	243	1,318	108	335	629	21	661	—	634	3,288	661	—	3,949	
At December 31	156	1,403	106	314	641	15	607	—	675	3,310	607	—	3,917	
Shell share of joint ventures and associates														
At January 1	8	251	—	—	—	—	—	—	—	259	—	—	259	
At December 31	11	240	—	—	—	—	—	—	—	251	—	—	251	

Proved undeveloped reserves 2019

Million barrels

	North America												Total
	Europe	Asia	Oceania	Africa	USA			Canada	South America				
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	
Shell subsidiaries													
At January 1	124	185	21	85	388	2	—	—	394	1,199	—	—	1,199
At December 31	118	149	15	80	341	3	—	—	358	1,064	—	—	1,064
Shell share of joint ventures and associates													
At January 1	1	30	—	—	—	—	—	—	—	31	—	—	31
At December 31	1	31	—	—	—	—	—	—	—	32	—	—	32

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**Proved developed and undeveloped reserves 2018**

Million barrels

	North America												Total
	Europe	Asia	Oceania	Africa	USA			Canada	South America				
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	
Shell subsidiaries													
At January 1	356	1,482	132	463	899	22	649	—	946	4,300	649	—	4,949
Revisions and reclassifications	94	227	14	18	81	7	32	—	48	489	32	—	521
Improved recovery	—	27	—	—	—	—	—	—	14	41	—	—	41
Extensions and discoveries	2	3	—	—	179	6	—	—	139	329	—	—	329
Purchases of minerals in place	—	—	—	—	—	—	—	—	3	3	—	—	3
Sales of minerals in place	(14)	(52)	(8)	—	(2)	—	—	—	—	(76)	—	—	(76)
Production [A]	(70)	(185)	(9)	(61)	(140)	(13)	(20)	—	(122)	(600)	(20)	—	(620)
At December 31	368	1,502	129	420	1,017	23	661	—	1,027	4,486	661	—	5,147
Shell share of joint ventures and associates													
At January 1	12	301	—	—	—	—	—	—	—	313	—	—	313
Revisions and reclassifications	(2)	(2)	—	—	—	—	—	—	—	(4)	—	—	(4)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and discoveries	—	18	—	—	—	—	—	—	—	18	—	—	18
Purchases of minerals in place	—	—	—	—	—	—	—	—	—	—	—	—	—
Sales of minerals in place	—	—	—	—	—	—	—	—	—	—	—	—	—
Production	(1)	(37)	—	—	—	—	—	—	—	(38)	—	—	(38)
At December 31	9	281	—	—	—	—	—	—	—	290	—	—	290
Total	377	1,783	129	420	1,017	23	661	—	1,027	4,776	661	—	5,437
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31													
	—	—	—	—	—	—	331	—	—	—	331	—	331

[A] Includes 1 million barrels consumed in operations for synthetic crude oil.

Proved developed reserves 2018

Million barrels

	North America												Total
	Europe	Asia	Oceania	Africa	USA			Canada	South America				
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	
Shell subsidiaries													
At January 1	250	1,364	46	373	569	21	649	—	651	3,274	649	—	3,923
At December 31	243	1,318	108	335	629	21	661	—	634	3,288	661	—	3,949
Shell share of joint ventures and associates													
At January 1	11	253	—	—	—	—	—	—	—	264	—	—	264
At December 31	8	251	—	—	—	—	—	—	—	259	—	—	259

Proved undeveloped reserves 2018

Million barrels

	North America												Total
	Europe	Asia	Oceania	Africa	USA			Canada	South America				
	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	Oil and NGL	Oil and NGL	Synthetic crude oil	Bitumen	
Shell subsidiaries													
At January 1	106	118	86	90	330	1	—	—	295	1,026	—	—	1,026
At December 31	124	185	21	85	388	2	—	—	394	1,199	—	—	1,199
Shell share of joint ventures and associates													
At January 1	1	48	—	—	—	—	—	—	—	49	—	—	49
At December 31	1	30	—	—	—	—	—	—	—	31	—	—	31

NATURAL GAS

Shell subsidiaries' proved reserves of natural gas at the end of the year, their share of the proved reserves of joint ventures and associates at the end of the year, and the changes in such reserves during the years are set out on pages 270-272. Significant changes in these proved reserves are discussed below. Volumes are not adjusted to standard heat content.

Apart from integrated projects, volumes of gas are reported on an "as-sold" basis. The price used to calculate future revenue and cash flows from proved gas reserves is the contract price or the 12-month average on "as-sold" volumes. Volumes associated with integrated projects are those measured at a designated transfer point between the upstream and downstream portions of the integrated project. Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

PROVED RESERVES 2020–2019

Shell subsidiaries

Oceania

The net decrease of 3,512 thousand million scf in revisions and reclassifications was mainly in Gorgon, Jansz-Io and Surat QGC.

USA

The net decrease of 319 thousand million scf in revisions and reclassifications was mainly in Permian. The 542 thousand million scf of Sales of minerals in place are mainly in Tioga.

PROVED RESERVES 2019–2018

Shell subsidiaries

Asia

The net increase of 859 thousand million scf in revisions and reclassifications was mainly in Qatar and Malaysia (Sabah and Sarawak).

Oceania

The net increase of 699 thousand million scf in revisions and reclassifications was mainly in Surat, Gorgon and Jansz-Io.

Africa

The net increase of 290 thousand million scf in revisions and reclassifications was mainly in Bonny and Gbaran (Nigeria).

Canada

The net increase of 317 thousand million scf in extensions and discoveries was mainly in Groundbirch.

Shell share of joint ventures and associates

Europe

The net decrease of 322 thousand million scf in revisions and reclassifications was mainly in Groningen (Netherlands).

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**Proved developed and undeveloped reserves 2020**

	Thousand million standard cubic feet							
	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Shell subsidiaries								
At January 1	2,998	10,618	8,360	2,608	1,868	1,281	1,259	28,992
Revisions and reclassifications	(209)	249	(3,512)	93	(319)	59	162	(3,477)
Improved recovery	—	—	—	—	—	—	—	—
Extensions and discoveries	—	2	33	5	66	122	—	228
Purchases of minerals in place	—	—	—	—	—	—	—	—
Sales of minerals in place	(28)	(29)	—	—	(542)	—	—	(599)
Production [A]	(319)	(913)	(705)	(343)	(272)	(167)	(293)	(3,012)
At December 31	2,442	9,927	4,176	2,363	801	1,295	1,128	22,132
Shell share of joint ventures and associates								
At January 1	595	4,198	36	—	—	—	—	4,829
Revisions and reclassifications	(200)	(62)	27	—	—	—	1	(234)
Improved recovery	—	—	—	—	—	—	—	—
Extensions and discoveries	—	1	—	—	—	—	1	2
Purchases of minerals in place	—	—	—	—	—	—	—	—
Sales of minerals in place	—	—	—	—	—	—	—	—
Production [B]	(133)	(459)	(22)	—	—	—	(1)	(615)
At December 31	262	3,678	41	—	—	—	1	3,982
Total	2,703	13,605	4,219	2,363	801	1,295	1,128	26,114
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31	—	—	—	—	—	—	—	—

[A] Includes 225 thousand million standard cubic feet consumed in operations.

[B] Includes 42 thousand million standard cubic feet consumed in operations.

Proved developed reserves 2020

	Thousand million standard cubic feet							Total
	Europe	Asia	Oceania	Africa	North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	2,060	10,091	5,769	1,523	1,615	781	968	22,807
At December 31	1,590	9,675	3,656	1,341	670	720	924	18,576
Shell share of joint ventures and associates								
At January 1	555	3,519	36	—	—	—	—	4,110
At December 31	227	3,175	42	—	—	—	1	3,445

Proved undeveloped reserves 2020

	Thousand million standard cubic feet							Total
	Europe	Asia	Oceania	Africa	North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	937	528	2,591	1,085	254	499	291	6,185
At December 31	852	252	520	1,022	132	575	203	3,556
Shell share of joint ventures and associates								
At January 1	39	680	—	—	—	—	—	719
At December 31	35	502	—	—	—	—	—	537

Proved developed and undeveloped reserves 2019

	Thousand million standard cubic feet							Total
	Europe	Asia	Oceania	Africa	North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	3,600	10,631	8,427	2,544	2,147	989	1,509	29,847
Revisions and reclassifications	(46)	859	699	290	114	235	29	2,180
Improved recovery	—	—	—	—	—	—	3	3
Extensions and discoveries	—	36	—	152	142	317	37	684
Purchases of minerals in place	—	—	—	—	5	—	—	5
Sales of minerals in place	(210)	—	—	—	(132)	(30)	—	(372)
Production [A]	(346)	(908)	(766)	(378)	(408)	(230)	(319)	(3,355)
At December 31	2,998	10,618	8,360	2,608	1,868	1,281	1,259	28,992
Shell share of joint ventures and associates								
At January 1	1,163	4,581	24	—	—	—	—	5,768
Revisions and reclassifications	(322)	64	34	—	—	—	—	(224)
Improved recovery	—	1	—	—	—	—	—	1
Extensions and discoveries	—	5	—	—	—	—	—	5
Purchases of minerals in place	—	—	—	—	—	—	—	—
Sales of minerals in place	—	—	—	—	—	—	—	—
Production [B]	(246)	(453)	(22)	—	—	—	—	(721)
At December 31	595	4,198	36	—	—	—	—	4,829
Total	3,593	14,816	8,396	2,608	1,868	1,281	1,259	33,821
Reserves attributable to non-controlling interest in shell subsidiaries at December 31	—	—	—	—	—	—	—	—

[A] Includes 247 thousand million standard cubic feet consumed in operations.

[B] Includes 42 thousand million standard cubic feet consumed in operations.

Proved developed reserves 2019

	Thousand million standard cubic feet							Total
	Europe	Asia	Oceania	Africa	North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	2,658	10,092	5,820	1,573	1,706	721	1,238	23,808
At December 31	2,060	10,091	5,769	1,523	1,615	781	968	22,807
Shell share of joint ventures and associates								
At January 1	1,136	3,938	24	—	—	—	—	5,099
At December 31	555	3,519	36	—	—	—	—	4,110

Proved undeveloped reserves 2019

	Thousand million standard cubic feet							Total
	Europe	Asia	Oceania	Africa	North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	942	539	2,607	971	441	268	271	6,039
At December 31	937	528	2,591	1,085	254	499	291	6,185
Shell share of joint ventures and associates								
At January 1	27	643	—	—	—	—	—	670
At December 31	39	680	—	—	—	—	—	719

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**Proved developed and undeveloped reserves 2018**

	Thousand million standard cubic feet							Total
	Europe	Asia	Oceania	Africa	North America		South America	
					USA	Canada		
Shell subsidiaries								
At January 1	3,100	11,822	7,978	2,082	2,569	1,272	1,501	30,324
Revisions and reclassifications	1,183	(483)	1,438	896	(296)	(153)	181	2,766
Improved recovery	—	—	—	—	—	—	7	7
Extensions and discoveries	3	354	—	—	283	131	65	836
Purchases of minerals in place	—	—	—	—	—	—	14	14
Sales of minerals in place	(192)	(157)	(232)	—	(32)	—	—	(613)
Production [A]	(494)	(906)	(757)	(434)	(377)	(261)	(258)	(3,487)
At December 31	3,600	10,631	8,427	2,544	2,147	989	1,509	29,847
Shell share of joint ventures and associates								
At January 1	5,125	4,964	19	—	—	—	—	10,108
Revisions and reclassifications	(3,653)	62	25	—	—	—	—	(3,566)
Improved recovery	—	—	—	—	—	—	—	—
Extensions and discoveries	—	5	—	—	—	—	—	5
Purchases of minerals in place	—	—	—	—	—	—	—	—
Sales of minerals in place	(37)	—	—	—	—	—	—	(37)
Production [B]	(273)	(450)	(20)	—	—	—	—	(743)
At December 31	1,163	4,581	24	—	—	—	—	5,768
Total	4,763	15,212	8,451	2,544	2,147	989	1,509	35,615
Reserves attributable to non-controlling interest in Shell subsidiaries at December 31	—	—	—	—	—	—	—	—

[A] Includes 245 thousand million standard cubic feet consumed in operations.

[B] Includes 41 thousand million standard cubic feet consumed in operations.

Proved developed reserves 2018

	Thousand million standard cubic feet							
	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Shell subsidiaries								
At January 1	2,978	11,460	5,026	1,493	1,652	859	1,225	24,693
At December 31	2,658	10,092	5,820	1,573	1,706	721	1,238	23,808
Shell share of joint ventures and associates								
At January 1	5,055	4,275	19	—	—	—	—	9,349
At December 31	1,136	3,938	24	—	—	—	—	5,099

Proved undeveloped reserves 2018

	Thousand million standard cubic feet							
					North America		South America	
	Europe	Asia	Oceania	Africa	USA	Canada		Total
Shell subsidiaries								
At January 1	122	362	2,952	589	917	413	276	5,631
At December 31	942	539	2,607	971	441	268	271	6,039
Shell share of joint ventures and associates								
At January 1	70	689	—	—	—	—	—	759
At December 31	27	643	—	—	—	—	—	670

STANDARDISED MEASURE OF DISCOUNTED FUTURE CASH FLOWS

The SEC Form 20-F requires the disclosure of a standardised measure of discounted future net cash flows, relating to proved reserves quantities and based on a 12-month unweighted arithmetic average sales price, calculated on a first-day-of-the-month basis, with cost factors based on those at the end of each year, currently enacted tax rates and a 10% annual discount factor. In our view, the information so calculated does not provide a reliable measure of future cash flows from proved reserves, nor does it permit a realistic comparison to be made of one entity with another because the assumptions used cannot reflect the varying circumstances within each entity. In addition, a substantial but unknown proportion of future real cash flows from oil and gas production activities is expected to derive from reserves which have already been discovered, but which cannot yet be regarded as proved.

STANDARDISED MEASURE OF DISCOUNTED FUTURE CASH FLOWS RELATING TO PROVED RESERVES AT DECEMBER 31

2020 – Shell subsidiaries

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	16,581	75,128	25,970	19,743	27,891	22,447	34,502	222,262
Future production costs	6,776	26,896	10,240	9,837	20,341	15,475	19,137	108,702
Future development costs	4,352	12,416	7,441	3,354	7,274	4,559	7,440	46,836
Future tax expenses	4,525	12,585	254	4,713	54	407	1,847	24,385
Future net cash flows	928	23,231	8,035	1,839	222	2,006	6,078	42,339
Effect of discounting cash flows at 10%	338	9,791	1,316	-50	-1,469	1,231	1,369	12,526
Standardised measure of discounted future net cash flows	590	13,440	6,719	1,889	1,691	775	4,709	29,813
Non Controlling Interest Included	-	-	-	-	-	398	-	398

2020 – Shell share of joint ventures and associates

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	1,209	22,209	139	-	-	-	21	23,578
Future production costs	2,801	11,472	136	-	-	-	17	14,426
Future development costs	948	5,165	111	-	-	-	2	6,226
Future tax expenses	-	3,026	-	-	-	-	-	3,026
Future net cash flows	-2,540	2,546	-108	-	-	-	2	-100
Effect of discounting cash flows at 10%	-583	412	-35	-	-	-	-	-206
Standardised measure of discounted future net cash flows	-1,957 [A]	2,134	-73 [A]	-	-	-	2	106

[A] While proved reserves are economically producible at the 2020 yearly average price, the standardised measure of discounted future net cash flows was negative for those proved reserves at December 31, 2020, due to addition of overhead, tax and abandonment costs and ongoing commitments post production of proved reserves.

2019 – Shell subsidiaries

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	33,762	111,802	71,775	31,046	55,800	31,522	64,957	400,664
Future production costs	11,818	32,581	21,589	12,158	30,139	16,651	32,362	157,298
Future development costs	6,047	13,449	10,103	4,081	11,137	4,603	13,219	62,639
Future tax expenses	9,285	25,938	7,016	10,542	2,397	2,313	5,429	62,920
Future net cash flows	6,612	39,834	33,067	4,265	12,127	7,955	13,947	117,807
Effect of discounting cash flows at 10%	1,917	17,851	13,328	377	1,815	5,571	4,094	44,953
Standardised measure of discounted future net cash flows	4,695	21,983	19,739	3,888	10,312	2,384	9,853	72,854
Non-controlling interest included	-	-	-	-	-	1,371	-	1,371

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**2019 – Shell share of joint ventures and associates**

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	3,615	38,099	122	–	–	–	–	41,836
Future production costs	2,810	18,336	81	–	–	–	–	21,227
Future development costs	935	6,946	36	–	–	–	–	7,917
Future tax expenses	718	6,160	4	–	–	–	–	6,882
Future net cash flows	(848)	6,657	1	–	–	–	–	5,812
Effect of discounting cash flows at 10%	(266)	1,190	(7)	–	–	–	–	917
Standardised measure of discounted future net cash flows	(582) [A]	5,467	8	–	–	–	–	4,893

[A] While proved reserves are economically producible at the 2019 yearly average price, the standardised measure of discounted future net cash flows was negative for those proved reserves at December 31, 2019, due to addition of overhead, tax and abandonment costs and ongoing commitments post production of proved reserves.

2018 – Shell subsidiaries

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	50,392	122,037	72,355	36,080	68,546	34,719	74,417	458,545
Future production costs	18,400	32,773	22,219	13,237	32,533	17,378	42,301	178,842
Future development costs	8,649	12,301	11,598	4,672	11,486	4,674	6,991	60,370
Future tax expenses	12,603	30,994	5,899	12,805	1,948	3,257	7,764	75,271
Future net cash flows	10,739	45,969	32,639	5,366	22,578	9,411	17,360	144,062
Effect of discounting cash flows at 10%	3,024	20,957	12,130	572	5,039	6,446	6,048	54,217
Standardised measure of discounted future net cash flows	7,715	25,012	20,509	4,794	17,539	2,964	11,312	89,845
Non-controlling interest included	–	1	–	–	–	1,638	–	1,639

2018 – Shell share of joint ventures and associates

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Future cash inflows	5,260	44,327	104	–	–	–	–	49,691
Future production costs	2,712	20,886	80	–	–	–	–	23,677
Future development costs	1,083	6,726	36	–	–	–	–	7,844
Future tax expenses	1,136	7,128	1	–	–	–	–	8,265
Future net cash flows	329	9,588	(13)	–	–	–	–	9,904
Effect of discounting cash flows at 10%	(76)	2,759	(8)	–	–	–	–	2,675
Standardised measure of discounted future net cash flows	405	6,829	(5) [A]	–	–	–	–	7,229

[A] While proved reserves are economically producible at the 2018 yearly average price, the standardised measure of discounted future net cash flows was negative for those proved reserves at December 31, 2018, due to addition of overhead, tax and abandonment costs and ongoing commitments post production of proved reserves.

CHANGE IN STANDARDISED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED RESERVES

2020

			\$ million
	Shell subsidiaries	Shell share of joint ventures and associates	Total
At January 1	72,854	4,893	77,747
Net changes in prices and production costs	(69,363)	(6,097)	(75,460)
Revisions of previous reserves estimates	695	17	712
Extensions, discoveries and improved recovery	(540)	0	(540)
Purchases and sales of minerals in place	24	(459)	(435)
Development cost related to future production	2,906	(426)	2,480
Sales and transfers of oil and gas, net of production costs	(16,904)	(1,954)	(18,858)
Development cost incurred during the year	8,197	759	8,956
Accretion of discount	9,881	832	10,713
Net change in income tax	22,063	2,541	24,604
At December 31	29,813	106	29,919

2019

			\$ million
	Shell subsidiaries	Shell share of joint ventures and associates	Total
At January 1	89,845	7,229	97,074
Net changes in prices and production costs	(18,759)	(1,017)	(19,776)
Revisions of previous reserves estimates	13,777	(293)	13,484
Extensions, discoveries and improved recovery	5,193	93	5,286
Purchases and sales of minerals in place	(2,831)	—	(2,831)
Development cost related to future production	(9,417)	(2)	(9,419)
Sales and transfers of oil and gas, net of production costs	(33,319)	(3,918)	(37,237)
Development cost incurred during the year	10,430	702	11,132
Accretion of discount	12,004	1,133	13,137
Net change in income tax	5,931	966	6,897
At December 31	72,854	4,893	77,747

2018

			\$ million
	Shell subsidiaries	Shell share of joint ventures and associates	Total
At January 1	50,524	7,109	57,633
Net changes in prices and production costs	58,128	6,156	64,284
Revisions of previous reserves estimates	15,265	(1,447)	13,818
Extensions, discoveries and improved recovery	8,936	532	9,468
Purchases and sales of minerals in place	(3,401)	(20)	(3,421)
Development cost related to future production	(3,876)	(308)	(4,184)
Sales and transfers of oil and gas, net of production costs	(38,014)	(4,858)	(42,872)
Development cost incurred during the year	10,724	666	11,390
Accretion of discount	7,060	994	8,054
Net change in income tax	(15,501)	(1,595)	(17,096)
At December 31	89,845	7,229	97,074

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES CAPITALISED COSTS**

The aggregate amount of property, plant and equipment and intangible assets, excluding goodwill, relating to oil and gas exploration and production activities, and the aggregate amount of the related depreciation, depletion and amortisation at December 31, are shown in the tables below.

Shell subsidiaries

	\$ million	
	2020	2019
Cost		
Proved properties [A]	276,762	265,700
Unproved properties	14,563	18,669
Support equipment and facilities	10,803	11,043
	302,128	295,412
Depreciation, depletion and amortisation		
Proved properties [A]	158,149	129,809
Unproved properties	5,342	4,089
Support equipment and facilities	5,031	4,078
	168,522	137,976
Net capitalised costs	133,606	157,436

[A] Includes capitalised asset decommissioning and restoration costs and related depreciation.

Shell share of joint ventures and associates

	\$ million	
	2020	2019
Cost		
Proved properties [A]	50,592	46,895
Unproved properties	2,512	2,428
Support equipment and facilities	5,037	4,882
	58,141	54,205
Depreciation, depletion and amortisation		
Proved properties [A]	36,876	34,120
Unproved properties	473 [B]	–
Support equipment and facilities	3,070	2,817
	40,419	36,937
Net capitalised costs	17,722	17,268

[A] Includes capitalised asset decommissioning and restoration costs and related depreciation.

[B] The major part of this cost consists of an impairment charge for the year.

OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES COSTS INCURRED

Costs incurred during the year in oil and gas property acquisition, exploration and development activities, whether capitalised or charged to income currently, are shown in the tables below. As a result of the adoption of IFRS 16 Leases as of January 1, 2019, leases are included in years 2020 and 2019. Development costs include capitalised asset decommissioning and restoration costs (including increases or decreases arising from changes to cost estimates or to the discount rate applied to the obligations) and exclude costs of acquiring support equipment and facilities, but include depreciation thereon.

Shell subsidiaries**2020**

	\$ million							
	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Other [A]		
Acquisition of properties								
Proved	4	156	–	5	–	–	–	165
Unproved	115	19	–	48	80	6	180	448
Exploration	287	102	33	168	951	275	390	2,206 [B]
Development	1,612	1,018	1,465	807	4,186	325	1,930	11,343

[A] Comprises Canada and Mexico.

[B] Includes \$504 million of Shales-related exploration activities. In 2020, we participated in 161 Shales productive exploratory wells with proved reserves allocated (Shell share: 77 wells).

2019

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Other [A]		Total
Acquisition of properties								
Proved	3	105	—	10	—	—	—	118
Unproved	—	11	—	67	118	5	3	204
Exploration	428	165	117	253	1,723	402	500	3,588 [B]
Development	2,054	1,434	1,225	1,480	4,455	287	2,418	13,353

[A] Comprises Canada and Mexico.

[B] Includes \$1,195 million of Shales-related exploration activities. In 2019, we participated in 231 Shales productive exploratory wells with proved reserves allocated (Shell share: 117 wells).

2018

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Other [A]		Total
Acquisition of properties								
Proved	3	3	—	596	44	—	—	646
Unproved	2	6	—	76	44	310	486	924
Exploration	384	182	49	188	1,912	251	502	3,468 [B]
Development	1,452	1,102	1,632	962	4,052	505	2,095	11,800

[A] Comprises Canada, Honduras and Mexico.

[B] Includes \$1,581 million of Shales-related exploration activities. In 2018, we participated in 234 Shales productive exploratory wells with proved reserves allocated (Shell share: 118 wells).

Shell share of joint ventures and associates

Joint ventures and associates did not incur costs in the acquisition of oil and gas properties in 2019 or 2018.

2020

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Canada		Total
Acquisition of properties								
Unproved	—	—	—	—	—	—	128	128
Exploration	—	94	10	—	—	—	105	209
Development	124	2,173	67	—	—	—	2	2,366

2019

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Canada		Total
Exploration	1	116	12	—	—	—	—	129
Development	94	1,400	65	—	—	—	—	1,559

2018

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Canada		Total
Exploration	—	90	14	—	—	—	—	104
Development	229	1,026	79	—	—	—	—	1,334

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES EARNINGS**

In Shell, extractive activities, or oil and gas exploration and production activities, are undertaken within the Integrated Gas segment, the Upstream segment and the Oil Products segment. Shell's extractive activities do not represent the full extent of Integrated Gas, Upstream and Oil Products activities, and exclude downstream GTL, some LNG activities, Marketing business in Oil Products, Power and New Energies, trading and optimisation, as well as other non-extractive activities.

The earnings disclosed in this "extractive activities" section are only a subset of Shell's total earnings and are therefore not suitable for modelling Shell's integrated businesses, for which we refer to the full segment earnings and descriptions of the Integrated Gas, Upstream and Oil Products businesses, which are available on page 46, 53 and 70 respectively. The earnings disclosed in this "extractive activities" section are not adjusted for items such as impairment charges, restructuring charges and charges for onerous contract provisions. Full segment information to the Consolidated Financial Statements is available on pages 230-232.

The results of operations for oil and gas producing activities are shown in the tables below. Taxes other than income tax include cash-paid royalties to governments outside North America.

Shell subsidiaries**2020**

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Other [A]		Total
Revenue								
Third parties	767	2,104	589	1,540	1,008	753	567	7,328
Sales between businesses	2,879	6,360	1,951	1,816	5,239	943	4,656	23,844
Total	3,646	8,464	2,540	3,356	6,247	1,696	5,223	31,172
Production costs excluding taxes	2,023	1,811	1,040	1,064	2,615	735	936	10,224
Taxes other than income tax	64	389	93	245	64	–	1,494	2,349
Exploration	256	149	234	202	325	108	473	1,747
Depreciation, depletion and amortisation	3,618	2,120	10,178	2,589	7,927	2,147	6,282	34,861
Other costs/(income)	553	1,127	(981)	645	230	631	161	2,366
Earnings before taxation	(2,868)	2,868	(8,024)	(1,389)	(4,914)	(1,925)	(4,123)	(20,375)
Taxation charge/(credit)	(423)	1,854	(3,175)	(104)	(790)	(449)	(300)	(3,387)
Earnings after taxation	(2,445)	1,014	(4,849)	(1,285)	(4,124)	(1,476)	(3,823)	(16,988)

[A] Comprises Canada and Mexico.

2019

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Other [A]		Total
Revenue								
Third parties	1,257	3,065	931	1,936	2,638	632	844	11,303
Sales between businesses	4,911	10,526	4,719	3,289	7,786	1,936	7,647	40,814
Total	6,168	13,591	5,650	5,225	10,424	2,568	8,491	52,117
Production costs excluding taxes	1,582	2,065	1,178	1,062	2,807	983	1,135	10,812
Taxes other than income tax	94	749	136	370	103	–	2,613	4,065
Exploration	619	583	107	187	411	159	288	2,354
Depreciation, depletion and amortisation	2,604	2,130	1,957	1,354	6,932	858	3,929	19,764
Other costs/(income)	(20)	1,599	(105)	121	(575)	818	1,379	3,217
Earnings before taxation	1,289	6,465	2,377	2,131	746	(250)	(853)	11,905
Taxation charge/(credit)	848	4,013	1,094	1,431	154	(110)	(78)	7,352
Earnings after taxation	441	2,452	1,283	700	592	(140)	(775)	4,553

[A] Comprises Canada, Honduras and Mexico.

2018

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Other [A]		Total
Revenue								
Third parties	1,875	3,364	1,389	2,401	2,165	507	1,023	12,724
Sales between businesses	6,705	11,284	4,683	3,586	7,716	1,946	7,154	43,074
Total	8,580	14,648	6,072	5,987	9,881	2,453	8,177	55,798
Production costs excluding taxes	2,262	2,143	1,073	1,093	2,573	1,069	1,401	11,614
Taxes other than income tax	122	841	199	328	83	—	2,767	4,340
Exploration	277	149	78	144	341	114	237	1,340
Depreciation, depletion and amortisation	2,684	2,301	1,571	1,394	4,543	(346)	3,271	15,418
Other costs/(income)	947	(180)	(514)	609	447	667	849	2,825
Earnings before taxation	2,288	9,394	3,665	2,419	1,894	949	(348)	20,261
Taxation charge/(credit)	2,047	4,851	893	902	550	236	1,162	10,641
Earnings after taxation	241	4,543	2,772	1,517	1,344	713	(1,510)	9,620

[A] Comprises Canada, Honduras and Mexico.

Shell share of joint ventures and associates

2020

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Canada		Total
Third-party revenue	514	3,464	65	—	—	—	32	4,075
Total	514	3,464	65	—	—	—	32	4,075
Production costs excluding taxes	272	726	72	—	—	—	8	1,078
Taxes other than income tax	22	423	5	—	—	—	4	454
Exploration	2	97	—	—	—	—	—	99
Depreciation, depletion and amortisation	366	1,219	270	—	(7)	—	23	1,871
Other costs/(income)	296	365	(14)	—	(1)	—	12	658
Earnings before taxation	(444)	634	(268)	—	8	—	(15)	(85)
Taxation charge	(281)	162	—	—	2	—	(9)	(126)
Earnings after taxation	(163)	472	(268)	—	6	—	(6)	41

2019

					North America		South America	\$ million
	Europe	Asia	Oceania	Africa	USA	Canada		Total
Third-party revenue	1,233	5,475	81	—	—	—	—	6,789
Total	1,233	5,475	81	—	—	—	—	6,789
Production costs excluding taxes	249	669	88	—	—	—	—	1,006
Taxes other than income tax	75	1,037	6	—	—	—	—	1,118
Exploration	4	51	—	—	—	—	—	55
Depreciation, depletion and amortisation	217	949	415	—	—	—	—	1,581
Other costs/(income)	547	622	(18)	—	1	1	—	1,153
Earnings before taxation	141	2,147	(410)	—	(1)	(1)	—	1,876
Taxation charge	39	957	—	—	—	—	—	996
Earnings after taxation	102	1,190	(410)	—	(1)	(1)	—	880

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**2018**

\$ million

	Europe	Asia	Oceania	Africa	North America		South America	Total
					USA	Canada		
Third-party revenue	1,395	5,884	79	—	—	—	—	7,358
Total	1,395	5,884	79	—	—	—	—	7,358
Production costs excluding taxes	307	674	105	—	—	—	—	1,086
Taxes other than income tax	82	1,259	4	—	—	—	—	1,345
Exploration	5	45	—	—	—	—	—	50
Depreciation, depletion and amortisation	318	1,016	163	—	—	—	—	1,497
Other costs/(income)	595	615	(26)	—	—	—	—	1,184
Earnings before taxation	88	2,275	(167)	—	—	—	—	2,196
Taxation charge	7	975	—	—	—	—	—	982
Earnings after taxation	81	1,300	(167)	—	—	—	—	1,214

ACREAGE AND WELLS

The tables below reflect acreage and wells of Shell subsidiaries, joint ventures and associates. The term “gross” refers to the total activity in which Shell subsidiaries, joint ventures and associates have an interest. The term “net” refers to the sum of the fractional interests owned by Shell subsidiaries plus the Shell share of joint ventures and associates’ fractional interests. Data below are rounded to the nearest whole number.

Oil and gas acreage (at December 31)

Thousand acres

	2020				2019				2018			
	Developed		Undeveloped		Developed		Undeveloped		Developed		Undeveloped	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Europe [A]	6,075	1,900	13,399	5,663	6,278 [B]	1,910 [B]	13,844 [C]	6,077 [C]	6,022	1,954	13,732 [D]	6,322 [D]
Asia	21,360	7,651	34,545	18,003	21,387	7,672	31,486	14,880	22,087	7,885	31,676	15,433
Oceania	3,151	1,275	9,156	4,974	3,025	1,215	11,720	6,260	3,202	1,220	15,319	10,095
Africa	4,764	1,996	69,194	37,743	4,663	1,938	62,965	32,564	4,666	1,940	38,874	22,732
North America – USA	1,145	728	1,916	1,408	1,346 [E]	906 [E]	2,483 [F]	1,911 [F]	1,548 [G]	977 [G]	2,133	1,638 [H]
North America – Mexico	—	—	5,178	3,291	—	—	5,178	3,291	—	—	5,178	3,885
North America – Canada	490	336	1,689	1,177	483	329	1,783	1,265	1,108	752	1,681	1,193
South America	1,449	609	20,147	11,731	1,393	595	16,446	10,214	1,490	710	10,352	6,725
Total	38,434	14,495	155,224	83,990	38,575	14,565	145,905	76,462	40,123	15,438	118,945	68,023

[A] Includes Greenland for 2018.

[B] Corrected from 6,289 Gross (1,915 Net)

[C] Corrected from 13,864 Gross (6,082 Net)

[D] Corrected from 14,385 Gross (6,540 Net)

[E] Corrected from 1,333 Gross (877 Net)

[F] Corrected from 2,489 Gross (1,917 Net)

[G] Corrected from 1,541 Gross (952 Net)

[H] Corrected from 1,635 Net

Number of productive wells [A] (at December 31)

	2020				2019				2018			
	Oil		Gas		Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Europe	814	197	1,055	336	894 [B]	217	1,095 [C]	345	1,077	277	1,205 [D]	379
Asia	8,505	3,105	342	193	7,860 [E]	2,874 [E]	336	193	7,449 [F]	2,728	331	189
Oceania	–	–	3,394	1,927	–	–	3,348 [G]	1,891 [G]	–	–	3,411	1,924
Africa	567	235	209	141	514	206	202	139	478	189	195	132
North America – USA	14,505	7,402	401	223	14,953 [H]	7,650 [H]	824 [I]	518 [I]	15,238 [J]	7,755 [J]	1,481 [K]	674 [K]
North America – Canada	–	–	757	684	–	–	748	676	1	1	936	846
South America	179	82	63	37	137	63	58	36	117	52	63	41
Total	24,570	11,021	6,221	3,541	24,358	11,010	6,611	3,798	24,360	11,002	7,622	4,185

[A] The number of productive wells with multiple completions at December 31, 2020, was 956 gross (416 Net); December 31, 2019: 950 Gross (418 net) corrected from 955 Gross, December 31, 2018: 1,055 Gross (454 net) corrected from 1,061 Gross

[B] Corrected from 893

[C] Corrected from 1,091 Gross

[D] Corrected from 1,201 Gross

[E] Corrected from 7,767 Gross (2,841 Net)

[F] Corrected from 7,455

[G] Corrected from 3,352 Gross (1,896 Net)

[H] Corrected from 14,935 Gross (7,638 Net)

[I] Corrected from 822 Gross (516 Net)

[J] Corrected from 15,224 Gross (7,745 Net)

[K] Corrected from 1,479 Gross (672 Net)

Number of net productive wells and dry holes drilled

	2020		2019		2018	
	Productive	Dry	Productive	Dry	Productive	Dry
Exploratory [A]						
Europe	–	1	–	4	1	2
Asia	10	8	25	17	22	11
Oceania	–	6 [B]	–	2	–	–
Africa	5	7	8	8	6	6
North America – USA	57	81 [C]	89	9	104	4
North America – Canada	17	1	24	–	14	–
South America	5	3	8	1	6	7
Total	94	107	154	41	153	30
Development						
Europe	6	–	4	1	4	–
Asia	169	–	182	–	198	–
Oceania	22	–	16	–	54	–
Africa	19	–	34	–	24	1
North America – USA	110	–	280	5	276	–
North America – Canada	–	–	6	–	53	–
South America	14	–	10	1	5	–
Total	340	–	532	7	614	1

[A] Productive wells are wells with proved reserves allocated. Wells in the process of drilling are excluded and presented separately below.

[B] Includes 4 Wells in Shell Australia (SAL) which were relinquished in June 2020

[C] Includes 75 sold wells in Tioga that were pending determination at time of sale

SUPPLEMENTARY INFORMATION – OIL AND GAS (UNAUDITED) continued**Number of wells in the process of exploratory drilling [A]**

	At January 1		Wells in the process of drilling at January 1 and allocated proved reserves during the year		Wells in the process of drilling at January 1 and determined as dry during the year		New wells in the process of drilling at December 31		At December 31	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Europe	15	8	–	–	(3)	(1)	–	–	12	7
Asia	53	20	(7)	(3)	(7)	(2)	18	7	57	22
Oceania	44 [B]	17 [B]	(1)	–	(11)	(6)	–	–	32	11
Africa	36 [C]	24 [C]	(1)	(1)	(7)	(4)	–	–	28	19
North America – USA	219 [D]	132 [D]	(101)	(38)	(90)	(79)	64	28	92	43
North America – Canada	21	21	(16)	(16)	–	–	10	10	15	15
South America	33	15 [E]	(7)	(3)	(5)	(3)	14	4	35	13
Total	421	237	(133)	(61)	(123)	(95)	106	49	271	130

[A] Wells in the process of exploratory drilling includes wells pending further evaluation.

[B] Corrected from 40 Gross (15 Net); Includes 8 Gross (4 Net) in Shell Australia (SAL) which were relinquished in June 2020

[C] Corrected from 45 (28 Net)

[D] Corrected from 197 (126 Net); Includes 75 Gross (75 Net) sold wells in Tioga that were pending determination at time of sale

[E] Corrected from 16

Number of wells in the process of development drilling

	At January 1		At December 31	
	Gross	Net	Gross	Net
Europe	9 [A]	3	7	2
Asia	53	21	41	24
Oceania	122 [B]	71	191	124
Africa	5	2	4	1
North America – USA	41	34	30	20
North America – Canada	–	–	–	–
South America	12	8	30	21
Total	242	139	303	192

[A] Corrected from 11

[B] Corrected from 123

In addition to the present activities mentioned above, the following recovery methods are operational in the following countries: water flooding (Brazil (including water alternating gas), Brunei, Egypt, Malaysia, Nigeria, Norway, Oman, Russia, the UK and the USA); gas injection (Brunei, Kazakhstan, Malaysia, Nigeria and Oman); steam injection (the Netherlands, Oman and the USA), and polymer flooding (Oman).

PARENT COMPANY FINANCIAL STATEMENTS

The Parent Company Financial Statements have not been audited in accordance with the standards of the Public Company Accounting Oversight Board (United States).

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PARENT COMPANY FINANCIAL STATEMENTS continued**STATEMENT OF INCOME**

		\$ million	
	Notes	2020	2019
Dividend income		8,481	21,051
Interest and other income	3	11	101
Administrative expenses		(58)	(54)
Interest and other expense	3	(1)	(146)
Income before taxation		8,433	20,952
Taxation credit/(charge)	6	8	(567)
Income for the period		8,441	20,385

STATEMENT OF COMPREHENSIVE INCOME

		\$ million	
		2020	2019
Income for the period		8,441	20,385
Comprehensive income for the period		8,441	20,385

BALANCE SHEET

		\$ million	
	Notes	Dec 31, 2020	Dec 31, 2019
Assets			
Non-current assets			
Investments in subsidiaries	4	256,663	256,654
		256,663	256,654
Current assets			
Amounts due from subsidiaries	13	1,488	1,864
Cash and cash equivalents		1	4
		1,489	1,868
Total assets		258,152	258,522
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	5	1,250	1,775
Total liabilities		1,250	1,775
Equity			
Share capital	8	651	657
Other reserves	9	235,419	235,561
Retained earnings		20,832	20,529
Total equity		256,902	256,747
Total liabilities and equity		258,152	258,522

Signed on behalf of the Board

/s/ Jessica Uhl

JESSICA UHLChief Financial Officer
March 10, 2021

STATEMENT OF CHANGES IN EQUITY

				\$ million
	Notes	Share capital	Other reserves	Retained earnings
At January 1, 2020		657	235,561	20,529
Comprehensive income for the period		–	–	8,441
Dividends	10	–	–	(7,270)
Repurchases of shares	8	(6)	6	(1,214)
Share-based compensation	9	–	(148)	346
At December 31, 2020		651	235,419	20,832
At January 1, 2019		685	235,536	25,458
Comprehensive income for the period		–	–	20,385
Dividends	10	–	–	(15,199)
Repurchases of shares	8	(28)	28	(10,286)
Share-based compensation	9	–	(3)	171
At December 31, 2019		657	235,561	20,529

STATEMENT OF CASH FLOWS

	Notes	2020	2019
Income before taxation for the period		8,433	20,952
Adjustment for:			
Dividend income		(8,481)	(21,051)
Interest income		(11)	(101)
Interest expense		–	111
Share-based compensation		25	19
Decrease in working capital		501	4,008
Cash flow from operating activities		467	3,938
Dividends received		8,481	21,051
Interest received		11	101
Share-based compensation		164	408
Cash flow from investing activities		8,656	21,560
Cash dividends paid	10	(7,424)	(15,198)
Shares repurchased	8	(1,702)	(10,188)
Interest and other expenses paid		–	(111)
Cash flow from financing activities		(9,126)	(25,497)
Change in cash and cash equivalents		(3)	1
Cash and cash equivalents at beginning of the year		4	3
Cash and cash equivalents at end of the year		1	4

[A] Cash dividends paid represents the payment of net dividends (after deduction of withholding taxes where applicable) and payment of withholding taxes on dividends paid in the previous quarter.

NOTES TO THE PARENT COMPANY FINANCIAL STATEMENTS

1 BASIS OF PREPARATION

The Financial Statements of Royal Dutch Shell plc (the "Company") have been prepared in accordance with international accounting standards in conformity with the requirements of the Companies Act 2006 (the "Act"). As applied to the Company, there are no material differences from International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB); therefore, the Financial Statements have been prepared in accordance with IFRS as issued by the IASB.

As described in the accounting policies in Note 2, the Financial Statements have been prepared under the historical cost convention except for certain items measured at fair value. Those accounting policies have been applied consistently in all periods.

The preparation of financial statements in conformity with IFRS requires the use of certain accounting estimates. It also requires management to exercise its judgement in the process of applying the Company's accounting policies. Actual results may differ from those estimates.

The financial results of the Company are included in the Consolidated Financial Statements on pages 216-264. The financial results of the Company incorporate the results of the Dividend Access Trust (the "Trust"), the financial statements of which are presented on pages 294-297.

The Company's principal activity is being the parent company for Shell, as described in Note 1 of the Consolidated Financial Statements (see page 221).

2 SIGNIFICANT ACCOUNTING POLICIES

The Company's accounting policies follow those of Shell as set out in Note 2 to the Consolidated Financial Statements on pages 221-229. The following are Company-specific policies.

Presentation and functional currency

The Company's presentation and functional currency is US dollars (dollars).

Investments

Investments in subsidiaries are stated at cost, net of any impairment. Investments are tested for impairment whenever events or changes in circumstances indicate that the carrying amounts for those investments may not be recoverable. For the purposes of determining whether impairment of investments in subsidiaries has occurred, and the extent of any impairment loss or its reversal, the key assumptions management uses in estimating future cash flows for value-in-use measures include future oil and gas prices, market supply and demand, potential costs associated with operational greenhouse gas (GHG) emissions, and expected product volumes and refining margins appropriate to the local circumstances and environment. These assumptions and the judgements of management that are based on them are subject to change as new information becomes available. Cash flow estimates are discounted at a rate based on Shell's marginal cost of debt. Changes in economic conditions can also affect the rate used to discount future cash flow estimates.

The original cost of the Company's investment in Royal Dutch Petroleum Company (Royal Dutch) was based on the fair value of the shares transferred to the Company by the former shareholders of Royal Dutch in exchange for A shares in the Company during the public exchange offer in 2005. The original cost of the Company's investment in The "Shell" Transport and Trading Company plc, now The Shell Transport and Trading Company Limited (Shell Transport), was the fair value of the shares held by the former shareholders of The "Shell" Transport and Trading Company plc, transferred in consideration for the issuance of B shares as part of the Scheme of Arrangement in 2005. The Company's investments in Royal Dutch and Shell Transport subsequently became an investment in Shell Petroleum N.V. (Shell Petroleum); this change had no impact on the cost of investments in subsidiaries. On February 15, 2016 the Company acquired all the voting rights in BG Group plc via the issuance of shares and cash payments of a total fair value \$53,086 million. In September 2016, the Company's shares in BG Group Limited (BG), formerly BG Group plc, were exchanged for an increased investment in Shell Petroleum. This change had no impact on the cost of investment in subsidiaries.

Dividend income

Dividends are recognised on a paid basis unless the dividend has been confirmed by a general meeting of Shell Petroleum, in which case income is recognised on the date at which receipt is deemed virtually certain.

Share-based compensation plans

The fair value of share-based compensation for equity-settled plans granted to employees of subsidiaries under the Company's plans is recognised as an investment in subsidiaries from the date of grant over the vesting period with a corresponding increase in equity.

In the year of vesting of a plan, the costs for the actual deliveries are charged to the relevant employing subsidiaries. This is recognised as a realisation of the investment originally booked. If the actual vesting costs are higher than the cumulatively recognised share-based compensation charge, the difference is recognised in income.

See Note 21 of the Consolidated Financial Statements (see page 256) for information on the Company's principal plan.

Taxation

The Company is tax-resident in the Netherlands. For the assessment of corporate income tax in the Netherlands, the Company and certain of its subsidiaries form a fiscal unit. The recognition and derecognition of deferred tax assets and or liabilities, as applicable, may be done either by the Company or by any of its subsidiary members. Any current tax receivable or payable (and deferred tax asset or liability) recognised by the Company for the fiscal unit as a whole is settled between the Company and other members of the fiscal unit at the balance sheet date. Balances not settled with the Company at the balance sheet date are recognised in the subsidiary member's financial statements and, to the extent they are material, are disclosed in the notes to the Company's financial statements.

The Company's tax charge or credit recognised in the income statement is calculated at the statutory tax rate prevailing in the Netherlands for current tax and statutory tax rate substantively enacted in the Netherlands for deferred tax.

3 INTEREST AND OTHER INCOME/EXPENSE

	2020	\$ million 2019
Interest and other income:		
Interest income	11	101
Total	11	101
Interest and other expenses:		
Interest expense	—	(111)
Foreign exchange losses	(1)	(35)
Total	(1)	(146)

4 INVESTMENTS IN SUBSIDIARIES

	2020	\$ million 2019
At January 1	256,654	256,920
Share-based compensation	332	506
Recovery of vested share-based compensation	(323)	(772)
At December 31	256,663	256,654

As at December 31, 2020, the market capitalisation of the Royal Dutch Shell plc and its subsidiaries (collectively referred to as the “Group”) was less than the Company’s carrying value of its investment in the Group. As such, management has performed an impairment test in order to compare the carrying value of the investment in the Group to the associated value in use. Cash flow projections have been derived from internally approved business plans, and reflect management’s forecasts of commodity prices, market supply and demand, potential costs associated with GHG emissions, product margins including refining margins and expected production volumes. Cash flows include a balanced view of risk arising from the integrated nature of the portfolio. The nominal pre-tax rate applied was 6% (see Note 8 to the Consolidated Financial Statements).

Oil and gas price assumptions applied for impairment testing are reviewed and, where necessary, adjusted on a periodic basis. Reviews include comparison with available market data and forecasts that reflect developments in demand such as global economic growth, technology efficiency, policy measures and, in supply, consideration of investment and resource potential, cost of development of new supply, and behaviour of major resource holders. The near-term commodity price assumptions applied in impairment testing were as follows:

Commodity price assumptions [A]

	2021	2022	2023	2024
Brent crude oil (\$/b)	40	50	60	63
Henry Hub natural gas (\$/MMBtu)	2.50	2.50	2.75	3.03

[A] Money of the day.

For periods after 2024, the real-terms long-term price assumptions applied were \$60 per barrel (/b) (2019: \$60/b) for Brent crude oil and \$3.00 per million British thermal units (/MMBtu) (2019: \$3.00/MMBtu) for Henry Hub natural gas, both at real-terms 2020.

Underlying cash flow forecasts used in determining value in use are consistent with those used to assess the recoverable amount of individual cash generating units in the Consolidated Financial Statements.

Based on the impairment test analysis performed, management remains satisfied that the carrying amount of the investment remains recoverable under the reasonable range of anticipated outcomes.

5 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	Dec 31, 2020		\$ million Dec 31, 2019	
	Current	Non-current	Current	Non-current
Amounts due to subsidiaries (see Note 13)	874	—	750	—
Accruals and other liabilities	44	—	730	—
Withholding tax payable	322	—	291	—
Unclaimed dividends	10	—	4	—
Total	1,250	—	1,775	—

Accruals and other liabilities at December 31, 2019, principally comprise commitments for share repurchases undertaken on the Company’s behalf under irrevocable, non-discretionary arrangements. There is no such liability outstanding as at December 31, 2020. See Note 20 to the Consolidated Financial Statements.

NOTES TO THE PARENT COMPANY FINANCIAL STATEMENTS continued**6 TAXATION**

	2020	\$ million 2019
Current tax:		
Charge in respect of current period	—	9
Total	—	9
Deferred tax:		
Relating to the origination and reversal of tax losses and credits	(8)	539
Relating to changes in tax rates and legislation	—	19
Total	(8)	558
Taxation (credit)/charge	(8)	567

In 2020, current taxes of nil and deferred taxes of \$8 million have been recognised in the Company's accounts. Derecognition of deferred tax assets of \$517 million (representing unused tax losses and tax credits related to the fiscal unit) have not been recognised in the Company, but in the income statement of Shell Petroleum, a subsidiary of the Company forming part of the same fiscal unit. The amount derecognised in the Company's accounts in 2019 was \$539 million.

Reconciliation of applicable tax charge at statutory tax rate to taxation charge

	2020	\$ million 2019
Income before taxation	8,433	20,952
Applicable tax charge at the statutory tax rate of 25.0% (2019: 25.0%)	2,108	5,238
Derecognition of deferred tax assets	—	539
Tax effects of:		
Income not subject to tax at statutory rates	(2,120)	(5,253)
Expenses not deductible for tax purposes	4	24
Other	—	19
Taxation (credit)/charge	(8)	567

Taxes payable are reported within accounts payable and accrued liabilities (see Note 5).

Deferred tax assets

	2020	\$ million 2019
At January 1	—	355
Recognised in income	8	(558)
Other movements	(8)	203
At December 31	—	—

As at December 31, 2020, in the Company's capacity as head of the fiscal unit, no deferred tax assets have been recognised (2019: nil). The Dutch Fiscal Unit has unrecognised unused tax losses amounting to \$3,776 million (2019: \$1,683 million) and unrecognised credits carried forward amounted to \$349 million (2019: \$273 million). Unused tax losses are available for relief against future taxable profits for a period of up to six to nine years, depending on the year in which the losses were incurred. Unused tax credits are available indefinitely. Under the proposed new tax legislation, which is not considered substantively enacted as at December 31, 2020, the losses are expected to be available indefinitely, to the extent not yet expired as at January 1, 2022.

7 FINANCIAL INSTRUMENTS

Financial assets and liabilities measured at amortised cost in the Company's Balance Sheet comprise amounts due from subsidiaries (see Note 13) and certain amounts reported within accounts payable and accrued liabilities (see Note 5). The fair value of financial assets and liabilities at December 31, 2020, and December 31, 2019, approximates their carrying amount.

Information on financial risk management is presented in Note 19 of the Consolidated Financial Statements (see pages 251-255). Foreign currency derivatives are used by the Company to manage foreign exchange risk, which arises when certain transactions are denominated in a currency that is not the Company's functional currency. No derivative financial instruments were held at December 31, 2020, or December 31, 2019.

8 SHARE CAPITAL

Issued and fully paid ordinary shares of €0.07 each [A]

	Number of shares		Nominal value (\$ million)		
	A	B	A	B	Total
At January 1, 2020	4,151,787,517	3,729,407,107	349	308	657
Repurchases of shares	(50,548,018)	(23,223,271)	(4)	(2)	(6)
At December 31, 2020	4,101,239,499	3,706,183,836	345	306	651
At January 1, 2019	4,471,889,296	3,745,486,731	376	309	685
Repurchases of shares	(320,101,779)	(16,079,624)	(27)	(1)	(28)
At December 31, 2019	4,151,787,517	3,729,407,107	349	308	657

[A] Share capital at December 31, 2020, and 2019, also included 50,000 issued and fully paid sterling deferred shares of £1 each.

At the Company's Annual General Meeting (AGM) on May 19, 2020, the Board was authorised to allot ordinary shares in the Company, and to grant rights to subscribe for or to convert any security into ordinary shares in the Company, up to an aggregate nominal amount of €182.7 million (representing 2,611 million ordinary shares of €0.07 each), and to list such shares or rights on any stock exchange. This authority expires at the earlier of the close of business on August 19, 2021, and the end of the AGM to be held in 2021, unless previously renewed, revoked or varied by the Company in a general meeting.

At the May 19, 2020 AGM, shareholders granted the Company the authority to repurchase up to 783 million ordinary shares (excluding any treasury shares), renewing the authority granted by the shareholders at previous AGMs. The authority will expire at the earlier of the close of business on August 19, 2021 and the end of the AGM of the Company to be held in 2021. Ordinary shares purchased by the Company pursuant to this authority will either be cancelled or held in treasury. Treasury shares are shares in the Company which are owned by the Company itself. The minimum price, exclusive of expenses, which may be paid for an ordinary share is €0.07. The maximum price, exclusive of expenses, which may be paid for an ordinary share is the higher of: (i) an amount equal to 5% above the average market value for an ordinary share for the five business days immediately preceding the date of the purchase; and (ii) the higher of the price of the last independent trade and the highest current independent bid on the trading venues where the purchase is carried out.

On March 23, 2020, in light of the economic and oil price environment, the Board decided not to continue with the next tranche of the share buyback programme following the completion of the tranche announced on January 30, 2020.

A and B shares repurchased in 2020 under the Company's share buyback programme were all cancelled.

B shares rank equally in all respects with A shares except for the dividend access mechanism described below. The Company, Shell Transport and BG can procure the termination of the dividend access mechanism at any time. Upon such termination, B shares will form one class with A shares ranking equally in all respects and A and B shares will be known as ordinary shares without further distinction.

The sterling deferred shares are redeemable only at the discretion of the Company for £1 each and carry no voting rights. There are no further rights to participate in profits or assets, including the right to receive dividends. Upon winding up or liquidation, the shares carry a right to repayment of paid-up nominal value, ranking ahead of A and B shares.

For information on the number of shares in the Company held by Shell employee share ownership trusts and trust-like entities to meet delivery commitments under employee share plans, see Note 21 of the Consolidated Financial Statements (see page 256).

Dividend access mechanism for B shares General

Dividends paid on A shares have a Dutch source for tax purposes and are subject to Dutch withholding tax.

It is the expectation and the intention, although there can be no certainty, that holders of B shares will receive dividends through the dividend access mechanism. Any dividends paid on the dividend access shares will have a UK source for UK and Dutch tax purposes. There will be no Dutch withholding tax on such dividends. From April 2016, there were changes to the taxation of dividends for individual shareholders resident in the UK. The dividend tax credit was abolished, and a tax-free dividend allowance introduced.

Description of dividend access mechanism

Shell Transport and BG have each issued a dividend access share to Computershare Trustees (Jersey) Limited as Trustee. Pursuant to a declaration of trust, the Trustee will hold any dividends paid in respect of the dividend access shares on trust for the holders of B shares and will arrange for prompt disbursement of such dividends to holders of B shares. Interest and other income earned on unclaimed dividends will be for the account of Shell Transport and BG and any dividends which are unclaimed after 12 years will revert to Shell Transport and BG once forfeited. Holders of B shares will not have any interest in either dividend access share and will not have any rights against Shell Transport and BG as issuers of the dividend access shares. The only assets held on trust for the benefit of the holders of B shares will be dividends paid to the Trustee in respect of the dividend access shares.

The declaration and payment of dividends on the dividend access shares will require board action by Shell Transport and BG (as applicable) and will be subject to any applicable limitations in law or in the Shell Transport or BG (as appropriate) articles of association in effect. In no event will the aggregate amount of the dividend paid by Shell Transport and BG under the dividend access mechanism for a particular period exceed the aggregate of the dividend announced by the Board of the Company on B shares in respect of the same period (after giving effect to currency conversions).

In particular, under their respective articles of association, Shell Transport and BG are each only able to pay a dividend on their respective dividend access shares which represents a proportional amount of the aggregate of any dividend announced by the Company on the B shares in respect of the relevant period, where such proportions are calculated by reference to, in the case of Shell Transport, the number of B shares in existence prior to completion of the Company's acquisition of BG and, in the case of BG, the number of B shares issued as part of the acquisition, in each case as against the total number of B shares in issue immediately following completion of the acquisition of BG.

NOTES TO THE PARENT COMPANY FINANCIAL STATEMENTS continued

8 SHARE CAPITAL continued

Operation of the dividend access mechanism

If, in connection with the announcement of a dividend by the Company on B shares, the Board of Shell Transport and/or the Board of BG elects to declare and pay a dividend on their respective dividend access shares to the Trustee, the holders of B shares will be beneficially entitled to receive their share of those dividends pursuant to the declaration of trust (and arrangements will be made to ensure that the dividend is paid in the same currency in which they would have received a dividend from the Company).

If any amount is paid by Shell Transport or BG by way of a dividend on the dividend access shares and paid by the Trustee to any holder of B shares, the dividend which the Company would otherwise pay on B shares will be reduced by an amount equal to the amount paid to such holders of B shares by the Trustee.

The Company will have a full and unconditional obligation, in the event that the Trustee does not pay an amount to holders of B shares on a cash dividend payment date (even if that amount has been paid to the Trustee), to pay immediately the dividend announced on B shares. The right of holders of B shares to receive distributions from the Trustee will be reduced by an amount equal to the amount of any payment actually made by the Company on account of any dividend on B shares.

If for any reason no dividend is paid on the dividend access shares, holders of B shares will only receive dividends from the Company directly. Any payment by the Company will be subject to Dutch withholding tax (unless an exemption is obtained under Dutch law or under the provisions of an applicable tax treaty).

The Dutch tax treatment of dividends paid under the dividend access mechanism has been confirmed by the Dutch Revenue Service in an agreement (vaststellingsovereenkomst) with the Company and N.V. Koninklijke Nederlandsche Petroleum Maatschappij (Royal Dutch Petroleum Company) dated October 26, 2004, as supplemented and amended by an agreement between the same parties dated April 25, 2005, and a final settlement agreement in connection with the acquisition of BG dated November 9, 2015. The agreements state, among other things, that dividend distributions on the dividend access shares by Shell Transport and/or BG will not be subject to Dutch withholding tax provided that the dividend access mechanism is structured and operated substantially as set out above.

The Company may not extend the dividend access mechanism to any future issuances of B shares without prior consultation with the Dutch Revenue Service.

Accordingly, the Company would not expect to issue additional B shares unless confirmation from the Dutch Revenue Service was obtained or the Company were to determine that the continued operation of the dividend access mechanism was unnecessary. Any further issue of B shares is subject to advance consultation with the Dutch Revenue Service.

The dividend access mechanism may be suspended or terminated at any time by the Company's Directors or the Directors of Shell Transport or BG, for any reason and without financial recompense. This might, for instance, occur in response to changes in relevant tax legislation.

9 OTHER RESERVES

	Merger reserve	Share premium reserve	Capital redemption reserve	Share plan reserve	Total
At January 1, 2020	234,231	154	123	1,053	235,561
Repurchases of shares	—	—	6	—	6
Share-based compensation	—	—	—	(148)	(148)
At December 31, 2020	234,231	154	129	905	235,419
At January 1, 2019	234,231	154	95	1,056	235,536
Repurchases of shares	—	—	28	—	28
Share-based compensation	—	—	—	(3)	(3)
At December 31, 2019	234,231	154	123	1,053	235,561

\$ million

The merger reserve was established as a consequence of the Company becoming the single parent company of Royal Dutch and Shell Transport and represented the difference between the cost of the investment in those companies and the nominal value of shares issued in exchange for those investments as required by the prevailing legislation at that time, section 131 of the Companies Act 1985. On February 15, 2016, the Company acquired all shares in BG Group plc by means of a Scheme of Arrangement under Part 26 of the Act, via the issuance of 218.7 million A shares and 1,305.1 million B shares and cash payments. This resulted in an increase in the merger reserve, representing the difference between the fair value and the nominal value of the shares issued by the Company.

On January 6, 2006, loan notes were converted into 4,827,974 A shares. The difference between the carrying value of the loan notes and the nominal value of the new shares issued was credited to the share premium reserve. The capital redemption reserve was established in connection with repurchases of shares of the Company. The share plan reserve is in respect of equity-settled share-based compensation plans (see Note 21 to the Consolidated Financial Statements) and movement in share-based compensation for the year is the net of the charge to equity and the release as a result of vested awards.

10 DIVIDENDS

See Note 23 of the Consolidated Financial Statements (see page 259).

11 LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

See Note 25 of the Consolidated Financial Statements (see page 260).

12 DIRECTORS AND SENIOR MANAGEMENT

See Note 27 of the Consolidated Financial Statements (see page 262) for the remuneration of Directors of the Company. In 2020, the Company recognised \$25 million (2019: \$25 million) in administrative expenses for the compensation of Directors and Senior Management.

13 RELATED PARTIES

Information about the Company's subsidiaries, and whether these are held directly or indirectly, and other related undertakings (all of which are held indirectly), at December 31, 2020, is set out in 'Appendix 1: Significant Subsidiaries and Other Related Undertakings'.

	Amounts due from subsidiaries		Amounts due to subsidiaries (see Note 5)	
	2020	2019	2020	2019
	\$ million			
Shell Petroleum	—	—	855	748
Shell Treasury Centre Limited	1,484	1,862	14	—
Other	4	2	5	2
Total	1,488	1,864	874	750

The amount due from Shell Treasury Centre Limited (STCL) comprises call deposits and overdrafts in dollars, sterling and euros. Interest is calculated at US LIBOR (2019: US LIBOR less 0.21%) on dollar balances, at GBP LIBOR less 0.03% (2019: GBP LIBOR less 0.19%) on sterling balances and at Euro Overnight Index Average (EONIA) (2019: EONIA) on euro balances, unless this results in a negative interest rate in which case no interest is earned. Net interest income in 2020 from STCL was \$11 million (2019: \$41 million).

The Company received no interest from Shell Petroleum in 2020 (2019: \$60 million). In 2019 interest was calculated at US LIBOR less 0.21%. At both December, 31 2020 and 2019 the closing amount due from Shell Petroleum was \$nil.

Other transactions and balances

The Company periodically enters into forward and spot foreign currency contracts with Treasury companies, which are subsidiaries. There were no open foreign currency contracts at December 31, 2020, or December 31, 2019.

The Company settles general and administrative expenses of the Trust, including the auditor's remuneration.

The Company has guaranteed contractual payments totalling \$63,146 million at December 31, 2020 (December 31, 2019: \$52,357 million), and related interest, in respect of listed debt issued by Shell International Finance B.V. The fair value of this guarantee was considered to be immaterial at initial recognition and since the likelihood of default is considered remote no subsequent expected credit losses have been recognised.

14 AUDITOR'S REMUNERATION

See Note 28 of the Consolidated Financial Statements (see page 263).

INDEPENDENT AUDITOR'S REPORT TO COMPUTERSHARE TRUSTEES (JERSEY) LIMITED AS TRUSTEE OF THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST AND THE BOARD OF DIRECTORS AND SHAREHOLDERS OF ROYAL DUTCH SHELL PLC

TO COMPUTERSHARE TRUSTEES (JERSEY) LIMITED AS TRUSTEE OF THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST AND THE BOARD OF DIRECTORS AND SHAREHOLDERS OF ROYAL DUTCH SHELL PLC

Opinion

We have audited the non-statutory financial statements of the Royal Dutch Shell Dividend Access Trust (the Financial Statements) for the year ended December 31, 2020 which comprise the Statement of Income, the Statement of Comprehensive Income, the Balance Sheet, the Statement of Changes in Equity, the Statement of Cash Flows and the related notes 1 to 8. The financial reporting framework that has been applied in their preparation is International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

In our opinion the Financial Statements give a true and fair view of the Royal Dutch Shell Dividend Access Trust's (the Trust) affairs as at December 31, 2020 and of its income for the year then ended; and have been properly prepared in accordance with IFRS as issued by the IASB.

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (UK) (ISAs (UK)) and applicable law. Our responsibilities under those standards are further described in the "Auditor's responsibilities for the audit of the financial statements" section of our report. We are independent of the Trust in accordance with the ethical requirements that are relevant to our audit of the Financial Statements in the UK, including the Financial Reporting Council's Ethical Standard, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Conclusions relating to going concern

In auditing the financial statements, we have concluded that the Trustee of Royal Dutch Shell Dividend Access Trust's (the Trustee) use of the going concern basis of accounting in the preparation of the financial statements is appropriate.

Based on the work we have performed, we have not identified any material uncertainties relating to events or conditions that, individually or collectively, may cast significant doubt on the Trust's ability to continue as a going concern until 31 March 2022 (the going concern period).

Our responsibilities and the responsibilities of the directors with respect to going concern are described in the relevant sections of this report. However, because not all future events or conditions can be predicted, this statement is not a guarantee as to the company's ability to continue as a going concern.

Other information

The other information comprises the information included in the annual report, other than the Financial Statements and our auditor's report thereon. The Board of Directors of Royal Dutch Shell plc (the Directors) are responsible for the other information contained within the annual report.

Our opinion on the Financial Statements does not cover the other information and, except to the extent otherwise explicitly stated in this report, we do not express any form of assurance conclusion thereon.

Our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the Financial Statements or our knowledge obtained in the audit or otherwise appears to be materially misstated. If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether there is a material misstatement in the Financial Statements themselves. If, based on the work we have performed, we conclude that there is a material misstatement of the other information, we are required to report that fact.

We have nothing to report in this regard.

Responsibilities of the Trustee

The Trustee is responsible for the preparation of the Financial Statements and for being satisfied that they give a true and fair view, and for such internal control as the Trustee determines is necessary to enable the preparation of Financial Statements that are free from material misstatement, whether due to fraud or error.

In preparing the Financial Statements, the Trustee is responsible for assessing the Trust's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Trustee either intends to liquidate the Trust or to cease operations, or have no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the Financial Statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs (UK) will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

Explanation as to what extent the audit was considered capable of detecting irregularities, including fraud

Irregularities, including fraud, are instances of non-compliance with laws and regulations. We design procedures in line with our responsibilities, outlined above, to detect irregularities, including fraud. The risk of not detecting a material misstatement due to fraud is higher than the risk of not detecting one resulting from error, as fraud may involve deliberate concealment by, for example, forgery or intentional misrepresentations, or through collusion. The extent to which our procedures are capable of detecting irregularities, including fraud is detailed below. However, the primary responsibility for the prevention and detection of fraud rests with both the Trustee and those charged with governance of Royal Dutch Shell plc and its management.

- We obtained an understanding of the legal and regulatory frameworks that are applicable to the Trust and determined that the most significant are those that relate to the reporting framework (IFRS and the US Securities Exchange Act of 1934).
- We understood how the Trust is complying with those frameworks by making enquiries of the Trustee, Royal Dutch Shell plc management and those responsible for legal and compliance procedures over the Trust. We corroborated our enquiries through our review of Resolutions of the Trust Committee of the Trustee, papers provided to the Royal Dutch Shell plc Audit Committee and correspondence received from regulatory bodies and noted that there was no contradictory evidence.

- We assessed the susceptibility of the Trust's financial statements to material misstatement, including how fraud might occur by regular meetings with the Trustee, Royal Dutch Shell plc management and those responsible for legal and compliance procedures over the Trust to understand where it was considered there was susceptibility to fraud. We considered the programmes and design, implementation and maintenance of internal controls that the Trustee and Royal Dutch Shell plc have established to prevent and detect fraud over the Trust and how the Trustee, Royal Dutch Shell plc management and those responsible for legal and compliance procedures over the Trust monitor those programmes and controls.
- Based on this understanding we designed our audit procedures to identify noncompliance with such laws and regulations. Our procedures involved review of Resolutions of the Trust Committee of the Trustee and Royal Dutch Shell plc Audit Committee minutes to identify noncompliance with laws and regulations, journal entry testing with a focus on journals meeting our defined risk criteria based on our understanding of the Trust and enquiries of the Trustee, Royal Dutch Shell plc management and those responsible for legal and compliance procedures over the Trust.

A further description of our responsibilities for the audit of the Financial Statements is located on the Financial Reporting Council's website at <https://www.frc.org.uk/auditorsresponsibilities>. This description forms part of our auditor's report.

Use of our report

This report is made solely to the Trustee and the Board of Directors and Shareholders of Royal Dutch Shell plc as a body, in accordance with our engagement letter. Our audit work has been undertaken so that we might state to the Trustee and the Board of Directors and Shareholders of Royal Dutch Shell plc those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the Trustee and the Board of Directors and Shareholders of Royal Dutch Shell plc as a body, for our audit work, for this report, or for the opinions we have formed.

/s/ Paul Sater

for and on behalf of Ernst & Young LLP, Statutory Auditor
London
March 10, 2021

ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST FINANCIAL STATEMENTS

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STATEMENT OF INCOME

	2020	2019	£ million 2018
Dividend income	2,777	5,484	5,328
Income before taxation and for the period	2,777	5,484	5,328

STATEMENT OF COMPREHENSIVE INCOME

	2020	2019	£ million 2018
Income for the period	2,777	5,484	5,328
Comprehensive income for the period	2,777	5,484	5,328

BALANCE SHEET

	Notes	Dec 31, 2020	£ million Dec 31, 2019
Assets			
Other current assets		7	—
Cash and cash equivalents		—	3
Total assets		7	3
Liabilities			
Unclaimed dividends	4	7	3
Total liabilities		7	3
Equity			
Capital account	5	—	—
Revenue account		—	—
Total equity		—	—
Total liabilities and equity		7	3

Signed on behalf of Computershare Trustees (Jersey) Limited as Trustee of the Royal Dutch Shell Dividend Access Trust

/s/ John Le Marquand

JOHN LE MARQUAND

March 10, 2021

/s/ Martin Fish

MARTIN FISH

ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST

FINANCIAL STATEMENTS continued

STATEMENT OF CHANGES IN EQUITY

	Notes	Capital account	Revenue account	£ million Total equity
At January 1, 2020		—	—	—
Comprehensive income for the period		—	2,777	2,777
Distributions made	6	—	(2,777)	(2,777)
At December 31, 2020		—	—	—
At January 1, 2019		—	—	—
Comprehensive income for the period		—	5,484	5,484
Distributions made	6	—	(5,484)	(5,484)
At December 31, 2019		—	—	—
At January 1, 2018		—	—	—
Comprehensive income for the period		—	5,328	5,328
Distributions made	6	—	(5,328)	(5,328)
At December 31, 2018		—	—	—

STATEMENT OF CASH FLOWS

	2020	2019	£ million 2018
Income for the period	2,777	5,484	5,328
Adjustment for:			
Dividends received	(2,777)	(5,484)	(5,328)
Cash flow from operating activities	—	—	—
Dividends received	2,772	5,484	5,328
Cash flow from investing activities	2,772	5,484	5,328
Cash distributions made	(2,775)	(5,484)	(5,327)
Cash flow from financing activities	(2,775)	(5,484)	(5,327)
Change in cash and cash equivalents	(3)	—	1
Cash and cash equivalents at January 1	3	3	2
Cash and cash equivalents at December 31	—	3	3

NOTES TO THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST

FINANCIAL STATEMENTS

1 THE TRUST

The Royal Dutch Shell Dividend Access Trust (the "Trust") was established on May 19, 2005, by The "Shell" Transport and Trading Company, plc, now The Shell Transport and Trading Company Limited (Shell Transport), and Royal Dutch Shell plc (the "Company"). The Trust is governed by the applicable laws of England and Wales and is resident and domiciled in Jersey. The Trust is not subject to taxation. The Trustee of the Trust is Computershare Trustees (Jersey) Limited, registration number 92182 (the "Trustee"), 13 Castle Street, St Helier, Jersey, JE1 1ES. The Trust was established as part of a dividend access mechanism.

Shell Transport and BG Group Limited (BG), have each issued a dividend access share to the Trustee. Following the announcement of a dividend by the Company on the B shares, Shell Transport and BG may declare a dividend on their dividend access shares.

The primary purposes of the Trust are to receive, on behalf of the B shareholders of the Company and in accordance with their respective holdings of B shares in the Company, any amounts paid by way of dividend on the dividend access shares and to pay such amounts to the B shareholders on the same pro rata basis. The Trust is not subject to significant market risk, credit risk or liquidity risk.

The Trust shall not endure for a period in excess of 80 years from May 19, 2005, being the date on which the Trust Deed was executed.

2 BASIS OF PREPARATION

The Financial Statements of the Trust have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

The Financial Statements have been prepared under the historical cost convention. The accounting policies described in Note 3 have been applied consistently in all periods presented.

The Financial Statements were approved and authorised for issue by the Trustee on March 10, 2021.

The financial results of the Trust are included in the Consolidated and Parent Company Financial Statements on pages 216-264 and pages 283-291 respectively.

3 SIGNIFICANT ACCOUNTING POLICIES

The Trust's accounting policies follow those of Shell as set out in Note 2 of the Consolidated Financial Statements (see pages 221-229). The following are Trust-specific policies.

Presentation and functional currency

The Trust's presentation and functional currency is sterling. The Trust's dividend income and dividends paid are principally in sterling.

Dividend income

Dividends on the dividend access shares are recognised on a paid basis unless the dividend has been confirmed by a general meeting of Shell Transport or BG, in which case income is recognised on the date on which receipt is deemed virtually certain. Dividend income includes amounts receivable from Shell Transport and BG in respect of dividends declared but unclaimed (see Note 4).

Distributions made

Amounts are recorded as distributed once a payment is made in the appropriate currency using various electronic transfer methods, or an unconditional payment obligation is established. Shell Transport or BG (as appropriate) may, each at their respective discretion, withhold any part of the funding relating to an unpayable dividend until such time as the relevant B shareholder provides accurate or complete details for payment of any such dividend.

4 UNCLAIMED DIVIDENDS

Unclaimed dividends of £7 million (2019: £3 million) include any pre-electronic transfer dividend cheque payments that have not been presented within 12 months, have expired or have been returned unpresented. Dividends are also classified as unclaimed where amounts have been withheld due to incomplete or incorrect electronic payment details. Dividends which are unclaimed after 12 years will unconditionally revert to Shell Transport and BG once forfeited.

5 CAPITAL ACCOUNT

The capital account is represented by the dividend access share of 25 pence settled in the Trust by Shell Transport and the dividend access share of 10 pence settled in the Trust by BG. There have been no changes in the capital account in the current or prior year.

6 DISTRIBUTIONS MADE

Distributions are made to the B shareholders of the Company in accordance with the Trust Deed. See Note 23 of the Consolidated Financial Statements (see page 259) for information about dividends per share.

7 RELATED PARTIES

The Trust recognised dividend income of £1,805 million (2019: £3,573 million; 2018: £3,470 million) in respect of the dividend access share from Shell Transport and £972 million (2019: £1,911 million; 2018: £1,858 million) in respect of the dividend access share from BG. The Trust made distributions of £2,777 million (2019: £5,484 million; 2018: £5,328 million) to the B shareholders of the Company.

As at December 31, 2020 the Trust recorded amounts due from Shell Transport of £5 million and BG of £2 million relating to unclaimed dividends, following a move to electronic settlement of dividend payments in the year.

The Company pays the general and administrative expenses of the Trust, including the auditor's remuneration.

8 AUDITOR'S REMUNERATION

Auditor's remuneration for 2020 audit services was £33,750 (2019: £33,750; 2018: £33,750).

ADDITIONAL INFORMATION

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RESPECTING **NATURE**

SHAREHOLDER INFORMATION

Royal Dutch Shell plc (the Company) was incorporated in England and Wales on February 5, 2002, as a private company under the Companies Act 1985, as amended. On October 27, 2004, the Company was re-registered as a public company limited by shares and changed its name from Forthdeal Limited to Royal Dutch Shell plc. The Company is registered at Companies House, Cardiff, under company number 4366849, and at the Chamber of Commerce, The Hague, under company number 34179503. The Legal Entity Identifier (LEI) issued by the London Stock Exchange is 21380068PIDRHMJ8KU70. The business address for the Directors and Senior Management is Carel van Bylandtlaan 30, 2596 HR, The Hague, The Netherlands.

The Company is resident in the Netherlands for Dutch and UK tax purposes and its primary objective is to carry on the business of a holding company. It is not directly or indirectly owned or controlled by another corporation or by any government and does not know of any arrangements that may result in a change of control of the Company.

NATURE OF TRADING MARKET

The Company has two classes of ordinary shares: A and B shares. The principal trading market for A shares is Euronext Amsterdam and the principal trading market for B shares is the London Stock Exchange. Ordinary shares are traded in registered form.

A and B American Depositary Shares (ADSs) are listed on the New York Stock Exchange [A]. A depositary receipt is a certificate that evidences ADSs. Depositary receipts are issued, cancelled and exchanged at the office of JP Morgan Chase Bank, N.A., 383 Madison Avenue, New York, New York 10179, USA, as depositary (the Depositary), under a deposit agreement between the Company, the Depositary and the holders of ADSs. Each ADS represents two €0.07 shares of Royal Dutch Shell plc deposited under the agreement. More information relating to ADSs is given on pages 300-304.

[A] At February 12, 2021, 307,263,635 A ADSs and 292,034,995 B ADSs were outstanding, representing 14.98% and 15.76% of the respective share capital class, held by 4,872 and 910 holders of record with an address in the USA, respectively. In addition to holders of ADSs, at February 12, 2021, 21,790 A shares and 929,184 B shares of €0.07 each were outstanding, representing 0.0002% and 0.119% of the respective share capital class, held by 299 and 3,063 holders of record registered with an address in the USA, respectively.

Listing information

	A shares	B shares
Ticker symbol London	RDSA	RDSB
Ticker symbol Amsterdam	RDSA	RDSB
Ticker symbol New York (ADS [A])	RDS.A	RDS.B
ISIN for shares	GB00B03MLX29	GB00B03MM408
ISIN for ADS	US7802592060	US7802591070
CUSIP	G7690A100	G7690A118
SEDOL Number Amsterdam	B09CBL4	B09CBN6
SEDOL Number London	B03MLX2	B03MM40
SEDOL Number New York	B03MM62	B03MM73
Weighting on FTSE 100 at 31/12/20	3.09%	2.71%
Weighting on AEX at 31/12/20	10.58%	not included

[A] Each A ADS represents two A shares of €0.07 each and each B ADS represents two B shares of €0.07 each.

SHARE CAPITAL

The issued and fully paid share capital of the Company at February 12, 2021, was as follows:

Share capital

	Issued and fully paid	
	Number	Nominal value
Ordinary shares of €0.07 each		
A shares	4,101,239,499	€287,086,765
B shares	3,706,183,836	€259,432,869
Sterling deferred shares of £1 each	50,000	£50,000

The Directors may only allot new ordinary shares if they have authority from shareholders to do so. The Company seeks to renew this authority annually at its AGM. Under the resolution passed at the Company's 2020 AGM, the Directors were granted authority to allot ordinary shares up to an aggregate nominal amount equivalent to approximately one-third of the issued ordinary share capital of the Company (in line with the guidelines issued by institutional investors).

The following is a summary of the material terms of the Company's ordinary shares, including brief descriptions of the provisions contained in the Articles of Association (the Articles) and applicable laws of England and Wales in effect on the date of this document. This summary does not purport to include complete statements of these provisions:

- upon issuance, A and B shares are fully paid and free from all liens, equities, charges, encumbrances and other interest of the Company and not subject to calls of any kind;
- all A and B shares rank equally for all dividends and distributions on ordinary share capital; and
- A and B shares are admitted to the Official List of the UK Financial Conduct Authority and to trading on the market for listed securities of the London Stock Exchange. A and B shares are also admitted to trading on Euronext Amsterdam. A and B ADSs are listed on the New York Stock Exchange.

At December 31, 2020, trusts and trust-like entities holding shares for the benefit of employee share plans of Shell held (directly and indirectly) 25 million shares of the Company with an aggregate market value of \$526 million and an aggregate nominal value of €2 million.

SIGNIFICANT SHAREHOLDINGS

The Company's A and B shares have identical voting rights, and accordingly the Company's major shareholders do not have different voting rights.

Notification of major shareholdings

The Company received two notifications pursuant to Disclosure Guidance and Transparency Rule (DTR) 5 from the Capital Group Companies, Inc. during the year and up to February 12, 2021, (being a date not more than one month prior to the date of the Company's Notice of Annual General Meeting). The information provided includes the percentage of issued capital as at the date of the notifications.

Investor	A shares		B shares		Total[A]	
	Number	%	Number	%	Number	%
The Capital Group Companies, Inc.[B]	42,482,002	0.54	349,161,475	4.45	391,643,477	4.99

[A] Excludes financial instruments according to Art. 13(1)(a) of Directive 2004/109/EC (DTR 5.3.1.1 (a)) and financial instruments with similar economic effect according to Art. 13(1)(b) of Directive 2004/109/EC (DTR 5.3.1.1 (b)).

[B] Notifications were announced on 20 January 2020 and 24 February 2020. The figures in the table above reflect that of the latest announcement, made on 24 February 2020.

Designation of the Netherlands as EU Home Member State for regulatory purposes

Following the exit of the UK from the EU and the end of the transition period, the Company has announced that the EU Home Member State of the Company for the purposes of the EU Transparency Directive will be the Netherlands as from January 1, 2021. As a consequence, going forward the Company will file Transparency Directive and Market Abuse Regulation-related regulatory information with the Netherlands Authority for the Financial Markets (Autoriteit Financiële Markten, or AFM). Major shareholders will have to report substantial holdings in Shell to the AFM in accordance with applicable Dutch law, in addition to their ongoing disclosure obligations under the UK Disclosure Guidance and Transparency Rules (DTR). The Company's status as a UK PLC, headquartered in the Netherlands, remains the same.

DIVIDENDS

The following tables show the dividends on each class of share and each class of ADS for the years 2016-2020.

A and B shares

	2020	2019	2018	2017	\$
Q1	0.16	0.47	0.47	0.47	0.47
Q2	0.16	0.47	0.47	0.47	0.47
Q3	0.17	0.47	0.47	0.47	0.47
Q4	0.17	0.47	0.47	0.47	0.47
Total announced in respect of the year	0.65	1.88	1.88	1.88	1.88

A shares

	2020	2019	2018	2017	€ [A]
Q1	0.14	0.42	0.4	0.42	0.42
Q2	0.14	0.43	0.4	0.39	0.42
Q3	0.14	0.42	0.41	0.4	0.44
Q4 [B]	TBA	0.42	0.42	0.38	0.44
Total announced in respect of the year [B]	TBA	1.68	1.64	1.59	1.72
Amount paid during the year	0.84	1.68	1.60	1.65	1.70

[A] Euro equivalent, rounded to the nearest euro cent.

[B] Q4 2020 euro equivalent will be announced on March 15, 2021.

SHAREHOLDER INFORMATION continued**B shares**

	Pence [A]				
	2020	2019	2018	2017	2016
Q1	12.68	36.97	35.18	37.12	32.98
Q2	12.09	38.01	36.5	36.28	35.27
Q3	12.48	35.73	36.77	35.02	37.16
Q4 [B]	TBA	36.4	35.94	33.91	38.64
Total announced in respect of the year [B]	TBA	147.11	144.39	142.33	144.05
Amount paid during the year	73.65	146.65	142.36	147.06	138.19

[A] Sterling equivalent.

[B] Q4 2020 sterling equivalent will be announced on March 15, 2021

A and B ADSs

	\$				
	2020	2019	2018	2017	2016
Q1	0.32	0.94	0.94	0.94	0.94
Q2	0.32	0.94	0.94	0.94	0.94
Q3	0.33	0.94	0.94	0.94	0.94
Q4	0.33	0.94	0.94	0.94	0.94
Total announced in respect of the year	1.31	3.76	3.76	3.76	3.76
Amount paid during the year	1.91	3.76	3.76	3.76	3.76

METHOD OF HOLDING SHARES OR AN INTEREST IN SHARES

There are several ways in which Royal Dutch Shell plc registered shares or an interest in these shares can be held, including:

- directly as registered shares either in uncertificated form or in certificated form in a shareholder's own name;
- indirectly through Euroclear Nederland (in respect of which the Dutch Securities Giro Act (Wet giraal effectenverkeer) is applicable);
- through the Royal Dutch Shell Corporate Nominee Service;
- through another third-party nominee or intermediary company; and
- as a direct or indirect holder of either an A or a B ADS with the Depositary.

AMERICAN DEPOSITORY SHARES

The Depositary is the registered shareholder of the shares underlying the A or B ADSs and enjoys the rights of a shareholder under the Articles. Holders of ADSs will not have shareholder rights. The rights of the holder of an A or a B ADS are specified in the Deposit Agreement with the Depositary and are summarised below.

The Depositary will receive all cash dividends and other cash distributions made on the deposited shares underlying the ADSs and, where possible and on a reasonable basis, will distribute such dividends and distributions to holders of ADSs. Rights to purchase additional shares will also be made available to the Depositary who may make such rights available to holders of ADSs. All other distributions made on the Company's shares will be distributed by the Depositary in any means that the Depositary thinks is equitable and practical. The Depositary may deduct its fees and expenses and the amount of any taxes owed from any payments to holders and it may sell a holder's deposited shares to pay any taxes owed. The Depositary is not responsible if it decides that it is unlawful or impractical to make a distribution available to holders of ADSs.

The Depositary will notify holders of ADSs of shareholders' meetings of the Company and will arrange to deliver voting materials to such holders of ADSs if requested by the Company. Upon request by a holder, the Depositary will endeavour to appoint such holder as proxy in respect of such holder's deposited shares entitling such holder to attend and vote at

shareholders' meetings. Holders of ADSs may also instruct the Depositary to vote their deposited securities and the Depositary will try, as far as practical and lawful, to vote deposited shares in accordance with such instructions. The Company cannot ensure that holders will receive voting materials or otherwise learn of an upcoming shareholders' meeting in time to ensure that holders can instruct the Depositary to vote their shares.

Upon payment of appropriate fees, expenses and taxes: (i) shareholders may deposit their shares with the Depositary and receive the corresponding class and amount of ADSs; and (ii) holders of ADSs may surrender their ADSs to the Depositary and have the corresponding class and amount of shares credited to their account.

Further, subject to certain limitations, holders may, at any time, cancel ADSs and withdraw their underlying shares or have the corresponding class and amount of shares credited to their account.

FEES PAID BY HOLDERS OF ADS

The Depositary collects its fees for delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal or from intermediaries acting for them. The Depositary collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of distributable property to pay the fees. The Depositary may generally refuse to provide fee-attracting services until its fees for those services are paid. See page 301.

PAYMENTS BY DEPOSITARY TO THE COMPANY

J.P. Morgan Chase Bank, N.A., as Depositary, has agreed to share with the Company portions of certain fees collected, less ADS programme expenses paid by the Depositary. For example, these expenses include the Depositary's annual programme fees, transfer agency fees, custody fees, legal expenses, postage and envelopes for mailing annual and interim financial reports, printing and distributing dividend cheques, electronic filing of US federal tax information, mailing required tax forms, stationery, postage, facsimile and telephone calls and the standard out-of-pocket maintenance costs for the ADSs. From January 1, 2020, to February 12, 2021, the Company received \$6,418,504.69 from the Depositary.

Persons depositing or withdrawing shares must pay:	For:
\$5.00 or less per 100 ADSs (or portion of 100 ADSs)	<ul style="list-style-type: none"> ■ Issuance of ADSs, including those resulting from a distribution of shares, rights or other property; ■ Cancellation of ADSs for the purpose of their withdrawal, including if the deposit agreement terminates; and ■ Distribution of securities to holders of deposited securities by the Depositary to ADS registered holders.
Registration and transfer fees	<ul style="list-style-type: none"> ■ Registration and transfer of shares on the share register to or from the name of the Depositary or its agent when they deposit or withdraw shares.
Expenses of the Depositary	<ul style="list-style-type: none"> ■ Cable, telex and facsimile transmissions (when expressly provided in the deposit agreement); and ■ Converting foreign currency into dollars.
Taxes and other governmental charges the Depositary or the custodian has to pay on any ADS or share underlying an ADS, for example, share transfer taxes, stamp duty or withholding taxes	<ul style="list-style-type: none"> ■ As necessary.

DIVIDEND REINVESTMENT PLAN

Equiniti Financial Services Limited, part of the same group of companies as the Company's Registrar, Equiniti Limited, operates a Dividend Reinvestment Plan (DRIP) which enables RDS shareholders to elect to have their dividend payments used to purchase RDS shares of the same class as those already held by them. More information can be found at www.shareview.co.uk/info/drip or by contacting Equiniti.

ABN AMRO Bank N.V. and JP Morgan Chase Bank N.A. also operate dividend reinvestment options. More information can be found by contacting the relevant provider.

In addition to the above, the Depositary may charge: (i) a dividend fee of \$5.00 or less per 100 ADSs (or portion of 100 ADSs) for cash dividends or issuance of ADSs resulting from share dividends and (ii) an administrative fee of \$5.00 or less per 100 ADSs (or portion of 100 ADSs) per calendar year. The Company and Depositary have agreed not to charge these fees at this time.

EXCHANGE CONTROLS AND OTHER LIMITATIONS AFFECTING SECURITY HOLDERS

Other than restrictions affecting those individuals, entities, government bodies, corporations or agencies that are subject to European Union (EU) sanctions for example, regarding Syria, and those sanctions adopted by the government of the UK, and the general EU prohibition to transfer funds to and from for example, North Korea, we are not aware of any other legislative or other legal provision currently in force in the UK, the Netherlands or arising under the Articles restricting remittances to holders of the Company's ordinary shares who are non-residents of the UK, or affecting the import or export of capital.

TAXATION General

The Company is incorporated in England and Wales and tax-resident in the Netherlands. As a tax resident of the Netherlands, it is generally required by Dutch law to withhold tax at a rate of 15% on dividends on its ordinary shares and ADSs, subject to the provisions of any applicable tax convention or domestic law. Depending on their particular circumstances, non-Dutch tax-resident holders may be entitled to a full or partial refund of Dutch withholding tax. The following sets forth the operation of other provisions on dividends on the Company's various ordinary shares and ADSs to UK and US holders, as well as certain other tax rules pertinent to holders. Holders should consult their own tax adviser if they are uncertain as to the tax treatment of any dividend.

Dividends paid on the dividend access shares

There is no Dutch withholding tax on dividends on B shares or B ADSs, provided that such dividends are paid on the dividend access shares pursuant to the dividend access mechanism (see "Dividend access

mechanism for B shares" on page 289). Dividends paid on the dividend access shares are treated as UK-source for tax purposes and there is no UK withholding tax on them.

In 2020, all dividends with respect to B shares and B ADSs were paid on the dividend access shares pursuant to the dividend access mechanism.

Dutch withholding tax

When Dutch withholding tax applies on dividends paid to a US holder (that is, dividends on A shares or A ADSs, or on B shares or B ADSs that are not paid on the dividend access shares pursuant to the dividend access mechanism), the US holder will be subject to Dutch withholding tax at the rate of 15%. A US holder who is entitled to the benefits of the 1992 Double Taxation Convention (the Convention) between the USA and the Netherlands as amended by the protocol signed on March 8, 2004, will be entitled to a reduction in the Dutch withholding tax, either by way of a full or a partial exemption at source or by way of a partial refund or a credit as follows:

- if the US holder is an exempt pension trust as described in article 35 of the Convention, or an exempt organisation as described in article 36 thereof, the US holder will be exempt from Dutch withholding tax; or
- if the US holder is a company that holds directly at least 10% of the voting power in the Company, the US holder will be subject to Dutch withholding tax at a rate not exceeding 5%.

In general, the entire dividend (including any amount withheld) will be dividend income to the US holder and the withholding tax will be treated as a foreign income tax that is eligible for credit against the US holder's income tax liability or a deduction subject to certain limitations. A "US holder" includes, but is not limited to, a citizen or resident of the USA, or a corporation or other entity organised under the laws of the USA or any of its political subdivisions.

When Dutch withholding tax applies on dividends paid to UK tax-resident holders (that is, dividends on A shares or A ADSs, or on B shares or B ADSs that are not paid on the dividend access shares pursuant to the dividend access mechanism), the dividend will typically be subject to withholding tax at a rate of 15%. Such UK tax-resident holder may be entitled to a credit (not repayable) for withholding tax against their UK tax liability. However, certain corporate shareholders are, subject to conditions, exempt from UK tax on dividends. Withholding tax suffered cannot be offset against such exempt dividends. UK tax-resident holders should also be entitled to claim a refund of one-third of the Dutch withholding tax from the Dutch tax authorities in reliance on the tax convention between the Netherlands and the UK. Pension plans meeting certain defined criteria can, however, be entitled to claim a full refund or exemption at source of the dividend tax withheld. Also, UK tax-resident corporate shareholders holding at least a 5% shareholding and meeting other defined criteria are exempted at source from dividend tax.

SHAREHOLDER INFORMATION continued

For holders who are tax-resident in any other country, the availability of a whole or partial exemption or refund of Dutch withholding tax is governed by Dutch tax law and/or the tax convention, if any, between the Netherlands and the country of the holder's residence.

There may be other grounds on which holders who are tax-resident in the UK, the USA or any other country can obtain a full or partial refund of the Dutch withholding tax, depending on their particular circumstances; see "Taxation: General" above.

Dutch capital gains taxation

Capital gains on the sale of shares of a Dutch tax-resident company by a US holder are generally not subject to taxation by the Netherlands unless the US holder has a permanent establishment therein and the capital gain is derived from the sale of shares that are part of the business property of the permanent establishment.

Dutch succession duty and gift taxes

Shares of a Dutch tax-resident company held by an individual who is not a resident or a deemed resident of the Netherlands will generally not be subject to succession duty in the Netherlands on the individual's death.

Capital gains tax

For the purposes of UK capital gains tax, the market values [A] of the shares of the former public parent companies of the Royal Dutch/Shell Group at the relevant dates were:

A gift of shares of a Dutch tax-resident company by an individual who is not a resident or a deemed resident of the Netherlands is generally not subject to Dutch gift tax.

UK stamp duty and stamp duty reserve tax

Sales or transfers of the Company's ordinary shares within a clearance service (such as Euroclear Nederland) or of the Company's ADSs within the ADS depositary receipts system will not give rise to a stamp duty reserve tax (SDRT) liability and should not in practice require the payment of UK stamp duty.

The transfer of the Company's ordinary shares to a clearance service (such as Euroclear Nederland) or to an issuer of depositary shares (such as ADSs) will generally give rise to a UK stamp duty or SDRT liability at the rate of 1.5% of consideration given or, if none, of the value of the shares. A sale of the Company's ordinary shares that are not held within a clearance service (for example, settled through the UK's CREST system of paperless transfers) will generally be subject to UK stamp duty or SDRT at the rate of 0.5% of the amount of the consideration, normally paid by the purchaser.

	£	
	March 31, 1982	July 20, 2005
Royal Dutch Petroleum Company (N.V. Koninklijke Nederlandsche Petroleum Maatschappij) which ceased to exist on December 21, 2005	1.1349	17.6625
The "Shell" Transport and Trading Company, p.l.c. which delisted on July 19, 2005	1.4502	Not applicable

[A] Restated where applicable to reflect all capitalisation issues since the relevant date. This includes the change in the capital structure in 2005, when Royal Dutch Shell plc became the single parent company of Royal Dutch Petroleum Company and of The "Shell" Transport and Trading Company, p.l.c., now The Shell Transport and Trading Company Limited, and one share in Royal Dutch Petroleum Company was exchanged for two Royal Dutch Shell plc A shares and one share in The "Shell" Transport and Trading Company, p.l.c. was exchanged for 0.287333066 Royal Dutch Shell plc B shares.

NON-GAAP MEASURES RECONCILIATIONS

These non-GAAP measures, also known as alternative performance measures, are financial measures other than those defined in International Financial Reporting Standards, which Shell considers provide useful information.

EARNINGS ON A CURRENT COST OF SUPPLIES BASIS

Segment earnings are presented on a current cost of supplies basis (CCS earnings), which is the earnings measure used by the Chief Executive Officer for the purposes of making decisions about allocating resources and assessing performance. On this basis, the purchase price of volumes sold during the period is based on the current cost of supplies during the same period after making allowance for the tax effect. CCS earnings therefore exclude the effect of changes in the oil price on inventory carrying amounts. The current cost of supplies adjustment does not impact cash flow from operating activities in the "Consolidated Statement of Cash Flows".

Reconciliation of income for the period to CCS earnings

	\$ million		
	2020	2019	2018
Income/(loss) attributable to Royal Dutch Shell plc shareholders	(21,680)	15,842	23,352
Income/(loss) attributable to non-controlling interest	146	590	554
Income/(loss) for the period	(21,534)	16,432	23,906
Current cost of supplies adjustment	1,833	(605)	458
Of which:			
Attributable to Royal Dutch Shell plc shareholders	1,759	(572)	481
Attributable to non-controlling interest	74	(33)	(23)
CCS earnings	(19,701)	15,827	24,364
Of which:			
Attributable to Royal Dutch Shell plc shareholders	(19,921)	15,270	23,833
Attributable to non-controlling interest	220	557	531

ADJUSTED EARNINGS

The "Adjusted Earnings" measure aims to facilitate a comparative understanding of Shell's financial performance from period to period by removing the effects of oil price changes on inventory carrying amounts and removing the effects of identified items. These items are in some cases driven by external factors and may, either individually or collectively, hinder the comparative understanding of Shell's financial results from period to period.

Adjusted Earnings

	\$ million		
	2020	2019	2018
Income/(loss) attributable to Royal Dutch Shell shareholders	(21,680)	15,842	23,352
Add: Current cost of supplies adjustment attributable to Royal Dutch Shell plc shareholders	1,759	(572)	481
Less: Identified items attributable to Royal Dutch Shell plc shareholders	(24,767)	(1,192)	2,429
Adjusted Earnings	4,846	16,462	21,404
Of which:			
Integrated Gas	4,383	8,955	9,399
Upstream	(2,852)	4,452	6,472
Oil Products	5,995	6,231	5,794
Chemicals	962	741	2,076
Corporate	(3,412)	(3,383)	(1,806)
less: Non-controlling interest	(230)	(535)	(531)

Adjusted Earnings per share

	\$ million		
	2020	2019	2018
Adjusted Earnings	4,846	16,462	21,404
Basic weighted average number of shares	7,796	8,058	8,283
Adjusted EPS	0.62	2.04	2.58

Identified Items

The objective of identified items is to remove material impacts on net income/loss arising from transactions which are generally uncontrollable and unusual (infrequent or non-recurring) in nature or giving rise to a mismatch of accounting and economic results, or certain transactions that are generally excluded from underlying results in the industry.

	\$ million		
	2020	2019	2018
Identified items before tax	(31,877)	(1,844)	3,089
Of which:			
Divestment gains/(losses)	316	2,611	3,283
Impairments	(28,061)	(4,155)	(1,020)
Fair value accounting of commodity derivatives and certain gas contracts	(1,151)	602	1,145
Redundancy and restructuring	(883)	(132)	(203)
Other	(2,098)	(770)	(116)
Total identified items before tax	(31,877)	(1,844)	3,089
Tax impact	7,100	674	(660)
Identified items after tax	(24,777)	(1,170)	2,429
Of which:			
Divestment gains/(losses)	4	2,170	3,064
Impairments	(21,267)	(3,162)	(1,112)
Fair value accounting of commodity derivatives and certain gas contracts	(1,034)	650	863
Redundancy and restructuring	(644)	(89)	(150)
Impact of exchange rate movements on tax balances	(240)	(69)	(338)
Other	(1,596)	(670)	102
Impact on CCS earnings	(24,777)	(1,170)	2,429
Of which:			
Identified items attributable to Royal Dutch Shell plc shareholders	(24,767)	(1,192)	2,429
Identified items attributable to Non-controlling interest	(10)	22	—

CASH CAPITAL EXPENDITURE

Cash capital expenditure monitors investing activities on a cash basis, excluding items such as lease additions which do not necessarily result in cash outflows in the period. The measure comprises the following lines from the Consolidated Statement of Cash flows: Capital expenditure, Investments in joint ventures and associates and Investments in equity securities.

With effect from January 1, 2020, "Capital investment" is no longer presented in this announcement since Cash capital expenditure is considered to be more closely aligned with management's focus on free cash flow generation.

NON-GAAP MEASURES RECONCILIATIONS continued

The reconciliation of "Capital expenditure" to "Cash capital expenditure" is as follows.

Cash capital expenditure

	\$ million		
	2020	2019	2018
Capital expenditure [A]	16,585	22,971	23,011
Investments in joint ventures and associates [A]	1,024	743	880
Investments in equity securities [A]	218	205	187
Cash capital expenditure	17,827	23,919	24,078
Of which:			
Integrated Gas	4,301	4,299	3,819
Upstream	7,296	10,205	12,134
Oil Products	3,328	4,907	4,643
Chemicals	2,640	4,090	3,212
Corporate	262	418	269

[A] Included within Cash flow from investing activities in the "Consolidated Statement of Cash Flows".

OPERATING EXPENSES

Operating expenses is a measure of Shell's cost management performance, comprising items from the "Consolidated Statement of Income" as follows.

Operating expenses

	\$ million		
	2020	2019	2018
Production and manufacturing expenses	24,001	26,438	26,970
Selling, distribution and administrative expenses	9,881	10,493	11,360
Research and development	907	962	986
Total	34,789	37,893	39,316
Of which			
Integrated Gas	6,555	6,667	6,014
Upstream	10,983	11,582	11,690
Oil Products	13,511	15,730	17,615
Chemicals	3,235	3,430	3,594
Corporate	505	486	402

RETURN ON AVERAGE CAPITAL EMPLOYED

Return on average capital employed (ROACE) measures the efficiency of our utilisation of the capital that we employ. In this calculation, ROACE is defined as income for the period, adjusted for after-tax interest expense, as a percentage of the average capital employed for the period. Capital employed consists of total equity, current debt and non-current debt.

Calculation of return on average capital employed

	\$ million		
	2020	2019	2018
Income for the period	(21,534)	16,432	23,906
Interest expense after tax	2,822	3,024	2,513
Income before interest expense	(18,712)	19,456	26,419
Capital employed – opening	286,887	295,398	283,477
Capital employed – closing	266,551	286,887	279,358
Capital employed – average	276,719	291,142	281,417
ROACE	(6.8)%	6.7%	9.4%

FREE CASH FLOW AND ORGANIC FREE CASH FLOW

Free cash flow is used to evaluate cash available for financing activities, including dividend payments, after investment in maintaining and growing our business.

Organic free cash flow is defined as Free cash flow excluding the cash flows from acquisition and divestment activities. It is a measure used by management to evaluate generation of cash flow without these activities.

Free cash flow and Organic free cash flow

	\$ million		
	2020	2019	2018
Cash flow from operating activities	34,105	42,178	53,085
Cash flow from investing activities	(13,278)	(15,779)	(13,659)
Free cash flow	20,828	26,399	39,426
Less: Cash inflows related to divestments [A]	4,010	7,871	10,465
Add: Tax paid on divestments	–	187	482
Add: Cash outflows related to inorganic capital expenditure [B]	817	1,400	1,740
Organic free cash flow	17,634	20,116	31,183

[A] Cash inflows related to divestments includes Proceeds from sale of property, plant and equipment and businesses, Proceeds from sale of joint ventures and associates, and Proceeds from sale of equity securities as reported in the "Consolidated Statement of Cash Flows".

[B] Cash outflows related to inorganic capital expenditure includes portfolio actions which expand Shell's activities through acquisitions and restructuring activities as reported in capital expenditure lines in the "Consolidated Statement of Cash Flows".

SHAREHOLDER DISTRIBUTION

Shareholder distribution is used to evaluate the level of cash distribution to shareholders. It is defined as the sum of Cash dividends paid to Royal Dutch Shell plc shareholders and Repurchases of shares, both of which are reported in the Consolidated Statement of Cash Flows.

Calculation of shareholder distribution

	\$ million		
	2020	2019	2018
Cash dividends paid to Royal Dutch Shell plc shareholders	(7,424)	(15,198)	(15,675)
Repurchases of shares	(1,702)	(10,188)	(3,947)
Shareholder distribution	(9,126)	(25,386)	(19,622)

DIVESTMENT PROCEEDS

Divestment proceeds represent cash received from divestment activities in the period. Management regularly monitors this measure as a key lever to deliver sustainable cash flow.

Calculation of Divestment proceeds

	\$ million		
	2020	2019	2018
Proceeds from sale of property, plant and equipment and businesses	2,489	4,803	4,366
Proceeds from sale of joint ventures and associates [A]	1,240	2,599	1,594
Proceeds from sale of equity securities	281	469	4,505
Divestment proceeds	4,010	7,871	10,465
Of which:			
Integrated Gas	503	723	3,156
Upstream	1,909	5,384	3,364
Oil Products	1,368	1,517	540
Chemicals	26	22	1
Corporate	205	225	3,405

[A] includes \$313 million (2019: \$155 million) of long-term of loan repayments received from joint ventures and associates

APPENDICES

APPENDIX 1

SIGNIFICANT SUBSIDIARIES AND OTHER RELATED UNDERTAKINGS (AUDITED)

Significant subsidiaries and other related undertakings at December 31, 2020, are set out below. Shell's percentage of share capital is shown to the nearest whole number. All subsidiaries have been included in the "Consolidated Financial Statements" on pages 216-264, and those held directly by the Company are marked with the footnote [a]. A number of the entities listed are dormant or not yet operational. Entities that are proportionately consolidated are identified by the footnote [b]. Shell-owned shares are ordinary (voting) shares unless identified with one of the following annotations against the company name: [c] Membership interest; [d] Partnership capital; [e] Non-redeemable; [f] Ordinary, Partnership capital; [g] Ordinary, Redeemable; [h] Ordinary, Redeemable, Non-redeemable; and [i] Redeemable, Non-redeemable.

Company by country and address of incorporation	%	Company by country and address of incorporation	%
ARGENTINA		QGC Train 2 Pty Ltd	100
AVENIDA PTE. ROQUE SÁENZ PENA 788, 2ND FLOOR, CIUDAD DE BUENOS AIRES, 1035		QGC Train 2 Tolling No.2 Pty Ltd	100
Bandurria Sur Investments S.A.	50	QGC Train 2 Tolling Pty Ltd	100
Shell Argentina S.A.	100	QGC Train 2 UJV Manager Pty Ltd	100
AUSTRALIA		QGC Upstream Finance Pty Ltd	100
C/O ALANDS ACCOUNTANTS, LEVEL 1/293 QUEEN STREET, BRISBANE, QLD 4000		QGC Upstream Holdings Pty Ltd	100
Alliance Automation Pty Ltd	50	QGC Upstream Investments Pty Ltd	100
C/O JEFFERY ZIVIN, UNIT 4, 4 GEORGE STREET, CAMBERWELL, VIC 3124		Queensland Gas Company Pty Ltd	100
Solpod Pty Ltd	24	Roma Petroleum Pty Limited	100
INFRASTRUCTURE CAPITAL GROUP, LEVEL 15 MARTIN PLACE, SYDNEY, NSW 2000		Select Carbon Pty Ltd	100
NewGen Neerabup Pty Ltd [b]	50	SGA (Queensland) Pty Ltd	100
LEVEL 30, 275 GEORGE STREET, BRISBANE, QLD 4000		SGAI Pty Limited	100
BC 789 Holdings Pty Ltd	100	Shell Energy Australia Pty Ltd	100
BG CPS Pty Limited	100	Shell New Energies Australia Pty Ltd	100
BNG (Sarat) Pty Ltd	100	Shell QGC Pty Ltd	100
Condamine 1 Pty Ltd	100	Starzap Pty Ltd	100
Condamine 2 Pty Ltd	100	Sunshine 685 Pty Limited	100
Condamine 3 Pty Ltd	100	Walloons Coal Seam Gas Company Pty Limited [g]	75
Condamine 4 Pty Ltd	100	LEVEL 39, 111 EAGLE STREET, BRISBANE, QLD 4000	
Condamine Power Station Pty Ltd	100	Arrow Energy Holdings Pty Ltd	50
ERM Power Limited	100	LEVEL 4, 13 CREMORNE STREET, RICHMOND, VIC 3121	
New South Oil Pty Ltd	100	ESCO Pacific Holdings Pty Ltd	49
OME Resources Australia Pty Ltd	100	LEVEL 4, 459 LITTLE COLLINS STREET, MELBOURNE, VIC 3000	
Petroleum Resources (Thailand) Pty. Limited	100	1st Energy Pty Ltd	30
Pure Energy Resources Pty Limited	100	LEVEL 42, BOURKE PLACE, 600 BOURKE STREET, MELBOURNE, VIC 3000	
QCLNG Operating Company Pty Ltd [g]	75	QGC Midstream Limited Partnership	100
QCLNG Pty Ltd	100	QGC Upstream Limited Partnership	100
QGC (B7) Pty Ltd	100	LEVEL 52, 111 EAGLE STREET, BRISBANE, QLD 4000	
QGC (Exploration) Pty Ltd	100	Braemar 3 Holdings Pty Ltd	100
QGC (Infrastructure) Pty Ltd	100	CCM Energy Solutions Pty Ltd	100
QGC Common Facilities Company Pty Ltd	100	E.R.M. Oakey Power Pty Ltd	100
QGC Holdings 2 Pty Ltd	100	ERM Braemar 3 Power Pty Ltd	100
QGC Holdings 3 Pty Ltd	100	ERM Braemar 3 Pty Ltd	100
QGC Holdings 4 Pty Ltd	100	ERM Employee Share Plan Administrator Pty Ltd	100
QGC Holdings 5 Pty Ltd	100	ERM Energy Solutions Holdings Pty Ltd	100
QGC Holdings 6 Pty Ltd	100	ERM Financial Services Pty Ltd	100
QGC Holdings 7 Pty Ltd	100	ERM Gas Pty Ltd	100
QGC Holdings 8 Pty Ltd	100	ERM Gas WA01 Pty Ltd	100
QGC Holdings 9 Pty Ltd	100	ERM Holdings Pty Ltd	100
QGC Midstream Holdings Pty Ltd	100	ERM Innovation Labs Pty Ltd	100
QGC Midstream Investments Pty Ltd	100	ERM Land Holdings Pty Ltd	100
QGC Midstream Land Pty Ltd	100	ERM Neerabup Power Pty Ltd	100
QGC Midstream Services Pty Ltd	100	ERM Neerabup Pty Ltd	100
QGC Northern Forestry Pty Ltd	100	ERM Oakey Power Holdings Pty Ltd	100
QGC Pty Limited	100	ERM Power Developments Pty Ltd	100
QGC Sales Qld Pty Ltd	100	ERM Power Engineering Pty Ltd	100
QGC Train 1 Pty Ltd	100	ERM Power Generation Pty Ltd	100
QGC Train 1 Tolling Pty Ltd	100	ERM Power International Pty Ltd	100
QGC Train 1 UJV Manager Pty Ltd	100	ERM Power Investments Pty Ltd	100

Company by country and address of incorporation	%
ERM Power Projects Pty Ltd	100
ERM Power Retail Pty Ltd	100
ERM Power Services Pty Ltd	100
ERM Power Utility Systems Pty Ltd	100
ERM Wellington 1 Holdings Pty Ltd	100
Greensense Pty Ltd	100
Lumaed Pty Ltd	100
Oakey Power Holdings Pty Ltd	100
Out Performers Trading Pty Ltd	100
Powermetric Metering Pty Ltd	100
Queensland Electricity Investors Pty Ltd	100
Richmond Valley Solar Thermal Pty Ltd	100
SHELL HOUSE, 562 WELLINGTON STREET, PERTH, WA 6000	
Austen & Butta Pty Ltd	100
North West Shelf LNG Pty Ltd	100
SASF Pty Ltd	100
Shell Australia FLNG Pty Ltd	100
Shell Australia Pty Ltd	100
Shell Australia Services Company Pty Ltd	100
Shell Development (PSC19) Pty Ltd	100
Shell Development (PSC20) Pty Ltd	100
Shell Energy Holdings Australia Limited	100
Shell Energy Investments Australia Pty Ltd	100
Shell Global Solutions Australia Pty Ltd	100
Shell Tankers Australia Pty Ltd	100
Trident LNG Shipping Services Pty Ltd	100
TENANCY 6, LIONSGATE BUSINESS PARK, 180 PHILIP HIGHWAY, ELIZABETH SOUTH, SA 5112	
Sonnen Australia Pty Limited	100
AUSTRIA	
INNSBRUCKER BUNDESSTRASSE 95, SALZBURG, 5020	
Salzburg Fuelling GmbH	33
KIENBURG 11, MATREI IN OSTTIROL, 9971	
Transalpine Ölleitung in Österreich GmbH	19
RETENLACKSTRASSE 3, SALZBURG, 5020	
TBG Tanklager Betriebsgesellschaft m.b.H.	50
SCHULHOF 6/1, VIENNA, 1010	
Shell China Holding GmbH	100
TECH GATE, DONAU-CITY-STR. 1, VIENNA, 1220	
Shell Austria Gesellschaft mbH	100
Shell Brazil Holding GmbH	100
BAHAMAS	
GTC CORPORATE SERVICES LIMITED, SASSOON HOUSE, SHIRLEY STREET & VICTORIA AVENUE, NASSAU	
Shell Western Supply and Trading Limited	100
P.O. BOX N4805, ST. ANDREW'S COURT, FREDERICK STREET STEPS, NASSAU	
Shell Bahamas Power Company Inc.	100
BARBADOS	
ONE WELCHES, WELCHES, ST. THOMAS, BB22025	
Shell Trinidad and Tobago Resources SRL	100
BELGIUM	
BORSBEEKSEBRUG 34/1, ANTWERPEN, 2600	
The New Motion Belgium BV	100
CANTERSTEEN 47, BRUSSELS, 1000	
Belgian Shell S.A.	100
New Market Belgium S.A.	100
PANTSERSCHIPSTRAAT 331, GENT, 9000	
Shell Catalysts & Technologies Belgium N.V.	100

Company by country and address of incorporation	%
BERMUDA	
3RD FLOOR CONTINENTAL BUILDING, 25 CHURCH STREET, HAMILTON, HM 12	
Gas Investments & Services Company Limited	85
Pecten Somalia Company Limited	100
Qatar Shell GTL Limited	100
Shell Australia Natural Gas Shipping Limited	100
Shell Bermuda (Overseas) Limited	100
Shell Deepwater Borneo Limited	100
Shell EP International Limited	100
Shell Holdings (Bermuda) Limited	100
Shell International Trading Middle East Limited	100
Shell Markets (Middle East) Limited	100
Shell Oman Trading Limited	100
Shell Petroleum (Malaysia) Ltd	100
Shell Saudi Arabia (Refining) Limited	100
Shell Trading (M.E.) Private Limited	100
Shell Trust (Bermuda) Limited	100
Solen Life Insurance Limited	100
CLARENDON HOUSE, 2 CHURCH STREET, HAMILTON, HM 11	
Egypt LNG Shipping Limited	25
Sakhalin Energy Investment Company Ltd	28
BRAZIL	
AVENIDA BRIGADEIRO FARIA LIMA Nº 3.311, CONJUNTO 82, ITAIM BIBI, SÃO PAULO, 04538-133	
Shell Energy do Brasil Ltda.	100
AVENIDA BRIGADEIRO FARIA LIMA, 4100, 11TH FLOOR, PART V, ITAIM BIBI, SÃO PAULO, 04538-132	
Raizen Energia S.A.	49
AVENIDA DAS ALMIRANTE BARROSO, Nº 81, 36º ANDAR, SALA 36A104, RIO DE JANEIRO, 20031-004	
Raizen Combustíveis S.A.	54
AVENIDA DAS REPUBLICA DO CHILE 330, 23º ANDAR (PARTE) – TORRE 2, CENTRO, RIO DE JANEIRO, 20031-170	
BG Petroleo & Gas Brasil Ltda.	100
AVENIDA DAS REPUBLICA DO CHILE 330, 23º ANDAR, TORRE 2, CENTRO, RIO DE JANEIRO, 20031-170	
BG Comercio e Importacao Ltda.	100
Avenida Paulista, 1274, 8º andar, Conjunto 23, Sala B, Bela Vista, São Paulo, 01310-100	
Marlim Azul Energia S.A.	30
AVENIDA REPÚBLICA DO CHILE Nº 330, BLOCO 2, SALA 2001, CENTRO, RIO DE JANEIRO, 20031-170	
Shell Energy do Brasil Gás Ltda.	100
AVENIDA REPÚBLICA DO CHILE Nº 330, BLOCO 2, SALA 2301, CENTRO, RIO DE JANEIRO, 20031-170	
Pecten do Brasil Servicos de Petroleo Ltda.	100
AVENIDA REPÚBLICA DO CHILE Nº 330, BLOCO 2, SALA 2401, CENTRO, RIO DE JANEIRO, 20031-170	
Seapos Ltda.	100
AVENIDA REPÚBLICA DO CHILE Nº 330, BLOCO 2, SALAS 2001, 2301, 2401, 2501, 3101, 3201, 3301 E 3401, CENTRO, RIO DE JANEIRO, 20031-170	
Shell Brasil Petroleo Ltda.	100
BRUNEI	
BRUNEI SHELL PETROLEUM COMPANY, SENDIRIAN BERHAD, SERIA, KB2933	
Brunei Shell Marketing Company Sendirian Berhad	50
C/O BSP HEAD OFFICE, NDCO BLOCK, GROUND FLOOR, JALAN UTARA, PANAGA SERIA, KB3534	
Shell Borneo Sendirian Berhad	100
JALAN UTARA, PANAGA, SERIA, KB2933	
Brunei Shell Petroleum Company Sendirian Berhad	50
Brunei Shell Tankers Sendirian Berhad	25
LUMUT, SERIA, KC2935	
Brunei LNG Sendirian Berhad	25

APPENDIX 1 continued

Company by country and address of incorporation	%
BULGARIA	
48, SITNYAKOVO BLVD., SERDIKA OFFICES, 8TH FLOOR, SOFIA, 1505	
Shell Bulgaria Ead	100
CAMBODIA	
186C, STREET NO. 155, N/A - TUOL TUMPUNG MUOY, CHAMKAR MON, PHNOM PENH	
Angkor Resources Company Limited	49
CANADA	
1701 HOLLIS STREET, SUITE 1400, HALIFAX, NOVA SCOTIA, B3J 3M8	
Sable Offshore Energy Inc.	33
199 BAY STREET, SUITE 5300, COMMERCE COURT WEST, TORONTO, ONTARIO, M5L 1B9	
SFJ Inc.	50
2100, 855 - 2ND STREET S.W., CALGARY, ALBERTA, T2P 4J8	
1745844 Alberta Ltd.	50
400 4TH AVENUE S.W., CALGARY, ALBERTA, T2P 0J4	
10084751 Canada Limited	100
7026609 Canada Inc.	100
7645929 Canada Limited	100
Cansolv Technologies Inc.	100
Coral Cibola Canada Inc.	100
FP Solutions Corporation	33
LNG Canada Development Inc. [b]	40
SCL Pipeline Inc.	100
Shell Americas Funding (Canada) Limited	100
Shell Canada BROS Inc.	100
Shell Canada Energy [c]	100
Shell Canada Limited	100
Shell Canada OP Inc.	100
Shell Canada Products	100
Shell Canada Resources [c]	100
Shell Canada Services Limited	100
Shell Catalysts & Technologies Canada Inc.	100
Shell Chemicals Canada [c]	100
Shell Energy Merchants Canada Inc.	100
Shell Energy North America (Canada) Inc.	100
Shell Global Solutions Canada Inc.	100
Shell Quebec Limitée	100
Shell Trading Canada [c]	100
Zeco Systems (Canada) Inc.	100
45 VOGEL ROAD, SUITE 310, RICHMOND HILL, ONTARIO, L4B 3P6	
Trans-Northern Pipelines Inc.	33
5305 MCCALL WAY N.E., CALGARY, ALBERTA, T2E 7N7	
Alberta Products Pipe Line Ltd.	20
830 HIGHWAY NO. 6 NORTH, FLAMBOROUGH, ONTARIO, L0R 2H0	
Sun-Canadian Pipe Line Company Limited	45
CAYMAN ISLANDS	
C/O APPLEBY GLOBAL SERVICES (CAYMAN) LIMITED, 71 FORT STREET, P.O. BOX 500, GEORGE TOWN, GRAND CAYMAN, KY1-1106	
KE STP Company	100
KE Suriname Company	100
Portfolio Holdings	100
C/O APPLEBY GLOBAL SERVICES (CAYMAN) LIMITED, 71 FORT STREET, PO BOX 500, GEORGE TOWN, GRAND CAYMAN, KY1-1106	
KE Namibia Company	100
CALEDONIAN TRUST (CAYMAN) LIMITED, CALEDONIAN HOUSE, 69 DR ROY'S DRIVE P.O. BOX 1043, GEORGE TOWN, GRAND CAYMAN, KY1-1102	
Schiehallion Oil & Gas Limited	100
CAMPBELLS, FLOOR 4, WILLOW HOUSE, CRICKET SQUARE, GEORGE TOWN, GRAND CAYMAN, KY1-9010	
BG Exploration and Production India Limited	100
MAPLES CORPORATE SERVICES LIMITED, UGLAND HOUSE, P.O. BOX 309, GEORGE TOWN, GRAND CAYMAN, KY1-1104	
Shell North Sea Holdings Limited	100

Company by country and address of incorporation	%
PICCADILLY CENTRE, 28 ELGIN AVENUE, SUITE 201, P.O. BOX 2570, GEORGE TOWN, GRAND CAYMAN, KY1-1103	
BG Egypt S.A.	100
Gas Resources Limited	100
Shell Bolivia Corporation	100
STERLING TRUST (CAYMAN) LIMITED, WHITEHALL HOUSE, 238 NORTH CHURCH STREET, P.O. BOX 1043, GEORGE TOWN, GRAND CAYMAN, KY1-1102	
Beryl North Sea Limited	100
CHILE	
C/O CAREY Y CIA ABOGADOS, MIRAFLORES 222, PISO 28, SANTIAGO	
Shell Chile S.A.	100
CHINA	
18TH FLOOR, TOWER 1, YONGLI INTERNATIONAL FINANCE CENTRE, JINYE NO. 1 ROAD, HIGH-TECH DISTRICT, XI'AN, 710075	
Yanchang and Shell Petroleum Company Limited	45
23F, YANLORD SQUARE, SECTION 2, RENMIN SOUTH ROAD, CHENGDU, SICHUAN, 610016	
Yanchang and Shell (Sichuan) Petroleum Company Limited	45
30/F UNIT 01-02, NO. 16 BUILDING, NO. 1 COURTYARD, JIAN GUO MEN WAI AVENUE, CHAOYANG DISTRICT, BEIJING, 100004	
Shell (China) Limited	100
39TH FLOOR AS PLANNING-DESIGNED (41ST FLOOR AS SELF-DESIGNATED), LEATOP PLAZA, NO. 32 EAST ZHUJIANG ROAD, ZHUJIANG NEW TOWN, TIANHE DISTRICT, GUANGZHOU	
Yanchang and Shell (Guangdong) Petroleum Co., Ltd.	49
8/F, BUILDING 1, NO. 818 SHENCHANG ROAD, MINHANG DISTRICT, SHANGHAI, 201106	
Shell Management and Consulting Company Limited	100
Shell Ventures Company Limited	100
BAISHA, HEKOU, SANSHUI DISTRICT, FOSHAN, GUANGDONG, 528133	
Shell Road Solutions Xinyue (Foshan) Co. Ltd.	60
BUILDING 4, JIN CHUANG BUILDING, NO. 4560, JIN KE ROAD, PILOT FREE TRADE ZONE, SHANGHAI	
Shell (Shanghai) Technology Limited	100
BUILDING NO. 2, HEBEI GUOKONG NORTHERN SILICON VALLEY HI, NO. 28 EAST ZHANQIAN STREET, QIAODONG DI, ZHANGJIAKOU, 075000	
Zhangjiakou City Transport and Shell New Energy Co., Ltd	48
DAYAWAN PETROCHEMICAL INDUSTRIAL PARK, HUIZHOU, GUANGDONG, 516086	
CNOOC and Shell Petrochemicals Company Limited	50
NANJIN WAN, GAOLAN DAO, GAOLAN HARBOUR ECONOMIC ZONE, ZHUHAI, 519050	
Shell (Zuhai) Lubricants Company Limited	100
NO. 1 DONGXIN ROAD, JIANGSU YANGTZE RIVER INTERNATIONAL, CHEMICAL INDUSTRY PARK, ZHANGJIAGANG, JIANGSU, 215600	
Infineum (China) Co. Ltd.	50
NO. 1 WANGJIABA, XINMIAOZHI VILLAGE, PUYUAN TOWN, TONGXIANG, JIAXING, ZHEJIANG, 314502	
Shell (Zhejiang) Petroleum Trading Limited	100
NO. 100, XINGANG DADAO, NANJING ECONOMIC AND TECHNOLOGICAL DEVELOPMENT ZONE, NANJING, JIANGSU, 210000	
Sinopec and Shell (Jiangsu) Petroleum Marketing Company Limited	40
NO. 196, SHUANG YUAN STREET, BEIBEI ZONE, CHONGQING, 400700	
Chongqing Shell Energy Company Limited	100
NO. 286 NANSAN ROAD, TIANJIN HARBOUR NANJIANG DEV. ZONE, TANGGU, BINHAI NEWDISTRICT, TIANJIN, 300452	
Shell (Tianjin) Oil and Petrochemical Company Limited	100
NO. 358 ZHUHUI ROAD, SUZHOU, 215000	
Suzhou Liyuan Retail Site Management Co., Ltd.	50
NO. 4, 5, 12/F, UNIT A, OCEANWIDE INTERNATIONAL CENTER OFFICE, 187 YUNXIA ROAD, CBD, JIANHAN DISTRICT, WUHAN, 430000	
Hubei Shell Energy Company Limited	100
NO. 68 XIANIEJIA, DAGANG, ZHENJIANG NEW DISTRICT, ZHENJIANG, 212132	
Shell Road Solutions (Zhenjiang) Co. Ltd	100
NORTH TO GANG BEI ROAD AND EAST TO HAI GANG ROAD, NANGANG INDUSTRIAL ZONE, TIANJIN ECONOMIC-TECHNOLOGICAL DEVELOPMENT AREA, TIANJIN, 300280	
Shell (Tianjin) Lubricants Company Limited	100
RM 1503, BUILDING 2, PLAZA OF ZBA, NO. 939 MINHE ROAD, NINGWEI STREET, XIAOSHAN, HANGZHOU, ZHEJIANG, 311215	
Zhejiang Transfar and Shell Energy Company Limited	49

Company by country and address of incorporation	%
ROOM 1801, BUILDING 1, INTERNATIONAL FINANCE CENTER, NO. 347, JIANGDONG MIDDLE ROAD, JIANYE DISTRICT, NANJING, JIANGSU, 210019	
Jiangsu Shell Energy Company Limited	100
ROOM 2103, NORTH TOWER, YEFENG MODERN CENTER, NO. 161, SHAOXING ROAD, XIACHENG DISTRICT, HANGZHOU, ZHEJIANG, 310004	
Zhejiang Shell Fuels Company Limited	49
ROOM 2407-2409, BUILDING 15, FANGMAOYUAN (PHASE II), NO. 1177 HUANHU ROAD, YUELU DISTRICT, CHANGSHA, 410006	
Hunan Shell Energy Company Limited	100
ROOM 2519-2522, 25/F, GREENLAND CENTER, CROSS-AREA OF SUSONG RD AND CHANGQIN ST, SOUTH ERHUA, BAOHE DISTRICT, HEFEI, ANHUI, 230000	
Anhui Shell Energy Company Limited	100
ROOM 518, 5TH FLOOR, OFFICE BUILDING, TIANJIN FOOD GROUP COMPANY LTD, NO. 96, QIXIANGTAI ROAD, HEXI DISTRICT, TIANJIN, 300074	
Shell North China Petroleum Group Co., Ltd.	49
ROOM 522, THE BRITISH ROAD NO. 38, CHINA (SHANGHAI) PILOT FREE TRADE ZONE, SHANGHAI, 200131	
Shell (Shanghai) Petroleum Company Limited	100
ROOM 530, 5TH FLOOR, BUILDING 1, NO. 239 GANG'AO ROAD, CHINA (SHANGHAI) FREE TRADE ZONE, SHANGHAI, 200137	
Shell Energy (China) Limited	100
ROOM 609, BUILDING NO. 1, NO. 388 NORTH MU HUA ROAD, FENGXIAN DIST, SHANGHAI, 200120	
Climate Bridge (Shanghai) Ltd.	49
THE PORT OF ZHAPU, JIAXING MUNICIPALITY, ZHEJIANG, 314201	
Zhejiang Shell Oil and Petrochemical Company Limited	100
UNIT 01, 32/F, NO. 16 BUILDING, NO. 1 COURTYARD, JIAN GUO MEN WAI AVENUE, CHAOYANG DISTRICT, BEIJING, 100004	
Shell (Beijing) Real Estate Consulting Ltd.	100
UNIT 01-08, LEVEL 31, NO. 16 BUILDING, NO. 1 JIAN GUO MEN WAI AVENUE, CHAOYANG DISTRICT, BEIJING, 100004	
Shell (China) Projects & Technology Limited	100
UNIT 09, LEVEL 31, NO. 16 BUILDING, NO. 1 JIAN GUO MEN WAI AVENUE, CHAOYANG DISTRICT, BEIJING, 100004	
Cansolv Technologies (Beijing) Company Limited	100
UNIT 1101-1104, LEVEL 11, BUILDING 1, NO. 19 CHAOYANG PARK ROAD, CHAOYANG DISTRICT, BEIJING, 100125	
Beijing Shell Petroleum Company Ltd.	49
UNIT 604, 6/F, BUILDING C, NO. 3 YUNAN FOURTH ROAD, FTPZ XIAMEN SUB-ZONE (TARIFF-FREE ZONE), XIAMEN, 361000	
Fujian Xiangyu and Shell Petroleum Company Limited	49
COLOMBIA	
CALLE 90 NO. 19 - 41, OFICINA 702- EDIFICIO QUANTUM, BOGOTÁ, 452	
Shell Colombia S.A.	100
COOK ISLANDS	
BERMUDA HOUSE, TUTAKIMOA ROAD, RAROTONGA	
Branstone (International) Limited [g]	100
CÔTE D'IVOIRE	
14, BLVD CARDE, IMM. LES HEVEAS, PLATEAU, ABIDJAN, BP V 194	
Cote d'Ivoire GNL	13
CYPRUS	
METECHIOU STR, 37, AGIOS ANDREAS, NICOSIA, CY-1101	
Rosneft-Shell Caspian Ventures Limited	49
CZECH REPUBLIC	
ANTALA STAŠKA 2027/77, PRAHA 4, 140 00	
Shell Czech Republic a.s.	100
DENMARK	
BREDGADE 30, KØBENHAVN K, 1260	
TetraSpar Demonstrator ApS	66
EGESKOVVEJ 265, FREDERICIA, 7000	
A/S Dansk Shell	100
Shell EP Holdingselskab Danmark ApS	100
NÆRUM HOVEDGADE 8, NÆRUM, 2850	
DCC & Shell Aviation Denmark A/S	49

Company by country and address of incorporation	%
EGYPT	
127 ABDEL AZIZ FAHMY ST., HELIOPOLIS, P.O. BOX 5958, CAIRO, 5958	
Alam El Shawish Petroleum Company [b]	20
Badr Petroleum Company [b]	50
North Alam El-Shawish Petroleum Company [b]	50
North Um Baraka Petroleum Company [b]	50
Obayed Petroleum Company [b]	50
Sitra Petroleum Company [b]	50
Tiba Petroleum Company [b]	26
West Sitra Petroleum Company [b]	50
28 ROAD 270, MAADI, CAIRO	
Burullus Gas Company S.A.E. [b]	25
38 STREET NO. 270, MAADI, CAIRO	
Rashid Petroleum Company S.A.E. [b]	50
BUSINESS VIEW BUILDING, NO. 79, 90 STREET (SOUTH), FIFTH SETTLEMENT- NEW CAIRO, CAIRO, 11835	
Shell Egypt Trading	100
Shell Lubricants Egypt	100
CITY OF RASHID, EL BEHERA GOVERNORATE	
El Behera Natural Gas Liquefaction Company S.A.E.	36
IDKU Natural Gas Liquefaction Company S.A.E.	38
The Egyptian LNG Company S.A.E.	36
The Egyptian Operating Company for Natural Gas Liquefaction Projects S.A.E.	36
FINLAND	
TEKNOBULEVARDI 3-5, VANTAA, 01530	
Shell Aviation Finland Oy	100
FRANCE	
10 PLACE DE CATALOGNE, PARIS, 75014	
Accurasea	100
Airefsol Energies	67
Airefsol Energies 2	67
Airefsol Energies 8	67
Airefsol Energies 9	67
Centrale Photovoltaïque Bouches-du-Rhône 1	100
Centrale Photovoltaïque Haute-Vienne 1	100
Centrale Photovoltaïque Landes 1	100
Centrale Photovoltaïque Var 1	100
Eolfi Offshore France	10
Eolfi SAS	100
Eoliennes du Gentilhomme	100
Ferme Eolienne Flottante de Groix & Belle-Ile	29
Ferme Eolienne Flottante Stenella Rhône	100
Parc Eolien Aisne 1	100
Parc Eolien Corrèze 1	100
Parc Eolien Côtes Armor 1	100
Parc Eolien de la Vrine	100
Parc Eolien De Mervent	100
Parc Eolien Haute-Saône 1	100
Parc Eolien HM1	100
Parc Eolien Jura 1	100
Parc Eolien Marne 1	100
Parc Eolien Oise 1	100
Parc Eolien Oise 2	100
Parc Eolien Somme 1	100
Parc Eolien Somme 2	100
Parc Eolien Yonne 1	100
92 AVENUE CHARLES DE GAULLE, CS 30082, NEUILLY SUR SEINE, 92522	
The New Motion France SAS	100

APPENDIX 1 continued

Company by country and address of incorporation	%
FRANCE continued	
AÉROPORT ROISSY CHARLES DE GAULLE, ZONE DE FRÊT 1, 3 RUE DES VIGNES, TREMBLAY-EN-FRANCE, 93290	
Groupe Pétrolier Aviation SNC	20
CHEMIN DÉPARTEMENTAL 54, BERRE-L'ÉTANG, 13130	
Infineum France	50
ORLY SUD NO. 144 - BAT. 438, ORLY AÉROGARES, 94541	
Service Aviation Paris SNC	33
ROUTE D'ARLES, LA FENOUILLE, FOS-SUR-MER, 13270	
Ste du Pipeline Sud Européen S.A.	21
TOUR PACIFIC, 11/13 COURS VALMY - LA DÉFENSE, PUTEAUX, 92800	
Avitair SAS	100
Shell Retraites SAS	100
Société de Gestion Mobilière et Immobilière SAS	100
Société des Pétroles Shell SAS	100
GERMANY	
AM HAUPTTOR, BAU 8322, LEUNA, 06237	
CRI Deutschland GmbH	100
Shell Catalysts & Technologies Leuna GmbH	100
AM RIEDBACH 1, WILDPOLDSRIED, 87499	
Sonnen eServices Deutschland GmbH	100
Sonnen eServices GmbH	100
Sonnen GmbH	100
Sonnen Holding GmbH	100
AUF DEM SCHOLLBRUCH 24-26, GELSENKIRCHEN, 45899	
Rheinland Kraftstoff GmbH	100
BERGHAUSENER STRASSE 96, LANGENFELD, 40764	
AGES Maut System GmbH & Co. KG	25
BRUEHLER STR. 95, WESSELING, 50389	
Wasserbeschaffungsverband Wesseling-Hersel	35
CAFFAMACHERREIHE 5, HAMBURG, 20355	
BEB Holding GmbH [b]	50
DEA-SCHOLVEN-STR., KARLSRUHE, 76187	
Mineraloelraffinerie Oberrhein Verwaltungs GmbH	32
Oberrheinische Mineraloelwerke GmbH [b]	42
EINSTEINSTR. 47, VAIHINGEN AN DER ENZ, 71665	
Enersol GmbH	100
EUREF-CAMPUS 10-11, BERLIN, 10829	
H2 Mobility Deutschland GmbH and Co. KG	28
FRANZÖSISCHE STRASSE 33 A-C, BERLIN, 10117	
Toll4Europe GmbH	15
GODORFER HAUPTSTRASSE 186, KÖLN, 50997	
Rhein-Main-Rohrleitungstransportgesellschaft mbH [b]	63
HOHE-SCHAAR-STRASSE 36, HAMBURG, 21107	
Shell Global Solutions (Deutschland) GmbH	100
NEUSSER LANDSTRASSE 16, KÖLN, 50735	
Deutsche Infineum GmbH & Co. KG	50
PASSOWER CHAUSSEE 111, SCHWEDT/ODER, 16303	
PCK Raffinerie GmbH [b]	38
PAUL WASSERMANN STR. 3, MUNICH, 81829	
Deutsche Transalpine Oelleitung GmbH	19
RIETHORST 12, HANNOVER, 30659	
BEB Erdgas und Erdoel GmbH & Co. KG [b]	50
Erdoel-Raffinerie Deurag-Nerag GmbH	50
ST.-LEONHARD-STRASSE 26, BALZHAUSEN, 86483	
Energeticum Energiesysteme GmbH	100
SUHRENKAMP 71 - 77, HAMBURG, 22335	
Carissa Verwaltungsgesellschaft mbH	100
Deutsche Shell GmbH	100
Deutsche Shell Holding GmbH	100

Company by country and address of incorporation	%
euroShell Deutschland GmbH & Co. KG	100
euroShell Deutschland Verwaltungsgesellschaft mbH	100
Shell Deutschland Additive GmbH	100
Shell Deutschland Oil GmbH	100
Shell Energy Deutschland GmbH	100
Shell Energy Retail GmbH	100
Shell Erdgas Beteiligungsgesellschaft mbH	100
Shell Erdgas Marketing GmbH & Co. KG	75
Shell Erdoel und Erdgas Exploration GmbH	100
Shell Exploration and Development Libya GmbH I	100
Shell Exploration and Production Colombia GmbH	100
Shell Exploration and Production Libya GmbH	100
Shell Exploration et Production du Maroc GmbH	100
Shell Exploration New Ventures One GmbH	100
Shell Exploration und Produktion Deutschland GmbH	100
Shell Hydrogen Deutschland GmbH	100
Shell Tunisia Offshore GmbH	100
Shell Verwaltungsgesellschaft für Erdgasbeteiligungen mbH	100
SPNV Deutschland Beteiligungsges. mbH	100
WATTSTRASSE 11, BERLIN, 13355	
The New Motion Deutschland GmbH	100
WEWORK EUROPAPASSAGE, HERMANNSTRASSE 13, HAMBURG, 20095	
OLF Deutschland GmbH	50
WILLINGHUSENER WEG 5 D-E, OSTSTEINBEK, 22113	
Carissa Einzelhandel- und Tankstellenservice GmbH & Co. KG	100
ZUM OELHAFEN 207, WILHELMSHAVEN, 26384	
Nord-West Oelleitung GmbH [b]	20
GHANA	
NO 4 MOMOTSE AVENUE, ADABRAKA, ACCRA, GP 1632	
Shell Energy Ghana Limited	100
GIBRALTAR	
57/63 LINE WALL ROAD, P.O. BOX 199, GIBRALTAR	
Shell LNG Gibraltar Limited	51
GREECE	
151 KIFISIAS AVE., MAROUSI, ATHENS, 15124	
Shell & MOH Aviation Fuels A.E.	51
GREENLAND	
P.O. BOX 510, ISSORTARFIMMUT 6, 102, NUUSSUAQ, 3905	
Shell Greenland A/S	100
GUAM	
643 CHALAN SAN ANTONIO, SUITE 100, TAMUNING, GU 96911	
Shell Guam Inc.	100
HONG KONG	
3 SCENIC ROAD, CHEK LAP KOK, LANTAU	
AFSC Operations Limited	11
AFSC Refuelling Limited	11
35/F AIA KOWLOON TOWER, LANDMARK EAST, 100 HOW MING STREET, KWUN TONG, KOWLOON	
Fulmar Limited	100
Ocean Century Tf Limited [g]	100
Shell Developments (HK) Limited [g]	100
Shell Hong Kong Limited	100
Shell Korea Limited	100
Shell Macau Limited	100
ESSO TSING YI TERMINAL, LOT 46 TSING YI ROAD, TSING YI ISLAND, NEW TERRITORIES	
Hong Kong Response Limited	25
HUNGARY	
BOCSKAI ÚT 134-146., BUDAPEST, 1113	
Shell Hungary Trading close Company Limited by shares	100

Company by country and address of incorporation	%
INDIA	
102, PRESTIGE SIGMA, VITTAL MALLA ROAD, BANGALORE, 560001	
Shell MRPL Aviation Fuels and Services Limited	50
2ND FLOOR, CAMPUS 4A, RMZ MILLENIA BUSINESS PARK II, 143 DR MGR ROAD, KANDHANCHAVADY, PERUNGUDI, CHENNAI, TN 600096	
Shell Energy Marketing and Trading India Private Limited	100
Shell India Markets Private Limited	100
3-C WORLD TRADE TOWER, NEW BARAKHAMBALANE, NEW DELHI, 110001	
BG India Energy Private Limited	100
BG India Energy Services Private Limited	100
BG India Energy Solutions Private Limited	100
BG LNG Regas India Private Limited	100
OFFICE NO 2008, WESTGATE - D BLOCK, NR YMCA CLUB, S.G.HIGHWAY, MAKARBA, AHMEDABAD, GUJARAT, 380051	
Hazira Port Private Limited	100
Shell Energy India Private Limited	100
PLATINA TOWER MG ROAD, NEAR SIKANDARPUR METRO STATION, SECTION, HARYANA, GURUGRAM, 122001	
Greenlots Technology India LLP	100
TIKI TAR INDUSTRIES VILLAGE ROAD, NEAR BHANDUP VILLAGE, BHANDUP WEST MUMBAI, MUMBAI, MH 400078	
Tiki Tar and Shell India Private Limited	50
INDONESIA	
TALAVERA OFFICE PARK 22-26TH FLOOR, JL. LETJEN. TB SIMATUPANG KAV. 22-26, JAKARTA SELATAN, JAKARTA, 12430	
PT Shell LNG Indonesia	100
PT. Shell Indonesia	100
PT. Shell Manufacturing Indonesia	100
IRAQ	
KHOR AL ZUBAIR, BASRAH	
Basrah Gas Company	44
IRELAND	
1ST FLOOR, TEMPLE HALL, TEMPLE ROAD, BLACKROCK, CO. DUBLIN, A94 K3K0	
Asiatic Petroleum Company (Dublin) Limited	100
Irish Shell Trust Designated Activity Company	100
SUITE 7 NORTHWOOD HOUSE, NORTHWOOD BUSINESS PARK, SANTRY, DUBLIN, 9	
Shell and Topaz Aviation Ireland Limited	50
ISLE OF MAN	
EUROMANX HOUSE, FREEPORT, BALLASALLA, IM9 2AP	
Shell Marine Personnel (I.O.M.) Limited	100
Shell Ship Management Limited	100
FIRST NAMES HOUSE, VICTORIA ROAD, DOUGLAS, IM2 4DF	
Petrolon Europe Limited	100
Petrolon International Limited	100
ISRAEL	
DERECH ABA HILEL 16, RAMAT GAN, 5250608	
Ravin AI Ltd.	36
ITALY	
PIAZZA SAN SILVESTRO 8, ROME, 00187	
Shell International Exploration and Development Italia S.p.A.	100
Shell Italia E&P S.p.A.	100
STRADA DI SCORRIMENTO 2, VADO LIGURE, SAVONA, 17047	
Infineum Italia S.R.L.	50
VIA AUTOSTRADA 32, BERGAMO, 24126	
Sonnen eServices Italia S.R.L.	100
Sonnen S.R.L.	100
VIA GIORGIO RIBOTTA 51, ROME, 00144	
Societa' Oleodotti Meridionali S.p.A.	30
VIA MUGGIA #1, SAN DORLIGO DELLA VALLE, TRIESTE, 34147	
Societa Italiana per l'Oleodotto Transalpino S.p.A.	19

Company by country and address of incorporation	%
VIA SUSA 40, TORINO, 10138	
Shell Fleet Solutions Consorzio	100
VIA TORTONA 25, MILANO, 20144	
BG Italia Power S.r.l	100
Brindisi LNG S.r.l.	100
VIA VITTOR PISANI 16, MILANO, 20124	
Alle S.R.L.	100
Aquila S.p.A.	100
Development S.R.L.	100
Marco Polo Solar S.R.L.	100
Ramacca Solar S.R.L.	100
Shell Energy Italia S.R.L.	100
Shell Italia Holding S.p.A.	100
Shell Italia Oil Products S.R.L.	100
JAPAN	
1-1-5 WAKAMIYA-CHO, SUMA-KU, KOBE-SHI, HYOGO, 654-0049	
Y.K. Nishi-Kobe Bosai Center	33
16F PACIFIC CENTURY PLACE MARUNOUCHI, 1-11-1, MARUNOUCHI, CHIYODA-KU, TOKYO, 100-6216	
Shell Japan Limited	100
Sonnen Japan Kabushiki Kaisha	100
2-3, KANDA, AWAJI-CHO, CHIYODA-KU, TOKYO, 101-0063	
Sakhalin LNG Services Company Ltd.	50
4052-2 NAKATSU, AIKAWA-CHO, AIKO-GUN, KANAGAWA, 243-0303	
K.K. SVC Tokyo	100
DAIBA FRONTIER BUILDING. 2-3-2, DAIBA, MINATO-KU, TOKYO, 135-8074	
K.K. Red and Yellow	100
Shell Lubricants Japan K.K.	100
JERSEY	
13 CASTLE STREET, ST. HELIER, JE1 1ES	
Shell Service Station Properties Limited	100
LUXEMBOURG	
412F, ROUTE D'ESCH, LUXEMBOURG, L-2086	
Denham International Power SCSp [d]	32
7, RUE DE L'INDUSTRIE, BERTRANGE, LUXEMBOURG, L-8005	
Shell Luxembourggeoise Sarl	100
7, RUE DE L'INDUSTRIE, BERTRANGE, LUXEMBOURG, L-8069	
Shell Finance Luxembourg Sarl	100
Shell Treasury Luxembourg Sarl	100
MACAU	
876 AVENIDA DA AMIZADE, EDIFICIO MARINA GARDENS, ROOM 310, 3RD FLOOR	
Shell Macau Petroleum Company Limited	100
MALAYSIA	
12TH FLOOR, MENARA SYMPHONY, NO. 5, JALAN PROF. KHOO KAY KIM, SEKSYEN 13, PETALING JAYA/SELANGOR DARUL EHSAN, 46200	
P S Terminal Sendirian Berhad	35
Pertini Vista Sdn. Bhd.	100
Provista Ventures Sdn. Bhd.	100
Sarawak Shell Berhad	100
Shell Business Service Centre Sdn. Bhd.	100
Shell Global Solutions (Malaysia) Sdn. Bhd.	100
Shell Malaysia Trading Sendirian Berhad	100
Shell MDS (Malaysia) Sendirian Berhad	72
Shell New Ventures Malaysia Sdn. Bhd. [g]	100
Shell People Services Asia Sdn. Bhd.	100
Shell Sabah Selatan Sendirian Berhad	100
Shell Timur Sdn. Bhd.	70

APPENDIX 1 continued

Company by country and address of incorporation	%
MALAYSIA continued	
KENSINGTON GARDENS, NO. U1317, LOT 7616, JALAN JUMIDAR BUYONG, LABUAN F.T., 87000	
Shell Treasury Malaysia (L) Limited	100
LEVEL 30, TOWER 1, PETRONAS TWIN TOWERS, KLCC, KUALA LUMPUR/FEDERAL TERRITORY, 50088	
P S Pipeline Sendirian Berhad	50
LEVEL 8, SYMPHONY HOUSE, BLOCK D13, PUSAT DAGANGAN DANA 1, JALAN PJU 1A/46, PETALING JAYA/SELANGOR DARUL EHSAN, 47301	
Bonuskad Loyalty Sdn. Bhd. [g]	33
LOT 7689 AND LOT 7690, SECTION 64, KUCHING TOWN LAND DISTRICT, JALAN PENDING, KUCHING, SARAWAK, 93450	
IOT Management Sdn. Bhd.	7
Tanjung Manis Oil Terminal Management Sdn. Bhd.	14
SUITE 13.03, 13 FLOOR, MENARA TAN & TAN, 207 TUN RAZAK, KUALA LUMPUR/FEDERAL TERRITORY, 50400	
Kebabangan Petroleum Operating Company Sdn. Bhd. [b]	30
MAURITIUS	
33 EDITH CAVELL STREET, PORT LOUIS, 11324	
Pennzoil Products International Company	100
6TH FLOOR, TOWER A, 1 CYBERCITY, EBENE, 72201	
BG Mauritius LNG Holdings Ltd	100
BG Mumbai Holdings Limited	100
MEXICO	
AVENIDA CERRO GORDO DEL CAMPESTRE, NUMBER 201, INTERIOR 202, OF COLONIA LAS QUINTAS, LEÓN, GUANAJUATO, 37125	
Mega Gasolineras SA de CV	50
AVENIDA PASEO DE LAS PALMAS 340, 1ST FLOOR, COLONIA LOMAS DE CHAPULTEPEC, DELEGACIÓN MIGUEL HIDALGO, CIUDAD DE MÉXICO, 11000	
Gas Del Litoral, S. de R.L. de C.V.	75
Shell Energy Mexico, S.A. de C.V.	100
Shell Exploración y Extracción de México, S.A. de C.V.	100
Shell México Gas Natural, S. de R.L. de C.V.	100
Shell México, S.A. de C.V.	100
Shell Servicios México, S.A. de C.V.	100
Shell Solutions Mexico S.A. de C.V.	100
Shell Trading México, S. de R.L. de C.V.	100
GUILLERMO GONZÁLEZ CAMARENA NO. 400, SANTA FÉ, ALVARO OBREGÓN, CIUDAD DE MÉXICO, 01210	
Comercial Importadora S.A. De C.V.	50
Concilia Asesores y Servicios, S.A. de C.V.	50
NETHERLANDS	
2E HAVENSTRAAT 5B, IJMUIDEN, 1976 CE	
Noordzeewind B.V.	50
Noordzeewind C.V. [d]	50
AMSTERDAMSEWEG 55, 1182 GP AMSTELVEEN, P.O. BOX 75650, LUCHTHAVEN SCHIPHOL, 1118 ZS	
Amsterdam Schiphol Pijpleiding Beheer B.V.	40
ANTARES LAAN 39, P.O. BOX 3068, 2130 KB, HOOFDDORP, 2132 JE	
Multi Tank Card B.V.	30
BUTAAANWEG 215, VONDELINGPLAAT, ROTTERDAM, 3196 KC	
N.V. Rotterdam-Rijn Pijpleiding Maatschappij [b]	56
CAREL VAN BYLANDT LAAN 16, THE HAGUE, 2596 HR	
Shell International Exploration and Production B.V.	100
CAREL VAN BYLANDT LAAN 30, THE HAGUE, 2596 HR	
Attiki Gas B.V.	100
B.V. Dordtsche Petroleum Maatschappij	100
B.V. Petroleum Assurantie Maatschappij	100
BG Gas Brazil E&P I2 B.V.	100
BG Gas Brazil Holdings B.V.	100
BG Gas International B.V.	100
BG Gas International Holdings B.V.	100
BG Gas Netherlands Holdings B.V.	100

Company by country and address of incorporation	%
BG Gas Sao Paulo Investments B.V.	100
BJS Oil Operations B.V.	80
BJSA Exploration and Production B.V.	100
Chosun Shell B.V.	100
CrossWind Beheer B.V. [b]	80
Crosswind C.V. [b] [d]	80
Geocombinatie Leeuwarden B.V.	30
HKN LP 1 B.V.	100
HKN LP 2 B.V.	100
HKN LP 3 B.V.	100
HKN LP 4 B.V.	100
HKN LP 5 B.V.	100
HKN LP 6 B.V.	100
Hkz Lp 18 B.V.	100
Hkz Lp 19 B.V.	100
Hkz Lp 20 B.V.	100
Hkz Lp 21 B.V.	100
Hkz Lp 22 B.V.	100
Integral Investments B.V.	100
Jordan Oil Shale Company B.V.	100
LNG Shipping Operation Services Netherlands B.V.	100
Netherlands Alng Holding Company B.V.	100
Raffinaderij Shell Mersin N.V.	100
RESCO B.V.	100
Rotterdam Hydrogen Company B.V.	100
Salym Petroleum Development N.V. [b]	50
Salym Petroleum Services B.V. [b]	50
Shell Abu Dhabi B.V.	100
Shell Additives Holdings (I) B.V.	100
Shell Additives Holdings (II) B.V.	100
Shell Albania Block 4 B.V.	100
Shell and Vivo Lubricants B.V.	50
Shell Brazil Holding B.V.	100
Shell Business Development Central Asia B.V.	100
Shell Caspian B.V.	100
Shell Caspian Pipeline Holdings B.V.	100
Shell China B.V.	100
Shell China Holdings B.V.	100
Shell Deepwater Tanzania B.V.	100
Shell Development Iran B.V.	100
Shell E and P Offshore Services B.V.	100
Shell Egypt N.V. [e]	100
Shell Energy Europe B.V.	100
Shell EP Holdings [EE&ME] B.V.	100
Shell EP Middle East Holdings B.V.	100
Shell EP Oman B.V.	100
Shell EP Russia Investments (III) B.V.	100
Shell EP Russia Investments (V) B.V.	100
Shell EP Somalia B.V.	100
Shell EP Wells Equipment Services B.V.	100
Shell Exploration and Production (100) B.V.	100
Shell Exploration and Production (101) B.V.	100
Shell Exploration and Production (102) B.V.	100
Shell Exploration and Production (103) B.V.	100
Shell Exploration and Production (105) B.V.	100
Shell Exploration and Production (106) B.V.	100
Shell Exploration and Production (107) B.V.	100

Company by country and address of incorporation	%
Shell Exploration and Production (82) B.V.	100
Shell Exploration and Production (84) B.V.	100
Shell Exploration and Production (89) B.V.	100
Shell Exploration and Production (90) B.V.	100
Shell Exploration and Production (91) B.V.	100
Shell Exploration and Production (92) B.V.	100
Shell Exploration and Production (93) B.V.	100
Shell Exploration and Production (94) B.V.	100
Shell Exploration and Production (96) B.V.	100
Shell Exploration and Production (99) B.V.	100
Shell Exploration and Production (LI) B.V.	100
Shell Exploration and Production (LVIII) B.V.	100
Shell Exploration and Production (LXI) B.V.	100
Shell Exploration and Production (LXII) B.V.	100
Shell Exploration and Production (LXV) B.V.	100
Shell Exploration and Production (LXVI) B.V.	100
Shell Exploration and Production (LXXI) B.V.	100
Shell Exploration and Production (LXXV) B.V.	100
Shell Exploration and Production (XL) B.V.	100
Shell Exploration and Production Brunei B.V.	100
Shell Exploration and Production Holdings B.V.	100
Shell Exploration and Production Investments B.V.	100
Shell Exploration and Production Mauritania (C10) B.V.	100
Shell Exploration and Production Mauritania (C19) B.V.	100
Shell Exploration and Production Services (RF) B.V.	100
Shell Exploration and Production South Africa B.V.	100
Shell Exploration and Production Ukraine I B.V.	100
Shell Exploration and Production Ukraine Investments (I) B.V.	100
Shell Exploration and Production Ukraine Investments (II) B.V.	100
Shell Exploration and Production West-Siberia B.V.	100
Shell Exploration B.V.	100
Shell Exploration Company (RF) B.V.	100
Shell Exploration Company (West) B.V.	100
Shell Exploration Company B.V.	100
Shell Exploration Venture Services B.V.	100
Shell Finance (Netherlands) B.V.	100
Shell Gas & Power Developments B.V.	100
Shell Gas (LPG) Holdings B.V.	100
Shell Gas B.V.	100
Shell Gas Iraq B.V.	100
Shell Gas Nigeria B.V.	100
Shell Gas Venezuela B.V.	100
Shell Generating (Holding) B.V.	100
Shell Geothermal B.V.	100
Shell Global Solutions (Eastern Europe) B.V.	100
Shell Global Solutions Services B.V.	100
Shell Hydrogen Operations & Production BV	100
Shell Information Technology International B.V.	100
Shell Integrated Gas Oman B.V.	100
Shell International B.V.	100
Shell International Finance B.V. [a]	100
Shell Internationale Research Maatschappij B.V.	100
Shell Internet Ventures B.V.	100
Shell Iraq Petroleum Development B.V.	100
Shell Iraq Services B.V.	100
Shell Kazakhstan B.V.	100
Shell Kazakhstan Development B.V.	100
Shell Kuwait Exploration and Production B.V.	100

Company by country and address of incorporation	%
Shell LNG Bunkering B.V.	100
Shell LNG Port Spain B.V.	100
Shell Manufacturing Services B.V.	100
Shell Mozambique B.V.	100
Shell Namibia Upstream B.V.	100
Shell Nanhai B.V.	100
Shell Nederland B.V.	100
Shell Netherlands Canada Financing B.V.	100
Shell New Energies Holding Europe B.V.	100
Shell New Energies NL B.V.	100
Shell Offshore (Personnel) Services B.V.	100
Shell Offshore Services B.V.	100
Shell Offshore Upstream South Africa B.V.	100
Shell OKLNG Holdings B.V.	100
Shell Olie OG Gas Holding B.V. [i]	100
Shell Oman Exploration and Production B.V.	100
Shell Overseas Holdings (Oman) B.V.	100
Shell Overseas Investments B.V.	100
Shell Petroleum N.V. [a]	100
Shell Philippines Exploration B.V.	100
Shell Project Development (VIII) B.V.	100
Shell RDS Holding B.V.	100
Shell Sakhalin Holdings B.V.	100
Shell Sakhalin Services B.V.	100
Shell Salym Development B.V.	100
Shell Sao Tome and Principe B.V.	100
Shell Services Oman B.V.	100
Shell Shared Services (Asia) B.V.	100
Shell South Syria Exploration B.V.	100
Shell Trademark Management B.V.	100
Shell Trading Russia B.V.	100
Shell Upstream Albania B.V.	100
Shell Upstream Development B.V.	100
Shell Upstream Indonesia Services B.V.	100
Shell Upstream Turkey B.V.	100
Shell Ventures B.V.	100
Shell Ventures Investments B.V.	100
Shell Western LNG B.V.	100
Shell Windenergy Netherlands B.V.	100
Shell Windenergy NZW I B.V.	100
Syria Shell Petroleum Development B.V. [h]	65
Tamba B.V.	50
The Green Near Future 5 B.V.	100
CHEMIEWEG 25, P.O. BOX 6060, MOERDIJK, 4780 LN	
Shell Nederland Chemie B.V. [g]	100
DR. HUB VAN DOORNEWEG 183, TILBURG, 5026 RD	
Travis Road Services International B.V.	34
EUROPAWEG 975, MAASVLAKTE, ROTTERDAM, 3199 LC	
Maasvlakte Olie Terminal C.V. [d]	16
HENRI BERSSENBRUGGESTRAAT 9, DEVENTER, 7425 SB	
B.R.E. B.V.	100
Waalbrug Exploitatie Maatschappij B.V.	100
HERENSTREEK 47, NIEUW-DORDRECHT, 7885 AT	
Energiepark Pottendijk B.V.	100
Pottendijk Energie B.V.	100
Pottendijk Wind B.V.	100
Pottendijk Zon B.V.	100

APPENDIX 1 continued

Company by country and address of incorporation	%
NETHERLANDS continued	
HERIKERBERGWEG 238, AMSTERDAM, 1101 CM	
Bogstone Holding B.V.	51
Cicerone Holding B.V.	51
Infineum Holdings B.V.	50
HOPPLEIN 20, ROTTERDAM, 3032 AC	
Shell TapUp B.V.	100
LANGE KLEIWEG 40, RIJSWIJK, 2288 GK	
Shell Global Solutions International B.V.	100
MUIDERSTRAAT 1, AMSTERDAM, 1011 PZ	
Caspi Meruerty Operating Company B.V. [b]	40
OOSTDUINLAAN 2, THE HAGUE, 2596 JM	
North Caspian Operating Company N.V. [b]	17
OOSTERHORN 36, FARMSUM, 9936 HD	
Zeolyst C.V.	50
P.O. BOX 477, GRONINGEN, 9700 AL	
Gasterra B.V.	25
POLARIS AVENUE 81, P.O. BOX 2047, 2130 GE, HOOFDORP, 2132 JH	
Loyalty Management Netherlands B.V.	40
POSTBUS 157, THE HAGUE, 2501 CD	
Shell Pensioenbureau Nederland B.V.	100
REACTORWEG 301, UNIT 1.3, UTRECHT, 3542 AD	
Paqell B.V.	50
RIGAKADE 20, AMSTERDAM, 1013 BC	
The New Motion B.V.	100
SCHEPERSMAAT 2, ASSEN, 9405 TA	
Nederlandse Aardolie Maatschappij B.V.	50
STATIONSPLEIN 45, ROTTERDAM, 3013 AK	
Fitzroy C.V. [d]	20
W2C GP B.V.	20
STRAWINSKYLAAN 1343, AMSTERDAM, 1077 XX	
Shell & AMG Recycling B.V. [d]	50
STRAWINSKYLAAN 1345, AMSTERDAM, 1077 XX	
Karachaganak Petroleum Operating B.V. [b]	29
STRAWINSKYLAAN 3127 8E ETAGE, AMSTERDAM, 1077 ZX	
Shell Technology Ventures Fund 1 B.V.	52
VONDELINGENWEG 601, VONDELINGENPLAAT, ROTTERDAM, 3196 KK	
Ellba B.V. [b]	50
Ellba C.V. [b] [d]	50
Shell MSPO 2 Holding B.V.	100
Shell Nederland Raffinaderij B.V.	100
WEENA 70, ROTTERDAM, 3012 CM	
Blauwwind II C.V. [d]	20
Blauwwind Management II B.V.	20
Euroshell Cards B.V.	100
Shell Chemicals Europe B.V.	100
Shell Downstream Services International B.V.	100
Shell Lubricants Supply Company B.V.	100
Shell Nederland Verkoopmaatschappij B.V.	100
Shell Trading Rotterdam B.V.	100
Snijders Olie B.V.	100
Tankstation Exploitatie Maatschappij Holding B.V.	100
WEENA 762, 9E VERDIEPING, ROTTERDAM, 3014 DA	
Guara B.V.	30
Iara B.V.	4
Lapa Oil & Gas B.V.	30
Libra Oil & Gas B.V.	20
Tupi B.V.	23
WINTHONTLAAN 200, UTRECHT, 3526 KV	
Solar-EW II B.V.	100

Company by country and address of incorporation	%
ZEELANDESTRAAT 1, MILLINGEN AAN DE RIJN, 6566 DE	
SolarNow B.V.	23
NEW ZEALAND	
C/O BAKER TILLY STAPLES RODWAY TARANAKI LIMITED, 109-113 POWDERHAM STREET, P.O. BOX 146, NEW PLYMOUTH, TARANAKI, 4340	
Energy Finance NZ Limited	100
Energy Holdings Offshore Limited	100
Shell (Petroleum Mining) Company Limited	100
Shell Energy Asia Limited	100
Shell Investments NZ Limited	100
Southern Petroleum No Liability	100
MERCER (N.Z.) LIMITED, FLOOR 2, 20 CUSTOMHOUSE QUAY, WELLINGTON, 6011	
Shell New Zealand Pensions Limited	100
NIGERIA	
CORPORATE OFFICE, INTELS ABA ROAD ESTATE, KMI6 ABA EXPRESSWAY, PORT HARCOURT, 500211	
Nigeria LNG Limited	26
NLNG Shipping Management Limited	20
FREEMAN HOUSE, 21/22 MARINA, P.M.B. 2418, LAGOS	
BG Exploration and Production Nigeria Limited	100
BG Upstream A Nigeria Limited	100
Delta Business Development Limited	100
Shell Exploration and Production Africa Limited	100
Shell Nigeria Business Operations Limited	100
Shell Nigeria Closed Pension Fund Administrator Ltd	100
Shell Nigeria Exploration and Production Company Ltd	100
Shell Nigeria Exploration and Production Echo Limited	100
Shell Nigeria Exploration Properties Alpha Limited	100
Shell Nigeria Exploration Properties Beta Limited	100
Shell Nigeria Exploration Properties Charlie Limited	100
Shell Nigeria Gas Ltd (SNG)	100
Shell Nigeria Infrastructure Development Limited	100
Shell Nigeria Offshore Prospecting Limited	100
Shell Nigeria Ultra Deep Limited	100
Shell Nigeria Upstream Ventures Limited	100
Shell Thrift & Loan Fund Trustees Nig Ltd	99
SHELL INDUSTRIAL AREA, P.O. BOX 263, RIVERS STATE, PORT HARCOURT, 500272	
The Shell Petroleum Development Company of Nigeria Limited	100
NORWAY	
BYGG 6, DRAMMENSVEIEN 134, OSLO, 0277	
Aviation Fuelling Services Norway AS	50
HELGANESVEGEN 59, AVALDSNES, KARMØY, 4262	
Gasnor AS	100
KARENSLYST ALLÉ 2, OSLO, 0278	
Shell New Energies Norway AS	100
KONGSGÅRDBAKKEN 1, STAVANGER, 4005	
Enhanced Well Technologies Group AS	22
MONGSTAD 71A, MONGSTAD, 5954	
Technology Centre Mongstad DA	8
NYHAMNA, AUKRA, 6480	
Ormen Lange Eiendom DA	18
TANKVEGEN 1, TANANGER, 4056	
A/S Norske Shell	100
OMAN	
P.O. BOX 38, MINA AL FAHAL, MUSCAT, 116	
Shell Oman Marketing Company SAOG	49
P.O. BOX 398, SOHAR FREE ZONE, NORTH AL BATINAH GOVERNORATE, SOHAR, 322	
Sohar Solar Qabas (FZC) LLC	100
P.O. BOX 560, MINA AL FAHAL, MUSCAT, 116	
Oman LNG LLC	30

Company by country and address of incorporation	%
P.O. BOX 74, MINA AL FAHAL, MUSCAT, 116	
Shell Development Oman LLC	100
P.O. BOX 81, MINA AL FAHAL, MUSCAT, 113	
Petroleum Development Oman LLC	34
PAKISTAN	
E110, KHAYABAN E JINNAH, LAHORE CANTONEMENT, PUNJAB, CANTONEMENT, 54810	
Pakistan Energy Gateway Limited	33
HOUSE NO. 2-B, NAZIMUDDIN ROAD, F-8/1, ISLAMABAD, 75400	
Pak Arab Pipeline Company Limited	20
SHELL HOUSE, 6 CH. KHALIQUZZAMAN ROAD, KARACHI, 75530	
Shell Energy Pakistan (smc-private) Limited	100
Shell Pakistan Limited	76
PERU	
CALLE DEAN VALDIVIA 111, OFICINA 802, SAN ISIDRO, LIMA, LIMA 27	
Shell GNL Peru S.A.C.	100
Shell Operaciones Peru S.A.C.	100
PHILIPPINES	
2ND FLOOR, BONIFACIO TECHNOLOGY CENTER, 31ST STREET CORNER 2ND AVENUE, BONIFACIO GLOBAL CITY, TAGUIG, METRO MANILA, 1635	
Bonifacio Gas Corporation	24
41ST FLOOR, THE FINANCE CENTER, 26TH STREET CORNER 9TH AVENUE, BONIFACIO GLOBAL CITY, TAGUIG, METRO MANILA, 1635	
Connected Freight Solutions Philippines, Inc.	80
Pilipinas Shell Petroleum Corporation	55
Shell Chemicals Philippines, Inc.	100
Shell Energy Philippines Inc	100
Shell Gas and Energy Philippines Corporation	100
Shell Solar Philippines Corporation	100
NDC BLDG., 116 TORDESILLAS ST., SALCEDO VILLAGE, MAKATI CITY, METRO MANILA, 1227	
Kamayon Realty Corporation	22
SUBIC BAY FREE PORT ZONE, OLANGAPO CITY, 2200	
Shell Gas Trading (Asia Pacific), Inc.	100
UNIT D 9TH FLOOR INOZA TOWER, 40TH STREET, NORTH BONIFACIO, BONIFACIO GLOBAL CITY, TAGUIG, METRO MANILA, 1634	
Tabangao Realty, Inc.	40
POLAND	
UL. BITWY WARSZAWSKIEJ 1920 R. NR 7A, WARSAW, 02-366	
Shell Polska Sp. z o.o.	100
UL. BITWY WARSZAWSKIEJ 1920R. 7A, WARSZAWA, 02-366	
Shell Mobility Polska Sp. z o.o.	100
UL. PAWIA 21, KRAKOW, 31-154	
Shell Energy Retail Poland Sp. z o.o.	100
PUERTO RICO	
P.O. BOX 186, YABUCOA, PR 00767-0186	
Station Managers of Puerto Rico, Inc.	100
QATAR	
1ST FLOOR, AL-MIRQAB TOWER, DOHA	
Marine LNG Solutions LLC [b]	50
AL MIRQAB TOWER, WEST BAY, P.O. BOX 3747, DOHA	
Qatar Shell Service Company W.L.L.	100
P.O. BOX 22666, DOHA	
Qatar Liquefied Gas Company Limited (4)	30
QATAR SCIENCE & TECHNOLOGY PARK TECH1, OFFICE 101, P.O. BOX 3747, DOHA	
Qatar Shell Research & Technology Centre QSTP-LLC	100
RUSSIA	
24 A YAKUBOVICH UL., SAINT PETERSBURG, 190000	
Khanty-Mansiysk Petroleum Alliance Closed Joint Stock Company [b]	50
9 LESNAYA STREET, FLOOR 3, MOSCOW, 125196	
Limited Liability Company "Shell Neft"	100

Company by country and address of incorporation	%
9 LESNAYA STREET, FLOOR 4, MOSCOW, 125196	
Limited Liability Company "Shell Neftegaz Development (V)"	100
LLC Shell NefteGaz Development	100
Syriaga Neftegaz Development LLC	100
SINOPSKAYA NABEREZHNYAYA, 22 A, OFFICE 811, SANKT-PETERBURG, 191167	
Gazpromneft-Aero Bryansk LLC [b]	50
SAINT KITTS AND NEVIS	
MORNING STAR HOLDINGS LIMITED, MAIN STREET, SUITE 556, CHARLESTOWN, NEVIS, WEST INDIES	
Shell Oil & Gas (Malaysia) LLC	90
SAINT LUCIA	
MERCURY COURT, CHOC ESTATE, CASTRIES	
BG Atlantic 1 Holdings Limited	100
BG Atlantic 2/3 Holdings Limited	100
BG Atlantic 4 Holdings Limited	100
BG Central Holdings Ltd.	100
BG West Indies No. 2 Limited	100
SAUDI ARABIA	
P.O. BOX 41467, RIYADH, 11521	
Al Jomaih and Shell Lubricating Oil Co.Ltd.	50
SINGAPORE	
1 COMMONWEALTH LANE, #09-30, ONE COMMONWEALTH, SINGAPORE, 149544	
Zeco Systems Pte. Ltd.	99
1 HARBOURFRONT AVENUE, #08-01/08, KEPPEL BAY TOWER, SINGAPORE, 098632	
Infineum Singapore LLP	50
15, AIRLINE ROAD, SINGAPORE, 819828	
Changi Airport Fuel Hydrant Installation Pte. Ltd.	11
160 TUAS SOUTH AVENUE 5, SINGAPORE, 637364	
Singapore Lube Park Pte. Ltd. [b]	44
25 CHURCH STREET, 03-04 CAPITAL SQUARE THREE, SINGAPORE, 049482	
Cleantech Renewable Assets Pte Ltd	49
50 GUL ROAD, SINGAPORE, 629351	
Fueling Pte. Ltd [b]	50
50 RAFFLES PLACE #06-00, SINGAPORE LAND TOWER, SINGAPORE, 048623	
Orb Energy Pte Ltd.	24
THE METROPOLIS TOWER 1, 9 NORTH BUONA VISTA DRIVE, #07-01, SINGAPORE, 138588	
BG Asia Pacific Holdings Pte. Limited	100
BG Asia Pacific Services Pte. Ltd.	100
BG Exploration & Production Myanmar Pte. Ltd.	100
BG Insurance Company (Singapore) Pte Ltd	100
BG Myanmar Pte. Ltd.	100
Connected Freight Pte. Ltd.	80
Ellba Eastern (Pte) Ltd	100
QPI and Shell Petrochemicals (Singapore) Pte Ltd	51
Shell Catalysts & Technologies Pte. Ltd.	100
Shell Chemicals Seraya Pte. Ltd.	100
Shell Eastern Petroleum (Pte) Ltd [g]	100
Shell Eastern Trading (Pte) Ltd [g]	100
Shell Gas Marketing Pte. Ltd.	100
Shell Integrated Gas Thailand Pte.Limited	100
Shell Myanmar Energy Pte. Ltd.	100
Shell Pulau Moa Pte Ltd	100
Shell Seraya Pioneer (Pte) Ltd	100
Shell Tankers (Singapore) Private Limited	100
Shell Treasury Centre East (Pte) Ltd	100
Sirius Well Manufacturing Services Pte. Ltd. [b]	50

APPENDIX 1 continued

Company by country and address of incorporation	%
SLOVAKIA	
EINSTEINOVA 23, BRATISLAVA, 851 01	
SHELL Slovakia s.r.o.	100
SLOVENIA	
BRAVNICARJEVA ULICA 13, LJUBLJANA, 1000	
Shell Adria d.o.o.	100
SOUTH AFRICA	
1ST FLOOR OXFORD PARKS, 199 OXFORD ROAD, DUNKELD, GAUTENG, 2196	
Sekelo Oil Trading (Pty) Limited	43
HONSHU ROAD, DURBAN, 4001	
Blendcor (Pty) Ltd. [b]	36
REUNION, DURBAN, 4001	
Shell & BP South African Petroleum Refineries (Pty) Limited [b]	36
SUITE OE/2, THE NAUTICA, THE WATERCLUB, BEACH ROAD, GRANGER BAY, CAPE TOWN, 8001	
STISA (Pty) Limited	72
TWICKENHAM, THE CAMPUS, 57 SLOAN STREET, EPSOM DOWNS, BRYANSTON, 2021	
Bituguard Southern Africa (Pty) Ltd	36
Shell Downstream South Africa (Pty) Ltd	72
Shell South Africa Energy (Pty) Ltd	100
Shell South Africa Exploration (Pty) Limited	100
Shell South Africa Holdings (Pty) Ltd	100
SOUTH KOREA	
#704-3, TOWER B. HYUNDAI KNOWLEDGE INDUSTRIAL CENTER, 70 DUSAN-RO, GEUMCHEON-GU, SEOUL, 08584	
Korea Impact Carbon Corporation	40
640-6, DAEJUK-RI, DAESAN-EUP, SEOSAN-SHI, CHUNGCHONGNAM-DO, 356-713	
Hyundai and Shell Base Oil Co., Ltd	40
NO. 250, SINSUN-RO, NAM-GU, BUSAN, 48561	
Hankook Shell Oil Company	54
SPAIN	
PASEO DE LA CASTELLANA, 257-6°, MADRID, 28046	
BG Energy Iberian Holdings, S.L.	100
Shell España, S.A.	100
Shell Spain LNG, S.A.U.	100
RIO BULLAQUE, 2, MADRID, 28034	
Shell & Disa Aviation España, S.L.	50
SUDAN	
SHELL HOUSE, P.O. BOX 320, KHARTOUM	
Shell (Sudan) Petroleum Development Company Limited	100
SWEDEN	
DELOITTE, P.O. BOX 450, ÖSTERSUND, 831 26	
BG International Services AB	100
GUSTAVSLUND SVÄGEN 22, BROMMA, 16751	
Shell Aviation Sweden AB	100
P.O. BOX 135, STOCKHOLM-ARLANDA, 190 46	
A Flygbränslehantering Aktiebolag	25
P.O. BOX 2154, GOTHENBURG, 438 14	
Gothenburg Fuelling Company AB	33
P.O. BOX 85, STOCKHOLM-ARLANDA, 190 45	
Stockholm Fuelling Services AB	25
STURUP FLYGPLATS, P.O. BOX 22, MALMÖ, 230 32	
Malmö Fuelling Services AB	33
SWITZERLAND	
AUTOSTRADA A2 (DIREZIONE GOTTARDO), HOTEL BELLINZONA SUD, MONTE CARASSO, 6513	
Stazioni Autostradali Bellinzona SA	50
BAARERMATTE, BAAR, 6340	
Shell (Switzerland) AG	100
Shell Brands International AG	100
Shell Corporate Services Switzerland AG	100
Shell Finance Switzerland AG	100

Company by country and address of incorporation	%
Shell Holdings Switzerland AG	100
Shell Trading Switzerland AG	100
Shell Treasury Company Switzerland AG	100
Solen Versicherungen AG	100
ROUTE DE PRÉ-BOIS 17, COINTRIN, 1216	
Saraco SA	20
ROUTE DE VERNIER 132, VERNIER, 1214	
SOGEP Société Genevoise des Pétroles SA	34
STEIGERHUBELSTRASSE 8, BERN, 3008	
Shell Lubricants Switzerland AG	100
ZWÜSCHETECH, RÜMLANG, 8153	
UBAG – Unterflurbetankungsanlage Flughafen Zürich AG	20
SYRIA	
DAMASCUS NEW SHAM WESTERN DUMMAR, ISLAND NO. 1 – PROPERTY 2299, P.O. BOX 7660, DAMASCUS	
Al Badiah Petroleum Company	22
Al Furat Petroleum Company	20
TAIWAN	
INTERNATIONAL TRADE BUILDING, ROOM 2001, 20TH FLOOR, 333, KEELUNG ROAD SECTION 1, TAIPEI, 110	
Shell Taiwan Limited	100
NO. 2, TSO-NAN ROAD, NAN-TZE DISTRICT, P.O. BOX 25-30, KAOHSIUNG, 811	
CPC Shell Lubricants Co. Ltd	51
TANZANIA	
1ST FLOOR KILWA HOUSE, PLOT 369, TOURE DRIVE, OYSTER BAY, P.O. BOX 105833, DAR ES SALAAM	
Fahari Gas Marketing Company Limited	53
Mzalendo Gas Processing Company Limited	53
Ruvuma Pipeline Company Limited	53
Tanzania LNG Limited	100
THAILAND	
10 SOONTHORKOSA ROAD, KLONGTOEY, BANGKOK, 10110	
Pattanaadhorn Company Limited	42
Sahapanichkijphun Company Limited	42
Shell Global Solutions (Thailand) Limited	100
Shell Global Solutions Holdings (Thailand) Limited	100
Shell Global Solutions Service (Thailand) Company Limited	100
Thai Energy Company Limited	100
Unitas Company Limited	42
TRINIDAD AND TOBAGO	
1 INTERNATIONAL DRIVE, WESTMOORINGS	
The International School of Port of Spain Limited	25
5 SAINT CLAIR AVENUE, SAINT CLAIR, PORT OF SPAIN	
BG 2/3 Investments Limited	100
Point Fortin LNG Exports Limited	81
Shell Gas Supply Trinidad Limited	100
Shell LNG T&T Ltd	100
Shell Manatee Limited	100
Shell Trinidad Central Block Limited	100
Shell Trinidad North Coast Limited	100
TRINLING Limited	100
SHELL ENERGY HOUSE, 5 ST. CLAIR AVENUE, PORT OF SPAIN	
Shell Trinidad Ltd	100
TUNISIA	
IMMEUBLE LE TANIT DU LAC, RUE DU LAC WINDERMERE, LES BERGES DU LAC, TUNIS, 1053	
Shell Tunisia LPG S.A.	100
IMMEUBLE LE TANIT DU LAC, RUE DU LAC WINDERMERE, LES BERGES DU LAC, TUNIS, 1053	
Tunisian Processing S.A.	100
IMMEUBLE MEZGHENNI, RUE DU LAC WINDERMERE, LES BERGES DU LAC, TUNIS, 1053 – BP 36	
Amilcar Petroleum Operations S.A.	50

Company by country and address of incorporation	%
TURKEY	
DILOVASI ORGANIZE SANAYI BOLGESI 1.KISIM, 1004 SOKAK NO:10, DILOVASI, KOCAELI	
Samsun Akaryakit VE Depolama A.S.	35
GULBAHAR MAH.SALIH TOZAN SOK., KARAMANCILAR IS MERKEZI B BLOK NO:18, ESENTEPE, SISLI, ISTANBUL, 34394	
Shell & Turcas Petrol A.S.	70
Shell Enerji A.S.	100
Shell Petrol A.S.	70
LIMAN MAHALLESİ 60. SOKAK NO. 25, KONYAALTI, ANTALYA, 07070	
Cekisan Depolama Hizmetleri Ltd. Sti.	35
SULTANKOY MAHALLESİ MALTEPE SOKAK NO:66, MARMARA EREGLİSİ, TEKİRDAG, 59750	
Marmara Depoculuk Hizmetleri A.S.	32
YAKUPLU MAH. GENCOSMAN CAD. NO:7, BEYIKDUZU, ISTANBUL, 34524	
Ambarlı Depolama Hizmetleri Ltd. Sti.	35
UK	
1 ALTENS FARM ROAD, NIGG, ABERDEEN, AB12 3FY	
Shell Trustee Solutions Limited	100
15 ATHOLL CRESCENT, EDINBURGH, EH3 8HA	
Eolfi Scotland Limited	100
4TH FLOOR, DAVIDSON BUILDING, 5 SOUTHAMPTON STREET, LONDON, WC2E 7HA	
The New Motion EVSE Limited	100
50 LOTHIAN ROAD, FESTIVAL SQUARE, EDINBURGH, EH3 9WJ	
BG General Partner Limited	100
BG Pension Funding Scottish Limited Partnership [j]	100
5-7 ALEXANDRA ROAD, HEMEL HEMPSTEAD, HERTFORDSHIRE, HP2 5BS	
British Pipeline Agency Limited	50
United Kingdom Oil Pipelines Limited [b]	48
Walton-Gatwick Pipeline Company Limited [b]	52
West London Pipeline and Storage Limited [b]	38
ATHENA HOUSE, ATHENA DRIVE, TACHBROOK PARK, WARWICK, CV34 6RL	
Autogas Limited	50
BUILDING 1204, SANDRINGHAM ROAD, HEATHROW AIRPORT, HOUNSLOW, MIDDLESEX, TW6 3SH	
Heathrow Airport Fuel Company Limited	14
Heathrow Hydrant Operating Company Limited	10
CANTERBURY COURT, KENNINGTON PARK, 1-3 BRIXTON ROAD, LONDON, SW9 6DE	
Limejump Energy Limited	100
Limejump Intermediate 1 Limited	100
Limejump Ltd	100
Limejump Virtual 1 Limited	100
Limejump Virtual 10 Limited	100
Limejump Virtual 11 Limited	100
Limejump Virtual 12 Limited	100
Limejump Virtual 13 Limited	100
Limejump Virtual 14 Limited	100
Limejump Virtual 15 Limited	100
Limejump Virtual 2 Limited	100
Limejump Virtual 3 Limited	100
Limejump Virtual 4 Limited	100
Limejump Virtual 5 Limited	100
Limejump Virtual 6 Limited	100
Limejump Virtual 7 Limited	100
Limejump Virtual 8 Limited	100
Limejump Virtual 9 Limited	100
LEVEL 39, ONE CANADA SQUARE, LONDON, E14 5AB	
Applied Blockchain Ltd	21

[j] Established by BG Group plc and the BG Trustee in 2013 as part of the funding agreements associated with the BG pension scheme. Under the exemption conferred by Regulation 7 of the Partnerships (Accounts) Regulations 2008, the accounts of this partnership have not been appended to Shell's Consolidated Financial Statements and have not been filed at the Companies House.

Company by country and address of incorporation	%
MAIN ROAD, WATERSTON, MILFORD HAVEN, PEMBROKESHIRE, SA73 1DR	
Dragon LNG Group Limited [b]	50
ONE BARTHOLOMEW CLOSE, LONDON, EC1A 7BL	
Manchester Airport Storage and Hydrant Company Limited	25
PANNONE CORPORATE LLP, 378-380 DEANS GATE, CASTLEFIELD, MANCHESTER, M3 4LY	
Steam Company Limited	35
SHELL CENTRE, LONDON, SE1 7NA	
Angkor Shell Limited	100
BG Central Holdings Limited	100
BG Cyprus Limited	100
BG Delta Limited	100
BG Employee Shares Trustees Limited	100
BG Energy Capital Plc	100
BG Energy Holdings Limited	100
BG Energy Marketing Limited	100
BG Equatorial Guinea Limited	100
BG Gas Services Limited	100
BG Gas Supply (UK) Limited	100
BG General Holdings Limited	100
BG Great Britain Limited	100
BG Group Employee Shares Trustees Limited	100
BG Group Limited	100
BG Group Pension Trustees Limited	100
BG Group Trustees Limited	100
BG Intellectual Property Limited	100
BG International Limited	100
BG Karachaganak Limited	100
BG Kenya L10A Limited	100
BG Kenya L10B Limited	100
BG LNG Investments Limited	100
BG Mongolia Holdings Limited	100
BG Netherlands	100
BG Netherlands Financing Unlimited	100
BG Norge Limited	100
BG North Sea Holdings Limited	100
BG OKLNG Limited	100
BG Overseas Holdings Limited	100
BG Overseas Investments Limited	100
BG Overseas Limited	100
BG Rosetta Limited	100
BG South East Asia Limited	100
BG Subsea Well Project Limited	100
BG Tanzania Holdings Limited	100
BG Trinidad LNG Limited	100
BG UK Holdings Limited	100
Brazil Shipping I Limited	100
B-Snug Limited	100
CRI Catalyst Company Europe Limited	100
Derivatives Trading Atlantic Limited	100
Eastham Refinery Limited [b]	50
Enterprise Oil Limited	100
Enterprise Oil Middle East Limited	100
Enterprise Oil Norge Limited	100
Enterprise Oil U.K. Limited	100

APPENDIX 1 continued

Company by country and address of incorporation	%
UK continued	
Gainrace Limited	100
Gatwick Airport Storage and Hydrant Company Limited	13
Glossop Limited	100
GOGB Limited	100
Khmer Shell Limited	100
Machine Max Limited	38
Methane Services Limited	100
Murphy Schiehallion Limited	100
Private Oil Holdings Oman Limited	85
Sabah Shell Petroleum Company Limited	100
Saxon Oil Limited	100
Saxon Oil Miller Limited	100
SELAP Limited	100
Shell Aircraft Limited	100
Shell Aviation Limited	100
Shell Business Development Middle East Limited	100
Shell Caribbean Investments Limited	100
Shell Catalysts & Technologies Limited	100
Shell Chemical Company of Eastern Africa Limited	100
Shell Chemicals (Hellas) Limited	100
Shell Chemicals Limited	100
Shell Chemicals U.K. Limited	100
Shell China Exploration and Production Company Limited	100
Shell Clair UK Limited	100
Shell Club Corringham Limited	100
Shell Company (Hellas) Limited	100
Shell Company (Pacific Islands) Limited	100
Shell Corporate Director Limited	100
Shell Corporate Secretary Limited	100
Shell Distributor (Holdings) Limited	100
Shell Employee Benefits Trustee Limited	100
Shell Energy Europe Limited	100
Shell Energy Investments Limited	100
Shell Energy Supply UK LTD.	100
Shell EP Offshore Ventures Limited	100
Shell Exploration and Production Tanzania Limited	100
Shell Finance GB Limited	100
Shell Gas Holdings (Malaysia) Limited	100
Shell Gas Marketing U.K Limited	100
Shell Global LNG Limited	100
Shell Hasdrubal Limited	100
Shell Holdings (U.K.) Limited	100
Shell Information Technology International Limited	100
Shell International Gas Limited	100
Shell International Limited	100
Shell International Petroleum Company Limited	100
Shell International Trading and Shipping Company Limited	100
Shell Malaysia Limited	100
Shell Marine Products Limited	100
Shell New Energies UK Ltd	100
Shell Overseas Holdings Limited	100
Shell Overseas Services Limited	100
Shell Pension Reserve Company (SIPF) Limited	100
Shell Pension Reserve Company (SOCPF) Limited	100

Company by country and address of incorporation	%
Shell Pension Reserve Company (UK) Limited	100
Shell Pensions Trust Limited	100
Shell Property Company Limited	100
Shell QGC Holdings Limited [g]	100
Shell QGC Midstream 1 Limited [g]	100
Shell QGC Midstream 2 Limited	100
Shell QGC Upstream 1 Limited	100
Shell QGC Upstream 2 Limited	100
Shell Research Limited	100
Shell Response Limited	100
Shell South Asia LNG Limited	100
Shell Supplementary Pension Plan Trustees Limited	100
Shell Tankers (U.K.) Limited	100
Shell Trading International Limited	100
Shell Treasury Centre Limited	100
Shell Treasury Dollar Company Limited	100
Shell Treasury Euro Company Limited	100
Shell Treasury UK Limited	100
Shell Trinidad 5(A) Limited	100
Shell Trinidad and Tobago Limited	100
Shell Trinidad Block E Limited	100
Shell Tunisia Upstream Limited	100
Shell U.K. Limited	100
Shell U.K. North Atlantic Limited	100
Shell U.K. Oil Products Limited	100
Shell Upstream Overseas Services (I) Limited	100
Shell Ventures New Zealand Limited	100
Shell Ventures U.K. Limited	100
Shell-Mex and B.P. Limited	60
STT (Das Beneficiary) Limited [a]	100
Synthetic Chemicals (Northern) Limited	100
Telegraph Service Stations Limited	100
The Anglo-Saxon Petroleum Company Limited	100
The Asiatic Petroleum Company Limited	100
The Consolidated Petroleum Company Limited	50
The Mexican Eagle Oil Company Limited	100
The Shell Company (W.I.) Limited	100
The Shell Company of Hong Kong Limited	100
The Shell Company of India Limited	100
The Shell Company of Nigeria Limited	100
The Shell Company of Thailand Limited	100
The Shell Company of The Philippines Limited	75
The Shell Company of Turkey Limited	100
The Shell Marketing Company of Borneo Limited	100
The Shell Petroleum Company Limited	100
The Shell Transport and Trading Company Limited	100
Thermocomfort Limited	100
UK Shell Pension Plan Trust Limited	100
Wonderbill Limited	100
SHELL ENERGY HOUSE, WESTWOOD BUSINESS PARK, WESTWOOD WAY, COVENTRY, CV4 8HS	
First Telecommunications Limited	100
First Utility Limited	100
Impello Limited	100
Shell Energy Retail Limited	100
Shell Energy UK Limited	100

Company by country and address of incorporation	%
UKRAINE	
4 MYKOLY GRINCHENKA STREET, KIEV, 03038	
Shell Ukraine Exploration and Production I LLC	100
N. GRINCHENKO, 4, KIEV, 03038	
Alliance Holding LLC [d]	51
Invest Region LLC [d]	51
UNITED ARAB EMIRATES	
EMDAD AVIATION FUEL STORAGE FZCO, P.O. BOX 261781, JEBEL ALI, DUBAI	
Emdad Aviation Fuel Storage FZCO	33
P.O. BOX 665, ABU DHABI	
Abu Dhabi Gas Industries Limited (GASCO)	15
URUGUAY	
LA CUMPARSITA, 1373 4TH FLOOR, MONTEVIDEO, 11200	
BG (Uruguay) S.A.	100
Dinaref S.A.	50
Gasoducto Cruz del Sur S.A.	40
USA	
10000 MING AVENUE, BAKERSFIELD, CA 93311	
Aera Energy LLC [b]	52
Aera Energy Services Company	50
1013 CENTRE ROAD, COUNTY OF NEW CASTLE, DELAWARE, WILMINGTON, DE 19805	
Zeco Holdings, Inc.	100
Zeco Systems, Inc.	100
10346 BRECKSVILLE RD, BRECKSVILLE, OH 44141	
True North Energy LLC	50
11111 WILCREST GREEN, SUITE 100, HOUSTON, TX 77042	
Texas Petroleum Group LLC	50
1191 2ND AVENUE, SUITE 1900, SEATTLE, WA 98101	
Airbiquity Inc.	26
150 N. DAIRY ASHFORD, HOUSTON, TX 77079	
Gaviota Terminal Company [d]	20
Ship Shoal Pipeline Company [d]	43
16285 PARK TEN PLACE, SUIT 300, HOUSTON, TX 77084	
Bluware Headwave Ventures Inc.	20
1740 ED TEMPLE BLVD, NASHVILLE, TN 37208	
Tri Star Energy LLC	33
1900 EAST LINDEN AVENUE, LINDEN, NJ 07036	
Infineum USA Inc.	50
2048 WEEMS ROAD, BLDG C, TUCKER, GA 30084	
Sonnen Inc.	100
2050 PLAINFIELD PIKE, CRANSTON, RI 02921	
Colbea Enterprises, LLC	50
2100 GENG ROAD, SUITE 210, SANTA CLARA, PALO ALTO, CA 94303	
D.Light Design Inc.	34
2237 HATCHER HILL ROAD, BACONTON, GA 31716	
Baconton Power LLC [c]	35
2441 HIGH TIMBERS DRIVE, SUITE 220, THE WOODLANDS, TX 77380	
Asset Management and Power Services LLC	50
Distributed Generation Solutions LLC	33
3333 HWY 6 SOUTH, HOUSTON, TX 77082	
Zeolyst International	50
3450 E. COMMERCIAL CT., MERIDIAN, ID 83642	
Pacwest Energy, LLC.	50
4080 WEST JONATHAN MOORE PIKE, COLUMBUS, IN 47201	
RDK Ventures, LLC	50
41805 ALBRAE STREET, FREMONT, CA 94538	
Au Energy, LLC	50

Company by country and address of incorporation	%
BECHTEL ENTERPRISES, 12011 SUNSET HILLS ROAD, RESTON, VA 20190	
Maple Power Holdings LLC [b]	68
CT CORPORATION SYSTEM, 1999 BRYAN STREET, SUITE 900, DALLAS, TX 75201	
EPP LLC [c]	100
J & J Lubrication, LLC [c]	100
Lazlyng Real Estate Company, LLC [c]	100
MP2 Energy LLC [c]	100
MP2 Energy NE LLC [c]	100
MP2 Energy NY LLC [c]	100
MP2 Energy Retail Holdings LLC [c]	100
MP2 Energy Texas LLC [c]	100
MP2 Generation LLC [c]	100
MP2 Mesquite Creek Wind LLC [c]	100
Mpower2 LLC [c]	100
Noble Assurance Company	100
CORPORATION SERVICE COMPANY, 251 LITTLE FALLS DRIVE, WILMINGTON, DE 19808	
Atlantic Shores Offshore Wind, LLC [c]	50
Bengal Pipeline Company LLC	39
Colonial Pipeline Company	11
Cumulus Digital Systems, Inc.	30
EcoSmart Solution LLC	35
West Shore Pipe Line Company	19
CORPORATION SERVICE COMPANY, 2711 CENTERVILLE ROAD, SUITE 400, WILMINGTON, DE 19808	
Infineum USA L.P. [f]	50
CT CORPORATION SYSTEM, 7700 E ARAPAHOE RD, STE 220, CENTENNIAL, CO 80112-1268	
Positive Energies, LLC [c]	100
RL & F SERVICE CORP, 920 N KING ST FLOOR 2, NEW CASTLE, WILMINGTON, DE 19801	
Atlantic 1 Holdings LLC [c]	46
Atlantic 2/3 Holdings LLC [c]	58
Atlantic 4 Holdings LLC [c]	51
THE CORPORATION TRUST COMPANY OF NEVADA, 311 SOUTH DIVISION STREET, CARSON CITY, NV 89703	
Pennzoil-Quaker State Nominee Company	100
THE CORPORATION TRUST COMPANY, CORPORATION TRUST CENTER, 1209 ORANGE STREET, WILMINGTON, DE 19801	
Amberjack Pipeline Company LLC [c]	42
Arizona A1 LLC [c]	100
Arizona B1 LLC [c]	100
BG Brasilia, LLC [c]	100
BG Energy Finance, Inc.	100
BG Energy Merchants, LLC [c]	100
BG Gulf Coast LNG, LLC [c]	100
BG LNG Services, LLC [c]	100
BG LNG Trading, LLC	100
BG North America, LLC [c]	100
BG US Services, Inc.	100
Brazil Crude Services, LLC [c]	100
Brazos Wind Ventures, LLC [c]	100
Caesar Oil Pipeline Company, LLC [c]	15
Concha Chemical Pipeline LLC [c]	100
Crestwood Permian Basin LLC	34
CRI Sales and Services Inc.	100
CRI Zeolites Inc.	100
Deer Park Refining Limited Partnership [b] [d]	50

APPENDIX 1 continued

Company by country and address of incorporation	%
USA continued	
Ellwood Land Holdings, LLC [c]	100
Endymion Oil Pipeline Company, LLC [c]	7
Enterprise Oil North America Inc.	100
Equilon Enterprises LLC [c]	100
Explorer Pipeline Company	26
GI Energy Storage LLC [c]	100
Husk Power Systems, Inc.	30
LOOP LLC	46
Mars Oil Pipeline Company LLC [c]	49
Mattox Pipeline Company LLC [c]	54
Mayflower Wind Energy LLC [c]	50
Odyssey Pipeline L.L.C. [c]	48
Oryx Caspian Pipeline, L.L.C. [c]	100
Pecten Arabian Company	100
Pecten Brazil Exploration Company	100
Pecten Midstream LLC [c]	68
Pecten Orient Company	100
Pecten Orient Company LLC [c]	100
Pecten Producing Company	100
Pecten Trading Company	100
Pecten Victoria Company	100
Pecten Yemen Masila Company	100
Pennzoil-Quaker State Company	100
Pennzoil-Quaker State International Corporation	100
Peru LNG Company LLC [c]	20
Poseidon Oil Pipeline Company, LLC	24
Power Limited Partnership [d]	100
PR Microgrids LLC [c]	100
Premium Velocity Auto LLC [c]	100
Proteus Oil Pipeline Company, LLC [c]	6
Quaker State Investment Corporation	100
RK Caspian Shipping Company, LLC [c]	100
S T Exchange, Inc.	100
Salamander Solutions Inc.	28
Sand Dollar Pipeline LLC [c]	68
SCOGI GP [d]	100
Shell (US) Gas & Power M&T Holdings, Inc.	100
Shell California Pipeline Company LLC [c]	100
Shell Catalysts & Technologies Americas LP [d]	100
Shell Catalysts & Technologies Company	100
Shell Catalysts & Technologies Holdings Inc.	100
Shell Catalysts & Technologies LP [d]	100
Shell Catalysts & Technologies US LP [d]	100
Shell Catalysts Ventures Inc.	100
Shell Chemical Appalachia LLC [c]	100
Shell Chemical LP [d]	100
Shell Chemicals Arabia L.L.C. [c]	100
Shell Communications, Inc.	100
Shell Deepwater Royalties Inc.	100
Shell Downstream Inc.	100
Shell Energy Company	100
Shell Energy Holding GP LLC [c]	100
Shell Energy North America (US), L.P. [d]	100
Shell Energy Resources Company	100

Company by country and address of incorporation	%
Shell EP Holdings Inc.	100
Shell Expatriate Employment US Inc.	100
Shell Exploration & Production Company	100
Shell Exploration Company Inc.	100
Shell Frontier Oil & Gas Inc.	100
Shell Gas Gathering Corp. #2	100
Shell Global Solutions (US) Inc.	100
Shell GOM Pipeline Company LLC [c]	100
Shell Gulf of Mexico Inc.	100
Shell Information Technology International Inc.	100
Shell International Exploration and Production Inc.	100
Shell Lake Charles Operations, LLC [c]	100
Shell Leasing Company	100
Shell Marine Products (US) Company	100
Shell Midstream LP Holdings LLC [c]	100
Shell Midstream Operating LLC [c]	68
Shell Midstream Partners GP LLC [c]	100
Shell Midstream Partners, L.P.	68
Shell NA Gas & Power Holding Company	100
Shell NA LNG LLC [c]	100
Shell New Energies US LLC [c]	100
Shell North America Gas & Power Services Company	100
Shell Offshore and Chemical Investments Inc.	100
Shell Offshore Inc.	100
Shell Offshore Response Company LLC [c]	100
Shell Oil Company	100
Shell Oil Company Investments Inc.	100
Shell Oil Products Company LLC [c]	100
Shell Onshore Ventures Inc.	100
Shell Petroleum Inc.	100
Shell Pipeline Company LP [d]	100
Shell Pipeline GP LLC [c]	100
Shell Rail Operations Company	100
Shell Retail and Convenience Operations LLC [c]	100
Shell RSC Company	100
Shell Thailand E&P Inc.	100
Shell Trademark Management Inc.	100
Shell Trading (US) Company	100
Shell Trading North America Company	100
Shell Trading Risk Management, LLC [c]	100
Shell Trading Services Company	100
Shell Transportation Holdings LLC [c]	100
Shell Treasury Center (West) Inc.	100
Shell US E&P Investments LLC [c]	100
Shell US Gas & Power LLC [c]	100
Shell US Hosting Company	100
Shell Ventures LLC [c]	100
Shell WindEnergy Inc.	100
Shell WindEnergy Services Inc.	100
Silicon Ranch Corporation	43
SOI Finance Inc.	100
SOPC Holdings East LLC [c]	100
SOPC Holdings West LLC [c]	100
SOPC Southeast Inc.	100
Studio X LLC [c]	100

Company by country and address of incorporation	%
SWEPI LP [d]	100
Tejas Coral GP, LLC [c]	100
Tejas Coral Holding, LLC [c]	100
Tejas Power Generation, LLC [c]	100
Texas-New Mexico Pipe Line Company	100
The Valley Camp Coal Company	100
Three Wind Holdings, LLC [c]	50
TMR Company LLC	100
Triton Diagnostics Inc.	100
Triton Terminaling LLC [c]	100
Triton West LLC [c]	68
URSA Oil Pipeline Company LLC [c]	45
Zydeco Pipeline Company LLC [c]	70
VENEZUELA	
AVENIDA LEONARDO DA VINCI, EDIFICIO PDV SERVICIOS, CARACAS, DISTRITO CAPITAL	
Sucre Gas, S.A.	30
AVENIDA ORINOCO, EDIFICIO CENTRO EMPRESARIAL PREMIUM, PISO 2, OFICINAS 2-A Y 2-B, URBANIZACIÓN LAS MERCEDES, CARACAS, DISTRITO CAPITAL, 1060	
Shell Venezuela Productos, C.A.	100
Shell Venezuela, S.A.	100
VIETNAM	
GO DAU INDUSTRIAL ZONE, PHUOC THAI COMMUNE, LONG THANH DISTRICT, DONG NAI PROVINCE	
Shell Vietnam Ltd	100
ZIMBABWE	
BLOCK 1, TENDESEKA OFFICE PARK, CNR SAMORA MACHEL AVENUE, RENFREW ROAD, HARARE	
Central African Petroleum Refineries (Private) Limited	21

APPENDIX 2

FIVE-YEAR FINANCIAL DATA SET

CONSOLIDATED STATEMENT OF INCOME

	2020	2019	2018	2017	\$ million 2016
Revenue	180,543	344,877	388,379	305,179	233,591
Share of profit of joint ventures and associates	1,783	3,604	4,106	4,225	3,545
Interest and other income	869	3,625	4,071	2,466	2,897
Total revenue and other income	183,195	352,106	396,556	311,870	240,033
Purchases	117,093	252,983	294,399	223,447	162,574
Production and manufacturing expenses	24,001	26,438	26,970	26,652	28,434
Selling, distribution and administrative expenses	9,881	10,493	11,360	10,509	12,101
Research and development	907	962	986	922	1,014
Exploration	1,747	2,354	1,340	1,945	2,108
Depreciation, depletion and amortisation	52,444	28,701	22,135	26,223	24,993
Interest expense	4,089	4,690	3,745	4,042	3,203
Total expenditure	210,162	326,621	360,935	293,740	234,427
(Loss)/income before taxation	(26,967)	25,485	35,621	18,130	5,606
Taxation (credit)/charge	(5,433)	9,053	11,715	4,695	829
(Loss)/income for the period	(21,534)	16,432	23,906	13,435	4,777
Income attributable to non-controlling interest	146	590	554	458	202
(Loss)/income attributable to Royal Dutch Shell plc shareholders	(21,680)	15,842	23,352	12,977	4,575
Basic earnings per share (\$)	(2.78)	1.97	2.82	1.58	0.58
Diluted earnings per share (\$)	(2.78)	1.95	2.80	1.56	0.58

RECONCILIATION OF INCOME FOR THE PERIOD TO CCS EARNINGS

	2020	2019	2018	2017	\$ million 2016
Income/(loss) attributable to Royal Dutch Shell plc shareholders	(21,680)	15,842	23,352	12,977	4,575
Income/(loss) attributable to non-controlling interest	146	590	554	458	202
Income/(loss) for the period	(21,534)	16,432	23,906	13,435	4,777
Current cost of supplies adjustment	1,833	(605)	458	(964)	(1,085)
Of which:					
Attributable to Royal Dutch Shell plc shareholders	1,759	(572)	481	(896)	(1,042)
Attributable to non-controlling interest	74	(33)	(23)	(68)	(43)
CCS earnings	(19,701)	15,827	24,364	12,471	3,692
Of which:					
Attributable to Royal Dutch Shell plc shareholders	(19,921)	15,270	23,833	12,081	3,533
Attributable to non-controlling interest	220	557	531	390	159

TAXATION CHARGE/(CREDIT)

	2020	2019	2018	2017	\$ million unless indicated 2016
Current tax	3,216	7,596	10,475	6,591	2,731
Deferred tax	(8,649)	1,457	1,240	(1,896)	(1,902)
Total taxation charge/(credit)	(5,433)	9,053	11,715	4,695	829
As a % of income before taxation	20	36	33	26	15

CONSOLIDATED BALANCE SHEET

\$ million

	Dec 31, 2020	Dec 31, 2019	Dec 31, 2018	Dec 31, 2017	Dec 31, 2016
Assets					
Non-current assets					
Intangible assets	22,822	23,486	23,586	24,180	23,967
Property, plant and equipment	210,847	238,349	223,175	226,380	236,098
Joint ventures and associates	22,451	22,808	25,329	27,927	33,255
Investments in securities	3,222	2,989	3,074	7,222	5,952
Deferred tax	16,311	10,524	12,097	13,791	14,425
Retirement benefits	2,474	4,717	6,051	2,799	1,456
Trade and other receivables	7,641	8,085	7,826	8,475	9,148
Derivative financial instruments	2,805	689	574	919	405
	288,573	311,647	301,712	311,693	324,706
Current assets					
Inventories	19,457	24,071	21,117	25,223	21,775
Trade and other receivables	33,625	43,414	42,431	44,565	39,707
Derivative financial instruments	5,783	7,149	7,193	5,304	5,957
Cash and cash equivalents	31,830	18,055	26,741	20,312	19,130
	90,695	92,689	97,482	95,404	86,569
Total assets	379,268	404,336	399,194	407,097	411,275
Liabilities					
Non-current liabilities					
Debt	91,115	81,360	66,690	73,870	82,992
Trade and other payables	2,304	2,342	2,735	3,447	3,610
Derivative financial instruments	420	1,209	1,399	981	3,315
Deferred tax	10,463	14,522	14,837	13,007	15,274
Retirement benefits	15,168	13,017	11,653	13,247	14,130
Decommissioning and other provisions	27,310	21,799	21,533	24,966	29,618
	146,780	134,249	118,847	129,518	148,939
Current liabilities					
Debt	16,899	15,064	10,134	11,795	9,484
Trade and other payables	41,677	49,208	48,888	51,410	46,999
Derivative financial instruments	5,308	5,429	7,184	5,253	6,418
Taxes payable	6,006	6,693	7,497	7,250	6,685
Retirement benefits	437	419	451	594	455
Decommissioning and other provisions	3,624	2,811	3,659	3,465	3,784
	73,951	79,624	77,813	79,767	73,825
Total liabilities	220,731	213,873	196,660	209,285	222,764
Equity					
Share capital	651	657	685	696	683
Shares held in trust	(709)	(1,063)	(1,260)	(917)	(901)
Other reserves	12,752	14,451	16,615	16,932	11,298
Retained earnings	142,616	172,431	182,606	177,645	175,566
Equity attributable to Royal Dutch Shell plc shareholders	155,310	186,476	198,646	194,356	186,646
Non-controlling interest	3,227	3,987	3,888	3,456	1,865
Total equity	158,537	190,463	202,534	197,812	188,511
Total liabilities and equity	379,268	404,336	399,194	407,097	411,275

APPENDIX 2 continued**CONSOLIDATED STATEMENT OF CASH FLOWS**

	\$ million				
	2020	2019	2018	2017	2016
(Loss)/income before taxation for the period [A]	(26,967)	25,485	35,621	18,130	5,606
Adjustment for:					
Interest expense (net)	3,316	3,705	2,878	3,365	2,752
Depreciation, depletion and amortisation	52,444	28,701	22,135	26,223	24,993
Exploration well write-offs	815	1,218	449	897	834
Net gains on sale and revaluation of non-current assets and businesses	(286)	(2,519)	(3,265)	(1,640)	(2,141)
Share of profit of joint ventures and associates	(1,783)	(3,604)	(4,106)	(4,225)	(3,545)
Dividends received from joint ventures and associates	2,591	4,139	4,903	4,998	3,820
(Increase)/decrease in inventories	4,477	(2,635)	2,823	(2,079)	(5,658)
(Increase)/decrease in current receivables	9,625	(921)	1,955	(2,577)	(4,127)
(Decrease)/increase in current payables	(9,494)	(1,223)	(1,336)	2,406	1,359
Derivative financial instruments	977	(1,484)	799	(1,039)	1,461
Retirement benefits [A]	568	(365)	390	(654)	127
Decommissioning and other provisions [A]	1,104	(686)	(1,754)	(1,706)	(649)
Other [A]	8	(28)	1,264	(142)	217
Tax paid	(3,290)	(7,605)	(9,671)	(6,307)	(4,434)
Cash flow from operating activities	34,105	42,178	53,085	35,650	20,615
Capital expenditure	(16,585)	(22,971)	(23,011)	(20,845)	(22,116)
Acquisition of BG Group plc, net of cash and cash equivalents acquired	—	—	—	—	(11,421)
Investments in joint ventures and associates	(1,024)	(743)	(880)	(595)	(1,330)
Investments in equity securities [A]	(218)	(205)	(187)	(93)	(132)
Proceeds from sale of property, plant and equipment and businesses	2,489	4,803	4,366	8,808	2,072
Proceeds from sale of joint ventures and associates	1,240	2,599	1,594	2,177	1,565
Proceeds from sale of equity securities [A]	281	469	4,505	2,636	3
Interest received	532	911	823	724	470
Other investing cash inflows [A]	3,239	2,921	1,373	2,909	1,744
Other investing cash outflows [A]	(3,232)	(3,563)	(2,242)	(3,750)	(1,818)
Cash flow from investing activities	(13,278)	(15,779)	(13,659)	(8,029)	(30,963)
Net decrease in debt with maturity period within three months	(63)	(308)	(396)	(869)	(360)
Other debt:				—	—
New borrowings	23,033	11,185	3,977	760	18,144
Repayments	(17,385)	(14,292)	(11,912)	(11,720)	(6,710)
Interest paid	(4,105)	(4,649)	(3,574)	(3,550)	(2,938)
Derivative financial instruments [B]	1,157	(48)	Check	—	—
Change in non-controlling interest	(42)	—	678	293	1,110
Cash dividends paid to:					
Royal Dutch Shell plc shareholders	(7,424) [C]	(15,198)	(15,675)	(10,877)	(9,677)
Non-controlling interest	(311)	(537)	(584)	(406)	(180)
Repurchases of shares	(1,702)	(10,188)	(3,947)	—	—
Shares held in trust: net purchases and dividends received	(382)	(1,174)	(1,115)	(717)	(160)
Cash flow from financing activities	(7,224)	(35,209)	(32,548)	(27,086)	(771)
Currency translation differences relating to cash and cash equivalents	172	124	(449)	647	(1,503)
Increase/(decrease) in cash and cash equivalents	13,775	(8,686)	6,429	1,182	(12,622)
Cash and cash equivalents at beginning of year	18,055	26,741	20,312	19,130	31,752
Cash and cash equivalents at end of year	31,830	18,055	26,741	20,312	19,130

[A] With effect from 2019, the starting point for the Consolidated Statement of Cash Flows is 'Income before taxation' (previously 'Income'). Furthermore, to improve transparency, 'Retirement benefits' and 'Decommissioning and other provisions' have been separately disclosed. The 'Other' component of cash flow from investing activities has been expanded to distinguish between cash inflows and outflows. Prior period comparatives for these line items have been revised to conform with current year presentation. Overall, the revisions do not have an impact on cash flow from operating activities, cash flow from investing activities or cash flow from financing activities, as previously published.

[B] As from 2019, a new line item 'Derivative financial instruments' has been introduced for derivatives related to debt.

[C] Cash dividends paid represents the payment of net dividends (after deduction of withholding taxes where applicable) and payment of withholding taxes on dividends paid in the previous quarter.

FREE CASH FLOW AND ORGANIC FREE CASH FLOW

	\$ million				
	2020	2019	2018	2017	2016
Cash flow from operating activities	34,105	42,178	53,085	35,650	20,615
Cash flow from investing activities	(13,278)	(15,779)	(13,659)	(8,029)	(30,963)
Free cash flow	20,828	26,399	39,426	27,621	(10,348)
Less: Cash inflows related to divestments [A]	4,010	7,871	10,465	13,619	3,641
Add: Tax paid on divestments	–	187	482	[C]	[C]
Add: Cash outflows related to inorganic capital expenditure [B]	817	1,400	1,740	1,138	11,481
Organic free cash flow	17,634	20,116	31,183	15,140	(2,507)

[A] Cash inflows related to divestments includes Proceeds from sale of property, plant and equipment and businesses, Proceeds from sale of joint ventures and associates, and Proceeds from sale of equity securities as reported in the "Consolidated Statement of Cash Flows".

[B] Cash outflows related to inorganic capital expenditure includes portfolio actions which expand Shell's activities through acquisitions and restructuring activities as reported in capital expenditure lines in the "Consolidated Statement of Cash Flows".

[C] Tax paid on divestments included in Cash flow from operating activities.

RETURN ON AVERAGE CAPITAL EMPLOYED

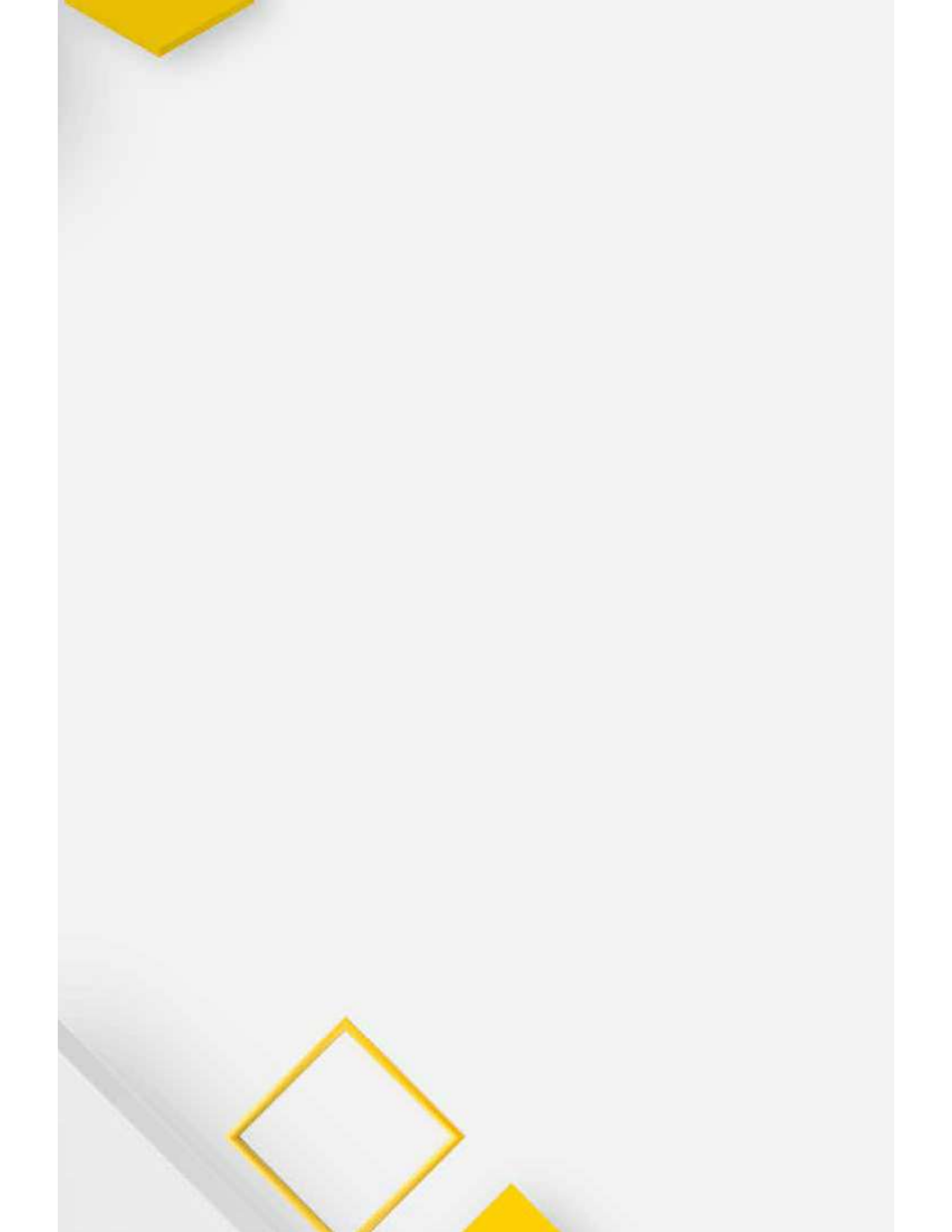
	\$ million unless indicated				
	2020	2019	2018	2017	2016
Income for the period	(21,534)	16,432	23,906	13,435	4,777
Interest expense after tax	2,822	3,024	2,513	2,995	2,730
Income before interest expense	(18,712)	19,456	26,419	16,430	7,507
Capital employed – opening	286,887	295,398	283,477	280,988	222,500
Capital employed – closing	266,551	286,887	279,358	283,477	280,988
Capital employed – average	276,719	291,142	281,417	282,233	251,744
ROACE	(6.8)%	6.7%	9.4%	5.8%	3.0%

GEARING

	\$ million unless indicated				
	2020	2019	2018	2017	2016
Current debt	16,899	15,064	10,134	11,795	9,484
Non-current debt	91,115	81,360	66,690	73,870	82,992
Total debt [A]	108,014	96,424	76,824	85,665	92,476
Add: Debt-related derivative financial instruments: net liability/(asset)	(1,979)	701	1,273	591	–
Add: Collateral on debt-related derivatives: net liability/(asset)	1,181	23	72	–	–
Less: Cash and cash equivalents	(31,830)	(18,055)	(26,741)	(20,312)	(19,130)
Net debt [A]	75,386	79,093	51,428	65,944	73,346
Add: Total equity [A]	158,537	190,463	202,534	197,812	188,511
Total capital [A]	233,923	269,556	253,962	263,756	261,857
Gearing [A]	32.2%	29.3%	20.3%	25.0%	29.1%

[A] Shell used the modified retrospective transition method for implementing IFRS 16 Leases. Comparative information was not restated, and continues to be presented as previously reported under IAS 17 Leases.

NOTES



FINANCIAL CALENDAR IN 2021

The Annual General Meeting will be held on May 18, 2021.

	2020 Fourth quarter [A]	2021 First quarter [B]	2021 Second quarter [B]	2021 Third quarter [B]
Results announcements	February 4	April 29	July 29	October 28
Interim dividend timetable				
Announcement date	February 4 [C]	April 29	July 29	October 28
Ex-dividend date for ADS.A and ADS.B [D]	February 18	May 13	August 12	November 10
Ex-dividend date for RDS A and RDS B	February 18	May 13	August 12	November 11
Record date	February 19	May 14	August 13	November 12
Closing of currency election date [E]	March 5	May 28	August 27	November 26
Pounds sterling and euro equivalents announcement date	March 15	June 7	September 6	December 6
Payment date	March 29	June 21	September 20	December 20

[A] In respect of the financial year ended December 31, 2020.

[B] In respect of the financial year ending December 31, 2021.

[C] The Directors do not propose to recommend any further distribution in respect of 2020.

[D] The New York Stock Exchange (NYSE), with effect from September 5, 2017, reduced the standard settlement cycle in accordance with the SEC amendments to Exchange Act Rule 15c6-1(a). Under these rules, regular settlement will occur on a T+2 basis for trades occurring on or after the SEC's implementation date of September 5, 2017. As a result, RDS A ADSs and RDS B ADSs traded on the NYSE markets will now settle in line with RDS A shares and RDS B shares traded on European markets, which moved to a T+2 settlement basis for trades in 2014, resulting in the same ex-dividend date for RDS A shares, RDS B shares, RDS A ADSs and RDS B ADSs. Record dates will not change. The timings of these are detailed above.

[E] A different currency election date may apply to shareholders holding shares in a securities account with a bank or financial institution ultimately through Euroclear Nederland. This may also apply to other shareholders who do not hold their shares either directly on the Register of Members or in the corporate sponsored nominee arrangement. Shareholders can contact their broker, financial intermediary, bank or financial institution for the election deadline that applies.

CONTACT US

The best way to get in touch is via the "Contact us" section of the Shell website. From here questions are properly directed to the Shell team that can assist. In addition, we have introduced an automated question response tool to assist with the most popular questions that we receive and reviewed and updated the "Frequently asked questions" section of our website to provide the most time efficient information for our investors.

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- Comprehensive financial information on our activities throughout 2020
- Detailed information on Shell's taxes
- Report on our progress in contributing to sustainable development

Attachment 5-3

Financial Reports - EDPR



2018

Financial Results

Conference call and webcast

Date: Tuesday, March 12th, 2019, 09:00 am (UK/Portuguese time)

Webcast: www.edp.com

Lisbon, March 12th, 2019

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Main Highlights



Key Operational Data	2018	2017	Δ %	Δ Abs.
Installed capacity (MW)	27,151	26,753	1%	+399
Weight of Renewables (1)	74%	74%	-	0p.p.
Production (GWh)	71,963	70,001	3%	+1,963
Weight of Renewables (1)	66%	56%	-	10p.p.
Customers supplied (thousand of contracts)	11,445	11,472	-0%	-26
Customers connected (thous.)	10,343	10,228	1%	+115

Key Income Statement data (€ m)	2018	2017	Δ %	Δ Abs.
Gross Profit	5,099	5,391	-5%	-292
EBITDA	3,317	3,990	-17%	-673
EBIT	1,584	2,318	-32%	-734
Financial Results & Equity results	(543)	(797)	32%	+254
Income taxes & CESE (2)	165	80	107%	+85
Non-controlling Interest	357	328	9%	+29
Net Profit (EDP Equity holders)	519	1,113	-53%	-594

Key Performance indicators (€ m)	2018	2017	Δ %	Δ Abs.
Recurring EBITDA (3)	3,287	3,383	-3%	-96
Iberia (Ex wind & Solar) & Other	1,413	1,399	1%	+14
Wind & Solar	1,300	1,368	-5%	-68
Brazil	574	616	-7%	-42
Recurring net profit (3)	797	770	3%	+27
OPEX (4) Performance				
OPEX Iberia (€ m)	856	912	-6%	-56
Core OPEX/MW (€/MW) - Wind & Solar	43	42	2%	+1
OPEX Brazil (BRL m)	1,115	1,085	3%	+29

Key Balance Sheet Data (€ m)	Dec-18	Dec-17	Δ %	Δ Abs.
Net debt	13,480	13,902	-3%	-422
Adjusted net debt/EBITDA (x) (5)	4.0x	3.9x	4%	0.2x

EDP results are materially impacted by one-off impacts in both 2017 and 2018, which materially distort YoY comparison: in 2017, +€268m in total, mainly driven by portfolio reshuffling and impairments in Iberia; in 2018, -€277m in total, mainly driven by an administrative decision on retroactive CMEC resulting in a one-off €285m provision booked in 3Q18 (full details on page 4). Excluding all the one-offs and the de-consolidation of gas distribution operations, **recurring net profit increased by 3% YoY, to €797m in 2018**, as market improvement in Iberia and Brazil outstood the effect from adverse regulatory developments in Portugal (announced in 4Q17), and particularly weak wind resources vs. LT average. Regulatory changes in Iberia (mostly in Portugal) dented net profit by €151m (excluding additional non-recurring after tax cost of €208m).

In 2018, EDP continued to implement its growth strategy focused on renewables and Brazil. **Total installed capacity reached 27.2 GW in Dec-18**, following the commissioning of 825 MW of new wind capacity, combined with the first sell down of a controlling stake in wind farms and the disposal of some mini-hydro plants in Portugal and Brazil. **By Dec-18, 74% of EDP installed capacity is renewables (hydro, wind and solar PV)**. Also worth to note is the increase in equity-method capacity to 920 MW in Dec-18: 539 MW of hydro capacity in Brazil (+0.2 GW YoY) and 371 MW of wind capacity (the first asset rotation deal of a majority stake: +40 MW).

In terms of **total production, the weight of renewables advanced 10 p.p. YoY, to 66% in 2018**. EDP keeps focused in improving customers' satisfaction, the quality of service provided and enhancing customers engagement, leveraging on its **customers portfolio of 11.5 million** contracts spread throughout Iberia and Brazil.

EBITDA in 2018 reached €3,317m. Excluding the contribution from Iberian gas networks disposed over the 2H17 and one-off impacts (as per page 3), recurring EBITDA fell 3% (-€96m) YoY, to €3,287m in 2018, as underlying growth was hampered by the negative forex impact in the period: -5% or -€163m, prompted by BRL and, to a lower extent, USD depreciation vs. the Euro. In 2018, EBITDA performance further reflected the positive effect from i) hydro recovery to normalised level (despite very poor 4Q18) and strong OPEX performance in Iberia, ii) strong underlying growth in Brazil (local currency) and iii) benefits from portfolio expansion, particularly in wind capacity (+6% on average). These positives were nevertheless offset by regulatory cuts in Portugal (-€210m YoY recurring), low wind resources (6% below P50 in 2018 and at 6-year low record in 2H18, over 10% below average) and lower revenue per MWh in wind.

On efficiency, OPEX (staff + supplies & services costs; excluding staff restructuring costs) excluding forex increased 1% YoY. By main division, OPEX in **Iberia** decreased 3%, Core OpeX/avg. MW at EDPR rose by 2% YoY and local currency OPEX at EDP **Brazil** grew 3%, 1pp short of inflation.

Net financial results (including equity results) **improved by 32% YoY (+€254m), to -€543m in 2018**, including a steady improvement in interest costs (-9% YoY) prompted by a lower average cost of debt (from 4.1% in 2017 to 3.8% in 2018) and the decrease of avg. debt (-10% or -€1.7bn YoY).

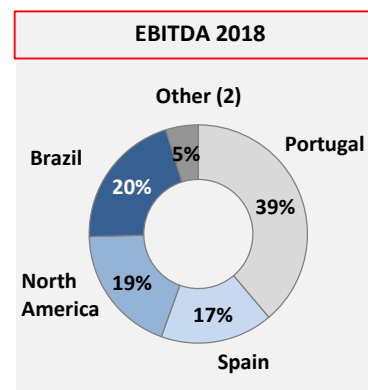
Net debt was down from €13.9bn in Dec-17 to €13.5bn in Dec-18. Recurring organic cash flow generated in 2018 (€1.2bn) more than covered the €0.7bn dividend payment to shareholders plus €0.4bn net debt reduction, while net expansion activity (€0.4bn) and one-off cash flow items were balanced with tariff deficit sales (contribution to a €0.6bn reduction in regulatory receivables).

EDP Executive Board of Directors will submit to the upcoming ASM (April 24th) a proposal for the distribution of €0.19 dividend per share as to 2018 fiscal year.

(1) Including Wind, Solar, Hydro and mini-hydro capacity; (2) CESE: Extraordinary contribution from the energy sector; (3) Excluding one-off impacts as per page 3 (EBITDA) and page 4 (Net profit); In 2017, it excludes the contribution from Gas distribution in Iberia (€140m on EBITDA; €75m on net profit); (4) OPEX = Supplies and services + Personnel costs + Costs with social benefits; (5) Net of regulatory receivables; Based on trailing 12 months recurring EBITDA and net debt excluding 50% of hybrid bond issue (including interest).

EBITDA Breakdown

EBITDA (€ m)	2018	2017	Δ %	Δ Abs.	1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18	4Q18	4Q18 YoY Δ %	Δ Abs.
Generation & Supply Iberia	762	555	37%	+208	201	160	158	36	185	252	185	141	286%	104
Regulated Networks Iberia	625	898	-30%	-273	265	248	205	181	159	155	162	149	-18%	-32
Wind & Solar Power	1,300	1,366	-5%	-66	373	345	272	376	381	305	184	431	15%	55
Brazil	649	615	6%	+34	164	151	148	151	163	143	149	194	29%	43
Other	(19)	556	-	-575	8	(13)	583	(23)	5	(26)	8	(7)	71%	16
Consolidated EBITDA	3,317	3,990	-17%	-673	1,011	892	1,367	721	893	829	688	907	26%	186
- Adjustments (1)	31	607	-95%	-576	58	57	583	(91)	(18)	-	-	49	-	140
Recurring EBITDA	3,287	3,383	-3%	-96	953	835	783	812	911	829	688	858	6%	46



Consolidated EBITDA amounted to €3,317m in 2018. Excluding the contribution from Iberian gas networks disposed over the 2H17 (€140m in 2017) and the one-off impacts^(*), **recurring EBITDA fell 3% (-€96m) YoY, to €3,287m in 2018**, largely impacted by the adverse forex impact (-5% or -€163m, mainly due to BRL depreciation vs. the Euro) and weaker-than-average wind resources (-€69m vs. normalised year). In 2018, growth drivers of EBITDA included i) hydro recovery and strong OPEX performance in Iberia, ii) strong underlying growth in Brazil and iii) benefits from portfolio expansion. Nevertheless, such positives were overshadowed by regulatory cuts in Portugal (-€210m YoY recurring) and low wind resources (particularly in 3Q18 and 4Q18: 11% and 12% below the LT average, respectively).

WIND & SOLAR POWER (39% of EBITDA) – EBITDA was 5% lower YoY (-€66m), at €1,300m in 2018, penalised by i) -€36m forex impact (due to USD and BRL depreciation), ii) weak wind resources in 2018 (6% below LT average), iii) avg. selling price -7% YoY Ex-forex, following lower green certificates revenues and the mix effect from new MWs (mainly in US, Brazil); and iv) expiration of the 10-year period PTCs in some wind farms in US (-€51m). These impacts outstood the effect from the 6% increase in avg. capacity and the gain on the first sell down transaction, corresponding to the upfront monetisation of value accretion of 499 MW built to sell and operate.

GENERATION & SUPPLY IN IBERIA (22% of EBITDA) – EBITDA advanced by 37% YoY to €762m, penalised by one-off effects (-€33m in 2018 vs. -€13m in 2017). **Recurring EBITDA increased 40% YoY, to €796m in 2018**, propelled by higher hydro contribution to the production mix (39% share in total production in 2018 vs. 22% in 2017, following improved hydro conditions) and higher selling prices, which more than compensated the adverse impact from weak thermal spreads and poor energy management results, due to the hedge position closed in 2017. Hydro resources improved from 53% below-the-average in 2017 to 5% above-the-average in 2018, although the seasonally strongest quarters (1Q and 4Q) were particularly weaker than average: hydro resources in 4Q18 fell 36% short of historical average.

REGULATED NETWORKS IN IBERIA (19% of EBITDA) – Excluding gas distribution in Iberia and restructuring costs (as per page 18), **EBITDA fell by 23% YoY, to €636m in 2018**, largely impacted by: (i) in Portugal (77% of total), the new regulatory terms applicable to electricity distribution and LRS as from 1-Jan-18 (-€164m YoY) which was only partially compensated by tight cost control; and (ii) in Spain (23% of total), our prudent approach to possible regulatory changes, even ahead of the end of the current regulatory period, in 2020.

BRAZIL (20% of EBITDA) - EBITDA was 6% higher YoY, to €649m in 2018, despite the adverse change of the BRL vs. the EUR (-16% YoY, -€127m impact). EBITDA in 2018 includes the gain booked in the sale of mini-hydros^(*), net of €7m restructuring costs). Adjusted for these, **local currency recurring EBITDA was up 12%, to R\$2,472m in 2018**, mainly reflecting: i) in **distribution (+7% YoY or +R\$56m)**, better operational performance; and ii) in **generation**, the successful portfolio integrated management (leading to a GSF impact net of hedging of R\$151m in 2018) and the revision of Pecém contracted availability.

(*) *Non-recurring items: (i) +€467m in 2017, resulting from the net impact of the sale of gas distribution business in Spain and Portugal (+€574m); regulatory-driven provisions in Generation & supply (-€35m) and Regulated networks (-€42m); RH restructuring costs (-€30m); (ii) +€31m in 2018, net impact of the sale of mini-hydro plants Brazil (+€82m), and 2H17's share of the impact from the difference between CMEC final adjustment recognised in Dec-17 and approved by the Government on May 3rd (-€18m), restructuring costs (-€34m).*

(1) Adjustments for one-off impacts^(*) and to exclude the 2017 contribution from Gas distribution in Iberia; (2) Includes Poland, Romania, France, Belgium, Italy and UK.

Profit & Loss Items below EBITDA



Profit & Loss Items below EBITDA (€ m)	2018	2017	Δ %	Δ Abs.	1Q18	2Q18	3Q18	4Q18	4Q18 YoY	
									Δ %	Δ Abs.
EBITDA	3,317	3,990	-17%	-673	893	829	688	907	26%	+186
Provisions	288	(4)	n.m.	+292	(7)	4	286	5	-	+10
Amortisation and impairment	1,445	1,676	-14%	-231	351	348	350	396	-36%	-225
EBIT	1,584	2,318	-32%	-734	549	477	53	506	383%	+401
Net financial interest	(626)	(691)	9%	+65	(148)	(144)	(148)	(186)	-3%	-6
Regulatory receivables-related fin. results	22	20	11%	+2	6	6	3	7	-	+11
Capitalized financial costs	34	33	1%	+0	7	8	9	10	14%	+1
Unwinding of long term liabilities(1)	(177)	(187)	6%	+11	(44)	(45)	(46)	(42)	14%	+7
Net foreign exchange differences and derivatives	(5)	(35)	86%	+30	25	(10)	(7)	(13)	-	-22
Investment income, net interest with associates and JV	(26)	(25)	-4%	-1	(8)	(5)	(7)	(7)	-	+1
Capital Gains/(Losses)	113	29	284%	+83	15	5	(0)	94	n.m.	+90
Other Financials	111	48	132%	+63	19	37	30	26	607%	+22
Financial Results	(554)	(808)	31%	+254	(127)	(150)	(166)	(111)	49%	+105
Share of net profit in JVs/associates (Details page 28)	11	12	-6%	-1	1	2	6	2	138%	+1
Pre-tax Profit	1,041	1,521	-32%	-480	423	330	(108)	397	-	+507
Income Taxes	100	10	867%	+89	74	43	(67)	49	-	+215
Effective Tax rate (%)	10%	1%	-	8.9 pp	18%	13%	62%	12%	-	-138 pp
Extraordinary Contribution for the Energy Sector	65	69	-6%	-4	66	(2)	1	0	-	+1
Non-controlling Interests (Details page 28)	357	328	9%	+29	116	75	40	125	41%	+37
Net Profit Attributable to EDP Shareholders	519	1,113	-53%	-594	166	214	(83)	222	-	+255

Amortisation and impairments fell by 14% YoY, to €1,445m in 2018, impacted by last year's impairments (€257m, mostly in coal plants in Iberia and EDPR), by the de-consolidation of gas distribution (€19m in 2017) and forex (-€43m). In 2018, amortisation and impairment charges reflect the impact from new capacity additions in the last 12 months and impairments in 4Q18 (€24m in coal plants in Iberia and €7m at EDPR).

On 26-Sep-18, DGEG notified EDP about an Order of the Secretary of State for Energy (SSE), from 29-Aug-18, quantifying at €285m the financial impact of an alleged overcompensation of the CMECs (details on page 11). Considering that the dispatch lacks legal, economic technical basis, EDP has taken necessary actions to protect its interests and rights. Although EDP considers that there were no innovative features weighted in the annual adjustments or in the final adjustment of the CMEC, a €285m provision was booked in 3Q18. As a result, total **provisions** amounted to €288m in 2018.

Net financial results amounted to -€554m in 2018 (+31% YoY). **Net interest expense improved by 9% YoY**, to €626m in 2018 supported by lower average debt in 2018 (-10% or €1.7bn YoY); better funding conditions and past years' liability management, gathering a 30bps YoY decline in the avg. cost of debt (from 4.1% in 2017 to 3.8% in 2018). These effects were smoothed by higher one-off costs mostly related to early debt prepayment: -€39m in 2018 vs. -€27m in 2017. **Capitalised financial expenses**, at €34m in 2018, are mainly related to new renewable capacity under construction and regulated networks. **Capital gains** (€113m in 2018) refer to the sale of our stake in Bioeletrica biomass plant in Portugal (€24m) vs. €25m in 2017 (sale of a stake in REN). It further includes the impact from the sale of some stakes in our UK (totalling 43%) and France (13.5%) offshore projects (totalling €87m). **Other financial results** in 2018 include the goodwill arising from the acquisition of a stake in Celesc (+€18m in 2018) and higher financial guarantees in Brazil.

(1) Includes unwinding of medium, long term liabilities (regarding dismantling & decommissioning provision for wind assets, TEIs and Alqueva/Pedrogão concessions) and interest on medical care and pension fund liabilities.

Share of net profit in joint ventures and associates was broadly stable at €11m in 2018, reflecting the mixed impact from contribution of CELESC (23.6% stake built up during 2018; +€6m on equity contribution) and early stage of operations at our hydro plants in Brazil. (Details on page 28).

Income taxes amounted to €100m (+€89m YoY). Note that excluding the major tax effect of €285m provision for alleged CMEC overcompensation, the effective tax rate stood at 14% in 2018.

Non-controlling interests amounted to €357m in 2018 (+9% or +€29m YoY). The evolution of non-controlling interests is justified by minorities' share on one-off impacts at EDP Brasil level (€40m). (Details on page 28)

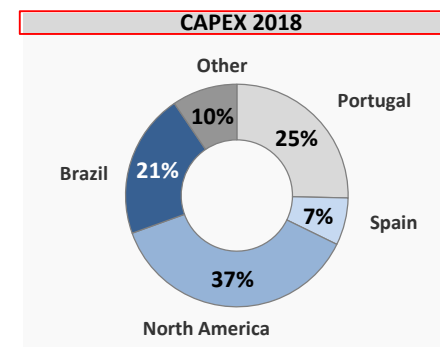
Overall, net profit reached €519m in 2018, heavily impacted by one-off impacts(*). Excluding one offs and the contribution from gas networks in 2017, **recurring net profit rose 3% YoY, to €797m in 2018**, supported by hydro recovery from very weak level in 2017, underlining growth in Brazil, which more than compensated the effects from adverse regulatory changes in Portugal and weak wind resources in 2018.

(*) **Non-recurring items:** (i) **+€268m in 2017**, including net gain on disposals (NED and EDP Gas: +€574m; REN stake: +€25m), restructuring costs (-€21m), regulatory-driven costs/provisions (-€61m); impairments at coal plants in Iberia and other (-€191m); debt prepayment fees and others (-€33m); impact from US fiscal reform (+€44m) and the extraordinary energy tax (-€69m); (ii) **-€277m in 2018**, including regulatory impacts (-€208m), impairments at coal plants in Iberia (-€21m), restructuring costs (-€21m), net gain on disposals (Mini-hydros: +€40m; Bioeletrica: +€24m); debt prepayment fees and others (-€26m) and the extraordinary contribution for the energy sector (-€65m).

Investment activity

Capex (€ m)	2018	2017	Δ %	Δ Abs.
Expansion	1,394	1,017	37%	+377
Wind & Solar	1,275	1,051	21%	+224
Brazil	77	11	n.m.	+67
Iberia and Other	42	(45)	-	+87
Maintenance	637	709	-10%	-72
Regulated Networks Iberia	276	349	-21%	-73
Regulated Networks Brazil	152	158	-4%	-6
Other	209	202	3%	+7
Consolidated Capex	2,031.17	1,725	18%	+306

1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18	4Q18
112	351	188	365	283	217	505	389
93	331	291	337	265	199	461	349
-	1	1	9	5	11	39	23
19	19	(103)	20	13	7	5	18
140	144	143	282	85	144	163	245
73	73	71	132	34	52	63	126
42	35	39	41	26	34	43	49
25	36	32	109	24	58	57	70
252	495	331	647	368	362	668	634



Net financial investments/ (Divestments) (1) (€m)	2018	2017	Δ %	Δ Abs.
Financial Investments	210	433	-51%	-222
EDPR Perimeter	105	10	911%	+95
EDP Brasil Perimeter	105	91	15%	+14
Tender offer for EDPR shares	-	299	-	-299
Iberia and Other	-	32	-	-32
Financial Divestments	745	3,081	-76%	-2,337
EDPR Perimeter	422	272	55%	+150
EDP Brasil Perimeter	150	13	1096%	+137
Sale of NED + EDP Gas	38	2,745	-99%	-2,707
Other	135	52	161%	+83
Net Financial Investment	(534)	(2,649)	80%	+2,114

Summary of Expansion Investment activity (1) (€m)	2018	2017	Δ %	Δ Abs.
Expansion capex	1,394	1,017	37%	+377
Net financial Investm./ (Divestm) (1)	(534)	(2,649)	80%	+2,114
Proceeds from TEI in US	(399)	(445)	10%	+46
Other (2)	(111)	299	-	-410
Total	350	(1,777)	-	+2,127

Consolidated capex amounted to €2,031m in 2018, supported by an acceleration of expansion capex, particularly in renewables and transmission in Brazil. In line with EDP strategy, the bulk of total capex (89%) was devoted to regulated and long term contracted activities, including expansion projects (c70% of total capex).

Maintenance capex (€637m in 2018) was mostly absorbed by regulated networks in Brazil and Iberia (67% of total). The decline in 2018 is mainly supported by the de-consolidation of gas distribution in Iberia (€24m capex in 2017) and weaker BRL/EUR rate underlying capex.

Expansion capex was mostly dedicated to new renewable capacity and the transmission lines in Brazil:

1) New wind & solar capacity: capex amounted to €1,275m in 2018, of which 59% was applied in North America, 27% in Europe and 13% in Brazil. Onshore wind under construction by the end of Dec-18 totalled 344 MW: 58% in US and 42% in Europe.

2) Transmission lines in Brazil: capex is ramping up, with €73m invested in 2018, as the execution of the R\$3.1bn capex planned until 2022 is proving ahead of schedule.

Net financial divestments amounted to €534m, including: (i) in Brazil, the acquisition of a 23.6% stake in Celesc (Centrais Elétricas de Santa Catarina) for €89m, combined with the sale of several small hydro plants (€150m); (ii) at EDPR level, the sale of a 43% stake in Moray East offshore wind project (23% in 4Q18), the sale of a 13.5% stake in our France offshore projects (4Q18) and the asset rotation of 499 MW of wind onshore capacity in the US and Canada (4Q18), explaining the bulk of €422m; (iii) in Iberia, the cash in of additional €38m relative to the disposal of Naturgas Energia Distribución ('NED') and the sale of mini hydro/biomass plants in Portugal (€135m).

Overall, net expansion activity resulted in net cash investment of €350m, including an acceleration of expansion capex (+€377m YoY, to €1,394m), proceeds from new TEI structures (€399m) and net impact from disposals/acquisitions (-€534m in 2018). Note that 2017 investment activity was marked by an intense portfolio reshuffling activity and changes in the consolidation perimeter.

(1) Includes shareholders loans; (2) Includes Change in WC Fixed asset suppliers, change in consolidation perimeter and other

Cash Flow Statement



Consolidated Cash Flow (€m)	2018	2017	Δ %	Δ Abs.
Operating Activities				
Cash receipts from customers	14,237	13,825	3%	+412
Proceeds from tariff adjustments sales	1,289	1,193	8%	+96
Cash paid to suppliers and personnel	(11,770)	(11,406)	-3%	-365
Concession rents & other	(694)	(718)	3%	+24
Net Cash from Operations	3,061	2,894	6%	+167
Income tax received/(paid)	(123)	(659)	81%	+535
Net Cash from Operating Activities	2,938	2,236	31%	+702
Net Cash from Investing Activities	(1,179)	570	-	-1,749
Net Cash from Financing Activities	(2,335)	(1,797)	-30%	-538
Changes in Cash and Cash Equivalents	(576)	1,008	-	-1,584
Effect of exchange rate fluctuations	(21)	(129)	84%	+109
Change in Net Debt (€ m)	2018	2017	Δ %	Δ Abs.
Recurring CF from Operations (1)	2,605	2,686	-3%	-80
Recurring EBITDA	3,287	3,383	-3%	-96
Change in operating working capital, taxes and other	(681)	(697)	2%	+16
Maintenance capex (2)	(664)	(754)	12%	+90
Net interests paid	(570)	(630)	10%	+60
Payments to Institutional Partnerships US	(174)	(195)	11%	+21
Other	(13)	(319)	96%	+306
Recurring Organic Cash Flow	1,184	787	50%	+397
Net Expansion	(350)	1,777	-	-2,127
Expansion capex	(1,394)	(1,017)	-37%	-377
Net Fin. Investm./Divestments	534	2,649	-80%	-2,114
Proceeds from Institut. Partnerships in US	399	445	-10%	-46
Other	111	(299)	-	+410
Change in Regulatory Receivables	602	34	1673%	+568
Dividends paid to EDP Shareholders	(691)	(691)	0%	+0
Effect of exchange rate fluctuations	(13)	618	-	-631
Other (including one-off adjustments)	(310)	(494)	37%	+185
Decrease/(Increase) in Net Debt	422	2,031	-79%	-1,608
Funds from Operations (€m)	2018	2017	Δ %	Δ Abs.
EBITDA	3,317	3,990	-17%	-673
Current income tax	(246)	(178)	-38%	-67
Net financial interests	(626)	(691)	9%	+65
Net Income and dividends received from Associates	(15)	17	-	-32
FFO Adjustments	(194)	(121)	-61%	-73
FFO - Funds From Operations	2,237	3,017	-26%	-780

Recurring organic cash flow amounted to €1.184m in 2018 (+50% YoY). Note that the adverse impact from regulatory developments in Portugal in late 2017 and the disposal of gas distribution in Iberia (-€129m YoY) on Recurring organic cash flow was smoothed out by the correspondent income tax effect. In detail, it is worth to highlight: (i) **Recurring cash flow from operations, reaching €2.6bn in 2018**, was €0.1bn lower YoY in the wake of the impact from weak wind resources and the de-consolidation of gas assets, even if this was cushioned by lower income taxes; (ii) **Net interests paid (net of capitalised expenses) amounted to €570m**, posting a €60m YoY improvement, mirroring EDP's improvement trajectory in terms of financial debt and the respective cost; (iii) Other items include €196m gain from the sale of stakes in renewable projects during 2018. Note that expenditure in maintenance capex (€664m) includes payables to fixed assets suppliers.

Net expansion activity comprised the construction of new wind capacity and execution of programmed capex in transmission lines in Brazil; but also, equity contributions by EDPR (mainly focused in wind offshore projects) and in Brazil (hydro generation). Additionally, our expansion activity encompassed the acquisition of 23.6% stake in CELESC for €89m and several disposals, mainly in 4Q18: asset rotation transactions in offshore wind (€189m in 2018), the first asset rotation of majority stake deal in wind onshore (€226m in 4Q18), the disposal of several small hydro plants in Brazil and Portugal (€285m closed in 4Q18). Note that in 2017, net expansion divestments (€1.8bn) included net proceeds from portfolio reshuffling (€2.4bn).

Regulatory receivables fell by €602m in 2018, driven by Portugal on system deleveraging (-€0.8bn YoY, to €3.8bn) and EDP's asset rotation deficit strategy (€1.3bn in 2018).

On 2-May-18, **EDP paid its annual dividend totaling €691m** (€0.19/share).

Effects of exchange rate fluctuations had a negligible impact on net debt, reflecting balanced effects from the appreciation of the USD (+5%) and depreciation BRL (-19%) vs. Dec-17, both against the Euro.

One-off impacts (included in **Other**) amounted to €0.3bn in 2018, including the taxes cash out (energy tax previously provisioned and fiscal revaluation: €0.2bn), extraordinary contribution to pension fund and early debt prepayment costs. In 2017, total one-off impacts amounted to €0.5bn, including €0.4bn tax-related (arising from 2016 reduction in regulatory receivables, fiscal revaluation program and other), extraordinary contribution to pension fund and costs arising from early debt prepayments.

Overall, recurring organic cash flow generated in 2018 more than covered dividend payment to shareholders plus net debt reduction. Net expansion activity and one-off cash flow items were balanced by lower regulatory receivables arising from tariff deficit sales. **Net debt** decreased by €0.4bn in the year, to €13.5bn as of Dec-18.

Funds from operations (FFO) were 26% lower YoY, at €2,237m in 2018, reflecting i) a €673m decrease in reported EBITDA (see details on page 3); ii) a €67m increase in current income tax; iii) a €65m decrease in net financial interests paid; iv) a €32m decrease in net income and dividends received from Associates, following the disposal of a 3.5% stake in REN in 2017; and v) higher impact from FFO adjustments mainly explained by higher extraordinary contribution to pension fund.

(1) Excluding Regulatory Receivables; (2) Maintenance capex includes payables to fixed assets suppliers.

Consolidated Financial Position



Assets (€ m)	Dec vs. Dec		
	Dec-18	Dec-17	Δ Abs.
Property, plant and equipment, net	22,708	22,731	-23
Intangible assets, net	4,737	4,747	-11
Goodwill	2,251	2,233	19
Fin. investments & assets held for sale (details page 28)	1,088	1,236	-148
Tax assets, deferred and current	1,560	1,390	170
Inventories	342	266	76
Other assets, net	6,946	7,028	-82
Collateral deposits	193	45	148
Cash and cash equivalents	1,803	2,400	-597
Total Assets	41,627	42,075	-448

Equity (€ m)	Dec vs. Dec		
	Dec-18	Dec-17	Δ Abs.
Equity attributable to equity holders of EDP	8,968	9,546	-578
Non-controlling Interest (Details on page 28)	3,932	3,934	-2
Total Equity	12,900	13,480	-580

Liabilities (€ m)	Dec vs. Dec		
	Dec-18	Dec-17	Δ Abs.
Financial debt, of wich:	16,085	16,918	-833
Medium and long-term	13,462	15,470	-2,007
Short term	2,623	1,448	1,174
Employee benefits (detail below)	1,407	1,522	-115
Institutional partnership liability (US wind)	1,269	1,249	20
Provisions	1,018	753	266
Tax liabilities, deferred and current	1,238	1,122	117
Deferred income from inst. partnerships	962	915	47
Other liabilities, net	6,746	6,117	630
Total Liabilities	28,727	28,595	132

Total Equity and Liabilities	41,627	42,075	-448
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Employee Benefits (€m)	Dec vs. Dec		
	Dec-18	Dec-17	Δ Abs.
Employee Benefits (bef. Tax)	1,407	1,522	-115
Pensions	759	763	-4
Medical care and other	648	759	-111
Deferred tax on Employee benefits (-)	-422	-459	37
Employee Benefits (Net of tax)	985	1,064	-78

Regulatory Receivables (€m)	Dec vs. Dec		
	Dec-18	Dec-17	Δ Abs.
Regulatory Receivables	287	870	-583
Portugal Distribution (1)	120	608	-488
Portugal Annual CMEC Deviation	96	237	-140
Brazil	71	26	45
Change in Fair value (+)	-	-	-
Deferred tax on Regulat. Receivables (-)	-68	-266	198
Regulatory Receivables (Net of tax)	219	604	-385

Total amount of **property, plant & equipment and intangible assets** remained flat vs. Dec-17 at €27.4bn as of Dec-18, mainly driven by an acceleration in CAPEX in the 2018 which outstood depreciation charges and forex impact from the depreciation of the BRL (-11%) against the EUR between Dec-17 and Dec-18. As of Dec-18, EDP works in progress amounted to €1.7bn (6% of total consolidated tangible and intangible assets): 51% at EDPR level, 9% at EDP Brasil level and the remaining 40% at Iberian level.

The book value of **financial investments & assets held for sale** decreased by €148m vs. Dec-17 (details on page 28). Worth noting in this regard that some mini-hydro plants, along with a biomass plant in Portugal and small hydro plants in Brazil, were sold during 4Q18. Note also that by Dec-18, financial investments include: i) €357m at EDPR level, corresponding to equity stakes in 356MW wind farms in US and Spain, and 33% and 29.5% stakes in offshore projects in UK and France, respectively; ii) €456m at EDP Brasil level (mainly related to 23.6% stake in Celesc, 50% stake in Jari, 50% stake in Cachoeira Caldeirão and 33% stake in São Manoel); and iii) €264m at EDP level, including a 50% equity stake in EDP Asia (the owner of a 21% stake in CEM) and other.

Tax assets net of liabilities, deferred and current remained flat vs. Dec-17 at €0.3bn in Dec-18. **Other assets (net)** decreased €0.1bn vs. Dec-17 to €6.9bn as of Dec-18, supported essentially by the €0.6bn reduction in regulatory receivables, which was mostly mitigated by the impact of changes to IFRIC 12 - Concessions through the adoption of IFRS 15 regarding under construction concession assets. Note that other assets (net) includes €0.16bn in cash yet to collect from the disposal of Naturgas Distribución.

Total amount of EDP's **net regulatory receivables** was €0.6bn lower vs. Dec-17, at €287m as of Dec-18 (**€219m net of tax**), due to the combined effect of the sale of €1.3bn of regulatory receivables in Portugal and the annual increase of deficit reflected in EDP's accounts. Worth noting that the total Portuguese system debt has decreased significantly in 2018 by €0.8bn to €3.8bn, on the back of demand growth (+2.9% YoY in the 2018) and past regulatory cuts in Portugal.

Equity book value attributable to EDP shareholders decreased by €0.6bn to €9.0bn as of Dec-18, reflecting the net profit for the period (€0.5bn) which was more than offset by the annual payment of dividends (€0.7bn), by the €0.1bn impact of IFRS 9 and IFRS 15 adoption and by the impact of exchange differences arising on consolidation, following the depreciation of BRL against EUR.

Non-controlling interest (details on page 28) were stable vs. Dec-17, at €3.9bn as of Dec-18, as the results attributable to minority stakes in the period were offset by the YTD depreciation of BRL against the EUR.

Pension fund, medical care and other employee benefit liabilities fell by €0.1bn vs. Dec-17 to €1.4bn as of Dec-18 (**€1.0bn, net of tax**), reflecting the recurrent payment of pension and medical care expenses in 2018, as well as a one-off €0.1bn contribution to the pension fund.

Institutional partnership liabilities increased 2% YoY, following the benefits appropriated by the tax equity partners during the period, new tax structure and forex impact.

Provisions by Dec-18 amounted to €1.0bn (+€266M vs Dec-17), mainly explained by the recognition of a provision of €285m related with CMEC and the payment of 2017 and 2018 CESE.

Other liabilities (net) increased €0.6bn YoY, mainly supported by the working capital related with wind farms construction activity.

(1) Tariff deviations to be recovered/(returned) through tariffs in the following years by electricity distribution and last resort supply and gas in Portugal.

Net Financial Debt



Net Financial Debt (€ m)	Dec-18	Dec-17	Δ %	Δ Abs.
Nominal Financial Debt	15,766	16,575	-5%	-809
EDP S.A. and EDP Finance BV	13,228	14,079	-6%	-851
EDP Renováveis	882	992	-11%	-110
EDP Brasil	1,656	1,504	10%	152
Accrued Interest on Debt	258	261	-1%	-3
Fair Value of Hedged Debt	61	81	-25%	-21
Derivatives associated with Debt (2)	(116)	(141)	18%	26
Collateral deposits associated with Debt	(193)	(45)	-326%	-148
Hybrid adjustment (50% equity content)	(391)	(391)	0%	0
Total Financial Debt	15,385	16,340	-6%	-955
Cash and cash equivalents	1,803	2,400	-25%	-597
EDP S.A., EDP Finance BV and Other	922	1,608	-43%	-687
EDP Renováveis	386	388	-1%	-2
EDP Brasil	496	404	23%	92
Financial assets at fair value through P&L	102	38	172%	64

EDP Consolidated Net Debt	13,480	13,902	-3%	-422
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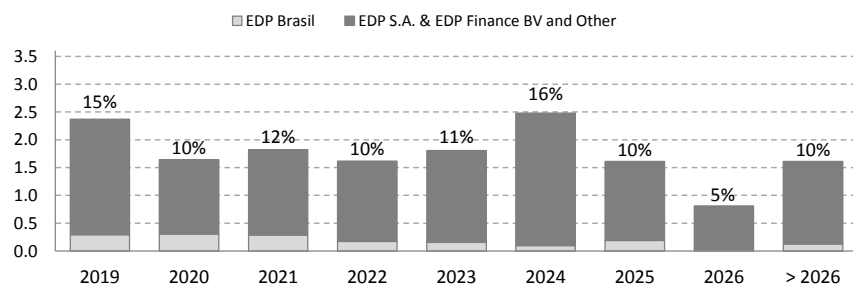
Credit Lines by Sep-18 (€m)	Maximum Amount	Number of Counterparts	Available Amount	Maturity
Revolving Credit Facilities	75	1	75	Jul-19
Revolving Credit Facility	3,300	24	3,300	Oct-23
Revolving Credit Facility	2,240	17	2,010	Mar-23
Domestic Credit Lines	226	7	226	Renewable
Underwritten CP Programmes	50	1	50	2021
Total Credit Lines	5,891		5,661	

Credit Ratings	S&P	Moody's	Fitch
EDP SA & EDP Finance BV	BBB-/Stable/A-3	Baa3/Stable/P3	BBB-/Stab/F3
Last Rating Action	08-08-2017	03-04-2017	05-12-2018

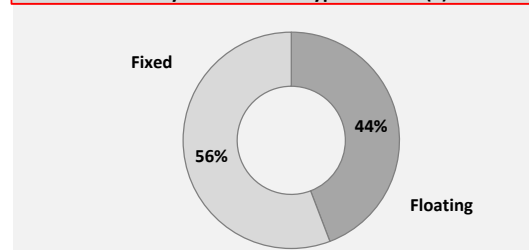
Key ratio	Dec-18 (3)	Dec-17
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Net Debt / EBITDA adjust. for Reg. Receivables (x) (3)	4.0x	3.9x
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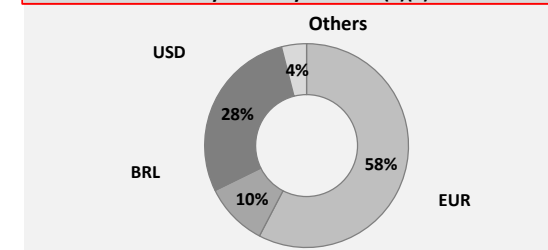
Debt Maturity (€ m) by Dec-18 (1)



Debt by Interest Rate Type - Dec-18 (1)



Debt by Currency - Dec-18 (1)(2)



EDP's financial debt is essentially issued at holding level (EDP S.A. and EDP Finance B.V.) through both debt capital markets and bank loans. Maintaining access to diversified sources of funding and assuring refinancing needs at least 12-24 months ahead continue to be part of the company's funding strategy.

In Dec-18, **Fitch** affirmed EDP's credit rating at "BBB-", with Stable outlook. In Aug-17, **S&P** upgraded EDP's credit rating to "BBB-" with Stable outlook. In Apr-17, **Moody's** affirmed EDP's credit rating at "Baa3" with Stable outlook.

Looking at 2018's major debt repayments and refinancing deals: in Feb-18 EDP repaid USD531m of a USD1,000m bond with a 6% coupon, of which USD469m had been bought back in Dec-16. In Mar-18, EDP signed a 5-year revolving credit facility (with options to extend for 2 additional years, subject to bank's approval) in the amount of €2.24bn, which can be drawn in either EUR or USD, replacing a €2.00bn facility that was maturing in Feb-20. In Jun-18, EDP issued a €750m bond with a yield of 1.67%, maturing in Jan-26. In Sep-18 EDP exercised the option (and obtained bank's approval) to extend the maturity of the €3.3bn RCF for 1 year to Oct-23. In Oct-18, EDP made its first ever "Green Bond" issuance of €0.6bn with a 7-year maturity and a yield of 1.959%. Also, in Oct-18, EDP issued R\$1.2bn, at a transmission line project level, with a coupon of IPCA + 6.72% maturing in Oct-28. EDP's long dated bond issues are in line with the Group's financial policy of extending the average term of its debt portfolio and reinforcing its financial flexibility.

In 4Q18, EDP bought-back €500m of several bonds and sold significant tariff deficit, which contributed to a decrease of the share of EUR in Debt.

The weight of consolidated financial debt through capital markets stood at 81%, while the remaining debt was raised mainly through bank loans. **Refinancing needs in 2019** amount to €2.4bn, consisting in €1.4bn in bonds and €1.0bn in bank loans. **In 2020 and 2021**, refinancing needs amount to approx. €3.5bn. Total cash and available liquidity facilities amounted to €7.6bn by Dec-18. This liquidity position allows EDP to cover its refinancing needs beyond 2020.

In Jan-19, EDP extended €2,095m out of the €2,240m Revolving Credit Facility maturity until Mar-24 and issued €1.000m of subordinated green notes with a yield of 4.5%.

(1) Nominal Value includ. 100% of the hybrid bond; (2) Derivatives designated for fair-value hedge of debt; (3) Based on trailing 12 months recurring EBITDA and net debt exclud. 50% of hybrid bond issue (includ. interest).



Business Areas

Iberian Electricity and Gas Markets

Electricity Balance (TWh)	Portugal			Spain			Iberian Peninsula		
	2018	2017	Δ%	2018	2017	Δ%	2018	2017	Δ%
Hydro	12.3	6.4	91%	36.1	20.6	76%	48.4	27.0	79%
Nuclear	-	-	-	53.2	55.6	-4%	53.2	55.6	-4%
Coal	11.1	13.6	-18%	34.9	42.6	-18%	46.0	56.2	-18%
CCGT	10.1	13.5	-25%	26.4	33.9	-22%	36.5	47.4	-23%
(-)Pumping	(1.6)	(2.2)	-29%	(3.2)	(3.7)	-13%	(4.8)	(5.9)	-19%
Conventional Regime	31.9	31.3	2%	147.4	149.0	-1%	179.3	180.3	-1%
Wind	12.4	12.0	3%	48.9	47.5	3%	61.3	59.5	3%
Other	9.3	9.0	3%	47.3	48.3	-2%	56.6	57.3	-1%
Special Regime	21.6	21.0	3%	96.2	95.8	1%	117.9	116.8	1%
Import/(export) net	(2.7)	(2.7)	-1%	9.9	8.0	24%	7.2	5.3	36%
Gross demand (before grid losses)	50.9	49.6	2.6%	253.5	252.8	0.3%	304.4	302.4	0.7%
Adjust. temperature, working days			1.7%			0.3%			n.a.

Gas Demand (TWh)	Portugal			Spain			Iberian Peninsula		
	2018	2017	Δ%	2018	2017	Δ%	2018	2017	Δ%
Conventional demand	44.1	42.1	5%	287.5	275.1	5%	331.6	317.2	5%
Demand for electricity generation	20.8	27.6	-25%	61.8	75.7	-18%	82.6	103.3	-20%
Total Demand	64.9	69.7	-7%	349.3	350.8	0%	414.3	420.5	-1%

Electricity demand in Iberia grew 0.7% in 2018, following a 1.1 % YoY decline in 4Q18 (vs. +0.8% in 3Q18). In Spain (83% of Iberia), demand adjusted for temperature and working days was up 0.3% YoY. In Portugal (17% of total), demand adjusted for temperature and working days increased 1.7% YoY (total demand up by 2.6%), driven by both the residential and business segments.

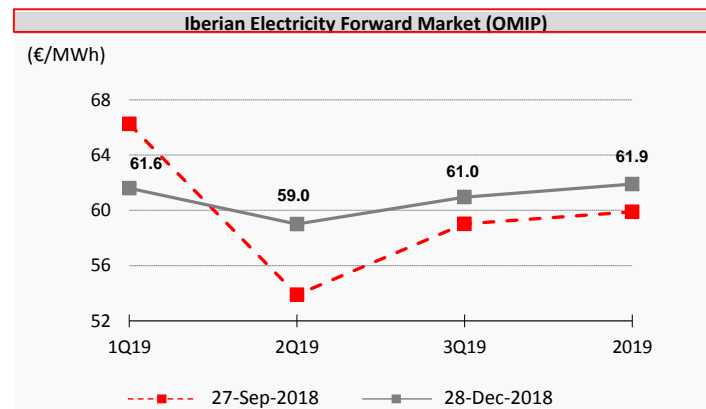
Installed capacity in Iberia decreased by 0.3 GW to 118.1 GW as of Dec-18, mainly reflecting a reduction in CCGT installed capacity.

Residual thermal demand (RTD) declined 20% YoY in 2018 (-21 TWh), mostly supported by a strong rebound of hydro resources in Iberia since Mar-18 (5% and 30% above the average year in Portugal and Spain in 2018, respectively, vs. c.50% below average year in 2017). Even so, an extremely dry 4Q in Portugal (hydro resources 33% below historical average) drove reservoirs levels below avg. historical levels as of Dec-18. All in all, hydro output (net of pumping) posted an YoY increase of 22 TWh. Wind output increased 1.8 TWh YoY backed by outstanding wind resources in 1Q18, and net imports increased 1.9 TWh YoY, fully driven by Spain. In turn, nuclear output fell 2.4 TWh, reflecting some nuclear outages, particularly in 2Q18. As a result, coal output decreased 18% YoY (-10 TWh) and CCGT output fell 23% YoY (-11 TWh). Overall, higher demand in Iberia (+2 TWh YoY) was tackled by higher production from renewables and net imports, leading to lower avg. load factors at both coal (-9p.p. YoY to 48%) and CCGTs (-4p.p. YoY to 14%), respectively.

Average electricity spot price rose 10% YoY, to c.€57/MWh in 2018 (+8% YoY in 4Q18), fuelled by the rise in commodities prices in the European markets. **Average CO₂ prices** soared 172% YoY, to €15.9/ton in 2018. The **average electricity final price** in Spain rose by 7%, to €63/MWh. The difference between final electricity price and pool price derives from the contribution from profiling, restriction market, ancillary services and capacity payments.

In the Iberian gas market, consumption was slightly lower, reflecting the mixed impact from: (i) 5% YoY increase in conventional gas demand (80% of total gas consumption in Iberia), mostly driven by the cold snap in the beginning of the year; and (ii) 20% YoY decline in gas consumption for electricity generation, due to a lower thermal gap.

Installed Capacity in Electricity (GW)	Iberian Peninsula		
	2018	2017	Δ%
Hydro	24.4	24.4	0%
Nuclear	7.0	7.0	-
Coal	11.3	11.3	0%
CCGT	28.4	28.8	-1%
Conventional Regime	71.0	71.4	-1%
Wind	28.1	28.1	0%
Other special regime	19.0	18.8	1%
Special Regime	47.0	47.0	0%
Total	118.1	118.4	-0.2%



Main Drivers (1)	2018	2017	Δ%
Hydro coefficient (1.0 = avg. year)			
Portugal	1.05	0.47	123%
Spain	1.30	0.50	160%
Wind coefficient (1.0 = avg. year)			
Portugal	1.00	0.97	3%
Electricity spot price, €/MWh			
Portugal	57	52	9%
Spain	57	52	10%
Electricity final price, €/MWh (2)			
Spain	63	59	7%
CO ₂ allowances (EUA), €/ton	15.9	5.8	172%
Coal (API2 CIF ARA), USD/tonne	92	84	9%
Mibgas, €/MWh	24	21	16%
Gas NBP, €/MWh	23	17	32%
Brent, USD/bbl	71	54	31%
EUR/USD	1.18	1.13	-4%

Generation & Supply in Iberia



Income Statement (€ m)	2018	2017	Δ%	Δ Abs.
Gross Profit	1,434	1,236	16%	+199
OPEX (1)	450	471	-5%	-21
Other operating costs (net)	222	210	6%	+12
Net Operating costs	672	681	-1%	-9
EBITDA	762	555	37%	+208
Amortisation, impairment and Provisions	696	583	19%	+113
EBIT	67	(28)	-	+95

On 3-May-18, it has come to EDP's knowledge, through a DGEG's letter of Apr-18, that the ERSE's amount of €154m for the final adjustment of CMEC had been officially approved. Although EDP considers that the administrative act contained in the Order of approval of the Secretary of State for Energy (SSE) lacks technical, economic and legal basis, a provision corresponding to the difference of the amounts already recognised in revenues was booked, with an impact on EBITDA of -€30m, of which -€18m relative to 2H17 (one-off).

Excluding the one-off impacts, **recurring EBITDA rose 40% YoY, to €796m in 2018**, propelled by hydro's higher output and contribution to the production mix (39% share in total production in 2018 vs. 22% in 2017) and higher selling prices, which more than compensated the adverse impact from weak energy management results, due to the hedge position closed in 2017. One-off impacts include CMEC adjustment (€18m in 2018) and restructuring costs (€15m in 2018 vs. €13m in 2017).

Gross Profit breakdown (€ m)	2018	2017	Δ%	Δ Abs.
Electricity Sources & Uses	1,247	956	30%	+290
Total Volume (TWh) - Details below	70.3	70.6	-0%	-0
Unit margin (€/MWh)	17.7	13.5	31%	+4
Before hedging (€/MWh) - Details below	18.9	12.8	47%	+6
From Hedging (€/MWh) (2)	(1.1)	0.7	-	-2
Other	187	279	-33%	-92
Electricity generation (Detail page 12), Energy supply	178	275	-35%	-97
Gas trading, other and adjustments	9	5	98%	+5
Total	1,434	1,236	16%	+199

Gross profit excluding CMEC one-off impact rose by 18% YoY, to €1,453m in 2018, mainly driven by higher avg. unit margin (up from €14/MWh in 2017 to €18/MWh in 2018):

Volumes: Total volume sold was broadly flat YoY, at 70 TWh in 2018, reflecting the mixed impact from an 8% fall in sales to customers, mainly prompted by business customers; and 2% rise in sales in the wholesale market, driven by higher production. Generation output was 2% higher YoY, reflecting an increase in hydro production; electricity purchases were 2% lower YoY.

Unit margin ⁽²⁾⁽³⁾: Avg. electricity spread before hedging rose from €12/MWh in 2017, to €19/MWh in 2018, mainly reflecting a cheaper generation mix. **Avg. sourcing cost** declined 5% YoY, to €44/MWh in 2018, mainly supported by a higher contribution from hydro production in the generation mix. **Avg. selling price** rose 6% YoY in 2018, almost in line with the increase in the electricity market final price.

Net operating costs amounted to €672m in 2018 (-1% YoY). Cost related to tax and levies fell by €32m YoY (€36m decrease in Spain, €4m YoY increase in Portugal), as a result of 2H17's increase in clawback in Portugal; and from Oct-18 the suspension of generation taxes and tax on gas in Spain and clawback in Portugal.

Electricity Sources & Uses	2018	2017	Δ%	2018	2017	Δ%
	Output (GWh)			Variable Cost (€/MWh) (3)		
Own production (4)	33,849	33,293	2%	29	33	-14%
Purchases	36,492	37,345	-2%	59	59	1%
Electricity Sources	70,341	70,638	-0%	44	47	-5%
	Volumes Sold (GWh)			Average Price (€/MWh) (5)		
Grid Losses	4,355	2,269	92%	n.a.	n.a.	-
Final customers	32,137	35,076	-8%	69	62	13%
Wholesale market	33,849	33,293	2%	65	61	7%
Electricity Uses	70,341	70,638	-0%	63	59	6%

On 26-Sep-18, DGEG notified EDP about a dispatch issued by the Secretary of State for Energy (SSE) on 29-Aug-2018 on the financial impact of the "innovative features" of the PPA Cessation Agreements, which quantified at €285 million the alleged overcompensation of EDP related to the calculation of the real availability factor of the plants under the CMEC regime. Additionally, the dispatch from SSE also mentioned that the possible charging of a maximum amount of €72.9 million for alleged overcompensation of plants under CMEC regime operating on ancillary services market is still under analysis. Considering that the dispatch lacks legal, economic technical basis, EDP presented in Oct-18 a complaint with the SSE, but with no follow up on the issue so far. As a result, EDP has taken legal action in Feb-19 as to protect its rights and interests. Even though EDP considers that there were no innovative features weighted in the annual adjustments or the final adjustment of the CMEC, this aspect was reflected in 3Q18 through a provision of €285m. As a result, **amortisation, impairment and provisions** increased by 19% YoY, to €696m in 2018, partly offset by higher impairments' recognition in 2017 (€196m from Sines and Soto 3) vs. 2018 (€24m from Sines and Soto 3).

In 2018, total gas consumed/sold declined by 4% YoY, driven by a 18% YoY decrease in gas consumption at our CCGT plants (-2.5 TWh) and 7% YoY decline in sales to final customers (-0.9 TWh). In turn, sales in wholesale market increased 17% YoY (+1.7 TWh).

EDP is adapting its hedging strategy to the current market conditions. As a result, for 2019, EDP has so far forward contracted with clients electricity sales of ~28 TWh, at an avg. price of c.€58/MWh (excluding naturally-hedged price-indexed volumes), and has already secured avg. thermal spread at a high single digit per MWh for around 90% of expected thermal production.

Gas Uses (TWh)	2018	2017	Δ%	Δ Abs.
Consumed at EDP power plants	11.7	14.2	-18%	-2.5
Sold in wholesale markets	12.0	10.3	17%	+1.7
Sold to Final customers	10.6	12.1	-13%	-1.5
Total	34.3	36.6	-6%	-2.3

(1) OPEX = Supplies and services + Personnel costs + Costs with social benefits; (2) Includes results from hedging on electricity; (3) Variable cost: fuel and CO2 cost, hedging costs (gains), system costs;

(4) Excludes production at mini-hydro, cogeneration and waste plants; (5) Average selling price: includes selling price (net of TPA tariff), ancillary services and others.

Electricity Generation in Iberia



Income Statement (€ m)	2018	2017	Δ%	Δ Abs.
Gross Profit	1,153	931	24%	+222
OPEX (1)	241	252	-4%	-11
Other operating costs (net)	154	166	-7%	-12
Net Operating costs	396	419	-5%	-23
EBITDA	757	512	48%	+245
Amortisation, impairment; Provision	656	576	14%	+81
EBIT	101	(63)	-	+164

Our liberalised generation & supply activities are jointly managed as most of our production is sold to our supply units at fixed prices. The current section refers only to electricity generation operations.

The **overall generation portfolio in Iberia** (excluding wind and solar) encompasses a total of 13.5 GW, of which 53% in hydro capacity, 28% in CCGT, 18% in coal (86% with DeNOx), 1% of cogeneration and waste; and 1% in nuclear. **Production** in 2018 increased 2% YoY (+0.8 TWh), to 34.6 TWh, reflecting a sharp rebound of hydro resources to normalized levels in 2018, which enabled a 6.1 TWh YoY increase in hydro output. This increase in hydro output was, however, partially offset by a lower production at our coal (-2.8 TWh) and CCGT (-2.7 TWh) plants.

Avg. production cost fell 14% YoY, to €29/MWh in 2018, driven by hydro's higher contribution to the production mix (39% of total output in 2018 vs. 22% in 2017). **Avg. production cost at our coal plants** increased 22% YoY, fuelled by a higher coal and CO₂ prices. **Avg. production cost at CCGTs** logged an 11% YoY increase, due to a higher cost of gas.

Key Operating Data	2018	2017	Δ%	Δ Abs.
Generation Output (GWh)	34,555	33,778	2%	+777
Hydro	13,305	7,182	85%	+6,123
CCGT	5,333	8,029	-34%	-2,696
Coal	14,016	16,847	-17%	-2,831
Nuclear	1,196	1,236	-3%	-40
Mini-hydro, Cogener. & Waste	706	485	46%	+221
Hydro pumping volume (GWh)	2,438	2,228	9%	+211
Generation Costs (€/MWh) (2)	29	33	-14%	-5
Hydro	7	19	-61%	-12
CCGT	59	53	11%	+6
Coal	39	32	22%	+7
Nuclear	5	5	4%	+0
Load Factors (%)				
Hydro	21%	12%	-	10p.p.
CCGT	16%	25%	-	-8p.p.
Coal	67%	80%	-	-13p.p.
Nuclear	88%	91%	-	0p.p.
Employees (#)	1,482	1,601	-7%	-119
Capex (€m)	142	172	-18%	-30
Expansion	35	71	-51%	-36
Maintenance	107	101	6%	+6

Gross profit from generation in Iberia rose 24%, to €1,153m in 2018, benefitting from a lower avg. production cost and higher gross profit from mini-hydro, cogeneration and waste plants (+39% YoY), on the back of the strong recovery in hydro output which more than compensated the impacts from: (i) the €18m one-off provision from CMEC; (ii) 23% YoY decrease in capacity payments following the interruption in Spain, by Jul-18; and (iii) weak energy management results, due to the hedge position closed in 2017. Also note that the annual deviation from PPA/CMEC gross profit vs CMEC reference, totalling €108m in 2017, ceased to be in force since Jun-17 (€5m booked in 2018 reflects prior years adjustments).

Net operating costs decreased by 5% YoY, to €396m in 2018, due to tight cost control. **Regulatory costs** decreased 8% YoY, to €218m in 2018, impacted by: (i) at gross profit level, a €13m YoY increase in social tariff and coal levy in Portugal; (ii) at 'Other operating costs' level, a €32m YoY decrease due to lower generation taxes in Spain, only partly offset by higher clawback in Portugal.

It is noteworthy that, in Spain, RDL 15/2018 of 5-Oct-18 approved a 6-month suspension of the 7% tax on generation with effect from 1-Oct-2018, and has put an end to the green cent tax on gas for electricity generation purposes. RDL 15/2018 was definitively approved by Parliament in 18-Oct-18. Accordingly, in order to harmonize the regulatory mechanisms in the Iberian electricity market, the Portuguese regulator suspended the clawback mechanism with effect from Oct-18.

In respect to capacity payments in Spain, availability payments have been definitely abolished in Dec-18. In Portugal, the Government decided to suspend the auction for the attribution of capacity payment in 2018 (Dispatch 93/2018) in Apr-18, until the EC formally pronounces on the fit of the auction rules with EC framework. Note that the EC has already approved capacity mechanism in 6 European countries. Moreover, note that the current rules have been set in Mar-17 and the auction for capacity payments in 2018 (Ministerial order nr. 2275-A/2017) was initially scheduled for May-17, revenues from capacity payments amounted to €5m in 2017.

Capex decreased by 18% YoY, to €142m in 2018. Note that the €35m of expansion capex in 2018 is mostly related to final works in Foz-Tua hydro plant surrounding area (vs. €71m in 2017 allocated to Venda Nova III and Foz-Tua).

Other financial details (€ m)	2018	2017	Δ%	Δ Abs.
At Gross profit level:				
Capacity payments & Other	41	54	-23%	-13
Mini-hydro, cogeneration & waste	54	39	39%	+15
CMEC annual deviation	5	108	-95%	-103
At EBITDA level:				
Regulatory costs (3)	218	237	-8%	-19

(1) OPEX = Supplies and services + Personnel costs + Costs with social benefits; (2) Includes fuel costs, CO₂ emission costs, hedging results;

(3) Includes: (i) at gross profit, social tariff in Portugal; (ii) at the level of operating costs, generation taxes in Spain (incl. fuel, nuclear waste, hydro resources), clawback in Portugal.

Electricity and Gas Supply in Portugal and Spain



Income Statement (€ m)	2018	2017	Δ%	Δ Abs.
Gross Profit	273	304	-10%	-30
OPEX (1)	214	227	-5%	-12
Other operat. costs (net)	64	39	63%	+25
Net Operating costs	278	266	5%	+12
EBITDA	(5)	38	-	-43
Amortisation, impairment; Provisions	39	7	433%	+32
EBIT	(44)	30	-	-74

Our electricity and gas supply activities in Portugal and Spain are managed by integrated platforms, ensuring a responsive and competitive commercial structure. EDP Group's subsidiaries that operate in this business segment have intra-group electricity and gas procurement contracts with our generation and energy trading divisions. The current section refers only to energy supply, but excludes gas trading and sourcing activities.

As of Dec-18, **EDP's electricity portfolio in Iberia** remained relatively stable YoY, totaling 5.3m customers, strongly biased towards residential and SME customers (c.43% of total consumption). In Portugal, according to the most recent data released by ERSE, 94% of total electricity consumption was in the liberalized market as of Dec-18. Note that, following the publication of DL 105/2017, electricity customers in Portugal are, since 1-Jan-18, allowed to return to the regulated market until the end of 2020.

Key data	2018	2017	Δ%	Δ Abs
Portfolio of Customers (th.)				
Electricity	5,273	5,287	0%	-14
Portugal	4,119	4,153	-1%	-35
Spain	1,154	1,133	2%	+20
Gas	1,555	1,541	1%	+14
Portugal	659	658	0%	+2
Spain	895	883	1%	+12
Dual fuel penetration rate (%)	30%	30%	1%	+0
Other Services				
Services to contracts ratio (%)	18%	17%	6%	0p.p.
Volume of electricity sold (GWh)	30,669	32,249	-5%	-1,580
Residential	13,216	12,869	3%	+347
Business	17,452	19,380	-10%	-1,928
Volume of gas sold (GWh)	11,256	12,119	-7%	-862
Residential	6,070	6,031	1%	+39
Business	5,186	6,088	-15%	-901
Electronic invoicing (%)	34%	30%	13%	4p.p.
Complaints per 1000 contracts (#)	31	26	19%	+5
Employees (#)	694	538	29%	+156
OPEX per customer (2) (€)	31	33	-5%	-2
EBITDA per customer (2) (€)	-1	6	-	-6
Capex (€m)	26	24	10%	+2

EDP targets to leverage on its portfolio of customers, offering additional products and innovative services, as part of its strategy to build a longer-term relationship with customers backed by the enhancement of customer's satisfaction and loyalty levels. The rate of dual fuel offer is currently at 30%, including different stages of evolution in Spain and Portugal: in Portugal, dual offer rate corresponds to 16% in Dec-18; in Spain, dual offer rate, is currently at 79%. As a result of this strategy, EDP's gas portfolio in Iberia increased 1% YoY, to 1.6m customers in Dec-18. The penetration rate of service contracts in Iberia increased from 17% in Dec-17 to 18% in Dec-18.

Electricity volumes sold in Iberia fell 5% YoY, to 31 TWh in 2018, reflecting the mixed impact from: (i) a 3% YoY increase in the residential segment; and (ii) a 10% YoY decrease in the business segment, reflecting more selective commercial criteria.

Gross profit at our supply activities in Iberia declined by 10% YoY, to €273m in 2018, penalised by higher sourcing costs, adverse regulatory changes in Portugal and prior year adjustments.

Net operating costs increased by 5% YoY, to €278m in 2018, impacted by the adoption of IFRS 9, related with the estimates of clients' impairments (€14m). **Amortisation** increased due to the accounting of the costs associated with the acquisition of new clients as D&A, following the adoption of the IFRS 15 methodology.

EDP is building the ground for a decrease in cost per customer through higher digitalisation rate and higher customer satisfaction: electronic invoicing (per avg. residential client) represents a 34% rate as of Dec-18, a 4pp increase vs. Dec-17.

(1) OPEX = Supplies and services + Personnel costs + Costs with social benefits; (2) Based on the number of contracts.

EDP Renováveis: Financial Performance



Income Statement	EDP Renováveis (€ m)			
	2018	2017	Δ %	Δ Abs.
Gross Profit	1,512	1,602	-6%	-90
OPEX (1)	460	428	8%	+33
Other operating costs (net)	(249)	(192)	29%	-56
Net Operating Costs	212	235	-10%	-24
EBITDA	1,300	1,366	-5%	-66
Amortisation, impair.; Provision	546	563	-3%	-17
EBIT	754	803	-6%	-49
Financial Results	(220)	(302)	-27%	+82
Share of Profit from associates	2	3	-39%	-1
Pre-tax profit	536	504	6%	+31
Capex (€m) (2)	1,275	1,051	21%	+224
Europe (3)	354	151	134%	+203
North America	757	708	7%	+49
Brazil	164	192	-15%	-28

Operational Overview	2018	2017	Δ %	Δ Abs.
Installed Capacity (MW)	11,301	10,676	6%	+625
Europe	5,272	5,061	4%	+211
North America	5,562	5,284	5%	+278
Brazil	467	331	41%	+137
Output (GWh)	28,359	27,621	3%	+738
Avg. Load Factor (%)	30%	31%	-3%	-1p.p.
Avg. Elect. Price (€/MWh)	53.7	59.2	-9%	-5
Employees (#)	1,388	1,220	14%	+168
Core Opex/Avg. MW (€ th) (4)	42.8	42.1	2%	+1
EBITDA (€m)	1,300	1,366	-5%	-66
Europe (3)	653	729	-10%	-76
North America	634	599	6%	+36
Brazil	33	56	-42%	-24
Other & Adjustments	(20)	(17)	16%	-3
EBIT (€m)	754	803	-6%	-49
Europe (3)	399	437	-9%	-38
North America	361	340	6%	+21
Brazil	19	46	-59%	-27
Other & Adjustments	(26)	(20)	31%	-6

EDPR Equity Market Data	2018	2017	Δ %	Δ Abs.
Share price at end of period (€/share)	7.78	6.97	12%	0.8
Number of Shares Issued (million)	872.3	872.3	-	-
Stake Owned by EDP (%)	82.6%	82.6%	-	-

EDPR Key Balance Sheet Figures (€ m)	2018	2017	Δ %	Δ Abs.
Financial investm, assets held for sale	357	312	14%	+45
Net Financial Debt	3,060	2,806	9%	+254
Bank Loans and Other (Net)	291	537	-46%	-246
Loans with EDP Group (Net)	2,769	2,269	22%	+500
Non-controlling interests	1,613	1,560	3%	+53
Net Institutional Partnership Liability (5)	1,269	1,249	2%	+20
Equity Book Value	6,509	6,335	3%	+174
EUR/USD - End of Period Rate	1.15	1.20	5%	-0.05

Financial Results (€ m)	2018	2017	Δ %	Δ Abs.
Net financial Interests	(139)	(139)	0%	+0
Institutional Partnership costs	(81)	(89)	9%	+8
Capitalised Costs	24	16	46%	+7
Forex Differences	(2)	(3)	40%	+1
Other	(22)	(87)	75%	+65
Financial results	(220)	(302)	27%	+82

EDP, through EDP Renováveis (EDPR, 82.6% owned by EDP) owns, operates and develops **wind and solar capacity**. As of **Dec-18**, **EDP has a portfolio of 11,301 MW** (of which 145 MW solar) and holds **equity stakes in further 371 MW**. During 2018, we built out 826 MW (mainly in US, Brazil, Italy) fully long term contracted, and executed our **first sell down transaction** (sale of 80% stake in 499 MW, 200 MW commissioned in 2018). As a result we added 40 MW to our equity portfolio in operation, retaining O&M operations of the whole capacity.

Wind & solar EBITDA decreased by 5% YoY (-€66m) to €1,300m in 2018, penalised by: i) adverse forex impact (-€35m) due to USD and BRL depreciation; ii) weak wind resources (-6% below the historical average in 2018; -12% in 4Q18), translated into an avg. load factor of 30% (-1pp YoY); iii) lower avg. selling price (-7% YoY ex-forex), following lower revenues from green certificates (Romania and Poland) and the mix effect from new MWs (mainly in US, Brazil); and iv) expiration of the 10-year period PTCs in some wind farms (-€51m). These impacts outstood the effect from 6% increase in avg. capacity and gain booked on the first sell down, corresponding to the upfront monetisation of value accretion of 499 MW built to sell and operate.

Opex rose by 8% YoY to €460m in 2018, on the back of the new capacity installed, higher headcount and offshore costs crossed charged to projects' SPVs. Core Opex per avg. MW in operation was €43K, +2% YoY. **Other operating costs (net), amounting to €249m net revenue (+€56m YoY)**, include: i) **in 2017**, +€29m gain on the sell down (with loss of control) of a stake in UK offshore project Moray East; ii) **in 2018**, €109m gain subsequent to the aforementioned sale of a majority stake in wind farms, along lower generation taxes in Spain.

EBIT decreased by 6% YoY, to €754m in 2018, following EBITDA performance, and lower depreciation charges YoY following lower impairments (€7m in 2018 vs. €50m in 2017) and forex impact.

Expansion activity resulted into €0.5bn net expenditure in 2018, mainly reflecting i) €1.1bn net investments devoted to capacity built out (+826 MW) and under construction in Dec-18 (344 MW), ii) proceeds from new tax equity financing structures (€0.4bn) and other. In Dec-18, we executed its first sell down on wind onshore, selling a 80% stake in some US/Canada wind farms. Along with the stake sales in wind offshore during the year, this transaction provided proceeds of €0.4bn in the period.

EDPR's net debt amounted to €3.1bn in 2018 (vs. €2.8bn in Dec-17), driven by recurring organic cash flow (€0.6bn), net investments, dividend payment and Forex impact.

Liabilities with Institutional partnerships (net) amounted to €1,269m (+2% YoY), reflecting the tax benefits retained by institutional investors (€140m), the establishment of new tax equity financing structures (€399m) and forex impact.

Financial results (net) amounted to -€220m in 2018 (+27% YoY), following stable Net interest costs, lower financial cost related to institutional partnerships costs (-9% YoY) and gain on the sale of non-controlling stakes in France and UK offshore projects (+€87m, at the level of Other financial results).

(1) OPEX = Supplies and services + Personnel costs + Costs with social benefits; (2) Net of government grants; (3) Includes Holding costs and adjustments at the level of EDPR Europe; (4) Core Opex defined by Supplies and services (including O&M activities) and Personnel costs; (5) Net of deferred revenue.

EDP Renováveis: North America & Brazil



North America	2018	2017	Δ %	Δ Abs.
EUR/USD - Avg. of period rate	1.18	1.13	-4%	0.05
Installed capacity (MW)	5,562	5,284	5%	+278
PPA's/Hedged/Feed-in tariff	4,768	4,600	4%	+168
Merchant	793	684	16%	+109
Avg. Load Factor (%)	34%	35%	-3%	-1 p.p.
Electricity Output (GWh)	15,644	15,091	4%	+553
US	14,873	14,410	3%	+463
Canada	71	75	-5%	-3
Mexico	700	606	15%	+93
Avg. Selling Price (USD/MWh)	45.3	46.4	-2%	-1.1
US	44.1	45.5	-3%	-1.5
Canada	112.8	112.1	1%	+1
Mexico	64.4	59.5	8%	-
Adjusted Gross Profit (USD m)	901	930	-3%	-29
Gross Profit (USD m)	682	676	1%	+7
PTC Revenues & Other (USD m)	219	255	-14%	-36
EBITDA (USD m)	749	676	11%	+73
EBIT (USD m)	427	384	11%	+43
Installed capacity (MW Equity)	219	179	22%	+40
Capex (1) (USD m)	894	799	12%	+94
Capacity under construction (MW)	199	480	-58%	-281

Brazil	2018	2017	Δ %	Δ Abs.
Euro/Real - Average of period rate	4.31	3.60	-16%	+0.70
Installed Capacity (MW)	467	331	41%	+137
Avg. Load Factor (%)	40%	43%	-7%	-3 p.p.
Electricity Output (GWh)	1,235	861	43%	+374
Avg. Final Selling Price (R\$/MWh)	195	289	-32%	-93
Gross Profit (R\$ m)	215	226	-5%	-11
EBITDA (R\$ m)	140	203	-31%	-63
EBIT (R\$ m)	82	166	-51%	-84
Capex (R\$ m)	706	693	2%	+13
Capacity under construction (MW)	-	137	-	-137

In North America (NA), installed capacity totalled 5,562 MW in Dec-18 (90 MW solar PV in US and the rest wind onshore: 5,242 MW in the US, 200 MW in Mexico, 30 MW in Canada). As of Dec-18, 86% total installed capacity is long term contracted (PPA/Hedged). Additionally, EDPR owns equity stakes in other wind projects, equivalent to 219 MW (+40 MW YoY).

During 2018, EDP group **built out 478 MW, all in the US and long term contracted**. The bulk of new capacity additions was concentrated in wind onshore, while solar capacity accounted for 60 MW additions. As part of **EDP asset rotation strategy**, the **first asset rotation of majority stake transaction** was announced in Dec-18, encompassing: **i)** As per capacity in operation, the sale of an 80% stake in Meadow Lake VI (already in operation and equivalent to 160 MW), retaining a 20% equity stake (40 MW); **ii)** As per future capacity additions, the sale of a controlling stake in 299 MW to be installed in 2019, of which 199 MW was already under construction by Dec-18. The asset rotation strategy, allowing capital recycling, enhances upfront value crystallization, reflected in a USD 129m contribution in 2018.

Electricity production in 2018 advanced by 4%, as 5% increase in installed capacity was hampered by wind and solar resources: 7% short historical average in 2018, following 15% shorter than LT average resources in 4Q18. **Average selling price** fell by 2%, to USD45/MWh, prompted by lower US prices.

Income from institutional partnerships declined 14% YoY to USD219m in 2018, following the expiration of the 10-year production tax credit ("PTCs") of some wind farms. In 2018, EDPR established **new institutional partnership** equity financing structures, in exchange for interests in Arkwright (78MW), Turtle Creek (199MW) and Meadow Lake VI (200MW) wind farms, for a total amount of USD464m.

All in all, EBITDA in North America rose by 11% YoY, to USD749m in 2018, reflecting particularly weak wind resources in 2018, the first asset rotation of majority stake gain and portfolio expansion.

As of Dec-18, **wind capacity currently under construction** in NA is fully concentrated in the US, Kansas: 199 MW Prairie Queen. Additionally, during 2018, EDPR has secured long-term PPAs in the US for nearly 1.2 GW of new capacity to be built in 2019-2020.

In Brazil, installed capacity reached 467 MW in Dec-18, fully long-term contracted (20 years from inception), following the commissioning of Babilônia wind project in 4Q18.

Gross profit in 2018 declined by 5%, driven by a 3 pp decline in the avg. load factor, to 40% and last year's temporary PPA unwinding at Baixas do Feijão. Along with the lower price of PPAs on capacity commissioned in the past 12 months impacted the evolution of both avg. selling price (-32% YoY to R\$195/MWh) and production (+43% YoY). **Avg. selling price** was down YoY justified by the lower PPA unwinding volumes. **All in all, EBITDA amounted to R\$140m in 2018.**

In 2018, EDPR signed: i) a 20-year PPA to sell the energy produced by two wind farms in Rio Grande do Norte (Jerusalem, 176MW; Monte Verde, 253MW), expected to start commercial operations in 2024; and ii) 15-year PPA to sell the energy produced by a solar photovoltaic park (Pereira Barreto, 199MW), expected to be commissioned in 2022.



- Energy is sold either under PPAs (up to 20 years), Hedges or Merchant prices; Green Certificates (Renewable Energy Credits, REC) subject to each state regulation
- Tax Incentive: (i) PTC collected for 10-years since COD (\$24/MWh in 2018); (ii) Wind farms beginning construction in 2009-10 could opt for 30% cash grant in lieu of PTC



- Feed-in Tariff for 20 years (Ontario)
- Renewable Energy Support Agreement (Alberta)



- Bilateral Electricity Supply Agreement for 25 years under self-supply regime



- Installed capacity under PROINFA program
- Competitive auctions awarding 20-years PPAs

(1) Net of cash grants

EDP Renováveis: Spain & Portugal



Spain	2018	2017	Δ %	Δ Abs.
Installed capacity (MW)	2,312	2,244	3%	+68
Avg. load factor (%)	26%	27%	-	-0 p.p.
Production (GWh)	5,164	5,095	1%	+68
Prod. w/capac. complement (GWh)	4,669	4,692	0%	-23
Standard production (GWh)	4,205	4,140	2%	+65
Above/(below) std. prod. (GWh)	464	552	-16%	-88
Prod. w/o cap. complement (GWh)	495	404	23%	+91
Avg. Price (€/MWh)	72.4	77.0	-6%	-5
Total GWh: realised pool (€/MWh)	52.9	49.9	6%	+3
Regulatory adj. on std. GWh (€m)	-45	-18	-156%	-27
Complement (€m)	181	181	0%	+0
Hedging gains/(losses) (€m)	-35	-25	-44%	-11
Gross profit (1)	407	416	-2%	-9
EBITDA (1)	266	276	-3%	-9
EBIT (1)	158	164	-3%	-6
Installed capacity (MW Equity)	152	152	0%	-
Capex (€m)	76	48	59%	+28
Capacity under construction (MW)	29	68	-58%	-39

In **Spain**, wind installed capacity totaled 2,312MW (MW EBITDA) in Dec-18, following new additions of 68 MW in 2H18 (Muxia). Additionally, EDPR owns equity stakes in other wind projects equivalent to 152MW.

In 2018, **total production** was broadly unchanged (+1% YoY), supported by capacity additions and stable load factor. **Average selling price** fell by 6% YoY, reflecting i) -€35m losses related to the hedging strategy in place (-€11m YoY), ii) a 6% increase in the average realised pool price, to €53/MWh, resulting in lower regulatory adjustment (-€45m, -€27m YoY, reflecting baseload higher than regulatory caps). **All in all, EBITDA in Spain declined 3% YoY to €266m in 2018.**

The remuneration framework in Spain is in place since Feb-17, establishing the new parameters of remuneration for renewable energy assets for 2017-2019 which includes: an increase of wind profile coefficient to 14.79% from previous 11.11%; 2014-2016 regulatory adjustments; and new forecasted pool prices with defined caps and floors for the standard production. 91% of Spanish capacity is entitled to receive capacity complement.

As of Dec-18, we had 68 MW of wind onshore capacity under construction in Spain.

Portugal	2018	2017	Δ %	Δ Abs.
Installed capacity (MW)	1,309	1,253	4%	+55
Avg. Load factor (%)	27%	27%	-	0 p.p.
Electricity output (GWh)	2,995	2,912	3%	+83
Avg. selling price (€/MWh)	90.8	90.0	1%	+1
Gross profit	272	261	4%	+11
EBITDA	223	212	5%	+11
EBIT	169	158	7%	+11
Capex (€m)	79	27	191%	+52
Capacity under construction (MW)	47	55	-15%	-9

In **Portugal**, total installed capacity reached 1,309 MW in Dec-18 (5 MW of which solar PV), following the commissioning of 55 MW during the year.

Total production in 2018 was up by 3% in 2018, mainly reflecting the increase in installed capacity and stable load factors, at 27%. **Avg. selling price** reached €91/MWh, as the 1% YoY increase translated the inflation indexation of the feed-in-tariff. **All in all, EBITDA in Portugal rose by 5% YoY, to €223m in 2018.**

As of Dec-18, EDPR had 47 MW of wind onshore capacity under construction in Portugal (Feed-in-tariff).



- Wind energy receives pool price and a premium per MW, if necessary, in order to achieve a target return established as 'Spanish 10-year Bond yields + 300bp'; Every 3 years, there will be revisions as to compensate deviations from the expected pool price
- Premium calculation is based on standard assets (standard load factor, production and costs)



- Older Wind farms: Feed-in Tariff inflation-indexed and inversely correlated with load factor. Duration: 15 years (Feed-in tariff updated with inflation) + 7 years (extension cap/floor system: €74/MWh - €98/MWh)
- ENEOP: price defined in a international competitive tender and set for 15 years (or the first 33 GWh per MW) + 7 years (extension cap/floor system: €74/MWh - €98/MWh). Tariff for first year established at c.€74/MWh and CPI monthly update for following years
- VENTINVEST: price defined in a international competitive tender and set for 20 years (or the first 44 GWh per MW)

EDP Renováveis: Rest of Europe



Rest of Europe	2018	2017	Δ %	Δ Abs.
Installed capacity (MW)	1,652	1,564	6%	+88
Avg. load factor (%)	23%	27%	-	-4 p.p.
Electricity output (GWh)	3,321	3,662	-9%	-341
Avg. selling price (€/MWh)	73.8	79.4	-7%	-6
Poland				
Installed capacity (MW)	418	418	0%	-
Avg. load factor (%)	25%	30%	-	-5 p.p.
Electricity output (GWh)	919	1,093	-16%	-174
Avg. selling price (PLN/MWh)	254	265	-4%	-11
EUR/PLN - Avg. Rate in period	4.26	4.26	0%	+0
Romania				
Installed capacity (MW)	521	521	0%	-
Avg. load factor (%)	23%	28%	-18%	-5 p.p.
Electricity output (GWh)	1,059	1,295	-18%	-236
Avg. selling price (RON/MWh)	255	337	-24%	-81
EUR/RON - Avg. Rate in period	4.65	4.57	-2%	+0
France				
Installed capacity (MW)	421	410	3%	+11
Avg. load factor (%)	23%	23%	-	-0 p.p.
Electricity output (GWh)	829	808	3%	+21
Avg. selling price (€/MWh)	90	90	0%	-0
Belgium & Italy				
Installed capacity (MW)	292	215	36%	+77
Avg. load factor (%)	25%	25%	-	-0 p.p.
Electricity output (GWh)	514	466	10%	+48
Avg. selling price (€/MWh)	109	117	-7%	-8
Gross profit	246	289	-15%	-43
EBITDA	169	238	-29%	-70
EBIT	82	117	-30%	-34
Capex (€m)	193	78	147%	+115
Capacity under construction (MW)	69	88	-22%	-19

In **European markets outside of Iberia**, EDP group installed capacity totaled 1,652 MW in Dec-18, the bulk of which concentrated in wind onshore (solar PV accounts for 50 MW, in Romania). Net additions during 2018 reached 88 MW (+77M in Italy and Belgium; +11MW in France) and further 69MW are **under construction**: +50MW in Italy and +19MW in France.

In **Poland**, we operate 418 MW of wind capacity. Average selling price was 4% lower YoY at PLN254/MWh driven by lower green certificates' prices arising from the change in the calculation method of the substitution fee (Sep-17). Avg. load factor decreased -5p.p. YoY, to 25% in 2018, justifying a 16% reduction in production).

In **Romania**, EDP group has 521 MW in operation: 471 MW in wind and 50MW of solar PV. In 2018, wind and solar production declined 18% to 1,059 GWh, reflecting a 6pp YoY decline in the avg. load factor (to 23%). Average selling price fell by 24%, following the previously defined reduction in the Green Certificates attributed per MWh produced post-2017.

In **France**, our wind onshore installed capacity rose by 11 MW, to 421 MW in Dec-18, contributing for a similar increase in production. Average tariff was stable at €90/MWh.

In **Belgium & Italy**, the 292 MW wind onshore in operation (221 MW in Italy, 71 MW in Belgium) represented a 36% YoY increase YoY, driven by new capacity additions in Italy. Electricity produced grew by 10% in 2018, to 514 GWh, backed by average capacity expansion and broadly stable load factor. Average selling price was lower at €109/MWh (-7% YoY), due to lower market prices in Italy (in wind farms installed before 2013) and different mix (production vs. price).

All in all, **EBITDA in Rest of Europe decreased by 29% YoY, to €169m in 2018**, driven by i) lower prices particularly in Poland (-4% YoY) and Romania (-26% YoY) mainly derived from regulatory changes; and ii) lower avg. load factor (-4 p.p. YoY), at 23% in 2018.

In Jul-18, EDPR secured a 20-year CfD at the **Greek energy auction** to sell electricity produced by Livadi 45MW wind farm, with expected commercial operation in 2020.

In the wind offshore, EDPR continues pursuing risk-controlled growth, with two projects secured in Europe:

i) In **UK**, EDPR has a 33.3% equity stake in 950MW Moray East project, with an awarded 15-year Contract for Difference ("CfD") of £57.5/MWh (2012 tariff-based) from 2022 onwards. The wind farm obtained FID in 4Q18 and will be equipped with 100 turbines of 9.5MW from Vestas, and has entered the construction phase. Moray East is expected to be commissioned in early 2022.

ii) In **France**, EDPR has a 29.5% equity stake in the consortium Eoliennes en mer des Iles d'Yeu et de Noirmoutier (in partnership with Engie and CDC), which has been developing two offshore wind projects since 2014 (round 2 tender), due to receive a feed-in tariff for 20 years, as defined by the French government (Jun-18): Dieppe-Le Tréport (496MW) and the islands of Yeu and Noirmoutier (496MW), with environmental and maritime permits granted.



- Price is set through bilateral contracts; Wind receive 1 GC/MWh which can be traded in the market. Electric suppliers have a substitution fee for non compliance with GC obligation. From Sep-17 onwards, substitution fee is calculated as 125% of the avg market price of the GC from the previous year and capped at 300PLN



- Wind assets (installed until 2013) received 2 GC/MWh until 2017 and 1 GC/MWh after 2017 until completing 15 years; 1 out of the 2 GC earned until Mar-2017 can only be sold from Jan-2018 and until Dec-2025. Solar assets receive 6 GC/MWh for 15 years. GC are tradable on market under a cap and floor system (cap €35 / floor €29.4); Wind assets (installed in 2013) receive 1.5 GC/MWh until 2017 and after 0.75 GC/MWh until completing 15 years. The GCs issued starting in Apr-2017 and the GCs postponed to trading from Jul-2013 will remain valid and may be traded until Mar-2032



- Feed-in tariff for 15 years: (i) €82/MWh up to 10th year, inflation updated; (ii) Years 11-15: €82/MWh @ 2,400 hours, decreasing to €28/MWh @3,600 hours, inflation updated
- Wind farms under RC 2016 scheme receive 15-year CfD which strike price value is similar to existing FIT fee plus a management premium



- Wind & solar energy sold at 'Market price + green certificate (GC)'; Separate GC prices with cap and floor for Wallonia (€65/MWh-100/MWh); Option to negotiate long-term PPAs



- Projects online before 2013 are (during 15 years) under a pool + premium scheme (premium=1x€180/MWh - "P-1")x0.78, being P-1 previous year average market price; Assets online from 2013 onwards were awarded a 20 years contract through competitive auctions

Regulated Networks in Iberia

Regulated Networks in Iberia (1)

Income Statement (€ m)	2018	2017	Δ %	Δ Abs.
Gross Profit	1,280	1,596	-20%	-316
OPEX (2)	413	467	-12%	-54
Other operating costs (net)	242	231	5%	+11
Net Operating Costs	655	698	-6%	-43
EBITDA	625	898	-30%	-273
Amortisation, impairm.; Provisions	286	307	-7%	-22
EBIT	339	591	-43%	-251
Capex & Opex Performance	2018	2017	Δ %	Δ Abs.
Controllable Operating Costs (3)	383	398	-4%	-14
Cont. costs/customer (€/supply point) (3)	56	58	-4%	-2
Cont. costs/km of network (€/Km) (3)	1,552	1,612	-4%	-61
Employees (#)	3,602	3,440	5%	+162
Capex (Net of Subsidies) (€m)	276	349	-21%	-73
Network ('000 Km) (3)	247	247	0.2%	+0

Electricity Distribution in Spain

Income Statement (€ m)	2018	2017	Δ %	Δ Abs.
Gross Profit	193	185	4%	+8
OPEX (2)	55	58	-4%	-2
Other operating costs (net)	(7)	(12)	40%	+5
Net Operating Costs	48	46	6%	+3
EBITDA	145	140	3%	+5
Amortisation, impairm.; Provisions	31	49	-36%	-17
EBIT	113	91	25%	+22
Gross Profit Performance	2018	2017	Δ %	Δ Abs.
Gross Profit	193	185	4%	+8
Regulated Revenues	189	188	1%	+1
Non-regulated gross profit	3	-3	-	+6
Electricity Supply Points (th)	666	664	0%	+2
Electricity Distributed (GWh)	9,360	9,331	0%	+29
Other Key data	2018	2017	Δ %	Δ Abs.
Capex (Net of Subsidies) (€m)	33	37	-11%	-4
Network (Km)	20,709	20,613	0.5%	+96
Employees (#)	307	307	-	-

Our Regulated networks in Iberia in 2017 and 2018 include our activities of distribution of electricity, in Portugal and Spain; and electricity last resort supply activity in Portugal (LRS). Furthermore, Regulated networks in Iberia in 2017 included gas distribution activities in Spain (up to Jul-17, when its disposal was completed) and Portugal (up to Oct-17, when disposal was completed).

Excluding the contribution from gas distribution in Iberia, EBITDA from regulated networks fell by 23% YoY (-€191m), to €636m in the 2018, largely impacted by: (i) in Portugal (77% of total), the new regulatory terms applicable to electricity distribution and LRS as from 1-Jan-18, which largely explain a €164m decrease in gross profit; and (ii) in Spain (23% of total), our prudent approach to possible regulatory changes, even ahead of the end of the current regulatory period, in 2020. Note that 2018 EBITDA from regulated networks includes €11m of one-off restructuring costs.

Controllable costs in the electricity networks fell by 4% YoY, to €383m in 2018, reflecting tight cost control and costs savings prompted by the increasing share of smart meters installed.

Capex amounted to €276m in 2018, the majority of it (88%) related to electricity in Portugal.

ELECTRICITY DISTRIBUTION IN SPAIN

The terms of regulated revenues for electricity distribution in Spain are set for the period 2016-19, under the regulatory framework designed in Dec-13 (Law 24/2013 and RD 1048/2013), Dec-15 (Ministerial order IET 2660/2015) and Jun-16 (Ministerial order IET 980/2016), encompassing a return on RAB equivalent to a 200bp premium over 10-year Spanish bond yields, equaling to 6.5%. Having said this, in Sep-17, the government initiated a process to change one of the terms of IET 980/2016 (*lesividad*), for which clarity is expected during 2019. Additionally, CNMC proposed a change in the regulatory framework from the current bond-linked model to a WACC-linked model, with a 5.58% return on RAB for the next regulatory period, starting in 2020. By means of Royal Decree-Law 1/2019 (Jan-19) CNMC is now entitled to establish the regulatory framework from 2020 on instead of Ministry or Government, so we expect that the specifics of the new regulatory period, including the rate of return, will be established by CNMC during 2019.

EBITDA from our electricity distribution activity in Spain amounted to €145m in 2018 (+3% YoY), reflecting by a prudent approach as to a possible regulatory change ('lesividad'), stable regulated revenues and cost discipline.

(1) In 2017, includes results from gas distribution in Spain and Portugal, sold in Jul-17 and Oct-17, respectively; (2) OPEX = Supplies and services + Personnel costs + Costs with social benefits;

(3) Only for electricity networks; Controllable Costs includes Supplies & services and personnel costs.

Electricity Distribution and Last Resort Supply in Portugal

Electricity Distribution & LRS in Portugal

Income Statement (€ m)	2018	2017	Δ %	Δ Abs.
Gross Profit	1,084	1,245	-13%	-160
OPEX (1)	355	368	-3.6%	-13
Concession fees	258	255	1.2%	+3
Other operating costs (net)	(9)	(9)	-1.7%	-0
Net Operating Costs	604	614	-1.6%	-10
EBITDA	480	630	-24%	-150
Amortisation, impairment; Provisions	254	246	3%	+8
EBIT	226	384	-41%	-158

Gross Profit Performance	2018	2017	Δ %	Δ Abs.
Gross Profit (€m)	1,084	1,245	-13%	-160
Regulated gross profit	1,076	1,240	-13%	-164
Non-regulated gross profit	9	5	79%	+4
Distribution Grid				
Regulated revenues (€ m)	1,039	1,203	-14%	-164
Electricity distributed (GWh)	46,059	44,753	2.9%	+1,306
Supply Points (th)	6,226	6,187	0.6%	+39
Last Resort Supply				
Regulated revenues (€ m)	36	36	0%	+0
Customers supplied (th)	1,125	1,223	-8%	-97
Electricity sold (GWh)	3,016	3,243	-7%	-227

Capex & Opex Performance	2018	2017	Δ %	Δ Abs.
Controllable Operating Costs (2)	330	344	-4%	-14
Cont. costs/client (€/customer)	53.0	55.6	-5%	-3
Cont. costs/km of network (€/Km)	1,457	1,521	-4%	-64
Employees (#)	3,285	3,129	5%	+156
Capex (Net of Subsidies) (€m)	243	288	-16%	-45
Network ('000 Km)	226	226	0.1%	+0
Equival. interruption time (min.) (3)	61	53	15%	+8

EBITDA from electricity distribution and last resort supply (LRS) in Portugal amounted to €480m in 2018 (-24% YoY or -€150m), penalized by the new regulatory terms in place as from 1-Jan-18 (-€164m on regulated revenues, in line with the regulatory framework in place until the end of 2020). Such impact was just partly offset by a good cost performance: controllable costs fell by 4% YoY.

In 2018, regulated gross profit amounted to €1,076m, posting a 13% decline YoY (-€164m).

In electricity distribution, regulated revenues amounted to €1,039m in 2018, declining by €164m YoY, driven by tougher regulatory terms and lower rate of return on HV/MV assets: 5.42% in 2018 vs. 6.68% in 2017 (and ERSE's assumption of 5.75%). **Electricity distributed in 2018** rose by 2.9% YoY (+1.3%, adjusted for temperature effect), mainly driven by the residential segment.

In the **last resort electricity supply activity (LRS)**, regulated revenues were flat at €36m in 2018. In 2018, **total number of customers supplied by the LRS** declined by 97 thousand, to 1,125 thousand at the end of 2018 (representing 18% of total electricity customers in Portugal), mostly in the residential segment. Note that, following the publication of DL 105/2017, electricity customers in Portugal are, since 1-Jan-18, allowed to return to the regulated market until the end of 2020. The volume of electricity supplied by our LRS fell by 7% YoY, to 3 TWh in the 2018.

Controllable operating costs were 4% lower YoY in 2018, supported by lower average headcount in 2018 and initial fruits reaped from the rising share of smart meters installed.

Capex amounted to €243m in 2018, including €31m invested in smart meters. The **equivalent interruption time** totaled 61 minutes in 2018 (vs. 53 minutes in 2017).

On 18-Dec-2018, ERSE released 2019 electricity tariffs, setting a 3.5% average tariff decrease for normal low voltage (NLV) segment, applicable to clients in the regulated market (out of the Social Tariff). Accordingly, **regulated revenues for 2019** were assumed at €1,060m in the electricity distribution and €31m in the last resort electricity supply. Electricity distribution regulated revenues preliminarily set assume a rate of return on assets (RoRAB) of 5.42% (reflecting an underlying avg. 10-year Portuguese bond yields of 1.86%) and an expected electricity demand in Portugal of 46.4 TWh in 2019 (0.8% above 2018 electricity distributed).

(1) OPEX = Supplies and services + Personnel costs + Costs with social benefits; (2) Supplies & services and personnel costs. (3) Adjusted for non-recurring impacts (rainstorms, high winds and summer fires).

EDP Brasil: Financial Performance



Income Statement	Consolidated (R\$ m)				Consolidated (€ m)			
	2018	2017	Δ %	Δ Abs.	2018	2017	Δ %	Δ Abs.
Gross Profit	3,779	3,494	8%	+285	877	969	-9%	-92
OPEX (1)	1,115	1,085	3%	+29	259	301	-14%	-42
Other operating costs (net)	(151)	192	-	-343	(30)	53	-	-84
Net Operating Costs	964	1,277	-25%	-313	228	354	-36%	-126
EBITDA	2,815	2,217	27%	+599	649	615	6%	+34
Amortisation, impairment; Provisions	668	621	8%	+47	155	172	-10%	-17
EBIT	2,147	1,595	35%	+551	494	443	12%	+51
Financial results	(366)	(548)	33%	+181	(85)	(152)	-44%	+67
Results from associates	3	(16)	-	+19	1	(5)	-	+5
Pre-tax profit	1,783	1,031	73%	+752	409	286	43%	+123

Capex & Financial Investments	(R\$ m)				(€ m)			
	2018	2017	Δ %	Δ Abs.	2018	2017	Δ %	Δ Abs.
Capex	1,132	764	48%	+369	263	214	23%	+49
Distribution	655	560	17%	+94	152	158	-4%	-6
Transmission	316	38	731%	+278	73	11	596%	+63
Generation	124	151	-18%	-27	29	42	-31%	-13
Supply and Other	38	14	163%	+23	9	4	120%	+5
Net Financial Invest. & Acquisitions	-203	319	-	-522	105	91	15%	+14

Energias do Brasil	2018	2017	Δ %	Δ Abs.
Share price at end of period (R\$/share)	14.75	14.00	5%	+0.75
Number of shares Issued (million)	606.9	606.9	-	-
Treasury stock (million)	0.6	0.7	-	-
Number of shares owned by EDP (million)	310.8	310.8	-	-
Euro/Real - End of period rate	4.44	3.97	-11%	+0.47
Euro/Real - Average of period rate	4.31	3.60	-16%	+0.70
Inflation rate (IPCA - YoY)	3.7%	3.5%	-	-
Net Debt / EBITDA (x)	1.6	2.0	-	-0.4
Average Cost of Debt (%)	8.8	11.4	-	-2.5p.p.
Average Interest Rate (CDI)	6.4	9.9	-	-3.5p.p.
Employees (#)	2,986	2,906	3%	+80

Key Balance Sheet Figures (R\$ Million)	YE18	YE17	Δ %	Δ Abs.
Financial investm, assets held for sale	2,025	1,547	31%	+478
Net financial debt	4,417	4,432	0%	-15
Regulatory receivables	316	101	211%	+214
Non-controlling Interests	1,149	1,158	-1%	-9
Equity book value	8,565	7,924	8%	+640

Financial Results (R\$ Million)	2018	2017	Δ %	Δ Abs.
Net Interest Costs	(464)	(458)	-1%	-7
Capitalised Costs	24	9	173%	+15
Forex Differences and Derivatives	(20)	14	-	-33
Other	94	(113)	-	+206
Financial Results	(366)	(548)	33%	+181

In local currency, EDP Brasil ("EDPB") EBITDA increased 27% YoY (+R\$599m) to R\$2,815m in 2018, impacted by (i) the sale of small-hydro plants (+R\$375m); (ii) better results in Pecém coal plant (+R\$129m YoY) mainly due to revision of the contracted availability; (iii) higher EBITDA in distribution (+R\$56m YoY) on better operational performance; (iv) successful portfolio integration management which led to a GSF impact net of hedging of R\$151m.

EBITDA in distribution increased 7% YoY, driven by the update of the concessions assets' value to inflation (+R\$34m), continuing reduction of losses (+R\$37m) and increase in distributed energy volumes (+R\$43m). However, gains due to overcontracting policy were R\$73m lower than in 2017. Generation & Supply EBITDA grew 9% YoY (+R\$138m), pushed by an active hedging strategy and by Pecém (reduction in the provision for penalties on unavailability). EBITDA in EUR terms, which reached €649m, was negatively impacted by BRL avg. depreciation against the EUR by 16% (-€127m).

OPEX costs increased 3%, below the average IPCA rate of +3.7% YoY. Net operating costs decreased by 25% YoY (-R\$313m), mainly impacted by gains on the sale of small-hydro plants in the 3Q18 (R\$34m) and the 4Q18 (R\$341m).

Net financial debt was flat at R\$4.4bn at the end of 2018. Financial results improved 33% YoY to R\$366m, reflecting lower cost of debt (from 11.4% in 2017 to 8.8% in 2018), in line with the declining interest rates in Brazil - average annual CDI stood at 6.4% in 2018 vs. 9.9% in 2017. Net debt/EBITDA decreased to 1.6x from 2.0x, backed on higher EBITDA levels.

Capex surged 48% (+R\$369m) in 2018 vs. 2017, mainly due to Transmission investments (+R\$278m), a segment in which EDPB was awarded with 5 transmission lines with a total investment of R\$3.1bn up to 2022. Espírito Santo line was the first one concluded, having entered into operation at the end of Dec-18, 20 months ahead of schedule. Capex in Distribution increased by R\$94m YoY, reflecting investments to improve operational efficiency of the distribution grids.

(1) OPEX = Supplies and services + Personnel costs + Costs with social benefits.

Brazil: Electricity Distribution



Income Statement (R\$ m)	2018	2017	Δ %	Δ Abs.
Gross Profit	1,832	1,731	6%	+101
OPEX (1)	760	718	6%	+42
Other operating costs (net)	185	182	2%	+3
Net Operating Costs	945	900	5%	+46
EBITDA	887	831	7%	+56
Amortisation, impairment; Provisions	256	222	15%	+34
EBIT	631	609	4%	+22

EBITDA from our electricity distribution activity in Brazil increased by +R\$56m YoY to R\$887m in 2018, mostly due to: (i) the growth in distributed energy volumes (+R\$43m); (ii) a reduction of the losses, which allowed for an increase in results of +R\$37m YoY; (iii) the update of the concession's assets value to inflation, as contemplated by the regulatory framework (+R\$34m). However, the gains due to overcontracting policy were R\$73m lower than in 2018.

Volumes of electricity sold increased slightly in 2018 by 1% vs. 2017. At the same time, **volumes distributed to clients in the free market** increased 6% YoY to 11.2 TWh in 2018. All in all, **electricity distributed** increased 3% YoY in 2018.

The volumes of energy contracted surpassed by more than 5% the volumes demanded by clients during 2018. The **overcontracted** volumes are sold at the spot price (PLD) which was higher than the long-term sourcing contracted prices, leading to a gain of R\$28m on 2018.

Gross Profit Performance	2018	2017	Δ %	Δ Abs.
Gross Profit (R\$ m)	1,832	1,731	6%	+101
Regulated revenues	1,650	1,628	1.4%	+23
Other	182	104	76%	+79
Regulatory Receivables (R\$ m)				
Beginning of period	101	(392)	-	+493
Recovery of past deviations	(11)	397	-	-408
Annual deviation (2)	225	96	134%	+129
CDE/ACR Account (3)	-	-	-	-
End of period	316	101	211%	+214
Customers Connected (th)	3,451	3,377	2%	+74
EDP São Paulo	1,887	1,839	3%	+48
EDP Espírito Santo	1,564	1,538	2%	+26
Electricity Distributed (GWh)	25,007	24,263	3%	+744
EDP São Paulo	15,192	14,806	3%	+386
EDP Espírito Santo	9,814	9,457	4%	+357
From which:				
To customers in Free Market (GWh)	11,224	10,552	6%	+672
Electricity Sold (GWh)	13,769	13,697	1%	+72
EDP São Paulo	7,934	7,974	-1%	-40
Resid., Commerc. & Other	6,638	6,570	1%	+69
Industrial	1,296	1,405	-8%	-109
EDP Espírito Santo	5,835	5,723	2%	+112
Resid., Commerc. & Other	5,240	5,067	3%	+173
Industrial	595	655	-9%	-61

The trajectory of **lower non-technical losses** observed in the recent quarters was maintained. Non-technical losses in the low-voltage segment have decreased both for EDP Espírito Santo, reaching 11.15% in 2018 (-0.8p.p. YoY), the lowest value of the last 16 years, as well as for EDP São Paulo, whose level stood at 8.46% in 2018 (-1.1p.p. YoY). Both figures stood below ANEEL threshold of 11.45% and 8.87% respectively. This is the reflex of strong investment for reducing losses (R\$93m in 2018), which allowed a revenue of R\$229m in this year.

Provisions for doubtful clients stood at R\$85m in 2018 (slightly higher than R\$82m in 2017). EDPB keeps tackling the situation through increased proximity to clients, regardless of some economic improvement and unemployment reduction in the region of EDP São Paulo.

Regulatory receivables amounted to R\$316m at the end of 2018 - which despite being an increase of +R\$214m vs Dec-17, it is still a significant reduction vs. R\$501m at 3Q18, to be recouped from the system in the following years.

OPEX and other operating costs were higher YoY at R\$760m (+R\$42m) and R\$185m (+R\$3m), respectively. **Distribution capex** in 2018 was more than twice the amount of depreciations, reflecting investments to improve quality of service and reducing energy losses.

Worth noting that in Nov-18, EDPB acquired 1,518,000 preferential shares of CELESC by R\$63.7m, which together with previous shares' purchases resulted in a total 23.56% stake in CELESC.

Capex & Opex Performance	2018	2017	Δ %	Δ Abs.
Controllable Operating Costs (1)	760	718	6%	+42
Cont. costs/customer (R\$/customer)	220	213	4%	+8
Cont. costs/km (R\$/Km)	8	8	5%	+0
Employees (#)	2,186	2,146	2%	+40
Capex (net of subsidies) (R\$m)	655	560	17%	+94
Network ('000 Km)	92	92	1%	+1

(1) OPEX = Supplies and services + Personnel costs + Costs with social benefits;

(2) Net of extraordinary tariff increase and tariff flags impacts;

(3) Including financial update of the corresponding regulatory assets/liabilities;

Brazil: Electricity Generation and Supply

Income Statement (R\$M)	Generation			
	2018	2017	Δ %	Δ Abs.
Gross Profit	1,684	1,545	9%	+139
OPEX (1)	228	231	-1%	-3
Other operating costs (net)	6	(1)	-	+7
Net Operating Costs	234	230	2%	+4
EBITDA	1,450	1,315	10%	+135
Amortisation, impairment; Provisions	368	372	-1.1%	-4
EBIT	1,082	943	15%	+139

EBITDA from our electricity generation activities and supply in Brazil went up 9% YoY (+R\$138m) to R\$1,628m in 2018, reflecting +R\$129m of higher EBITDA at Pecém coal plant in 2018, mostly due to the revision of the availability reference and consequent reduction in the provision for penalties on unavailability.

Hydro gross profit increased 2% YoY to R\$959m. Worth noting that EDPB hedging and GSF insurance coupled with the sale of uncontracted volumes, offset the impact of GSF which otherwise would have had a negative impact of -R\$603m in 2018 (-R\$662m in 2017).

EDP will continue to manage its portfolio of plants and contracts, handling volumes and hedges together with its supply business as to minimize the impact of hydro deficits and price volatility.

Key Data	2018	2017	Δ %	Δ Abs.
Gross Profit (R\$ m)	1,684	1,545	9%	+139
Hydro	959	943	2%	+15
PPA contracted revenues & Other	971	1,073	-9%	-102
GSF impact (net of hedging)	(13)	(130)	90%	+117
Thermal	725	601	21%	+125
PPA contracted revenues	700	680	3%	+20
Other	26	(79)	-	+105
Installed Capacity (MW)	2,320	2,466	-6%	-147
Hydro	1,599	1,746	-8%	-147
Thermal	720	720	-	-
Electricity Sold (GWh)	13,336	13,289	0%	+48
PPA contracted	10,858	11,663	-7%	-804
Hydro	7,403	7,065	4.8%	+338
Thermal	3,455	4,597	-25%	-1,142
Other	2,478	1,626	52%	+852
Avg. Hydro Sale Price (R\$/MWh) (2)	186	181	3%	+5
Installed Capacity (MW Equity)	539	364	48%	+175
Capex (R\$ m)	124	151	-18%	-27
Financial Investments (R\$ m)	62	319	-81%	-257
Employees (#)	433	488	-11%	-55

The average price of hydro volumes was R\$186/MWh in 2018, 3% higher YoY, due to PPA prices being inflation updated annually, but also due to higher prices on new short-term and long-term contracts. Hydro volumes sold increased 5%.

Pecém gross profit reached R\$725 in 2018, a 21% increase YoY, mainly due to the abovementioned availability effect. Pecém's electricity sold decreased 25% YoY, due to the increase of hydro resources in the 4Q18 and programmed maintenance that occurred in the 2H18.

EDPB operates 2.9 GW of capacity, of which 0.5 GW are equity consolidated. Equity accounted capacity refers to a 50% equity stake in Santo Antônio do Jari hydro plant (393 MW), to a 50% equity stake in Cachoeira-Caldeirão hydro plant (219 MW), both in partnership with CTG, to a 33% equity stake in São Manoel hydro plant (700 MW, fully online in Apr-18) in partnership with CTG and Furnas.

Hydro installed capacity at EBITDA level was reduced by 147 MW, reflecting the sale of EDP PCH (previous owner of 7 small-hydro plants) and Santa Fé and Costa Rica small-hydro plants in the 2H18.

Capex was reduced by R\$27m to R\$124m in 2018, mainly due to lower capex needs in Pecém coal plant. Worth noting that the final equity investments devoted to São Manoel, Jari and Cachoeira-Caldeirão hydro plants are classified as "financial investments" (equity-method accounted) and in 2018 amounted to R\$62m (-81% YoY).

Electricity supply EBITDA increased 2% YoY to R\$178m in 2018, reflecting higher volumes and evidencing the integration of the portfolio through the hedging strategy developed to deal with price volatility.

EBITDA Breakdown (R\$ m)	2018	2017	Δ %	Δ Abs.
Pecém (100%)	596	467	28%	+129
Lajeado (73% owned by EDPB)	359	363	-1%	-3
Peixe Angical (60% owned by EDPB)	202	259	-22%	-57
Other (100%)	292	226	29%	+66
EBITDA	1,450	1,315	10%	+135

Supply	2018	2017	Δ %	Δ Abs.
Gross profit (R\$ m)	220	211	4%	+9
Net Operating costs (R\$ m)	42	36	18%	+6
EBITDA (R\$ m)	178	176	2%	+3
Electricity sales (GWh)	18,102	17,804	2%	+298
Capex (R\$ m)	22	5	316%	+17

(1) OPEX = Supplies & services + Personnel costs + Costs with social benefits; (2) Calculated with PPA prices and volumes.



Income Statements & Annex

Income Statement by Business Area

2018 (€m)	Generation & Supply Iberia	Regulated Networks Iberia	Wind & Solar	Brazil	Corpor. Activ. & Adjustments	EDP Group
Revenues from energy sales and services and other	8,382	4,795	1,528	3,212	(2,638)	15,278
Gross Profit	1,434	1,280	1,512	877	(4)	5,099
Supplies and services	291	276	345	146	(101)	957
Personnel costs and employee benefits	159	137	115	113	127	652
Other operating costs (net)	222	242	(249)	(30)	(11)	174
Operating costs	672	655	212	228	15	1,782
EBITDA	762	625	1,300	649	(19)	3,317
Provisions	278	3	0	11	(5)	288
Amortisation and impairment (2)	417	282	546	144	55	1,445
EBIT	67	339	754	494	(69)	1,584

2017 (€m)	Generation & Supply Iberia	Regulated Networks Iberia(1)	Wind & Solar	Brazil	Corpor. Activ. & Adjustments	EDP Group Pro-forma	Gas Networks Iberia	EDP Group Reported
Revenues from energy sales and services and other	7,818	5,067	1,637	3,433	(2,481)	15,473	273	15,746
Gross Profit	1,236	1,428	1,602	969	(10)	5,225	166	5,391
Supplies and services	314	292	327	172	(127)	976	14	991
Personnel costs and employee benefits	158	137	101	129	146	671	10	681
Other operating costs (net)	210	234	(192)	53	(573)	(268)	(2)	(270)
Operating costs	681	663	235	354	(558)	1,375	26	1,401
EBITDA	555	766	1,366	615	548	3,850	140	3,990
Provisions	(6)	(2)	(0)	8	(4)	(4)	0	(4)
Amortisation and impairment (2)	589	297	563	164	43	1,657	19	1,676
EBIT	(28)	470	803	443	509	2,197	121	2,318

(1) Includes only Electricity distribution in Portugal and Spain, LRS in Portugal; Excludes Gas distribution in Spain and Portugal, stated on column "Gas Networks Iberia", following its disposal, in Jul-17 and Oct-17, respectively.

(2) Depreciation and amortisation expense net of compensation for depreciation and amortisation of subsidised assets.

Quarterly Income Statement



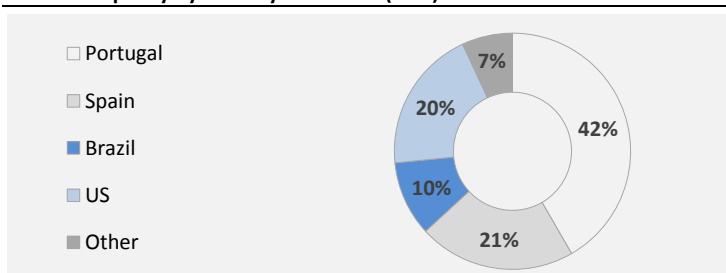
Quarterly P&L (€ m)	1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18	4Q18	Δ YoY %	Δ QoQ %
Revenues from energy sales and services and other	4,233	3,642	3,779	4,092	4,032	3,527	3,752	3,967	-3%	6%
Cost of energy sales and other	(2,710)	(2,272)	(2,549)	(2,823)	(2,639)	(2,227)	(2,582)	(2,730)	3%	-6%
Gross Profit	1,523	1,370	1,229	1,269	1,393	1,299	1,170	1,237	-3%	6%
Supplies and services	227	246	235	283	209	233	234	280	-1%	19%
Personnel costs and Employee Benefits	171	169	159	181	163	162	147	180	-1%	22%
Other operating costs (net)	114	64	(531)	83	128	75	100	(130)	-	-
Operating costs	512	479	(137)	548	501	470	482	330	-40%	-32%
EBITDA	1,011	892	1,367	721	893	829	688	907	26%	32%
Provisions	4	(2)	(0)	(5)	(7)	4	286	5	-	-98%
Amortisation and impairment (1)	359	349	346	621	351	348	350	396	-36%	13%
EBIT	648	545	1,021	105	549	477	53	506	383%	863%
Financial Results	(197)	(173)	(223)	(215)	(127)	(150)	(166)	(111)	49%	33%
Share of net profit in joint ventures and associates	(1)	8	4	1	1	2	6	2	138%	-66%
Profit before income tax and CESE	450	379	801	(110)	423	330	(108)	397	-	-
Income taxes	66	53	56	(165)	74	43	(67)	49	-	-
Extraordinary contribution for the energy sector	70	(2)	2	(0)	66	(2)	1	0	-	-64%
Net Profit for the period	315	328	743	56	282	289	(43)	347	526%	-
Net Profit Attributable to EDP	215	235	696	(33)	166	214	(83)	222	-	-
Non-controlling Interests	100	93	47	89	116	75	40	125	0	212%

(1) Depreciation and amortisation expense net of compensation for depreciation and amortisation of subsidised assets.

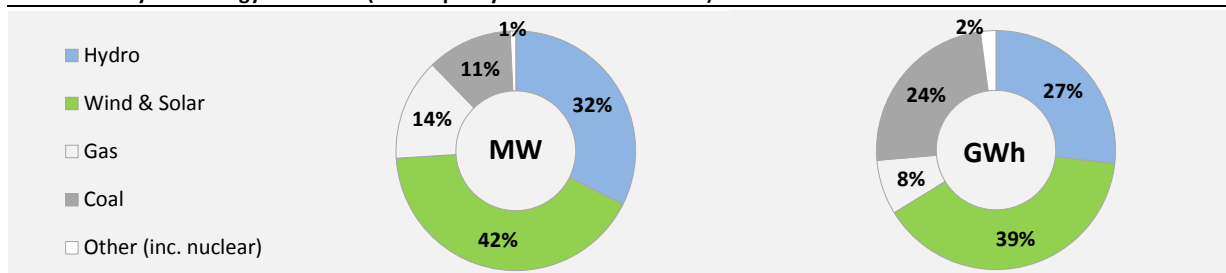
Generation Assets: Installed Capacity and Generation

Technology	Installed Capacity - MW (1)				Electricity Generation (GWh)				Electricity Generation (GWh)							
	2018	2017	Δ MW	Δ %	2018	2017	Δ GWh	Δ %	1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18	4Q18
Wind	11,156	10,531	625	6%	28,133	27,466	667	2%	7,690	6,777	5,224	7,775	8,719	6,620	5,145	7,648
US	5,242	4,965	278	6%	14,721	14,332	389	3%	4,059	3,764	2,348	4,161	4,455	3,735	2,666	3,865
Portugal	1,304	1,249	55	4%	2,987	2,904	83	3%	876	657	670	702	1,064	608	455	860
Spain	2,312	2,244	68	3%	5,164	5,095	68	1%	1,442	1,223	1,065	1,365	1,766	1,101	894	1,404
Brazil	467	331	136	41%	1,235	861	374	43%	147	167	249	298	159	262	416	399
Rest of Europe (2)	1,601	1,513	88	6%	3,255	3,592	-337	-9%	1,050	754	713	1,075	1,068	697	541	948
Rest of the World (3)	230	230	0	0%	771	681	90	13%	115	213	179	174	208	217	173	173
Solar	145	145	0	0%	226	155	71	46%	28	51	47	29	43	69	70	44
Hydro	8,792	9,019	-226	-3%	19,296	11,424	7,872	69%	4,364	2,606	1,813	2,641	6,154	5,863	3,189	4,090
Portugal	6,767	6,847	-80	-1%	12,648	6,948	5,700	82%	2,921	1,537	1,160	1,330	3,790	4,172	2,249	2,437
Pumping activity	2,806	2,806	0	0%	-2,438	-2,228	-211	9%	-550	-652	-334	-692	-636	-329	-130	-1,343
Run of the river	2,408	2,395	13	0%	6,161	2,802	3,359	120%	1,364	713	370	356	1,685	2,424	1,098	954
Reservoir	4,294	4,303	-9	0%	6,090	3,907	2,183	56%	1,409	771	779	947	1,940	1,605	1,120	1,425
Small-Hydro	65	148	-83	-126%	397	238	159	67%	148	52	10	27	165	143	32	58
Spain	426	426	0	0%	1,054	472	582	123%	175	88	58	151	408	370	108	168
Brazil	1,599	1,746	-147	-8%	5,594	4,004	1,590	40%	1,268	981	596	1,160	1,956	1,321	832	1,485
Gas/ CCGT	3,729	3,729	0	0%	5,333	8,029	-2,696	-34%	1,713	1,388	2,833	2,095	1,302	846	1,802	1,383
Portugal	2,031	2,031	0	0%	4,091	5,941	-1,850	-31%	1,105	1,203	2,336	1,297	907	660	1,532	992
Spain	1,698	1,698	0	0%	1,242	2,087	-846	-41%	608	185	497	798	395	186	270	391
Coal	3,124	3,124	0	0%	17,471	21,444	-3,973	-19%	5,041	5,304	5,444	5,656	3,965	3,926	5,260	4,320
Portugal	1,180	1,180	0	0%	8,067	9,426	-1,359	-14%	2,192	2,486	2,497	2,250	1,734	1,635	2,431	2,267
Spain	1,224	1,224	0	0%	5,948	7,421	-1,473	-20%	1,860	1,758	1,723	2,080	1,045	1,248	1,861	1,794
Brazil	720	720	0	0%	3,455	4,597	-1,142	-25%	988	1,060	1,224	1,326	1,186	1,043	968	258
Nuclear - Trillo (15.5%)	156	156	0	0%	1,196	1,236	-40	-3%	333	223	339	340	331	187	337	340
Other	49	49	0	0%	309	247	62	25%	45	57	72	73	84	82	73	70
Portugal	24	24	0	0%	182	119	64	53%	15	26	38	40	51	50	41	40
Spain	25	25	0	0%	126	128	-2	-1%	30	31	34	33	32	32	32	30
TOTAL	27,151	26,753	399	1%	71,963	70,001	1,963	3%	19,215	16,406	15,773	18,607	20,598	17,593	15,877	17,895
Of Which:																
Portugal	11,311	11,336	-25	0%	27,984	25,346	2,638	10%	7,110	5,912	6,729	5,595	7,548	7,127	6,711	6,598
Spain	5,840	5,772	68	1%	14,729	16,439	-1,710	-10%	4,449	3,508	3,715	4,766	3,976	3,123	3,502	4,128
Brazil	2,787	2,797	-10	0%	10,285	9,463	822	9%	2,403	2,208	2,069	2,783	3,301	2,626	2,216	2,142
US	5,332	5,055	278	5%	14,873	14,410	463	3%	4,074	3,789	2,369	4,177	4,486	3,779	2,711	3,896

Installed capacity by Country as of 2018 (MW)



Breakdown by Technology as of 2018 (MW Capacity & GWh of Production)



(1) Installed capacity that contributed to the revenues in the period; (2) Includes Poland, Romania, France, Belgium; (3) Includes Canada and Mexico.

Regulated Networks: RAB, Networks, Customers and Performance indicators



RAB	2018	2017	Δ %	Δ GWh
Portugal (€ m)	2,996	2,970	0.9%	25
High / Medium Voltage	1,832			
Low Voltage	1,164			
Spain (€ m)	950	950	0.0%	-
Brazil (BRL m)	4,696	4,204	11.7%	492
EDP Espírito Santo	2,449	2,226	10.0%	223
EDP São Paulo	2,247	1,978	13.6%	269
TOTAL (€ m)	5,036	4,979	1.2%	57

Networks	2018	2017	Δ %	Δ Abs.
Length of the networks (Km)	339,177	338,179	0.3%	998
Portugal	226,308	226,027	0.1%	281
Spain	20,709	20,613	0.5%	96
Brazil	92,160	91,538	0.7%	622
DTCs (thous.)				
Portugal	19	15	28%	4
Spain	7	-	-	7
Energy Box (th)				
Portugal	1,923	1,270	51%	653
Spain	644	609	6%	35

Customers Connected (th)	2018	2017	Δ %	Δ Abs.
Portugal	6,226	6,187	0.6%	39
Very High / High / Medium Voltage	25	25	1.0%	0.2
Special Low Voltage	36	36	2.0%	0.7
Low Voltage	6,164	6,126	0.6%	38
Spain	666	664	0.3%	2
High / Medium Voltage	1	1	1.1%	0.0
Low Voltage	665	663	0.3%	2.3
Brazil	3,451	3,377	2.2%	74
EDP São Paulo	1,887	1,839	2.6%	48
EDP Espírito Santo	1,564	1,538	1.7%	26
TOTAL	10,343	10,228	1.1%	115

Quality of service	2018	2017	Δ %	Δ Abs.
Losses (% of electricity distributed)			-	-
Portugal (1)	9.6%	10.0%	-3.6%	-0.4 p.p.
Spain	3.4%	3.5%	-3.1%	-0.1 p.p.
Brazil				
EDP São Paulo	8.4%	8.7%	-3.4%	-0.3 p.p.
Technical	5.6%	5.5%	1.6%	0.1 p.p.
Comercial	2.8%	3.2%	-12.0%	-0.4 p.p.
EDP Espírito Santo	11.9%	13.0%	-8.0%	-1 p.p.
Technical	7.5%	8.3%	-9.2%	-0.8 p.p.
Comercial	4.4%	4.7%	-5.7%	-0.3 p.p.
Telemetering (%)				
Portugal	69%	66%	5%	3 p.p.

Electricity Distributed (GWh)	2018	2017	Δ %	Δ GWh
Portugal	46,056	44,748	2.9%	1,308
Very High Voltage	2,366	2,158	9.6%	208
High / Medium Voltage	21,996	21,715	1.3%	281
Low Voltage	21,694	20,875	3.9%	819
Spain	9,360	9,331	0.3%	29
High / Medium Voltage	7,110	7,109	0.0%	1
Low Voltage	2,250	2,222	1.3%	28
Brazil	25,007	24,704	1.2%	303
Free Customers	11,224	10,993	2.1%	231
Industrial	1,890	2,060	-8.2%	-170
Residential, Comercial & Other	11,892	11,651	2.1%	242
TOTAL	80,423	78,783	2.1%	1,640

(1) Excludes Very High Voltage

Financial investments & Assets for Sale; Non-controlling interests; Provisions

Financial investments & Assets for Sale	Attributable Installed Capacity - MW (1)				Share of profit (2) (€ m)				Book value (€ m)			
	2018	2017	Δ MW	Δ %	2018	2017	Δ Abs.	Δ %	2018	2017	Δ Abs.	Δ %
EDP Renováveis	371	331	40	12%	2	3	-1	-39%	357	312	45	14%
Spain	152	152										
US	219	179										
Other	0	0										
EDP Brasil	539	364	175	48%	1	-5	5	-	456	381	74	20%
Generation - Hydro	539	364										
Distribution												
Iberia (Ex-wind) & Other	10	10	0	0%	9	13	-5	-36%	264	311	-47	-15%
Spain - Cogeneration & Waste	10	10										
Macao - Distribution (CEM)												
Other												
Assets Held for Sale (net of liabilities)									11	116	-105	-90%
TOTAL	920	705	215	30%	11	12	-1	-6%	1,088	1,121	-33	-3%

Non-controlling interests	Attributable Installed Capacity - MW (1)				Share of profits (2) (€ m)				Book value (€ m)			
	2018	2017	Δ MW	Δ %	2018	2017	Δ Abs.	Δ %	2018	2017	Δ Abs.	Δ %
EDP Renováveis	4,747	4,643	104	2%	210	231	-21	-9%	2,739	2,654	85	3%
At EDPR level:	2,781	2,785	-5	0%	159	180	-22	-12%	1,613	1,560	53	3%
Iberia	851	851										
North America	1,210	1,215										
Rest of Europe	557	557										
Brazil	162	162										
17.4% attributable to free-float of EDPR (3)	1,966	1,858	109	6%	51	51	0	1%	1,125	1,094	32	3%
EDP Brasil	1,742	1,814	-72	-4%	151	100	51	51%	1,225	1,308	-83	-6%
At EDP Brasil level:	606	606	0	0%	33	22	11	50%	259	291	-32	-11%
Hydro	606	606										
Other	0	0										
49% attributable to free-float of EDP Brasil	1,137	1,208	-72	-6%	118	78	40	51%	967	1,017	-51	-5%
Iberia (Ex-wind) & Other	12	12	0	0%	-4	-3	-1	39%	-32	-28	-4	15%
TOTAL	6,501	6,469	32	1%	357	328	29	9%	3,932	3,934	-2	0%

Provisions (Net of tax)	Employees benefits (€ m)			
	2018	2017	Δ Abs.	Δ %
EDP Renováveis	0	0		
EDP Brasil	115	135		
Iberia (Ex-wind) & Other	870	928		
TOTAL	985	1,064		

(1) MW attributable to associated companies & JVs and non-controlling interests; (2) Share of profit in JVs & associates and from non-controlling interests; assets held for sale not included; (3) 22.5% up to Aug-17. 17.4% thereafter.

EDP - Sustainability performance



Main Events 2018 (a)

EDP elected world leader in the social dimension of sustainability

The Group is in the top 2 of energy companies on the Dow Jones Sustainability Index and was considered the best in the world in criteria such as environmental policy management.

EDP increases score on FTSE4Good Global Index

EDP is in the top 2 of companies with the highest ESG score on FTSE4Good Global Index with a score 4.6 out of 5.

Ethisphere Institute - World's Most Ethical Companies 2018

The Most Ethical Companies in the World in 2018, published by the Ethisphere Institute, includes 135 companies from 23 countries and recognizes the EDP Group for its seventh consecutive year.

EDP has been recognized as one of the companies in the world with the best climate change practices

For the 4th consecutive year, having been recognized an A- in the CDP Climate Change category ranked at the highest performance level ('Leadership') and in the CDP Water category, maintaining its 'Management' performance level and B rating.

Green Bond Pioneer Awards 2019

EDP has been recognized by the Climate Bond Initiative (CBI) for being the first portuguese company which issued green bonds.

EDP Internal Sustainability Index (base 2010-12)

	2018	2017	Δ %
Sustainab. Index (b)(c)(d)	108	103	5%
Environmental %Weight	107 33%	93 33%	15%
Economic %Weight	106 37%	106 37%	0%
Social %Weight	113 30%	111 30%	2%

This Sustainability Index was developed by EDP and is based on 33 sustainability performance indicators.

Economic Metrics	2018	2017	Δ %
Economic Value (€m)	16,308	17,234	-5%
Distributed	14,471	14,910	-3%
Accumulated	1,837	2,324	-21%
Energy Serv. Revenues (b)	1,443	1,104	31%
Energy Efficiency Serv.	151	134	13%

Social Metrics	2018	2017	Δ %
Employees	11,631	11,657	0%
Total hours of training	398,394	473,078	-16%
On-duty Accidents (e)	29	28	4%
Severity Rate (Tg) (f)	114	131	-13%
Freq. rate (Tf) (f)	2.11	2.03	4%
Fatal accidents (3rds)	7	10	-30%

Environmental Metrics	2018	2017	Δ %
Absolute Atmospheric Emissions (kt)			
CO2 (c)(g)	18,404	23,129	-20%
NOx	14.3	17.0	-16%
SO2	21.3	29.8	-29%
Particle	2.050	1.494	37%

Specific Atmospheric Emissions (g/KWh)			
CO2 (c)(g)	257.0	333.5	-23%
NOx	0.20	0.25	-19%
SO2	0.30	0.43	-31%

GHG emissions (ktCO2 eq)			
Direct Emissions (scope 1) (c)	18,429	23,159	-20%
Indirect emissions (scope 2) (d)	602	802	-25%
Other indirect emissions (scope 3)	11,334	13,039	-13%

Primary Energy Consumption (TJ) (h)	221,634	276,668	-20%
Max. Net Certified Capacity (%)	97%	90%	8%
Water Use (10³ m³)	1,537,614	1,758,417	-13%
Total Waste to final disposal (t)	349,329	666,771	-48%

Environmental Matters (€ th) (i)	264,482	237,469	11%
Investments	68,987	73,197	-6%
Expenses	195,495	164,272	19%

Environmental Fees and Penalties (€)	3,389	18,848	-82%
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Environmental Metrics - CO2 Emissions

CO2 Emissions	Absolute (ktCO2) (c)		Specific (t/MWh)		Generation (i) (GWh)	
	2018	2017	2018	2017	2018	2017
Iberia	14,433	17,737	0.70	0.68	20,503	25,985
Coal	12,245	14,558	0.87	0.86	14,016	16,847
CCGT	2,030	3,030	0.38	0.38	5,332	8,029
Cogeneration + Waste	158	150	0.14	0.13	1,155	1,109
Brazil	3,971	5,392	1.15	1.17	3,455	4,597
Coal (PPA contracted)	3,971	5,392	1.15	1.17	3,455	4,597
Thermal Generation	18,404	23,129	0.77	0.76	23,958	30,582
CO₂ Free Generation					47,656	39,045
CO₂ Emissions			0.26	0.33	71,614	69,627

(a) Detailed information about the progress of EDP contribution to the United Nations Sustainable Development Goals can be found at: www.edp.com>Investors.

(b) Services provided under energy supply, installation of more efficient and/or building retrofit, and sustainable mobility, which generate revenues for the company.

(c) The stationary emissions do not include those produced by the burning of ArcelorMittal steel gases in EDP's power plant in Spain.

(d) Scope 2 emissions according with GHG Protocol based location methodology.

(e) Accidents leading to an absence of one more calendar day and fatalities.

(f) EDP + ESP (External Services Provider).

(g) Includes only stationary emissions.

(h) Including vehicle fleet.

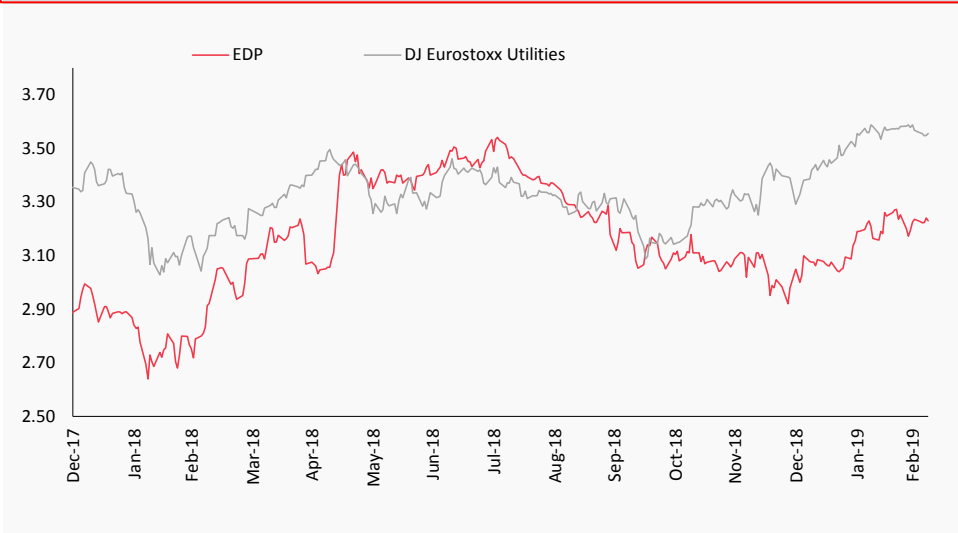
(i) Includes heat generation (2018: 643 GWh vs 2017: 639 GWh).

(j) Report methodology was revised. Inclusion of consumptions CO2 emissions licenses, as environmental expenses in 2018.

EDP Share Performance



EDP Stock Performance on Euronext Lisbon



EDP Stock Market Performance

YTD 52W 2016

08-03-2019

EDP Share Price (Euronext Lisbon - €)

Close	3.230	3.230	2.885
Max	3.549	3.549	3.389
Min	2.631	2.837	2.641
Average	3.075	3.207	3.012

EDP's Liquidity in Euronext Lisbon

Turnover (€ m)	10,597	4,656	5,044
Average Daily Turnover (€ m)	19	18	20
Traded Volume (million shares)	3,446	1,452	1,675
Avg. Daily Volume (million shares)	6.2	5.7	6.6

EDP Share Data

2018 2017 Δ %

Number of shares Issued (million)	3,656.5	3,656.5	-
Treasury stock (million)	21.8	21.9	-0.6%

EDP's Main Events

- 29-Jan:** EDP sells EUR 97 million of tariff deficit in Portugal
- 7-Mar:** EDP signed a 5-year revolving credit facility in the amount of €2,240,000,000
- 12-Mar:** EDP sells EUR 150 million of tariff deficit in Portugal
- 21-Mar:** EDP Brasil acquires 14.5% of Celesc and will launch bid for up to 33.6%
- 23-Mar:** EDPR announces the sale of a 20% stake in UK wind offshore project
- 27-Mar:** EDP Brasil launches bid for up to 33.6% of CELESC
- 5-Apr:** EDP's General Shareholders' Meeting
- 5-Apr:** Payment of Dividends – Financial Year 2017
- 6-Apr:** Appointment of Representatives for the General Supervisory Board
- 9-Apr:** EDP informs about news published today on BFM Business
- 27-Apr:** EDP Brasil announces results of the bid for CELESC
- 15-May:** Announcement regarding launching of preliminary offer announcement over EDP
- 18-May:** Capital Group's ownership interest in the capital of EDP decreases to 9.973%
- 12-Jun:** EDP sells EUR 641m in securitization of electricity tariff deficit in Portugal
- 20-Jun:** EDP issues EUR 750 million bond maturing in January 2026
- 4-Jul:** EDP Renováveis is awarded long-term CfD for 45MW of wind at Greek energy auction
- 19-Sep:** EDP Renováveis successfully establishes new institutional partnership structure for 280MW in the US
- 27-Sep:** Secretary of State for Energy's decision on alleged CMEC overcompensation
- 1-Oct:** Capital group's ownership interest in the share capital of EDP decreases to 2.958%
- 9-Oct:** EDP issues first EUR 600 million green bond maturing in October 2025
- 14-Oct:** Capital Group leaves its Qualified Shareholding Position in EDP
- 16-Oct:** ERSE announces proposal for electricity tariffs in 2019
- 16-Oct:** Paul Elliott singer notifies qualified shareholding in EDP
- 26-Oct:** EDP Brasil sells mini-hydro plants
- 29-Oct:** EDP Brasil closes R\$ 1.2 billion funding for new transmission line
- 14-Nov:** EDPR announces sale of additional 13.4% in UK wind offshore project
- 7-Dec:** EDP sells Portuguese tariff deficit for 384 Million euros
- 7-Dec:** Results and pricing of cash tender offers for debt securities
- 18-Dec:** EDPR sells 13.5% stake in French offshore wind projects
- 19-Dec:** EDP concludes sale of 100% of EDP Small Hydro
- 21-Dec:** EDP concludes sale of EDP PCH and Santa Fé
- 28-Dec:** EDPR concludes the sale of 10% stake in Moray Offshore (UK) to CTG
- 31-Dec:** EDPR announces its first sell down transaction in North America of a 499 MW portfolio of onshore wind assets

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2019 Financial Results

Conference call and webcast

Date: Friday, February 21st, 2020, 11:30 am (UK/Portuguese time)

Webcast: www.edp.com

Lisbon, February 20th, 2020

EDP - Energias de Portugal, S.A. Headquarters: Av. 24 de Julho, 12 1249 - 300 Lisboa, Portugal

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Important notice

On 1-Jan-19, EDP adopted IFRS 16, which supersedes IAS 17 in what respects the regulation of operating leases. The new standard requires the recognition of lease commitments for the entire duration of contracts into the balance sheet liabilities as well as the recognition of a new asset "Right Of Use Asset" as counterparty. The adoption of IFRS 16 implied higher liabilities (€737m) and higher assets (€748m) on 1-Jan-19. In 2019, it resulted in higher EBITDA (€65m) and lower net profit (-€12m).

Main highlights for the period

Key Operational Data	2019	2018	Δ %	Δ Abs.
Installed capacity (MW)	26,681	27,177	-2%	-497
Weight of Renewables (1)	73%	74%	-	-1p.p.
Production (GWh)	66,670	71,963	-7%	-5,294
Weight of Renewables (1)	66%	66%	-	0p.p.
Customers supplied (thousand of contracts)	11,426	11,444	-0%	-18
Customers connected (thous.)	10,470	10,343	1%	+127

Key Income Statement data (2) (€ million)	2019	2018	Δ %	Δ Abs.
Gross Profit	5,217	5,099	2%	+118
EBITDA	3,706	3,317	12%	+388
EBIT	1,838	1,584	16%	+254
Financial Results & Results JV/Assoc.	(645)	(543)	-19%	-101
Income taxes & CESE (3)	294	165	78%	+129
Non-controlling Interest	388	357	9%	+31
Net Profit (EDP Equity holders)	512	519	-1%	-7

Key Performance indicators (€ million)	2019	2018	Δ %	Δ Abs.
Recurring EBITDA (4)	3,716	3,287	13%	+430
Renewables	2,286	2,126	8%	+160
Networks	1,001	848	18%	+152
Clients solutions & EM	476	333	43%	+143
Other	(46)	(21)	-124%	-26
Recurring net profit (4)	854	797	7%	+57
OPEX Performance				
OPEX Iberia (€ million)	858	889	-4%	-32
Core OPEX/MW (€/MW) - Wind & Solar (5)	40.5	42.8	-5%	-2
OPEX Brazil (R\$ million) (5)	973	1,115	-13%	-142

Key Balance Sheet Data (€ million)	Dec-19	Dec-18	Δ %	Δ Abs.
Net debt	13,827	13,480	3%	+347
Adjusted net debt/EBITDA (x) (6)	3.6x	4.0x	-10%	-0.4x

In 2019, EDP reinforced its strategic positioning as a leader in energy transition: in renewables, EDP installed +0.9 GW of new wind and solar projects in the US, Europe and Brazil. Furthermore, since the beginning of 2019, EDP has secured 3.0 GW of new wind and solar projects through long-term contracts that are expected to start operations during our current strategic plan horizon (2019-2022). This represents 76% of the growth target for this period. Out of these projects, 1.0 GW were under construction as of December 2019. Regarding offshore wind, EDP installed the largest wind turbine ever installed on a floating platform and secured another long-term contract for 800 MW in a project to be built in Massachusetts, USA. Additionally, in January 2020, the terms for the 50/50 joint venture with Engie were agreed upon. **In electricity networks**, growth is concentrated in Brazil: i) in distribution, following previous years' significant investments, the recent regulatory revisions of EDP São Paulo and EDP Espírito Santo, resulted in an upward revision of our regulated asset base (+36%), reaching R\$5 bn (€1.1 bn); ii) in transmission, we reached c.40% of investment execution with the partial inauguration, in January 2020, of a second line with 203 km – Maranhão's line – 19 months ahead of schedule. **In energy supply**, the focus continues to be on our clients' satisfaction (-23% of complaints YoY, in Iberia), which prompted a stable number of electricity customers and an increase in new services provided, especially, maintenance of home appliance equipment within the residential segment, and energy efficiency within the corporate segment.

The 13% growth in recurring EBITDA benefited from good performance across all platforms. In renewables, wind and solar average installed capacity increased 1% to 10.9 GW. Moreover, the progress on execution of our asset rotation strategy as announced in March 2019, namely through the sale of a portfolio of wind farms in Europe and Brasil, yielded €0.3 bn gain. On the other hand, **hydro production** in Iberia fell 25% vs. 2018, standing 19% short of historical average in Portugal, as a result of weak hydro resources, which had a negative impact on EBITDA of nearly €0.2 bn. In **regulated networks**, growth stemmed mostly from Brazil, prompted by the impact from the recent regulatory revisions at our distribution concessions and expansion of transmission. In Iberia, our distribution networks benefited primarily from greater efficiency in operating expense, which decreased by 4%. In **Client solutions and energy management**, the Iberian supply segment was impacted by i) good results from our energy management activity and an adequate hedging policy in energy markets that more than compensated the deterioration of market conditions for coal-fired power plants; ii) in supply, the normalization of the market and regulatory environment compared to the extremely adverse context of 2018.

The 7% growth in recurring net profit reflects not only the 13% EBITDA expansion, but also the normalization of the effective tax rate and the an average cost of debt 10 bp higher YoY, at 3.9%, penalized by the higher cost of the €1 bn Green Hybrid bond issued in January 2019. The reported net profit was impacted by an €86m provision regarding Fridão hydro project, as well as by the €297m impairment in coal plants in Iberia (both before tax). Hence, the **conventional operations in Portugal** (including electricity distribution network, hydro and thermal generation, as well as energy supply), recorded at net loss of €98m in 2019 (vs. a loss of €18m in 2018), penalized by a continued adverse regulatory and fiscal context, which was worsened in 2019 by abnormally low hydro production.

As of December 2019, net debt stood at €13.8 bn, with an improvement in Adjusted Net Debt/EBITDA to 3.6x (vs. 4.0x in 2018). **Recurring organic cash flow grew 20% to €1.4 bn in 2019**, supported by global renewables strategy: the asset rotation option presented in our 2019-2022 strategic plan allowed for the gross investment in the development of new renewable assets and regulated networks to be offset by the sale of operating renewable assets (€1 bn gain in 2019). Furthermore, in December 2019, EDP reached an agreement for the sale of 6 hydro plants in Portugal (1.7 GW) for €2.2 bn with closing expected in second half of 2020. The disposal aims to fulfil the targets of portfolio optimization and improvement of risk profile, reflected in the strategic plan presented in March 2019.

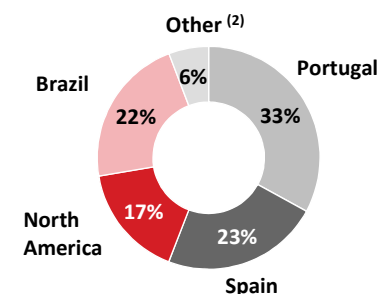
The Executive Board of Directors will propose at the Annual Shareholders' Meeting (April 16th) the distribution of a dividend for the year of 2019 in the amount of €0.19 per share, which represents a payout of 81% on net recurring income.

(1) Including Wind, Solar, Hydro and mini-hydro capacity; (2) Full P&L statement on page 24; (3) CESE: Extraordinary contribution from the energy sector; (4) Excluding one-off impacts as per page 3 (EBITDA) and page 4 (Net profit); (5) Adjusted for IFRS 16; (6) Net of regulatory receivables; Based on trailing 12 months recurring EBITDA and net debt excluding 50% of hybrid bond issues (including interest).

EBITDA Breakdown

EBITDA (€ million)	2019	2018	Δ %	Δ Abs.	1Q18	2Q18	3Q18	4Q18	1Q19	2Q19	3Q19	4Q19	4Q YoY	
													Δ %	Δ Abs.
Renewables	2,286	2,197	4%	+89	585	570	390	651	556	708	398	624	-4%	-27
Wind & Solar	1,648	1,300	27%	+348	381	305	184	431	385	576	257	430	0%	-1
Hydro Iberia	465	624	-25%	-159	142	217	167	97	112	93	109	151	55%	+53
Hydro Brazil	173	273	-37%	-100	62	48	40	123	59	39	31	44	-64%	-79
Networks	991	831	19%	+160	219	201	214	197	243	229	276	243	23%	+46
Iberia	632	625	1%	+7	159	155	162	149	165	173	159	134	-10%	-15
Brazil	360	206	75%	+154	60	46	52	48	78	55	116	110	128%	+62
Client solutions & EM	474	312	52%	+162	85	82	71	74	116	92	76	191	159%	+117
Iberia	336	137	145%	+199	45	32	14	46	84	59	44	149	222%	+103
Brazil	138	175	-21%	-37	41	49	57	27	32	33	32	42	52%	+14
Other	(46)	(23)	-100%	-23	8	(22)	12	(21)	7	(42)	3	(13)	-35%	+7
Consolidated EBITDA	3,706	3,317	12%	+388	898	832	687	901	921	987	753	1,044	16%	+143
- Adjustments (1)	(11)	31	-	-41	(18)	0	-	49	(0)	(0)	0	(11)	-122%	-59
Recurring EBITDA	3,716	3,287	13%	+430	916	832	687	852	921	987	753	1,055	24%	+203

EBITDA 2019



EBITDA advanced 12% YoY, to €3,706m in 2019, with a positive contribution across all the platforms. Our growth strategy of combining portfolio expansion (+€0.1 bn YoY) with asset rotation strategy (+€0.2 bn YoY) proved outstanding, surpassing the adverse weather effect on hydro production (nearly -€0.2 bn below normalized levels, mostly in Portugal) de-consolidation effects (-€0.1 Bn) and lower one-off contributions (-€41m YoY*). EBITDA performance was also driven by: (i) in Brazil, positive impact from regulatory reviews and execution of transmission investments; (ii) In Iberia, outstanding energy management results in 4Q19 (+€133m QoQ). **Recurring EBITDA was up by 13%, to €3,716m in 2019.** ForEx impact, amounted to +€10m, as USD appreciation vs. Euro (+5%), was largely compensated by Brazilian real depreciation (-2%). The adoption of IFRS16 impacted EBITDA by +€65m (+€45m of which at EDPR level).

RENEWABLES (61% of EBITDA, €2,286m in 2019) – Excluding one-off effects (€71m in 2018 mainly backed by gains on mini-hydro disposals in Brazil), **recurring EBITDA grew by 8% (+€160m YoY)**, driven by higher volumes and realised prices in wind & solar (+€97m YoY) and the benefits from our organic growth and asset rotation strategy (+€72m YoY and +€204m YoY, respectively). Nevertheless, EBITDA performance in 2019 was affected by below-the-average hydro resources in Portugal (nearly -€0.2 bn below normalized levels) and by the the de-consolidation of the wind farms in Europe (-€65m YoY) and some mini-hydros in Portugal and Brazil (-€46m YoY).

NETWORKS (26% of EBITDA, €991m in 2019) - EBITDA increased 19% YoY, prompted by Brazil (+€154m YoY), following: (i) **in distribution**, the positive outcome from regulatory reviews at both our concessions, resulting in regulated gross profit increases (+€31m) and on the update of the concessions assets' residual value (+€53m); (ii) ramp up of **transmission** activity (+€44m YoY on EBITDA), as the construction of our transmission lines progresses. In **Iberia**, EBITDA performance was mainly supported by a disciplined cost management, while gross profit evolution reflects Portugal's declining rate of return (-30 bp YoY, to 5.13%), in line with Portugal's 10-year bond yields during 2019 and the recognition of one-off provision (-€28m).

CLIENT SOLUTIONS & ENERGY MANAGEMENT (13% OF EBITDA, €474m in 2019) - EBITDA rose by 52% YoY (+€162m YoY), following a strong Energy Management performance, particularly in the 4Q19, and the normalization of the market and regulatory context for supply in Iberia from particularly weak 2018 conditions (+€93m YoY). Thermal generation & energy management in Iberia (+75% YoY, to €248m), reflected a strong performance of our energy management business, which benefitted from the increasing volatility in energy markets in 4Q19, namely due to lower spot prices in the wake of higher hydro output and lower gas prices. **In Brazil**, last year's EBITDA was positively impacted by the downward revision of the contracted level of thermal plant availability. In 2019, energy management activity was penalized by lower liquidity in the wholesale market and lower margins.

(*) *Non-recurring items: (i) +€31m in 2018, net impact of the sale of mini-hydro plants Brazil (+€82m), and 2H17's share of the impact from the difference between CMEC final adjustment recognised in Dec-17 and approved by the Government on May 3rd (-€18m), restructuring costs (-€34m); (ii) -€11m in 2019, including restructuring costs (-€13m), provision for the sharing of some gains with consumers (-€28m in electricity distributon in Portugal) and gain following the change in medical plan of employees in Brazil (+€30m).*

(1) Adjustments for one-off impacts, described above(*); (2) Includes Poland, Romania, France, Belgium, Italy and UK.

Profit & Loss Items below EBITDA

Profit & Loss Items below EBITDA (€ million)	2019	2018	Δ %	Δ Abs.	4Q18	1Q19	2Q19	3Q19	4Q19	4Q YoY	
										Δ %	Δ Abs.
EBITDA	3,706	3,317	12%	+388	907	921	987	753	1,044	15%	+137
Provisions	102	288	-65%	-186	5	4	1	92	4	-15%	-1
Amortisations and impairments	1,766	1,445	22%	+321	396	374	362	358	672	70%	+276
EBIT	1,838	1,584	16%	+254	506	544	624	303	368	-27%	-138
Net financial interest	(597)	(626)	5%	+28	(186)	(155)	(151)	(152)	(139)	-25%	+47
Capitalized financial costs	48	34	42%	+14	10	9	12	11	15	51%	+5
Unwinding of long term liabilities (1)	(204)	(177)	-15%	-27	(42)	(53)	(52)	(48)	(51)	21%	-9
Net foreign exchange differences and derivatives	(19)	(5)	-278%	-14	(13)	(6)	(11)	1	(3)	-80%	+10
Capital Gains/(Losses)	(3)	113	-	-116	94	-	(1)	(2)	0	-100%	-94
Other Financials	105	106	-1%	-1	26	19	18	15	53	105%	+27
Financial Results	(670)	(554)	-21%	-116	(111)	(186)	(185)	(175)	(124)	12%	-14
Share of net profit in JVs/associates (Details page 27)	25	11	130%	+14	2	5	7	2	11	475%	+9
Pre-tax Profit	1,194	1,041	15%	+153	397	364	446	130	254	-36%	-143
Income Taxes	226	100	127%	+126	49	99	38	9	80	62%	+31
<i>Effective Tax rate (%)</i>	<i>19%</i>	<i>10%</i>			<i>12%</i>	<i>27%</i>	<i>9%</i>	<i>7%</i>	<i>32%</i>		
Extraordinary Contribution for the Energy Sector	68	65	5%	+3	0	67	(0)	1	1	171%	+1
Non-controlling Interests (Details page 27)	388	357	9%	+31	125	98	104	65	121	-3%	-4
Net Profit Attributable to EDP Shareholders	512	519	-1%	-7	222	100	305	55	51	-77%	-171

In both 2019 and 2018, the amount of **provisions** includes one-off effects: (i) in 2019, €86m related to amounts invested on Fridão hydro project since concession awarding; (ii) in 2018, a €285m provision for CMEC innovative features.

The increase in amortisations and impairments (+22% YoY) is mainly driven by €312m impairments in 2019 (€297m on coal plants in Iberia, following the deterioration of market conditions arising from the increase in CO₂ prices; €15m at EDPR), the adoption of the IFRS 16 on leases (+€53m in 2019) and net capacity additions.

The evolution of Financial results (-21% YoY, to -€670m in 2019) primarily reflects gains in 2018 on the sale of some stakes in our offshore wind projects in UK and France (+€87m) and in Bioelectrica (+€24m). **Net interest costs decreased 5% YoY**, to €597m in 2019, reflecting last year's one-off costs mostly related to early debt prepayment (€39m cost) and while unveiling in 4Q19 a €12m cost decline vs 3Q19: avg. cost of debt stood at 3.9% in 2019 (vs. 3.8% in 2018) following the combined impact of higher average weight of the more expensive USD and BRL denominated debt and issuance of €1 bn hybrid bond at a 4.5% yield in Jan-19. Moreover, it is worth mentioning the effect of the adoption of IFRS 16 (€34m higher cost of 'Unwinding'); higher capitalised financial costs, driven by investments in transmission (Brazil); and other financials, including 2018's badwill on the acquisition of Celesc (+€18m in 2018) and revaluation gain at our equity stake in Feedzai in 2019 (+€31m).

Share of net profit in joint ventures and associates increased €14m YoY to €25m in 2019, mainly reflecting higher contribution from our hydro plants and Celesc, both in Brazil (details on page 27).

Income taxes amounted to €226m (+€126m YoY), representing an effective tax rate of 19% in 2019, up from an abnormally low level in 2018.

Non-controlling interests include €218m related to EDPR and €178m related to EDP Brasil. The 9% YoY increase in 2019 is mainly justified by the increase in net profit of EDP Brasil and EDPR (details on page 27).

Overall, net profit remained broadly stable YoY, totalling €512m in 2019. Adjusted by one-off impacts(*), **recurring net profit increased 7% YoY, to €854m in 2019**, as the asset rotation strategy and growth at networks in Brazil more than offset below-the-average hydro resources in 2019 and 2018's low effective tax rate.

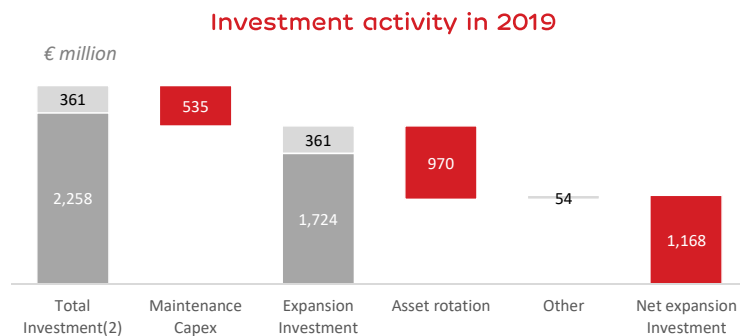
(*) *Non-recurring items impact at net profit level: (i) -€277m in 2018, including the regulatory impacts (-€208m), the impairments at coal plants in Iberia (-€21m), restructuring costs (-€21m), net gain on disposals (mini-hydros: +€40m; Bioelectrica: +€24m), debt prepayment fees and others (-€26m) and the extraordinary contribution for the energy sector (-€65m); (ii) -€342m in 2019, including the impairments (-€224m, mainly coal in Iberia), the provision for Fridão (-€59m), provision reversal at S Manoel and the gain on the revaluation of Feedzai (+€28m), one offs at EBITDA level (-€20m net of tax) and the extraordinary contribution for the energy sector (-€66m).*

(1) Includes unwinding of medium, long term liabilities (TEIs, IFRS-16, dismantling & decommissioning provision for generation assets, concessions) and interest on medical care and pension fund liabilities.

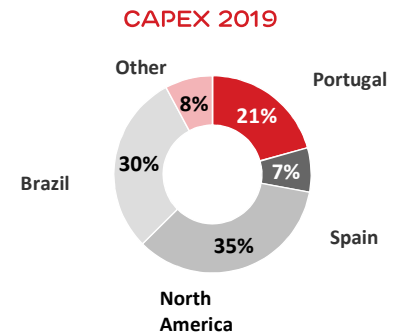
Investment activity

Capex (€ million)	2019	2018	Δ %	Δ Abs.
Expansion	1,724	1,394	24%	+329
Renewables	1,121	1,309	-14%	-188
Networks	585	73	-	+512
Other	18	12	52%	+6
Maintenance	535	637	-16%	-102
Renewables	46	41	14%	+6
Networks	326	428	-24%	-102
Other	162	168	-4%	-6
Consolidated Capex	2,258	2,031	11%	+227

Net expansion investment (€ m)	2019	2018	Δ %	Δ Abs.
Expansion Capex	1,724	1,394	24%	+329
Financial investments	361	210	71%	+150
Renewables	336			
Networks	11			
Other	14			
Financial divestments	(974)	(745)	-31%	-230
Renewables	(970)			
Asset rotations	(970)			
Other	-			
Networks	-			
Other	(4)			
Proceeds from TEI in US	(186)	(399)	53%	+213
Other (1)	244	(111)	-	+355
Net expansion investment	1,168	350	234%	+818



1Q18	2Q18	3Q18	4Q18	1Q19	2Q19	3Q19	4Q19
283	217	505	389	257	299	351	816
278	202	465	365	158	226	212	525
5	11	39	19	63	108	136	278
1	4	1	5	36	(34)	3	13
85	144	163	245	87	182	105	161
6	6	9	20	5	8	11	22
61	86	106	175	91	101	59	75
19	52	48	51	(9)	72	35	64
368	362	668	634	344	481	456	977



Consolidated capex amounted to €2,258m in 2019, 76% of which dedicated to expansion: 65% share in renewables, c35% share in Networks, with highlight to electricity transmission projects in Brazil.

Financial investments in 2019 (€361m) include: i) **In renewables**, amounts allocated to the build-out of wind onshore capacity in the U.S. and Canada (as committed under our Asset rotation deal in Dec-18), equity contributions to several offshore wind projects (UK, US, France and floating wind in Portugal) and on the construction of San Gaban hydro plant in Peru; ii) **In Networks**, the amount invested to increase our stake in Celesc, from 23% to 25.4%

Maintenance capex (€535m in 2019) was mostly dedicated to our regulated networks in Iberia and Brazil (60% of total), targeting a reduction of grid losses (Brazil) and the implementation of several digitalisation projects (Iberia).

Expansion investments (including financial investment) was focused in renewables globally and grids in Brazil:

1) €1,457m in new renewable capacity (c70% of the total) was distributed between North America (c70%), Europe (c25%) and Latam (c5%). (details on page 10).

2) €596m in networks in Brazil, dedicated to the roll out of transmission lines (€455m on construction works equivalent to 59% of capex program) and to grid expansion in distribution (€141m), which until 2018 was included in maintenance capex.

Financial divestment in 2019 is mainly impacted by €970m proceeds from asset rotation strategy: (i) €780m net proceeds from the sale of c51% stake in a 997 MW wind portfolio in Europe; and (ii) €190m proceeds associated with CAPEX incurred over 2019 with the full completion of Prairie Queen wind farm in US (disposal previously agreed in Dec-18).

All in all, net expansion investments amounted to €1,168m in 2019. The bulk of this (c55%) was dedicated to renewables, mainly wind in the US. Net expansion investments include €186m proceeds from new Tax Equity partnerships and +€244m effect mainly related to payments to fixed asset suppliers (mostly in wind), changes in consolidation perimeter and other.

(1) Includes Proceeds from Tax Equity Partnerships, Change in WC Fixed asset suppliers, Change in consolidation perimeter, reclassification of asset rotation gain and other; (2) Includes Capex and Financial investment.

Cash Flow Statement

Consolidated Cash Flow (€ million)	2019	2018	Δ %	Δ Abs.
Profit before income tax and CESE	1,194	1,041	15%	+153
Changes in Working capital	(919)	129	-	-1,048
Income tax and CESE	(285)	(256)	-11%	-29
Adjustments(1)	2,544	2,220	15%	+324
Net Cash from Operations	2,534	3,135	-19%	-600
Asset rotation (Gains)/Losses	-313	-196	-60%	-117
Net Cash from Operating Activities	2,221	2,938	-24%	-717
Net Cash from Investing Activities	(1,645)	(1,179)	-40%	-466
Net Cash from Financing Activities	(834)	(2,335)	64%	+1,501
Changes in Cash and Cash Equivalents	(258)	(576)	55%	+318
Effect of exchange rate fluctuations	(2)	(21)	90%	+19

Change in Net Debt (€ million)	2019	2018	Δ %	Δ Abs.
Recurring CF from Operations (2)	2,584	2,605	-1%	-21
Recurring EBITDA	3,716	3,287	13%	+430
Change in operating working capital, taxes and other	(1,132)	(681)	-66%	-451
Maintenance capex (3)	(657)	(664)	1%	+7
Net interests paid	(549)	(565)	3%	+16
Payments to Institutional Partnerships US	(81)	(174)	53%	+93
Other	129	(13)	-	+142
Recurring Organic Cash Flow	1,426	1,189	20%	+237
Net Expansion	(1,168)	(350)	-234%	-818
Expansion capex	(1,724)	(1,394)	-24%	-329
Proceeds from asset rotations	970	422	130%	+548
Acquisition and disposals	(38)	(60)	36%	+22
Other net Financial Investm. (exc. Asset rotations)	(318)	172	-	-490
Proceeds from Institut. Partnerships in US	186	399	-53%	-213
Other	(244)	111	-	-355
Change in Regulatory Receivables	(65)	602	-	-667
Dividends paid to EDP Shareholders	(691)	(691)	0%	-0
Effect of exchange rate fluctuations	(49)	(13)	-267%	-36
Other (including one-off adjustments)	200	(315)	-	+515
Decrease/(Increase) in Net Debt	(347)	422	-	-769

Funds from Operations (€ million)	2019	2018	Δ %	Δ Abs.
EBITDA	3,706	3,317	12%	+388
Current income tax	(146)	(246)	41%	+100
Net financial interests	(597)	(626)	5%	+28
Net Income and dividends received from Associates	2	(15)	-	+18
FFO Adjustments	(317)	(194)	-63%	-123
FFO - Funds From Operations	2,648	2,237	18%	+411

Recurring organic cash flow amounted to €1.4 Bn in 2019, translating the cash generated and available to fulfil EDP's key strategic pillars of sustainable growth, deleveraging and shareholder remuneration (dividends). In 2019, Recurring organic cash flow rose by €0.2 Bn YoY (+20%), driven by higher gains with asset rotation transactions and lower payments to Tax Equity Partnerships.

Maintenance capex (including payables to fixed assets suppliers) amounted to €657m in the period, mostly related to the networks business and higher YoY payments to fixed asset suppliers (including the impact from the adoption of IFRS16).

The increase in 'Other' recurring organic cash flow items (+€142m YoY to €129m) is mainly justified by higher gains on asset rotation transactions to €313m.

Net expansion investment activity amounted to €1.2 Bn in 2019, c70% of which devoted to renewables and the bulk of the rest to transmission in Brazil. (details on page 5).

Regulatory receivables increased by €65m in 2019, mainly driven by Portugal, following new receivables arising from deviations between the system's real costs and ERSE's assumptions (details on page 7).

On 15-May-19, EDP paid its annual **dividend totalling €691m (€0.19/share)**, in line with the previous year.

Effects of exchange rate fluctuations resulted in a €49m increase on net financial debt in 2019, mainly justified by the appreciation of the USD vs. Euro (+2% YTD, to 1.12).

The caption **Other** includes +€0.5 Bn relative to the 50% equity content attributed by the credit rating agencies to the new €1 bn hybrid bond issued in Jan-19 and -€0.3 Bn one-off impacts in 2019, including an extraordinary contribution to employees' medical care services fund (-€0.17 Bn) and €0.17 Bn tax payment relative to 2018 deficit sales.

Overall, net debt increased by €0.3 Bn in 2019, to €13.8 Bn as of Dec-19, reflecting the pace of expansion activity focused in renewables and grids, while the cash in of proceeds from asset rotation deal in Brazil happened in Feb-20.

Funds from operations (FFO) rose by 18% YoY, to €2,648m in 2019, mainly impacted by higher EBITDA (details on page 3) and lower current income tax.

(1) Includes Amortisation and Impairments, Provisions, Financial Income and expenses, Other; (2) Excluding Regulatory Receivables; (3) Maintenance capex includes payables to fixed assets suppliers.

Consolidated Financial Position

Assets (€ million)	Dec vs. Dec		
	Dec-19	Dec-18	Δ Abs.
Property, plant and equipment, net	19,676	22,708	-3,031
Right-of-use assets	829	-	+829
Intangible assets, net	4,224	4,737	-513
Goodwill	2,120	2,251	-132
Fin. investments & assets held for sale (details page 27)	3,525	1,088	+2,437
Tax assets, deferred and current	1,889	1,560	+329
Inventories	368	342	+26
Other assets, net	8,127	6,946	+1,181
Collateral deposits	61	193	-131
Cash and cash equivalents	1,543	1,803	-260
Total Assets	42,362	41,627	+735

Equity (€ million)	Dec-19	Dec-18	Δ Abs.
Equity attributable to equity holders of EDP	8,858	8,968	-110
Non-controlling Interest (Details on page 27)	3,774	3,932	-158
Total Equity	12,632	12,900	-268

Liabilities (€ million)	Dec-19	Dec-18	Δ Abs.
Financial debt, of wich:	16,571	16,085	+487
<i>Medium and long-term</i>	13,125	13,462	-338
<i>Short term</i>	3,447	2,623	+824
Employee benefits (detail below)	1,312	1,407	-96
Institutional partnership liability (US wind)	1,287	1,269	+18
Provisions	1,053	1,018	+34
Tax liabilities, deferred and current	1,121	1,238	-118
Deferred income from inst. partnerships	1,003	962	+41
Other liabilities, net	7,384	6,746	+637
Total Liabilities	29,730	28,727	+1,003

Total Equity and Liabilities	42,362	41,627	+735
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Employee Benefits (€ million)	Dec-19	Dec-18	Δ Abs.
Employee Benefits (bef. Tax)	1,312	1,407	-96
Pensions	631	759	-129
Medical care and other	681	648	+33
Deferred tax on Employee benefits (-)	-404	-422	+18
Employee Benefits (Net of tax)	908	985	-78

Regulatory Receivables (€ million)	Dec-19	Dec-18	Δ Abs.
Regulatory Receivables	370	287	+82
Portugal	366	216	+150
Brazil(1)	4	71	-67

Change in Fair value (+)	-	-	-
Deferred tax on Regulat. Receivables (-)	-115	-68	-47
Regulatory Receivables (Net of tax)	255	219	+35

Total amount of **property, plant & equipment and intangible assets** decreased €3.5 bn vs. Dec-18 to €23.9 bn as of Dec-19, mainly driven by the transfer of a portfolio of hydro assets in Portugal and others to 'Assets held for sale' (-€1.9 bn), the derecognition (-€1.2 bn) of wind assets in Europe and Brazil related with the Asset Rotation strategy, the transfer to 'Other assets, net' of €0.3 bn related with the Fridão Hydro plant and the impairment recognized in the coal plants in Iberia (-€0.3bn). Such effects were partly mitigated by: (i) the construction activity (+€1.3 bn); (ii) the net impact from the evolution of USD (+2%) and the BRL (-2%) against the EUR (+€0.1 bn). As of Dec-19, works in progress amounted to €1.9 bn (8% of total consolidated tangible and intangible assets): 77% at EDPR level, 3% at EDP Brasil level and the remaining 20% at Iberian level.

The adoption of IFRS 16, on January 1st 2019, resulted in a €0.75 bn accounted as '**Right-of-use assets**'. Along with this, a liability of €0.74 bn was booked under 'Other liabilities, net'. The current amount of €0.8 bn is the result of the normal activity of the group.

The book value of **financial investments & assets held for sale net of liabilities** increased by €2.4 bn vs. Dec-18, mainly due to the recognition under the account "assets held for sale" of the abovementioned portfolio of hydro assets (+€1.9 bn) and the wind offshore assets under the scope of the strategic memorandum of understanding with Engie (+€0.2 bn). (More details on page 27).

Tax assets net of liabilities, deferred and current increased €0.4 bn vs. Dec-18 at €0.8 bn in Dec-19. **Other assets (net)** increased €1.2 bn vs. Dec-18 to €8.3 bn as of Dec-19, mainly supported by the development of transmission lines and execution of CAPEX in Networks and the abovementioned effect related with Fridão hydro plant.

Equity book value attributable to EDP shareholders decreased by €0.1 bn to €8.9 bn as of Dec-19, reflecting on one hand the positive effects of the net profit for the period and the Forex and on the other hand the payment of annual dividend. **Non-controlling interests** declined €0.16 bn largely reflecting the effect of the asset rotation deal completed in Jul-19.

Pension fund, medical care and other employee benefit liabilities fell by €0.1 bn vs. Dec-18, to €1.3 bn as of Dec-19 (**€0.9bn, net of tax**), reflecting the recurrent payment of pension and medical care expenses in 2019, the extraordinary contribution to the pension fund in Portugal (€142m).

Institutional partnership liabilities were flat vs Dec-18 at €1.3 bn, following the benefits appropriated by the tax equity partners during the period which offset a new institutional partnership secured and the USD appreciation against the EUR.

Provisions were broadly flat vs. Dec-18, at €1.1 Bn. This caption includes, among others, provisions for dismantling (€486m, +€5m YoY), of which €270m related with wind farms and a provision related with the amount invested on the Fridão hydro plant since the concession attribution (€86m).

Other liabilities (net) increased €0.6 bn vs Dec-19, includes the adoption of the IFRS-16 (+€0.76 bn) and the increase in equipment suppliers liabilities (+€0.2 bn), associated with the augmented development of expansion projects. These effects were mitigated by the deconsolidation of wind projects associated with the asset rotation transactions executed (-€0.4 bn)

Net regulatory receivables amounted to €370m as of Dec-19 (**€255m net of tax**). The evolution during 2019 is mainly justified by unanticipated deviations vs. ERSE's assumptions: i) lower amounts allocated to the electricity system regarding mitigation measures (+€212m); ii) special regime over-cost caused by lower realized prices and higher volumes (+€182m). In 2019, Portuguese electricity system debt amounted to €3.57 bn, including a €0.44 bn decrease in ex-ante debt and higher tariff deviations, due to be recovered in 1-2 years.

Also worth to note is EDP's full disposal of ex-ante deficit created in 2019: €1.1bn sold in 2Q19.

(1) Excluding the amount corresponding to the impact from the exclusion of ICMS from the calculation of PIS/COFINS from past years in our distribution companies (R\$1.8 Bn), since the receivable (recognized under current tax assets) is a pass-through to the tariff.

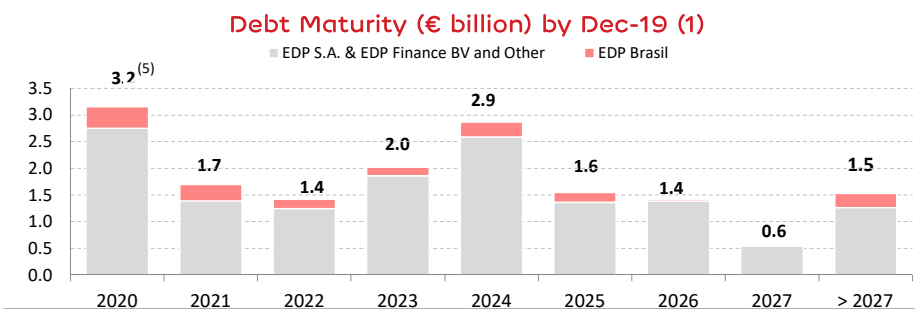
Net Financial Debt

Net Financial Debt (€ million)	Dec-19	Dec-18	Δ %	Δ Abs.
Nominal Financial Debt	16,222	15,766	3%	+456
EDP S.A., EDP Finance BV and Other	13,618	13,228	3%	+390
EDP Renováveis	769	882	-13%	-113
EDP Brasil	1,835	1,656	11%	+179
Accrued Interest on Debt	288	258	12%	+30
Fair Value of Hedged Debt	61	61	1%	+1
Derivatives associated with Debt (2)	(135)	(116)	-16%	-19
Collateral deposits associated with Debt	(61)	(193)	68%	+131
Hybrid adjustment (50% equity content)	(906)	(391)	-132%	-515
Total Financial Debt	15,469	15,385	1%	+84
Cash and cash equivalents	1,543	1,803	-14%	-260
EDP S.A., EDP Finance BV and Other	377	922	-59%	-545
EDP Renováveis	582	386	51%	+196
EDP Brasil	584	496	18%	+89
Financial assets at fair value through P&L	99	102	-3%	-3
EDP Consolidated Net Debt	13,827	13,480	3%	+347

Credit Lines by Dec-19 (€ million)	Maximum Amount	Number of Counterparts	Available Amount	Maturity
Revolving Credit Facilities	75	1	75	Jul-21
Revolving Credit Facility	3,300	24	3,300	Oct-24
Revolving Credit Facility	2,240	17	1,790	Mar-25
Domestic Credit Lines	256	9	256	Renewable
Underwritten CP Programmes	50	1	50	2021
Total Credit Lines	5,921		5,471	

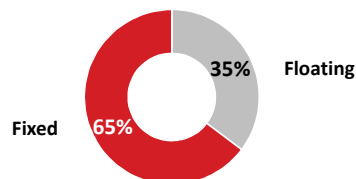
Credit Ratings	S&P	Moody's	Fitch
EDP SA & EDP Finance BV	BBB-/Stable/A-3	Baa3/Stable/P3	BBB-/Stable/F3
Last Rating Action	15/04/2019	03/04/2017	05/12/2018

Key ratio	Dec-19	Dec-18
Net Debt / EBITDA adjust. for Reg. Receivables (4)	3.6x	4.0x

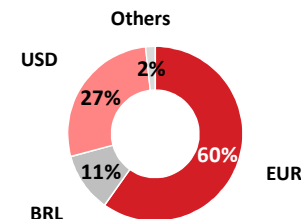


(1) Nominal Value incl. 100% of the hybrid bonds; (2) Derivatives designated for fair-value hedge of debt including accrued interest; (3) After FX-derivatives; (4) Based on trailing 12 months recurring EBITDA and net debt excl. 50% of hybrid bond issue (including interest); (5) Includes 100% (€750M) of the 2015 Hybrid bond

Debt by Interest Rate Type (1) - Dec-19



Debt by Currency (1) (3) - Dec-19



EDP's financial debt is mostly issued at holding level (EDP S.A. and EDP Finance B.V.), accounting for 84% of the Group's Nominal Financial Debt. Debt for the group is raised mostly through debt capital markets (83% in Dec19, +2% YoY), with the remaining through bank loans.

Maintaining access to diversified sources of funding and assuring refinancing needs, mostly through underwritten syndicated facilities, at least 12-24 months ahead continue to be part of the company's prudent financial strategy.

In April-19, S&P affirmed EDP's credit rating at "BBB-", with Stable outlook on the expectation of EDP successfully executing its strategy. The company's current credit rating under Moody's is "Baa3" with Stable outlook and under Fitch is "BBB-", with Stable outlook.

Looking at 2019's major debt repayments and financing transactions: In Jan-19, EDP extended €2,095m out of the €2,240m Revolving Credit Facility maturity until Mar-24 (except for €145m which matures in Mar-23) and issued €1.000m of subordinated green notes with a yield of 4.5% with maturity in 2079 (green hybrid); in Apr-19, EDP repaid at maturity the remainder € 501m of a €600m bond that carried a coupon of 2.625%;. In Sep-19, EDP issued a €600m green note with 7-year maturity and a record-low yield of 0.4%. Also, in Sep-19, EDP extended €3,295m out of the €3,300m Revolving Credit Facility until Oct-24 (except for €5m which matures in Oct-23). Lastly, in Oct-19 19 EDP repaid at maturity the remainder \$637m of a \$1,000m bond that carried a coupon of 4.9%.

Refinancing needs for 2020 amount to €3.2 Bn including €2.2 Bn of bonds. Note that the increase in 2020 maturities over the past quarter is fully explained by an increase in outstanding ECP and by the repurchase of our 2015 €750m hybrid in 1Q2020: **as of Jan-2020**, EDP issued a new €750 million Green Hybrid with a coupon of 1.7%, first call date in Apr-25 and final maturity in 2080; together with the new issuance, EDP also launched a tender over the abovementioned 2015 hybrid (coupon of 5.375%), that had a success rate of 91% and will allow EDP to exercise the clean-up call in March over the remaining 9%. Additionally, in Jan-2020 a USD bond matured with a total outstanding value of \$583m and a coupon of 4.125%. For the remainder of 2020, there are two Euro bonds maturing in June and September with coupons of 4.125% and 4.875%, respectively, with a total outstanding amount of €695m. **In 2021 and 2022**, refinancing needs amount to approx. €3.1 Bn.

Total cash and available liquidity facilities amounted to €7.1 Bn by Dec-19, of which €5.5bn are credit facilities.

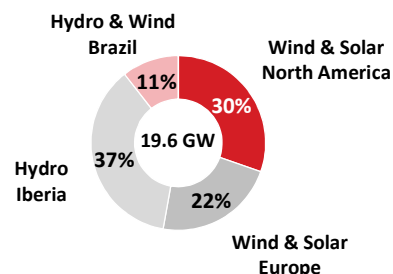


Business Segments

Renewables: Asset base & Investment activity

Installed capacity (MW)	Dec-19	Δ YTD	Δ Abs.	YoY Additions	Reductions	Under Construc.
EBITDA MW	19,597	-497	-497	+749	-1,239	+664
Wind & Solar	10,812	-489	-489	+749	-1,239	+664
US	5,714	382	+382	+581	-199	+409
Canada	30	-	-	-	-	+100
Mexico	200	-	-	-	-	-
North America	5,944	+382	+382	+581	-199	+509
Spain	1,974	-337	-337	+53	-390	+18
Portugal	1,164	-144	-144	+47	-191	+6
France	53	-368	-368	+19	-388	+63
Belgium	-	-71	-71	-	-71	+10
Poland	418	-	-	-	-	+58
Romania	521	-	-	-	-	-
Italy	271	+50	+50	+50	-	-
Europe	4,401	-871	-871	+169	-1,040	+154
Brazil	467	-	-	-	-	-
Hydro	8,785	-8	-8	-	-	-
Iberia	7,186	-8	-8	-	-	-
Brazil	1,599	-	-	-	-	-
Equity MW	1,101	+191	+191	+139	+40	+408
Wind onshore & Solar	550	+179	+179	+139	+40	-
US	398	+179	+179	+139	+40	-
Spain	152	-	-	-	-	-
Wind offshore	-	-	-	-	-	+330
Hydro	551	+12	+12	-	-	+78
Latam	551	+12	+12	-	-	+78

Installed Capacity EBITDA MW - Dec-19



Assets' average life and residual life

(Years)

Hydro Iberia	31	35
Hydro Brazil	17	14
Wind & Solar Brazil	3	27
Wind & Solar Europe	10	20
Wind & Solar North America	7	23

Renewables capacity accounts **77%** of our total installed capacity, equivalent to **20.6 GW** (including Equity MW).

In 2019, we commissioned **888 MW** of wind and solar capacity (139 MW of which equity), the bulk of which in US (81%). On the other hand, as part of our asset rotation strategy, we completed, in July, the sale of our **c51% stake in 997 MW in operation in Europe** (388 MW in France, 348 MW in Spain, 191 MW in Portugal and 71 MW in Belgium), leading to the deconsolidation of the full EBITDA MW capacity.

As of today, we have **PPAs secured for 5.4 GW** (+3.0 GW vs Dec-18) to support installations in 2019-22, representing around **76% of our targeted global renewables capacity built-out plans**. To date, we secured PPAs in North America (2.8 GW), Europe (1.2 GW), LatAm (1.2 GW) and Offshore (0.2 GW).

As of Dec-19, our wind & solar capacity under construction totaled **994 MW**, including attributable capacity of 316 MW in Moray East (UK) and 14 MW Windplus floating project (Portugal), both offshore technologies as Equity MW.

In **North America**, we have currently **509 MW of wind farms under construction**, including Harvest Ridge I (200 MW) and Reloj del Sol (209 MW) that are expected to be commissioned in 2020 and Nation Rise (100 MW in Canada). The last one, we have already sold an 80% stake, though keeping the commitment to complete construction.

In **Europe**, we have 154 MW of wind onshore under construction of which 18 MW are wind repowering projects in Spain.

Our **hydro portfolio** comprises **7,186 MW in Iberia** (c. 40% of which pumping capacity) and 1,599 MW in Brazil. In LatAm, we own equity stakes on 3 hydro plants (Jari, Cachoeira-Caldeirão and S. Manoel, all in Brazil) and own a 50% share in a hydro plant under construction in Peru (San Gaban, 78 MW net).

Lastly, in 2019, we agreed on the **asset rotation of Babilonia wind farm** (137 MW) in operation in Brazil and the disposal of **1,689 MW of hydro plants in Portugal**. The deconsolidation of the full EBITDA MW capacity will follow the financial closing of these transactions (deal in Brazil on February 12th and Hydro disposal in Portugal expected in 2H20).

All in all, **net expansion investments amounted** to €621m in 2019, mainly due to proceeds from the asset rotation deals (+€780m equity proceeds from the deal in Europe and +€190m cash received relating to Prairie Queen). The **expansion investment** is mainly devoted to projects in North America (~70%) and Europe (~27%). **Financial investments of €318m** includes expenditures mostly in Prairie Queen, Nation Rise, San Gaban and wind offshore. Lastly, impact of €338m, mainly related to payments to **fixed asset suppliers** (largely in wind) and **changes in consolidation perimeter** (mostly related to the agreed asset rotation deals in Europe and Brazil).

Net expansion investment (€ million)	2019	2018	Δ %	Δ Abs.
Expansion capex	1,121	1,310	-14%	-188
North America	784	757	4%	+27
Europe	307	389	-21%	-82
Brazil & Other	31	164	-81%	-133
Financial investment	318			
Proceeds from TEI in US	186			
Proceeds from asset rotations	970			
Other (1)	338			
Net expansion investment	621			

Maintenance Capex (€ million)	2019	2018	Δ %	Δ Abs.
Iberia	39	35	12%	+4
Brazil	8	6	28%	+2
Maintenance capex	46	41	14%	+6

(1) Includes Change in WC Fixed asset suppliers and changes in consolidation perimeter. Excludes asset rotation gain.

Renewables: Financial performance

Income Statement (€ million)	2019	2018	Δ %	Δ Abs.
Gross Profit	2,409	2,495	-3%	-86
OPEX	547	586	-7%	-40
Other operating costs (net)	-424	-288	-47%	-135
Net Operating Costs	123	298	-59%	-175
EBITDA	2,286	2,197	4%	+89
Amortisation, impairments; Provision	898	979	-8%	-81
EBIT	1,388	1,218	14%	+170

EBITDA (€ million)	2019	2018	Δ %	Δ Abs.
Wind & Solar	1,648	1,300	27%	+348
North America	615	654	-6%	-40
Europe	914	653	40%	+261
Brazil & Other	120	-7	-	+127
Hydro	638	897	-29%	-259
Iberia	465	625	-26%	-160
Brazil	173	273	-37%	-100
EBITDA	2,286	2,197	4%	+89

Output (GWh)	2019	2018	Δ %	Δ Abs.
Wind & Solar	30,041	28,359	6%	+1,682
Hydro	13,958	18,899	-26%	-4,941
Iberia	9,830	13,305	-26%	-3,476
Brazil	4,129	5,594	-26%	-1,465
Total output	43,999	47,258	-7%	-3,260

Core OPEX/Average MW	2019	2018	Δ %	Δ Abs.
Wind & Solar	40.5	42.8	-5%	-2.3
Hydro				
Iberia	11.8	23.6	-50%	-11.7
Brazil	13.7	13.9	-1%	-0.2

In 2019, EBITDA rose by 4% YoY to €2,286m, mainly driven by higher volumes and prices (+€97m YoY) in the wind & solar business and by a favorable forex impact of +€22m. Moreover, the benefits from our portfolio expansion (+€72m on EBITDA) and asset rotation strategy (+€203m YoY) were mitigated by below-the-average hydro resources in Iberia (-€0.2 bn) and de-consolidation of assets sold (-€65m).

Wind and solar EBITDA increases to nearly €1,648m (+27% YoY) was driven by:

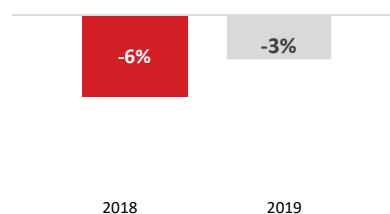
- net growth effect, including higher gain on both asset rotation deals (+€313m in 2019 vs €110m in 2018), de-consolidation of assets sold (-€65m YoY in 2H19) and portfolio expansion (+€72m YoY);
- stronger wind resources (+3 pp, although still 3% short of P50), average selling price of +3% YoY (backed by eastern Europe) and by the adoption of IFRS 16 (+€45m YoY). Finally, EBITDA performance also reflected the expiring of 10-year PTC incentive in US wind projects (-€33m YoY).

The 29% YoY decline in hydro EBITDA to €638m was mainly driven by extremely weak hydro resources in Iberia (trimming EBITDA by €0.2 Bn vs. normalized level) and the deconsolidation of mini hydro plants disposed on in 4Q18 in Portugal and Brazil (-€46m on EBITDA loss and +€82m of net gain in 2018).

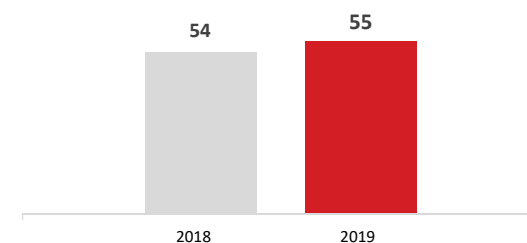
OPEX performance in renewables (-7% YoY) reflected tight cost control and successful implementation of ongoing savings program, both in Iberia and Brazil. In wind and solar, **Core OPEX per average MW decreased to €40.5k** (-5% YoY), before IFRS 16 adjustment (+€45m YoY). Considering additional impacts (IFRS16, offshore and one-offs), Adjusted Core OPEX per average MW is **stable at 0% YoY** (ex-forex).

Other operating costs (net), amounting to a **€424m** revenue in 2019, includes the gain of the asset rotation deals (+€313m in 2019) completed in July of 2019. In Iberia, lower generation taxes at €36m (vs. €51m in 2018), mainly due to the underlying lower production and lower PTC revenue (-\$15m YoY).

Wind portfolio resources 2019
vs. LT average (P50)

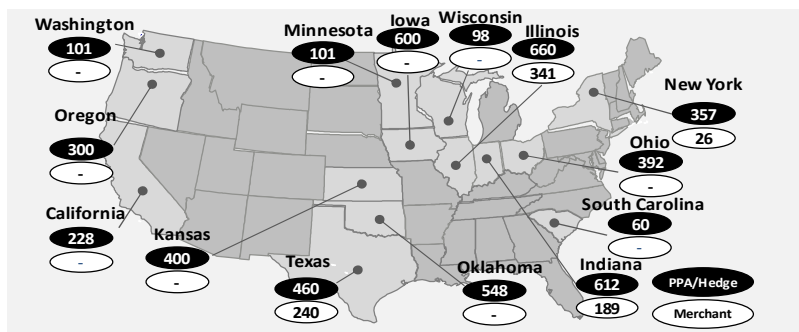


Wind & Solar Avg. Selling Price 2019
vs. 2018 (€/MWh)



Renewables in North America

USA: EBITDA MW by market - Dec-19



In North America, **installed capacity** (5,944 EBITDA MW) is **98% wind** while the remaining is **solar** (90 MW). Additionally, we own **equity stakes in other wind projects**, equivalent to **398 MW** (+82% YoY), following the commissioning of 199 MW Prairie Queen, in Aug-19 (20% equity stake) and acquisition of 50% of First Solar portfolio (139 MW net). In 2019, **87% of total installed capacity is PPA/Hedged contracted**.

Electricity production increased +5% YoY, mainly reflecting the growth of installed capacity (+7% YoY) and stable wind resources YoY (although 7% short of LT average). **Wind resources improvements** were YoY concentrated in the **Eastern region**, while **Central and West** had **poorer resources**.

Gross profit rose to USD 729m (+7% YoY) in 2019, mainly supported by the 5% **output growth**. **PTC Revenue & Other declined to USD 203m** (-7% YoY), mainly due to the combined effect from the **expiration of 10-year PTC fiscal incentives** in some wind projects (-USD 39m YoY) and **establishment of new partnerships** (+USD 21m YoY).

EBITDA stood at USD 688m (-8% YoY) in 2019, mainly justified by 2018's gain from the asset rotation of 80% stake from 499 MW of wind onshore capacity in the US and Canada (€109m gain booked in 4Q18).

Operating data	2019	2018	Δ %	Δ Abs.
Installed capacity (MW EBITDA)	5,944	5,562	7%	+382
US PPA/Hedge	4,917	4,539	8%	+378
US Merchant	797	793	0%	+3
Canada	30	30	0%	-
Mexico	200	200	0%	-
Load Factor (%)	34%	34%	0%	0 p.p.
US	34%	34%	-1%	0 p.p.
Canada	27%	27%	-2%	-1 p.p.
Mexico	42%	40%	4%	2 p.p.
Electricity Output (GWh)	16,492	15,644	5%	+848
US	15,696	14,873	6%	+823
Canada	70	71	-2%	-1
Mexico	726	700	4%	+26
Avg. Selling Price (USD/MWh)	45	45	0%	-0
US	44	44	0%	-0
Canada (\$CAD/MWh)	147	146	1%	+1
Mexico	65	64	1%	+1
EUR/USD (Avg. of the period)	1.12	1.18	5%	-0.06
Financial data (USD million)	2019	2018	Δ %	Δ Abs.
Adjusted Gross Profit	932	901	3%	+31
Gross Profit	729	682	7%	+46
PTC Revenues & Other	203	219	-7%	-15
EBITDA	688	749	-8%	-61
EBIT	333	427	-22%	-94
Equity stakes	2019	2018	Δ %	Δ Abs.
Equity MW	398	219	82%	+179
Share of net profit in JVs/associates	0	-2	84%	+2



- Sales can be agreed under PPAs (up to 20 years), through Hedges or Merchant prices;
- Green Certificates (Renewable Energy Credits, REC) subject to each state regulation;
- Tax Incentive:
 - i) PTC collected for 10-years since CoD (\$25/MWh in 2019);
 - ii) Wind farms beginning construction in 2009 and 2010 could opt for 30% cash grant in lieu of PTC.



- Feed-in Tariff (Ontario). Duration: 20-years;
- Renewable Energy Support Agreement (Alberta).



- Technological-neutral auctions (opened to all technologies) in which bidders offer a global package price for the 3 different products (capacity, electricity generation and green certificates);
- EDPR project: bilateral Electricity Supply Agreement under self-supply regime for a 25-year period.

NA Wind resources 2019 vs. LT average (P50)



2018 2019

Renewables in Iberia

Operating data	2019	2018	Δ %	Δ Abs.
Installed capacity (MW EBITDA)	10,324	10,813	-5%	-489
Wind & Solar	3,139	3,620	-13%	-481
Spain	1,974	2,312	-15%	-337
Portugal	1,164	1,309	-11%	-144
Hydro	7,186	7,193	0%	-8
Load Factor (%)				
Wind & Solar				
Spain	28%	26%	8%	2 p.p.
Portugal	29%	27%	8%	2 p.p.
Hydro	16%	21%	-26%	-5 p.p.
Electricity Output (GWh)	18,287	21,464	-15%	-3,177
Wind & Solar	8,458	8,159	4%	+299
Spain	5,298	5,164	3%	+134
Portugal	3,160	2,995	5%	+165
Hydro	9,830	13,305	-26%	-3,476
Net production	8,461	11,476	-26%	-3,015
Pumping	1,368	1,829	-25%	-461
Avg. Selling Price (€/MWh)				
Wind & Solar				
Spain	71	72	-2%	-1
Portugal	89	91	-2%	-2
Hydro	54	62	-14%	-9

Financial data (€ million)	2019	2018	Δ %	Δ Abs.
Gross Profit	1,239	1,417	-13%	-177
Wind & Solar (1)	668	679	-2%	-11
Spain	384	372	3%	+12
Portugal	284	272	4%	+12
Hydro	572	738	-23%	-166
EBITDA	1,201	1,114	8%	+87
Wind & Solar (1)	736	489	50%	+247
Hydro	465	625	-26%	-160
EBIT	768	644	19%	+125
Wind & Solar (1)	574	327	76%	+247
Hydro	194	317	-39%	-123

Equity stakes (€ million)	2019	2018	Δ %	Δ Abs.
Installed capacity (Equity MW)	152	152	0%	-
Share of net profit in JVs/associates	3.7	4.5	-18%	-1

In Iberia, **installed capacity** (10.3 GW) is split between wind (~30%) and hydro (70%), following the deconsolidation of 348 MW in Spain and 191 MW in Portugal resulting from the sale of our c. 51% stake in an European wind portfolio of assets (Jul-19). In Dec-19 and as part of our disposal plan, we agreed to sell 6 hydro plants in Portugal (1.7 GW) for €2.2 bn. The closing is expected in 2H20.

In Iberia **wind & solar output** increased to 8.5 TWh (+4% YoY), experiencing a stronger wind resource and high load factors, despite the deconsolidation of capacity sold in Jul-19 (-539 MW YoY). Moreover, the average selling price decreased 2% YoY and as a result, gross profit amounted to €668m (-2% YoY).

Hydro gross profit was down to €572m (-23% YoY), mainly driven by weak hydro resources despite a strong recovery of this resource in the last quarter (+56% resource above historical average in 4Q19).

Hydro resources in Portugal were 19% below historical average (vs. +5% in 2018), resulting in a decline of 26% YoY in net production. In the 4Q19 there was a strong recovery of hydro resources in Iberia, allowing to store the levels of our reservoirs (+0.4 TWh above historical average) in Portugal.

The **average unit pumping margin** was above €15/MWh while **average selling price of hydro production** stood at €54/MWh (-14% YoY) being supported by hedging gains.

Regarding **one-off provisioning**: (i) in 2019, we booked an €86m provision for invested amounts on Fridão hydro plant project since concession attribution; (ii) in 3Q18, hydro's share in the €285m provision related to the alleged CMEC overcompensation.

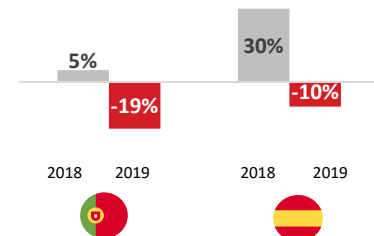


- Wind energy developed until 2015 receives pool price + premium / MW, if necessary, in order to achieve a target return of 7.4% for the 2016-2019 period;
- Premium calculation is based on standard assets (load factor, production and costs);
- Since 2016, all the new renewable capacity is allocated through competitive auctions.



- MWs from previous regime: Feed-in Tariff inversely correlated with load factor throughout the year. Tariff monthly inflation-updated, through the later of: 15y of operation or 2020, + 7 years (cap/floor system: €74/MWh - €98/MWh);
- ENEOP portfolio : price set in an international competitive tender for 15y (or the first 33 GWh/MW) + 7y (extension cap/floor system: €74/MWh - €98/MWh). First year tariff at c.€74/MWh, CPI monthly-updated;
- VENTINVEST portfolio: price defined in an international competitive tender and set for 20y (or the first 44 GWh/MW) of €66/MWh.

Hydro resources 2019 vs. LT average P50



(1) Includes hedging adjustments

Renewables in the Rest of Europe

Operating data	2019	2018	Δ %	Δ Abs.
Installed capacity (MW EBITDA)	1,263	1,652	-24%	-389
Romania	521	521	0%	-
Poland	418	418	0%	-
France	53	421	-87%	-368
Italy	271	221	22%	+50
Belgium	0	71	-	-71
Load Factor (%)	26%	24%	10%	2 p.p.
Romania	25%	23%	9%	2 p.p.
Poland	30%	25%	19%	5 p.p.
France	22%	23%	-4%	-1 p.p.
Italy	27%	27%	1%	0 p.p.
Belgium	22%	21%	6%	1 p.p.
Electricity Output (GWh)	3,333	3,321	0%	+12
Romania	1,151	1,059	9%	+92
Poland	1,098	919	19%	+179
France	465	829	-44%	-364
Italy	551	385	43%	+166
Belgium	68	129	-47%	-60
Avg. Selling Price (€/MWh)	78	73	6%	+4
Romania (RON/MWh)	323	255	27%	+68
Poland (PLN/MWh)	309	254	21%	+54
France	90	90	0%	-0
Italy	95	110	-14%	-15
Belgium	106	104	2%	+2
ForEx rate - average in the period				
EUR/PLN	4.30	4.26	-1%	+0.04
EUR/RON	4.75	4.65	-2%	+0.09

Financial data (€ million)	2019	2018	Δ %	Δ Abs.
Gross Profit	267	246	9%	+21
Romania	83	57	46%	+26
Poland	84	59	41%	+24
France & Belgium	49	87	-44%	-39
Italy	52	42	24%	+10
EBITDA	221	169	31%	+53
EBIT	134	82	63%	+52

In the Rest of Europe (ex-Iberia), installed capacity stands heavily focused in onshore wind (~1,203 MW) and 50 MW of solar capacity in Romania. Our average installed capacity decreased 389 MW, mostly due to the deconsolidation of our asset rotation strategy deal in Europe in Jul-19.

Output was stable at 3,333 GWh, as the benefit from stronger wind resources (+2.5 pp vs LT Average) was offset by the de-consolidation of wind farms sold (388 MW in France and 71 MW in Belgium). Poland and Romania factored considerable high load factors being the main contributors to keep generation stable.

Average selling price was 6% higher YoY, reflecting a recovery in prices in Poland and Romania.

As a result, EBITDA rose to €221m (+31% YoY), following stronger wind resources, market price recovery in Eastern Europe, portfolio expansion and asset rotation gains.



- Wind assets (installed until 2013) receive 2 GC/MWh until 2017 and 1 GC/MWh after 2017 until completing 15 years. 1 out of the 2 GC earned until Mar-2017 can only be sold from Jan-2018 and until Dec-2025. Solar assets receive 6 GC/MWh for 15 years. 2 out of the 6 GC earned until Dec-2020 can only be sold after Jan-2021 and until Dec-2030. GC are tradable on market under a cap and floor system (cap €35 / floor €29.4); Wind assets (installed in 2013) receive 1.5 GC/MWh until 2017 and after 0.75 GC/MWh until completing 15 years; The GCs issued starting in Apr-2017 and the GCs postponed to trading from Jul-2013 will remain valid and may be traded until Mar-2032.



- Electricity price can be established through bilateral contracts; Wind receive 1 GC/MWh which can be traded in the market. Electric suppliers have a substitution fee for non compliance with GC obligation. From Sep-17 onwards, substitution fee is calculated as 125% of the avg market price of the GC from the previous year and capped at 300PLN.



- Feed-in tariff for 15 years: (i) €82/MWh up to 10th year, inflation updated; (ii) Years 11-15: €82/MWh @2,400 hours, decreasing to €28/MWh @3,600 hours, inflation updated; Wind farms under the RC 2016 scheme receive 15-yr CfD which strike price value similar to existing FIT fee plus a management premium.



- MW <2013 are (during 15 years) under a pool + premium scheme; MW >2013 were awarded a 20 years contract through competitive auctions. According with the auction scheme, the electricity produced by these wind farms is sold on the market with CfD.



- Market price plus green certificate (GC) system;
- Separate GC prices with cap and floor for Wallonia (€65/MWh-100/MWh);
- Option to negotiate long-term PPAs.

Renewables in Brazil

Operating data	2019	2018	Δ %	Δ Abs.
Installed capacity (MW EBITDA)	2,066	2,066	0%	-
Wind	467	467	0%	-
Hydro	1,599	1,599	0%	-
Load Factor (%)				
Wind	43%	40%	6%	2 p.p.
Hydro	29%	40%	-26%	-10 p.p.
Electricity Output (GWh)	5,886	6,829	-14%	-943
Wind	1,757	1,235	42%	+522
Hydro	4,129	5,594	-26%	-1,465
Hydro volume sold - Brazil (GWh)	10,952	8,502	29%	+2,450
PPA contracted	10,568	7,403	43%	+3,165
Other	384	1,099	-65%	-715
Hydro physical guarantee (GWh)	6,672	7,278	-8%	-606
Avg. Selling Price (R\$/MWh)				
Wind	205	195	5%	+10
Hydro	170	186	-9%	-16
ForEx rate - average in the period				
EUR/BRL	4.41	4.31	-2%	+0.11

Financial data (R\$ million)	2019	2018	Δ %	Δ Abs.
Gross Profit	1,187	1,174	1%	+13
Wind	327	215	52%	+112
Hydro	859	959	-10%	-99
PPA contracted	1740	1182	47%	+558
GSF impact (net of hedging) & Other	-881	-224	-294%	-657
EBITDA	1,387	994	40%	+393
Wind	613	140	337%	+473
Hydro	774	854	-9%	-80
Lajeado	408	359	13%	+48
Peixe Angical	246	202	22%	+44
Other	120	292	-59%	-172
EBIT	1,179	731	61%	+448

Equity stakes (R\$ million)	2019	2018	Δ %	Δ Abs.
Installed capacity (Equity MW)	551	539	2%	+12
Share of net profit in JVs/associates	24	-23	-	+47

Our renewable portfolio in Brazil encompasses 2.1 GW of consolidated installed capacity: 1,599 MW in hydro plants and 467 MW in wind farms. Additionally, EDP owns **equity stakes in hydro plants, representing an attributable capacity of 551 MW.**

Hydro output decreased by 26% YoY, but this figure is affected by the sale of mini hydro plants in 2018 (EDP PCH, Santa Fé and Costa Rica).

The 10% YoY decline in **Hydro gross profit** (-R\$99m YoY) derives from the aforementioned de-consolidation of small hydro plants (-R\$123m). Excluding this, gross profit rose by +3% YoY. Hydro energy sold under PPA increased by 43% YoY, mainly due to the increased number of bilateral contracts, including short-term purchases of energy. In parallel, the average selling price of hydro decreased 9%, impacted by Peixe Angical, which output is entirely sold in the market (and thus, the decline in the selling price reflects lower PLD) and Energest which selling price of bilateral contracts in 2019 was lower than in 2018.

EBITDA from hydro declined by R\$80m, not only due to the 10% decline in gross profit as above mentioned, but also due to booked gains of R\$375m in the 2018 due to the sale of mini hydro plants.

Wind output grew by 42% YoY, mainly due to the commissioning of wind capacity in 4Q18 (137 MW), which also contributed to improve the average load factor. **Wind gross profit grew by +R\$112m**, reflecting new capacity added and higher selling price.

EBITDA from wind increased by +R\$473m, reflecting gross profit underlying performance and the asset rotation gain booked on the sale of Babilonia wind farm (+R\$377m).

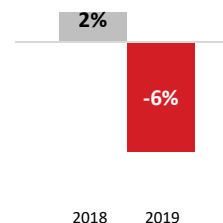
Wind:

- Old installed capacity under a feed-in tariff program ("PROINFA")
- Since 2008, competitive auctions awarding 20-years PPAs

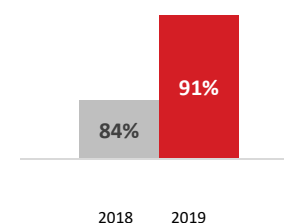
Hydro:

- All the capacity has long term contracted remuneration regimes at the inception,
- Hydro plants are remunerated at an established PPA price and are obliged to deliver a certain amount of physical guarantee of energy.

BR Wind resources 2019 vs. LT average



BR GSF (1) 2019 Generating Scale Factor



(1) In Brazil, Generation Scale Factor (GSF), reflecting the total (real) generation, accounted as a proportion of the total volume of Physical Guarantee in the system (when has a strong volatility on quarterly basis).

Networks: Financial performance

Income Statement (€ million)	2019	2018	Δ %	Δ Abs.
Gross Profit	1,816	1,715	6%	+102
OPEX	551	597	-8%	-46
Other operating costs (net)	274	286	-4%	-13
Net Operating Costs	825	884	-7%	-59
EBITDA	991	831	19%	+160
Amortisation, impairments; Provision	370	348	6%	+22
EBIT	621	483	29%	+138

OPEX & Capex performance	2019	2018	Δ %	Δ Abs.
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Controllable Costs (1)				
Iberia (€ m)	362	383	-6%	-21
Brazil (R\$ m)	697	715	-3%	-19

Controllable Costs				
Iberia (€/Supply point)	52	56	-6%	-3
Brazil (R\$/Supply point))	198	207	-5%	-10

Employees (#)	5,752	5,788	-1%	-36
Iberia	3,459	3,602	-4%	-143
Brazil	2,293	2,186	5%	+107

Capex (2) (Net of Subsidies) (€ million)	911	501	82%	+409
Portugal	270	243	11%	+28
Spain	39	33	18%	+6
Brazil	601	225	-	+376
Distribution	147	152	-4%	-5
Transmission	455	73	-	+381

Network ('000 Km) (3)	341	339	0%	+2
Portugal	227	226	0%	+1
Spain	21	21	0%	+0
Brazil	93	92	1%	+1

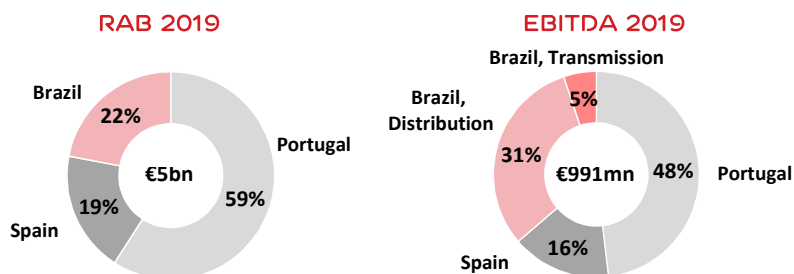
Our Networks segment includes activities of distribution of electricity, in Portugal, Spain and Brazil; electricity last resort supply activity in Portugal (LRS); and the new activity of transmission, in Brazil.

The 19% YoY growth in 2019 EBITDA (to €991m, +€160m YoY) was prompted by Brazil, namely: (i) In distribution, the positive outcome from regulatory reviews at both our concessions, resulting in tariff increases (+€31m) and the update of the concessions assets' residual value (+€53m); (ii) ramp up of transmission activity (+€44m on EBITDA), as the construction of our transmission lines progresses. **In Iberia,** EBITDA performance was mainly supported by the cost cutting trajectory and disciplined cost management, while gross profit evolution reflects Portugal's declining rate of return (-30 bp YoY, to 5.13%), in line with Portugal's 10-year bond yields; and the recognition of provisions for amounts deemed to be returned to the system (-€28m).

The overall impact of one-off impacts on EBITDA growth was immaterial: (i) **in 2019,** €28m provision for the amounts to return to the tariff, €31m gain related with a change in future liabilities arising from a change in health care services supplier, in Brazil, and restructuring costs (€12m) mainly in Portugal; (ii) **In 2018,** restructuring costs (€17m).

OPEX improved by 8% YoY to €551m in 2019, including a net positive one-off impact of €19m. In Iberia, controllable costs fell by 6% YoY, reflecting cost saving efforts and an increasing penetration of smart meters installed. **In Brazil,** OPEX was mostly impacted by a gain arising from a change in the medical plan (+€31m). It is also worth highlighting that despite the increase in headcount and annual inflation update in wages our tight cost control, insourcing and digital strategies yielded significant cost savings: controllable costs per customer decreased 5% YoY, in BRL (-7% in EUR terms).

Capex in 2019 (€911m) includes €513m dedicated to expansion, of which €455m related to the new transmission lines under construction in Brazil (Lot 11, 18 and 21, in Maranhão, São Paulo/Minas Gerais and Santa Catarina states, respectively) and €58m committed to develop the distribution network in Brazil. Maintenance capex is related to the distribution network: (i) in Iberia, it includes €40m invested in the installation of ~691k smart meters in Portugal during 2019; (ii) in Brazil, it includes investments targeting network improvements and reduction of losses.



(1) Supplies & services + Personnel costs; (2) Net of subsidies; (3) Relative to distribution.

Networks in Iberia

Electricity Distribution & LRS in Portugal

Income Statement (€ million)	2019	2018	Δ %	Δ Abs.
Gross Profit	1,050	1,084	-3%	-34
OPEX	334	355	-6%	-21
Concession fees	262	258	1%	+4
Other operating costs (net)	-23	-9	-	-15
Net Operating Costs	573	604	-5%	-32
EBITDA	477	480	-1%	-2
Amortisation, impairment; Provisions	267	254	5%	+13
EBIT	210	226	-7%	-16

Gross Profit Performance	2019	2018	Δ %	Δ Abs.
Gross Profit (€ million)	1,050	1,084	-3%	-34
Regulated	1,039	1,076	-3%	-37
Non-regulated	11	9	26%	+2

Distribution Grid				
Regulated revenues (€ million)	1,007	1,039	-3%	-32
Electricity distributed (GWh)	45,589	46,059	-1%	-469
Supply Points (th)	6,277	6,226	1%	+52

Last Resort Supply				
Regulated revenues (€ million)	32	36	-13%	-5
Customers supplied (th)	1,034	1,125	-8%	-91
Electricity sold (GWh)	2,658	3,016	-12%	-358

Electricity Distribution in Spain

Income Statement (€ million)	2019	2018	Δ %	Δ Abs.
Gross Profit	197	193	2%	+4
OPEX	55	55	-1%	-1
Other operating costs (net)	-12	-7	-	-5
Net Operating Costs	43	48	-12%	-6
EBITDA	155	145	7%	+10
Amortisation, impairment; Provisions	36	31	14%	+4
EBIT	119	113	5%	+6

Gross Profit Performance	2019	2018	Δ %	Δ Abs.
Gross Profit (€ million)	197	193	2%	+4
Regulated	191	189	1%	+1
Non-regulated	7	3	92%	+3
Electricity Supply Points (th)	668	666	0%	+2
Electricity Distributed (GWh)	8,262	9,360	-12%	-1,099

Electricity distribution and LRS in Portugal

In 2019, distribution allowed revenue, amounting to €1,007m, was impacted by: (i) one-off cost of €28m on account of past gains to be returned to the system during 2020; and (ii) lower than preliminarily set regulated revenues following weak demand and lower Portuguese government 10-year bond yields, which resulted in a rate of return on HV/MV assets of 5.13%, 29 bp below ERSE's assumption in 2019 tariffs.

Electricity distributed in 2019 posted a 1% YoY decline, mostly due to an adverse temperature effect, with a particular impact on the residential segment. Supply points advanced by 1%.

In the **last resort electricity supply (LRS) activity**, gross profit declined €5m YoY, reflecting a lower number of customers (-91 thousand YoY), to a share of 16% of total electricity customers in Portugal.

Net operating costs were 5% lower YoY (-€32m), driven by tight cost control and continuing efforts of digitalization and processes streamlining. This cost performance is closely related to fewer clients' claims (-19% YoY), fewer clients switching between suppliers and higher share of telemetering: as of Dec-19 there were ~2.6m smart meters installed, of which ~70% were remotely operated. Other operating costs reflect the recovery of previous periods' revenues.

Overall, EBITDA was flat YoY as operational efficiencies and disciplined cost management largely mitigated the adverse effect from lower sovereign yields and electricity demand, along with one-off adjustments at both gross profit and OPEX levels (HR restructuring costs of €9m). The implementation of IFRS16 explains +€5m YoY on EBITDA.

On 16-Dec-2019, **ERSE released 2020 electricity tariffs**, setting a 0.4% average tariff decrease for normal low voltage (NLV) segment, applicable to clients in the regulated market (out of the Social Tariff). Accordingly, regulated revenues for 2020 were assumed at €1,029m in the electricity distribution and €32m in the last resort electricity supply. Electricity distribution regulated revenues preliminarily set assume a rate of return on HV/MV assets (RoRAB) of 5.13% (reflecting an underlying avg. 10-year Portuguese bond yields of 1.14%) and an expected electricity demand in Portugal of 46.3 TWh in 2019 (1.4% above 2019).

Electricity distribution in Spain

EBITDA from electricity distribution activity in Spain rose 7% (+€10m YoY), to €155m.

It is worth noting that distributed electricity fell by 12% YoY, penalised by a strong decline of one large industrial consumer's production activity.

Networks in Brazil

ForEx rate - average in the period	2019	2018	Δ %	Δ Abs.
EUR/BRL	4.41	4.31	-2%	0.11

Income Statement (R\$ million)	2019	2018	Δ %	Δ Abs.
Gross Profit	2,498	1,870	34%	+629
OPEX	664	767	-13%	-103
Other operating costs (net)	211	185	14%	+26
Net Operating Costs	875	952	-8%	-77
EBITDA	1,624	917	77%	+706
Amortisation, impairment; Provisions	282	256	10%	+27
EBIT	1,341	661	103%	+680

Distribution - Key drivers (R\$ million)	2019	2018	Δ %	Δ Abs.
Customers Connected (th)	3,524	3,451	2.1%	+73
EDP São Paulo	1,936	1,887	2.6%	+49
EDP Espírito Santo	1,588	1,564	1.5%	+24
Electricity Distributed (GWh)	25,591	25,007	2.3%	+584
Regulated customers	14,202	13,834	2.7%	+368
Customers in Free Market	11,389	11,173	1.9%	+216
Electricity Sold (GWh)	14,143	13,769	2.7%	+375
EDP São Paulo	7,980	7,934	0.6%	+46
EDP Espírito Santo	6,163	5,835	5.6%	+329
Technical losses (% of electricity distributed)				
EDP São Paulo	5.6%	5.6%	1.0%	0.1 p.p.
EDP Espírito Santo	7.9%	7.5%	4.4%	0.3 p.p.
Gross Profit	2,253	1,832	23%	+420
Regulated revenues	1,869	1,650	13%	+219
Other	384	182	110%	+201
EBITDA	1,393	887	57%	+506
EDP São Paulo	634	460	38%	+174
EDP Espírito Santo	759	427	78%	+332

Transmission - Key drivers (R\$ million)	2019	2018	Δ %	Δ Abs.
Gross Profit	246	37	-	+209
EBITDA	231	30	-	+201
EBIT	232	30	-	+202

Equity stakes (R\$ million)	2019	2018	Δ %	Δ Abs.
Share of net profit in JVs/associates	47	29	62%	+18

Gross profit from distribution activities increased by 23% **(+R\$420m)**, propelled by the regulatory review at our distribution companies, leading to **the recognition of higher asset base (+R\$234m), the tariff update (+R\$136m) and +R\$39m YoY from higher volumes of electricity distributed (+2.3% YoY).**

Gross profit from **transmission** reached R\$246m in 2019 **(+R\$209m YoY)**, following the commissioning of our first line in Dec-18 and the evolution of construction works in the remaining lines. In early Jan-2020, lot 11 was partially commissioned, 19 months ahead of the regulatory schedule, which will allow an anticipation of Regulated Revenues by R\$17m.

OPEX decreased 13% YoY, justified by a one-off change in social benefits related to a change in the provider of medical assistance, which resulted into a booked gain of R\$134m in EDP Espírito Santo. Excluding this one-off, OPEX would have increased 4%, reflecting the strategy of insourcing and digitalization of processes.

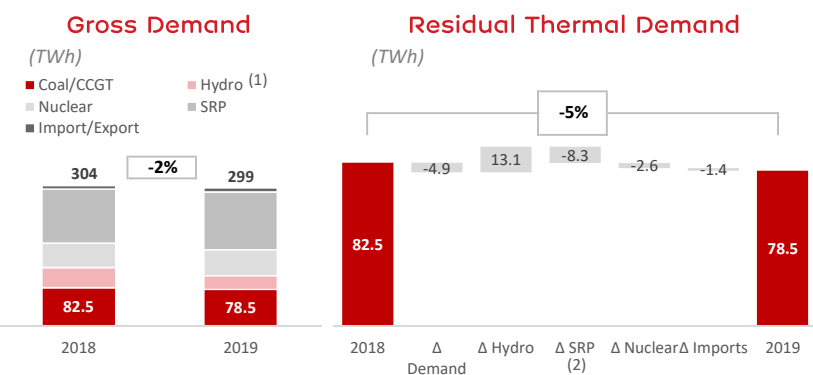
Overall, reported EBITDA from networks activities rose 77% YoY (+R\$706m), backed by a strong performance of both our distribution and transmission activities.

Also to note that in Dec-19, EDP Brasil acquired 692k preferential shares of **Celesc**, which increased our stake in this company to 25.35%. Stronger results from Celesc, together with the successive increases in our stake since 2018, led to +62% YoY results from this equity stake.



- EDP operates both in distribution in and transmission businesses, through its subsidiary EDP Brasil
- EDP Brasil holds 100% of EDP São Paulo and EDP Espírito Santo. Furthermore, EDP Brasil owns a 25,35% stake in CELESC, which operates the concession of the distribution grid in Santa Catarina state.
- A new regulatory period began for EDP Espírito Santo in Aug-19 (renewed every 3 years) and for EDP São Paulo in Oct-19 (renewed every 4 years). The regulated WACC is currently defined at 8.09%
- EDP operates one transmission line (since Dec-18) and part of another line (since Jan-20), while developing 4 other transmission lines, including a new one, acquired in May-19.

EDP in the Iberian market



Main Drivers (3)	2019	2018	Δ %	Δ Abs.
Electricity spot price (Spain), €/MWh	48	57	-17%	-10
Electricity final price (Spain), €/MWh (4)	53	63	-17%	-11
Iberian Electricity 1Y Fwd Price (€/MWh)	55	61	-10%	-6
CO2 allowances (EUA), €/ton	25	16	56%	+9
Coal (API2), USD/ton	61	92	-34%	-31
Mibgas, €/MWh	15	24	-36%	-9
Gas NBP, €/MWh	14	23	-41%	-10
Brent, USD/bbl	64	71	-9%	-7
EUR/USD (Avg. of the period)	1.12	1.18	5%	-0.06
Gas Demand in Iberia (TWh)	466	414	13%	+52

Income Statement (€ million)	2019	2018	Δ %	Δ Abs.
Gross Profit	825	677	22%	+148
OPEX	376	360	4%	+16
Other operating costs (net)	113	180	-37%	-66
EBITDA	336	137	145%	+199
EBIT	-156	-170	8%	+14

Key financial data breakdown (€ million)	2019	2018	Δ %	Δ Abs.
Gross Profit	825	677	22%	+148
Supply	353	273	29%	+79
Thermal & Energy Management	472	403	17%	+68
EBITDA	336	137	145%	+199
Supply	88	-5	-	+93
Thermal & Energy Management	248	142	75%	+106
EBIT	-156	-170	8%	+14
Supply	47	-44	-	+91
Thermal & Energy Management	-202	-126	-61%	-77

Iberian electricity market context

During 2019, electricity demand in Iberia declined 2% YoY (-4.9 TWh). Residual thermal demand (RTD), i.e. coal and CCGT generation, decreased 5% YoY in 2019 (-4.0 TWh), reflecting: (i) +8.3 TWh YoY of renewables/cogeneration (SRP) output mainly driven by better wind resources and, to a lower extent, by solar; (ii) +2.6 TWh YoY of nuclear output; and (iii) a 1.4 TWh increase in net imports. On the opposite direction, hydro output (net of pumping) declined 13 TWh YoY in the wake of extremely weak hydro resources (19% and 10% below-the-average resources in Portugal and Spain in 2019, respectively; vs. 5% and 30% above-the-average in 2018, respectively). Coal output declined 66% YoY (-30 TWh), as lower gas prices and higher CO₂ costs prompted for a switch towards CCGT production (+72% YoY, +26 TWh).

Average electricity spot price declined 17% YoY, to ~€48/MWh in 2019 (~€41/MWh in 4Q19), fuelled by the decreasing trajectory of coal and gas prices (-34% YoY and -36% YoY respectively). Consequently, average electricity final price in Spain declined 17% YoY in 2019, to €53/MWh.

EDP Performance

EBITDA increased +€199m YoY to €336m (€149m in 4Q19), propelled by: (i) strong performance of our thermal & energy management business mainly in 4Q19, due to our hedging results which more than offset the increase in avg. production costs of thermal plants in Iberia; (ii) normalisation of operating conditions in Supply business vs. a weak 2018; and (iii) lower generation taxes in Spain and clawback levy in Portugal following its suspension during 1Q19.

In 2019, the outlook for our coal plants deteriorated materially following: (i) worsening market conditions arising from the rise in CO₂ prices and decline in gas prices; (ii) stronger political will to anticipate the closure of coal capacity, namely in Portugal. As a result, EDP booked an impairment of €297m on its coal power plants in Iberia. As a result, EBIT was negative at -€156m in 2019. In 2018, EBIT figure was highly impacted by the thermal's share in the €285m provision related to the alleged overcompensation of the CMEC.

On energy management, it is worth noting that EDP keeps tracking market conditions to adapt its hedging strategy. For 2020, EDP already forward contracted spreads for over 90% of expected production, with hydro/nuclear production contracted at €55/MWh and average thermal spreads at high single digit.

- Our client solutions & energy management segment in Iberia incorporates our supply, thermal and energy management activities, encompassing 6.4 GW of thermal installed capacity, ~5.3m electricity clients and energy trading activities in Iberia.
- These businesses are the roots for the success of our integrated portfolio management, ensuring a responsive and competitive structure capable of offering clients diversified solutions and the necessary security of supply.

Sources: EDP, REN, REE; (1) Net of pumping; (2) Special Regime Production, namely wind, solar and cogeneration; (3) Average in the period; (4) Final price reflects spot price and system costs (capacity payment, ancillary services);

Clients solutions & Energy management in Iberia

Supply - Key drivers and financials	2019	2018	Δ %	Δ Abs.
Portfolio of Clients (th)				
Electricity	5,270	5,273	0%	-2
Portugal	4,104	4,119	0%	-15
Spain	1,166	1,154	1%	+12
Gas	1,562	1,555	0%	+7
Portugal	659	659	0%	-1
Spain	903	895	1%	+8
Dual fuel penetration rate (%)	30.4%	30.3%	0%	+0
Services to contracts ratio (%)	18.9%	18.0%	5%	+0
Volume of electricity sold (GWh)	30,358	30,669	-1%	-311
Residential	12,889	13,216	-2%	-328
Business	17,469	17,452	0%	+16
Volume of gas sold (GWh)	12,218	11,917	3%	+302
Residential	6,470	6,730	-4%	-260
Business	5,748	5,186	11%	+562
Gross Profit (€ million)	353	273	29%	+79
EBITDA (€ million)	88	-5	-	+93
Capex (€ million)	38	26	48%	+12

Supply Iberia

Number of electricity clients in Portugal and Spain was broadly stable YoY, as EDP maintains its focus on service quality and is leveraging on its customer portfolio to increase the share of wallet. In fact, the number of complaints per 1,000 contracts decreased 23% in 2019, the penetration rate of new services increased by 5% YoY to 18.9% in Dec-19, while the rate of dual fuel offer (electricity + gas) increased slightly to 30.4% in Dec-19 (vs. 30.3% in Dec-18).

Electricity volumes sold in Iberia fell by 1% YoY, while **gas volumes rose** by 3% YoY, reflecting the adverse impact of mild temperatures on residential consumption.

EBITDA at our supply activities in Iberia increased +€93m YoY to €88m (€16m in 4Q19), supported by the normalisation of regulatory conditions, following a particularly adverse 2018. **EBITDA** performance was highly impacted by gross profit evolution, coupled with a lower value of provisions for doubtful clients at EBITDA level.



- EDP's electricity clients portfolio in Iberia (~5.3m clients), has a significant weight of residential and SME clients, corresponding to ~42% of total consumption.

Thermal generation & Energy management Iberia

Production in 2019 decreased 10% YoY, due to the reduction in coal output (-49% YoY) leading to a 32 p.p. decrease in the load factor of our coal plants to 34% in 2019 (18% in 4Q19), which was partly mitigated by higher CCGT output. **Avg. thermal production cost** posted a 21% YoY rise (to €51/MWh in 2019), due to the increase in CO₂ prices.

The decline in thermal generation EBITDA, mostly due to lower volumes and margins was more than compensated by the strong performance of our energy management business, which benefitted from the decline in gas prices and our hedging policy based on forward contracting of thermal spreads. Our hedging policy benefitted from the increasing volatility in energy markets in 4Q19, namely due to stronger hydro volumes, lower spot prices and lower gas prices, enhancing energy management results. Note that generation taxes in Spain and clawback levy in Portugal (-€32m YoY), were suspended during the 1Q19.

Due to the aforementioned factors, **EBITDA from thermal generation & energy management in Iberia** increased 75% YoY to €248m in 2019 (€133m in 4Q19).

Thermal & EM - Drivers and financials	2019	2018	Δ %	Δ Abs.
Generation Output (GWh)	18,826	20,853	-10%	-2,027
CCGT	10,183	5,333	91%	+4,851
Coal	7,149	14,016	-49%	-6,867
Nuclear	1,223	1,196	2%	+28
Other	270	309	-12%	-38
Load Factors (%)				
CCGT	31%	16%	91%	+15p.p.
Coal	34%	66%	-49%	-32p.p.
Nuclear	90%	88%	2%	+2p.p.
Generation Costs (€/MWh) (1)	51	42	21%	+9
CCGT	57	59	-3%	-2
Coal	51	39	31%	+12
Nuclear	5	5	-4%	-0
Gross Profit (€ million)	472	403	17%	+68
EBITDA (€ million)	248	142	75%	+106
Capex (€ million)	57	69	-18%	-13

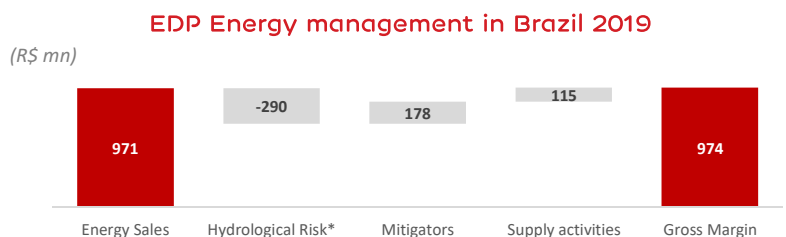


- Our thermal portfolio in Iberia encompasses 6.4 GW installed capacity, which plays an active role in ensuring the security of electricity supply: 59% in CCGT, 38% in coal, 2% in nuclear and 1% of cogeneration and waste.

(1) Includes fuel costs, CO₂ emission costs and hedging results.

Clients solutions & Energy management in Brazil

Key drivers	2019	2018	Δ %	Δ Abs.
PLD	227	288	-21%	-61
GSF	91%	84%	8%	+7p.p.



* Includes GSF, PLD and MRE

ForEx rate - average in the period	2019	2018	Δ %	Δ Abs.
EUR/BRL	4.41	4.31	-2%	+0.11

Income Statement (R\$ million)	2019	2018	Δ %	Δ Abs.
Gross Profit	779	946	-18%	-166
OPEX	159	175	-9%	-16
Other operating costs (net)	-1	-3	71%	+2
EBITDA	628	775	-19%	-147
EBIT	428	605	-29%	-177

Supply & EM - Key drivers and financials	2019	2018	Δ %	Δ Abs.
Electricity sales (GWh)	14,100	18,102	-22%	-4,002
Gross Profit (R\$ million)	160	220	-27%	-60
EBITDA (R\$ million)	111	178	-38%	-67
EBIT (R\$ million)	103	173	-41%	-70

Thermal - Key drivers and financials (1)	2019	2018	Δ %	Δ Abs.
Installed Capacity (MW)	720	720	0%	-
Electricity Sold (GWh)	8,291	4,834	72%	+3,457
PPA contracted	3,707	3,455	7%	+252
Other	4,584	1,379	232%	+3,205
Pecém Availability	95%	80%	19%	+15p.p.
Gross Profit (R\$ million)	619	725	-15%	-106
EBITDA (R\$ million)	516	596	-13%	-80
EBIT (R\$ million)	325	432	-25%	-107

(1) Values of individual accounts.

As part of our risk-controlled approach to its portfolio management, EDP follows a hedging strategy to mitigate the GSF/PLD risk, aiming at reducing the volatility of earnings. While this strategy resulted in significant gains in 2017-18, which compensated for the harsh effect of an extremely adverse energy context in Brazil on energy sales; results in 2019, given a more favorable context with higher GSF and lower PLD, resulted in a smoother evolution of energy sales combined with lower gains on our energy management strategy. Nevertheless, results from energy management in the 4Q19 improved significantly, due to our strategy of allocating physical guarantee to the second half of the year.

At our Supply and energy management activities, EBITDA decreased R\$67m YoY, to R\$111m in 2019, despite a strong recovery in the 4Q (+R\$69m QoQ) due to results from hedging, as we were expecting higher PLD at the end of the year (which was confirmed) and thus we contracted previously energy at lower PLD. However, for the full year, lower results in this segment reflect weaker results from energy management, as described above, but also a 22% YoY reduction in volumes supplied due to low liquidity in the free market.

At our thermal generation plant, Pecém I, EBITDA YoY comparison (-13% or -R\$80m) is impacted by last year's positive effect from the downward revision of the regulatory level of availability of this plant to 83.75% (R\$106m positive impact on EBITDA 2018). Excluding this effect, EBITDA would have grown by 5% YoY, reflecting higher availability at 95%, lower O&M costs and inflation update of contracted revenues.



Income Statements & Annex

Income Statement by Business Segment

2019 (€ million)	Renewables	Networks	Clients solutions & Energy management	Corpor. Activ. & Adjustments	EDP Group
Revenues from energy sales and services and other	2,783	6,195	8,639	(3,284)	14,333
Gross Profit	2,409	1,816	1,001	(9)	5,217
Supplies and services	365	352	285	(104)	898
Personnel costs and employee benefits	182	200	129	110	620
Other operating costs (net)	(424)	274	113	31	(6)
Operating costs	123	825	527	36	1,512
EBITDA	2,286	991	474	(46)	3,706
Provisions	82	14	6	(0)	102
Amortisation and impairment (1)	816	356	539	55	1,766
EBIT	1,388	621	(70)	(100)	1,838

2018 (€ million)	Renewables	Networks	Clients solutions & Energy management	Corpor. Activ. & Adjustments	EDP Group
Revenues from energy sales and services and other	2,775	6,637	9,874	(4,008)	15,278
Gross Profit	2,495	1,715	897	(7)	5,099
Supplies and services	407	383	273	(106)	957
Personnel costs and employee benefits	179	214	133	126	652
Other operating costs (net)	(288)	286	179	(4)	174
Operating costs	298	884	585	15	1,782
EBITDA	2,197	831	312	(23)	3,317
Provisions	187	14	92	(5)	288
Amortisation and impairment (1)	791	334	264	56	1,445
EBIT	1,218	483	(43)	(73)	1,584

(1) Depreciation and amortisation expense net of compensation for depreciation and amortisation of subsidised assets.

Quarterly Income Statement

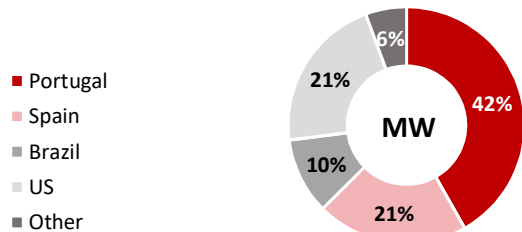
Quarterly P&L (€ million)	1Q18	2Q18	3Q18	4Q18	1Q19	2Q19	3Q19	4Q19	Δ YoY %	Δ QoQ %	2018	2019	Δ %
Revenues from energy sales and services and other	4,032	3,527	3,752	3,967	3,744	3,363	3,340	3,886	-2%	16%	15,278	14,333	-6%
Cost of energy sales and other	2,639	2,227	2,582	2,730	2,383	2,123	2,131	2,479	-9%	16%	10,179	9,116	-10%
Gross Profit	1,393	1,299	1,170	1,237	1,361	1,240	1,209	1,407	14%	16%	5,099	5,217	2%
Supplies and services	209	233	234	280	200	221	223	253	-9%	14%	957	898	-6%
Personnel costs and Employee Benefits	163	162	147	180	159	164	156	140	-22%	-10%	652	620	-5%
Other operating costs (net)	128	75	100	(130)	81	(133)	77	(31)	-76%	-140%	174	(6)	-
Operating costs	501	470	482	330	439	253	456	363	10%	-20%	1,782	1,512	-15%
EBITDA	893	829	688	907	921	987	753	1,044	15%	39%	3,317	3,706	12%
Provisions	(7)	4	286	5	4	1	92	4	-15%	-95%	288	102	-65%
Amortisation and impairment (1)	351	348	350	396	374	362	358	672	70%	88%	1,445	1,766	22%
EBIT	549	477	53	506	544	624	303	368	-27%	21%	1,584	1,838	16%
Financial Results	(127)	(150)	(166)	(111)	(186)	(185)	(175)	(124)	12%	-29%	(554)	(670)	-21%
Share of net profit in joint ventures and associates	1	2	6	2	5	7	2	11	475%	453%	11	25	130%
Profit before income tax and CESE	423	330	(108)	397	364	446	130	254	-36%	95%	1,041	1,194	15%
Income taxes	74	43	(67)	49	99	38	9	80	62%	805%	100	226	127%
Extraordinary contribution for the energy sector	66	(2)	1	0	67	(0)	1	1	171%	n.a.	65	68	5%
Net Profit for the period	282	289	(43)	347	198	408	120	173	-50%	44%	876	899	3%
Attrib. to EDP Shareholders	166	214	(83)	222	100	305	55	51	-77%	-7%	519	512	-1%
Attrib. to Non-controlling Interests	116	75	40	125	98	104	65	121	-3%	87%	357	388	9%

(1) Depreciation and amortisation expense net of compensation for depreciation and amortisation of subsidised assets.

Generation Assets: Installed Capacity and Production

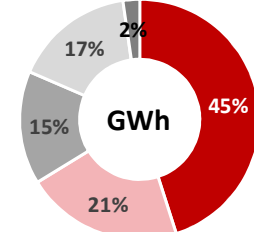
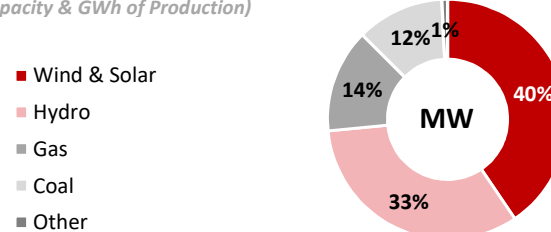
Technology	Installed Capacity - MW (1)				Electricity Generation (GWh)				Electricity Generation (GWh)							
	Dec-19	Dec-18	Δ MW	Δ %	2019	2018	Δ GWh	Δ %	1Q18	2Q18	3Q18	4Q18	1Q19	2Q19	3Q19	4Q19
Wind	10,667	11,156	-489	-4%	29,768	28,133	+1,635	6%	8,719	6,620	5,145	7,648	8,356	7,661	5,651	8,100
US	5,624	5,242	+382	7%	15,501	14,721	+780	5%	4,455	3,735	2,666	3,865	4,196	4,113	2,975	4,217
Portugal	1,160	1,304	-144	-11%	3,151	2,987	+164	5%	1,064	608	455	860	832	799	549	971
Spain	1,974	2,312	-337	-15%	5,298	5,164	+134	3%	1,766	1,101	894	1,404	1,621	1,388	893	1,397
Brazil	467	467	-	-	1,757	1,235	+522	42%	159	262	416	399	314	384	561	499
Rest of Europe (2)	1,212	1,601	-389	-24%	3,264	3,255	+9	0%	1,068	697	541	948	1,160	770	498	835
Rest of the World (3)	230	230	-	-	796	771	+25	3%	208	217	173	173	233	208	174	181
Solar	145	145	-	-	273	226	+47	21%	43	69	70	44	55	85	85	48
Hydro	8,785	8,792	-8	-0%	14,096	19,296	-5,200	-27%	6,154	5,863	3,189	4,090	4,055	2,748	2,161	5,132
Portugal	6,759	6,767	-8	-0%	9,087	12,648	-3,561	-28%	3,790	4,172	2,249	2,437	2,395	1,523	1,539	3,629
Pumping activity	2,806	2,806	-	-	-1,824	-2,438	+614	25%	-636	-329	-130	-1,343	-423	-414	-363	-624
Run of the river	2,408	2,408	-	-	4,099	6,161	-2,062	-33%	1,685	2,424	1,098	954	1,285	615	703	1,497
Reservoir	4,294	4,294	-	-	4,850	6,090	-1,240	-20%	1,940	1,605	1,120	1,425	1,067	880	827	2,076
Small-Hydro	57	65	-	-	138	397	-259	-65%	165	143	32	58	43	28	10	57
Spain	426	426	-	-	880	1,054	-174	-16%	408	370	108	168	274	143	59	404
Brazil	1,599	1,599	-	-	4,129	5,594	-1,465	-26%	1,956	1,321	832	1,485	1,386	1,081	563	1,099
Gas/ CCGT	3,729	3,729	-	-	10,183	5,333	+4,851	91%	1,302	846	1,802	1,383	1,315	2,405	3,745	2,719
Portugal	2,031	2,031	-	-	5,837	4,091	+1,746	43%	907	660	1,532	992	768	1,618	2,133	1,318
Spain	1,698	1,698	-	-	4,346	1,242	+3,104	250%	395	186	270	391	547	786	1,612	1,400
Coal	3,150	3,150	-	-	10,856	17,471	-6,615	-38%	3,965	3,926	5,260	4,320	3,778	2,645	2,307	2,126
Portugal	1,180	1,180	-	-	4,020	8,067	-4,047	-50%	1,734	1,635	2,431	2,267	1,934	1,221	512	353
Spain	1,250	1,250	-	-	3,129	5,948	-2,819	-47%	1,045	1,248	1,861	1,794	1,036	837	668	588
Brazil	720	720	-	-	3,707	3,455	+252	7%	1,186	1,043	968	258	807	587	1,127	1,185
Nuclear - Trillo (15.5%)	156	156	-	-	1,223	1,196	+28	2%	331	187	337	340	332	220	337	335
Other	49	49	-	-	270	309	-38	-12%	84	82	73	70	82	79	64	46
Portugal	24	24	-	-	163	182	-19	-10%	51	50	41	40	49	46	36	32
Spain	25	25	-	-	107	126	-19	-15%	32	32	32	30	32	33	28	14
TOTAL	26,681	27,177	-497	-2%	66,670	71,963	-5,294	-7%	20,598	17,593	15,877	17,895	17,974	15,842	14,349	18,505
Of Which:																
Portugal	11,159	11,311	-152	-1%	22,268	27,984	-5,717	-20%	7,548	7,127	6,711	6,598	5,981	5,210	4,772	6,305
Spain	5,529	5,866	-337	-6%	14,983	14,729	+254	2%	3,976	3,123	3,502	4,128	3,843	3,407	3,597	4,137
Brazil	2,787	2,787	-	-	9,593	10,285	-691	-7%	3,301	2,626	2,216	2,142	2,507	2,052	2,250	2,783
US	5,714	5,332	+382	7%	15,696	14,873	+823	6%	4,486	3,779	2,711	3,896	4,235	4,174	3,035	4,253

Installed capacity by Country as of Dec-19



Breakdown by Technology as of 2019

(MW Capacity & GWh of Production)



Regulated Networks: Asset and Performance indicators

RAB (€ million)	Dec-19	Dec-18	Δ %	Δ Abs
Portugal	2,974	2,996	-0.7%	-22
High / Medium Voltage	1,816	1,832	-0.8%	-15
Low Voltage	1,157	1,164	-0.6%	-7
Spain	950	950	0.0%	-
Brazil (R\$ million)	4,997	4,696	6.4%	+301
EDP Espírito Santo	2,656	2,449	8.4%	+207
EDP São Paulo	2,341	2,247	4.2%	+95
TOTAL	5,031	5,002	0.6%	+28

Networks	Dec-19	Dec-18	Δ %	Δ Abs.
Lenght of the networks (Km)	340,744	339,177	0.5%	+1,567
Portugal	226,823	226,308	0.2%	+515
Spain	20,766	20,709	0.3%	+57
Brazil	93,155	92,160	1.1%	+995
DTCs (thous.)				
Portugal	23	19	18%	+3
Spain	7	7	0%	-
Energy Box (th)				
Portugal	2,578	1,923	34%	+655
Spain	666	644	3%	+22

Quality of service	2019	2018	Δ %	Δ Abs.
Losses (% of electricity distributed)			-	-
Portugal (1)	9.6%	9.6%	-0.6%	-0.1 p.p.
Spain	3.6%	3.4%	6.6%	0.2 p.p.
Brazil				
EDP São Paulo	8.1%	8.4%	-3.9%	-0.3 p.p.
Technical	5.6%	5.6%	1.0%	0.1 p.p.
Commercial	2.5%	2.8%	-13.3%	-0.4 p.p.
EDP Espírito Santo	12.5%	11.9%	4.3%	0.5 p.p.
Technical	7.9%	7.5%	4.4%	0.3 p.p.
Commercial	4.6%	4.4%	4.3%	0.2 p.p.
Telemetering (%)				
Portugal	73%	69%	6%	3.9 p.p.
Spain	100%	N.A	N.A	N.A.

Customers Connected (th)	Dec-19	Dec-18	Δ %	Δ Abs.
Portugal	6,277	6,226	0.8%	+52
Very High / High / Medium Voltage	25	25	1.2%	+0
Special Low Voltage	37	36	1.9%	+1
Low Voltage	6,215	6,164	0.8%	+51
Spain	668	666	0.3%	+2
High / Medium Voltage	1	1	0.3%	+0
Low Voltage	667	665	0.3%	+2
Brazil	3,524	3,451	2.1%	+73
EDP São Paulo	1,936	1,887	2.6%	+49
EDP Espírito Santo	1,588	1,564	1.5%	+24
TOTAL	10,470	10,343	1.2%	+127

Electricity Distributed (GWh)	2019	2018	Δ %	Δ GWh
Portugal	45,589	46,059	-1.0%	-469
Very High Voltage	2,344	2,366	-0.9%	-22
High / Medium Voltage	21,953	21,996	-0.2%	-43
Low Voltage	21,292	21,697	-1.9%	-405
Spain	8,262	9,360	-11.7%	-1,099
High / Medium Voltage	6,032	7,110	-15.2%	-1,078
Low Voltage	2,229	2,250	-0.9%	-21
Brazil	25,591	25,007	2.3%	584
Free Customers	11,389	11,173	1.9%	216
Industrial	1,719	1,890	-9.1%	-172
Residential, Commercial & Other	12,484	11,943	4.5%	540
TOTAL	79,442	80,426	-1.2%	-984

(1) Excludes Very High Voltage

Financial investments, Non-controlling interests and Provisions

Financial investments & Assets for Sale	Attributable Installed Capacity - MW (1)				Share of profit (2) (€ million)				Book value (€ million)			
	Dec-19	Dec-18	Δ %	Δ MW	2019	2018	Δ %	Δ Abs.	Dec-19	Dec-18	Δ %	Δ Abs.
EDP Renováveis	550	371	48%	+179	3	2	106%	+2	476	357	33%	+119
Spain	152	152										
US	398	219										
Other	0	0										
EDP Brasil	551	539	2%	+12	15	1	2136%	+15	465	456	2%	+9
Renewables	551	539										
Networks												
Iberia (Ex-wind) & Other	10	10	0%	-	6	9	-27%	-2	328	264	24%	+64
Generation	10	10										
Networks												
Other												
Assets Held for Sale (net of liabilities)									2,177	11	-	+2,166
TOTAL	1,111	920	15%	+191	25	11	130%	+14	3,446	1,088	217%	+2,359

Non-controlling interests	Attributable Installed Capacity - MW (1)				Share of profits (2) (€ million)				Book value (€ million)			
	Dec-19	Dec-18	Δ %	Δ MW	2019	2018	Δ %	Δ Abs.	Dec-19	Dec-18	Δ %	Δ Abs.
EDP Renováveis	4,112	4,747	-13%	-636	218	210	4%	+8	2,547	2,739	-7%	-191
At EDPR level:	2,230	2,781	-20%	-551	148	159	-7%	-11	1,362	1,613	-16%	-252
Iberia	589	851										
North America	1,210	1,210										
Rest of Europe	269	557										
Brazil	162	162										
17.4% attributable to free-float of EDPR	1,881	1,966	-4%	-85	70	51	38%	+19	1,186	1,125	5%	+60
EDP Brasil	1,734	1,742	0%	-8	178	151	17%	+26	1,267	1,225	3%	+41
At EDP Brasil level:	598	606	-1%	-8	35	33	7%	+2	246	259	-5%	-13
Hydro	598	606										
Other	0	0										
49% attributable to free-float of EDP Brasil	1,137	1,137	0%	-	142	118	20%	+24	1,021	967	6%	+54
Iberia (Ex-wind) & Other	119	118	0%	+0	-8	-4	101%	-4	-40	-32	26%	-8
TOTAL	5,965	6,501	-8%	-536	388	357	9%	+31	3,774	3,932	-4%	-158

Provisions (Net of tax)	Employees benefits (€ million)			
	Dec-19	Dec-18	Δ %	Δ Abs.
EDP Renováveis	0	0	-49%	-0
EDP Brasil	134	115	16%	+19
Iberia (Ex-wind) & Other	774	870	-11%	-96
TOTAL	908	985	-8%	-78

(1) MW attributable to associated companies & JVs and non-controlling interests; (2) Share of profit in JVs & associates and from non-controlling interests; assets held for sale not included;

Sustainability performance

Environmental Metrics	2019	2018	Δ %
Renewable installed capacity (%)	73%	74%	-1%
ISO 14001 certification (%)	96%	96%	0%
Emissions			
Specific CO ₂ emissions (g/kWh) (1)	216	257	-16%
GHG Emission Scope 1 (ktCO _{2eq}) (2)	14,363	18,429	-22%
Stationary combustion	14,338	18,404	-22%
SF6 Emissions	9.27	10.35	-10%
Company fleet	15.17	15.17	0%
Natural gas consumption	0.04	0.19	-79%
GHG Emission Scope 2 (ktCO _{2eq}) (2)	846	602	41%
Electricity consumption in office buildings	0.80	1.83	-56%
Electricity losses	824	577	43%
Renewable plants self-consumption	21	23	-6%
NOx emissions (kt)	10.80	14.26	-24%
SO ₂ emissions (kt)	16.31	21.25	-23%
Particulate matter emissions (kt)	1.66	2.05	-19%

Natural Resources			
Primary Energy Consumption (Tj) (3)	184,903	221,634	-17%
Waste sent to final disposal (t)	229,441	349,329	-34%
Specific fresh water consumption (m ³ /GW) (4)	254	257	-1%

Environmental Matters (€ th)			
Investments	88,317	68,987	28%
Expenses	265,880	195,495	36%
Environmental Fees and Penalties (€ th)	4	3	18%

Sustainable Mobility			
Light-duty fleet electrification (%)	9.0%	7.5%	20%
Electric charging points (#)	772	385	101%
Customers with electric mobility solutions (#)	10,100	5,546	82%

Social Metrics	2019	2018	Δ %
Employment			
Employees (#)	11,660	11,631	0%
Female employees (%)	25%	25%	1%
Turnover (%)	10.51%	10.32%	2%

Training			
Total hours of training (h)	400,448	398,394	1%
Employees with training (%)	97%	100%	-2%
Direct training investment (€ th)	3,756	4,043	-7%

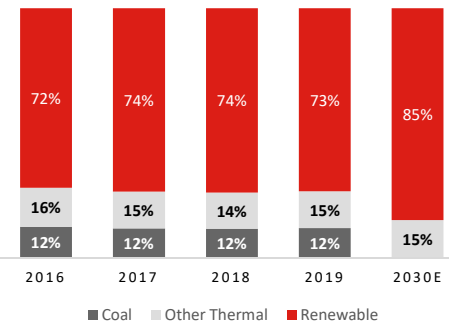
Health and Safety			
Accidents EDP (5)	29	29	0%
Accidents Contractors (5)	82	106	-23%
Fatal Accidents EDP	0	2	-100%
Fatal Accidents Contractors	2	5	-60%
Frequency rate EDP	1.50	1.36	11%
Frequency rate Contractors	1.84	2.50	-26%

Economic Metrics	2019	2018	Δ %
Economic Value Generated (€ million)	15,438	16,308	-5%
Distributed	13,214	14,471	-9%
Accumulated	2,224	1,837	21%

Low carbon economy			
EBITDA in Renewables (%)	62%	66%	-6%
CAPEX in Renewables (%)	51%	66%	-23%

New market opportunities			
Smart meters in Iberian Peninsula (%)	48%	38%	25%
Energy Services Revenues / Turnover (%)	7%	9%	-22%
Energy Efficiency Services Revenues (€ th)	169,391	151,468	12%

Installed Capacity Mix



Ratings	Range	2019 *	Ranking **
SAM ESG Ratings (DJSI)	[0-100]	90	1 ^a
FTSE Russel (FTSE4Good)	[0-5]	4.7	Top 5
VigeoEiris (Euronext Vigeo)	[0-100]	68	1 ^a
ISS-Oekom (GCI)	[D ⁻ -A ⁺]	B-	n.a.
Sustainalytics (STOXX ESG)***	[100-0]	22.1	13 ^a
MSCI Reserch (MSCI ESG)	[CCC-AAA]	AAA	n.a.
CDP	[D ⁻ -A]	A-	n.a.
Ethisphere	Y/N	Yes	n.a.

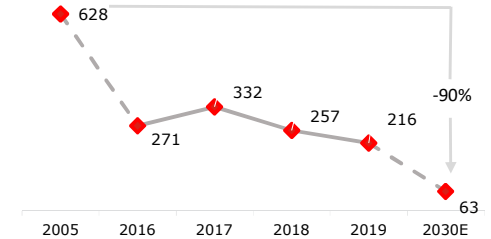
* Ratings are independent and, therefore, should not be compared. The above rankings were assessed in 2018, except for SAM and Sustainalytics, which refers to 2019.

** Comparable Peers. Regarding SAM and VIGEOEiris exclude the companies that manage transmission grids.

*** Sustainalytics' ESG risk rating provides a quantitative measure of unmanaged ESG risk and distinguishes between five levels of risk: negligible, low, medium, high and severe. The rating scale goes from 0-100, where 100 is the most severe.

Detailed information can be found at: www.edp.com>Sustainability>Economic Dimension>Sustainable Investment>ESG Indexes

Specific CO₂ Emissions (g/kWh)



Sustainable Development Goals (SDG)

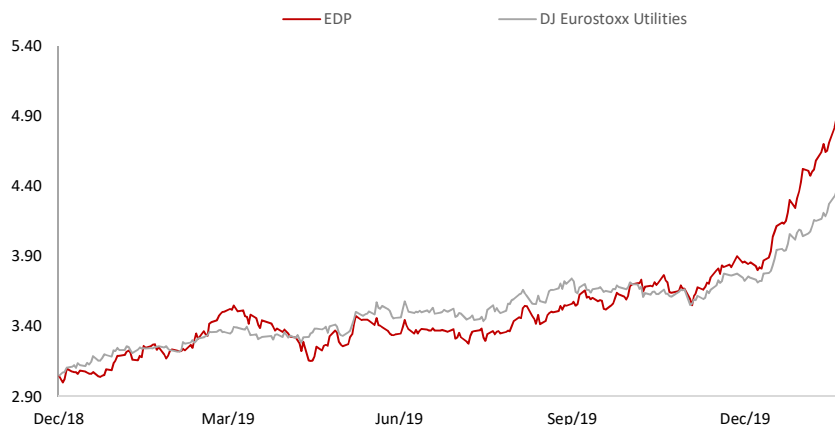


EDP is committed to ensuring that its activity contributes actively to 9 of the 17 United Nations SDG to be achieved by 2030.

- (1) The stationary emissions do not include those produced by the burning of ArcelorMittal steel gases in EDP's power plant in Spain.
- (2) Scope 2 emissions according with GHG Protocol based location methodology.
- (3) Including vehicle fleet.
- (4) The series was revised in according to GRI 303 update.
- (5) Accidents leading to an absence of one more calendar day and fatalities.

Share performance

EDP Stock Performance on Euronext Lisbon



EDP Stock Market Performance

	YTD ¹	52W 19/02/2020	2019
EDP Share Price (Euronext Lisbon - €)			
Close	4.926	4.926	3.864
Max	4.987	4.987	3.918
Min	3.785	3.089	2.986
Average	4.318	3.606	3.432

EDP's Liquidity in Euronext Lisbon

Turnover (€ million)	1,324	6,778	6,018
Average Daily Turnover (€ million)	38	26	24
Traded Volume (million shares)	307	1,880	1,753
Avg. Daily Volume (million shares)	8.76	7.34	6.88

EDP Share Data (million)

	2019	2018	Δ %
Number of shares Issued	3,656.5	3,656.5	-
Treasury stock	21.4	21.8	-2%

EDP's Main Events

- 23-Jan:** EDP prices € 1,000 Million subordinated green notes
- 01-Feb:** EDP signs a Build & Transfer agreement for 102 MW wind farm project in the US
- 12-Feb:** EDP secures a 104 MW PPA for a new wind farm in the US
- 12-Mar:** Strategic Update
- 15-Apr:** S&P affirms EDP at "BBB-" with stable outlook
- 23-Apr:** EDP announces €0.8bn asset rotation deal for wind farms in Europe
- 24-Apr:** EDP's Annual General Shareholders' Meeting
- 26-Apr:** Payment of dividends of the year 2018 at May 15th
- 13-May:** EDP sells Portuguese tariff deficit for €0.6 billion
- 21-May:** EDP and Engie join forces to create a leading global offshore wind player
- 25-Jun:** EDP agrees to sell €470 million in securitization of Portuguese tariff deficit
- 08-Jul:** EDP secures PPA for 126 MW in Brazil
- 29-Jul:** EDP announced R\$1.2 billion asset rotation transaction for wind farm in Brazil
- 30 Jul:** EDP concludes €808M asset rotation deal for wind farms in Europe
- 6-Aug:** ANEEL approves regulatory terms at EDP Espírito Santo for 2019-2022
- 7-Aug:** EDP secures a new PPA for Sonrisa Solar project with storage system in the US
- 30-Aug:** EDP awarded with 142 MW of solar energy in Portugal
- 10-Sep:** EDP issues a €600 million 7-year green bond
- 19-Sep:** Competition Authority's decision on alleged abuse of dominance position
- 30-Sep:** EDP successfully established new Institutional partnership Structure for 405 MW in the US
- 30-Sep:** EDP secures a new PPA for 100 MW in Mexico
- 16-Oct:** ERSE announces proposal for electricity tariffs in 2020
- 22-Oct:** ANEEL approves regulatory terms at EDP São Paulo for 2019-2023
- 23-Oct:** EDP enters the Colombian wind energy market with two 15-year PPA contracts awarded
- 24-Oct:** EDP build and transfer of 302 MW wind farm project in the US
- 25-Oct:** EDP secures a 200 MW PPA for a new solar project
- 29-Oct:** EDP expands its US solar base securing 50% stake in a portfolio of projects of 278 MW
- 30-Oct:** EDP joint venture proposal wins Massachusetts offshore wind contract
- 31-Oct:** CNIC notifies decrease of qualified shareholding in EDP
- 28-Nov:** EDP secured a PPA for new wind farm in Brazil
- 19-Dec:** EDP agrees to sell 6 hydro plants in Portugal for €2.2 billion
- 19-Dec:** Lower competitiveness of coal plants leads to extraordinary cost of €0.3 Bn in 2019
- 19-Dec:** EDP was awarded a long-term CfD for 307 MW of wind at polish energy auction

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(1) 1/Jan/2020 to 19/Feb/2020



2020

Financial Results

Webcast details

Webcast: www.edp.com

Date: Friday, February 24th, 2021, 5:00 pm (UK/Portuguese time)

Lisbon, February 24th, 2021

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Main highlights for the period

Key Operational Data	2020	2019	Δ %	Δ Abs.
Installed capacity (MW)	23,680	26,681	-11%	-3,001
Weight of Renewables (1)	79%	73%	-	5p.p.
Production (GWh)	64,318	66,670	-4%	-2,352
Weight of Renewables (1)	74%	66%	-	7p.p.
Specific CO₂ emissions (g/KWh)	146	216	-33%	-71
Customers supplied (thousand of contracts)	9,307	11,426	-19%	-2,120
Customers connected (thous.)	11,274	10,470	8%	+804

Income Statement (€ million)	2020	2019	Δ %	Δ Abs.
Gross Profit	5,092	5,217	-2%	-125
OPEX	1,524	1,518	0%	+6
Other operating costs (net)	(379)	(6)	-6005%	-373
Operating costs	1,145	1,512	-24%	-367
Joint Ventures and Associates (2)	3	25	-87%	-22
EBITDA	3,950	3,731	6%	+219
EBIT	2,206	1,863	18%	+343
Financial Results	(671)	(670)	-0%	-1
Income taxes & CESE (3)	374	294	27%	+80
Non-controlling Interest	361	388	-7%	-27
Net Profit (EDP Equity holders)	801	512	56%	+289

Key Performance indicators (€ million)	2020	2019	Δ %	Δ Abs.
Recurring EBITDA (4)	3,657	3,733	-2%	-76
Renewables	2,326	2,289	2%	+37
Networks	891	1,006	-11%	-115
Clients solutions & EM	480	482	-0%	-2
Other	(40)	(44)	9%	+4
Recurring net profit (4)	901	854	6%	+47

Key Financial data (€ million)	Dec-20	Dec-19	Δ %	Δ Abs.
Net debt	12,243	13,827	-11%	-1,584
Net debt/EBITDA (x) (5)	3.2x	3.6x	-10%	-0.4x

EDP's recurring net profit increased 6%, in 2020, to €901m, supported by the growth in the activity of renewable energy production, which registered a 7% increase YoY to 47.3 TWh from wind, hydro and solar. On the other hand, in 2020, demand and short-term electricity market prices, as well as thermal generation, presented significant drops in comparison with 2019. In Portugal, distributed electricity fell 3%, mainly penalized by the industrial consumption contraction, in line with the tendency observed in Spain and Brazil. The COVID-19 pandemic crisis had a negative impact of €100m in 2020's recurring EBITDA, excluding ForEx impact, mainly due to the aforementioned fall in electricity demand and increase in provision for doubtful debts. EDP's conventional activities in Portugal, (including conventional production, networks and energy retailing), after two consecutive years with losses in 2018 (-€18m) and 2019 (-€98m), presented in 2020 a net profit of €92m, which represented 11% of EDP's Group net profit.

One-offs had a net negative impact of €101m, leading to a reported net profit, in 2020, of €801m. From these effects, we highlight: (i) costs related to the closure of Sines coal power plant, (ii) provision on the alleged overcompensation regarding CMEC plants' participation in the ancillary services market, during 2009-2013, (iii) the cost of the extraordinary energy tax in Portugal, (iv) impairment losses related with thermal power plants in Portugal and Spain, (v) curtailment costs due to early retirements, (vi) accounting gains from disposal of conventional means of production and retailing business unit in Spain and Portugal and (vii) accounting gains resulting from the final terms of the regulatory dispute over GSF costs in Brazil.

Recurring EBITDA fell 2% to €3,657m, in 2020. Excluding ForEx impact, recurring EBITDA grew 3% YoY. The evolution of the recurring EBITDA was supported by several factors, including the normalization of hydro resources in Iberia (compared to the dry period of 2019) and by our hedging strategy in energy markets. Moreover, higher gains, in comparison with 2019, with renewable assets rotation, which amounted to €434m in 2020, resulted from transactions concluded in 2020 in the USA and in Spain, and due to the creation of the joint-venture with Engie for the offshore wind segment, with the contribution from assets in a further advanced development stage in the United Kingdom, France and USA. These effects more than compensated the Brazilian Real depreciation against the Euro (-25% in average terms), wind resources 8% lower than long-term average, as well as the 25% fall in thermal energy production.

As of December 2020, EDP had 18.6 GW of renewables' installed capacity, having during 2020, accelerated its contribution to the economy decarbonization, with a **33% reduction YoY of specific CO₂ emissions**. In networks, growth was concentrated in Brazil: regarding the 6 transmission lines, 82% of the total investment has already been concluded. Iberian networks EBITDA was penalized by the lower regulated rates of return (6,0% in Spain and 4,86% before the energy tax (CESE), in Portugal). In the client solutions and energy management segment, results were supported by the good performance of our energy management activity, which mitigated the reduction in the load factors of thermal power plants. **In clients services in Portugal and Spain, the penetration rate of new services increased to 26.1%.** The financial results in 2020 were in line YoY. Excluding the one-off cost, related with the repurchase of debt, net financial interests improved 17%, with the positive impact of **lower average cost of debt at 3.3% (-60 bps YoY)**.

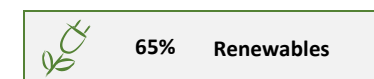
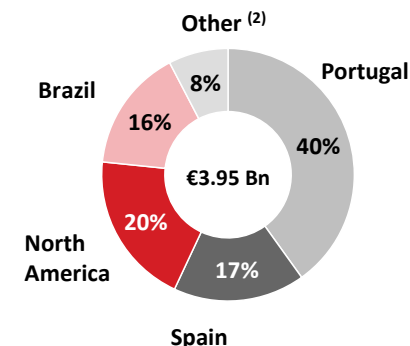
Net debt and adjusted Net Debt/EBITDA ratio, in 2020, were the EDP's lowest, in the last 13 years. As of December 2020, net debt was €12.2 Bn, representing a 11% reduction YoY, while the Adjusted Net Debt/EBITDA decreased from 3.6x in 2019 to 3.2x in 2020. This positive impact in the ratio resulted from the conclusion in December 2020 of several transactions, namely the disposal of 2 CCGTs and B2C supply in Spain, the sale of 6 hydro plants in Portugal. Additionally, 2 asset rotation deals in Europe and USA, as well as the Viesgo acquisition and consequently the partnership with Macquarie for the electricity distribution in Spain, this last acquisition financed by the €1 Bn rights issue concluded in Aug-20. These transactions reinforce EDP's low-risk profile and focus on the energy transition.

The Executive Board of Directors will propose at the Annual Shareholders' Meeting, scheduled for April 16th 2021, the distribution of a dividend concerning the year of 2020 in the amount of €0.19 per share, in line with last year.

EBITDA Breakdown

EBITDA (€ million)	2020	2019	Δ %	Δ Abs.	1Q19	2Q19	3Q19	4Q19	1Q20	2Q20	3Q20	4Q20	4Q YoY Δ % Δ Abs.	
Renewables	2,613	2,297	14%	+316	559	710	396	631	549	614	409	1,041	65%	+409
Wind & Solar	1,655	1,651	0%	+3	387	578	256	431	340	453	280	581	35%	+151
Hydro Iberia	764	465	64%	+299	112	93	109	151	177	127	97	363	141%	+212
Hydro Brazil	194	181	7%	+13	60	39	31	50	32	34	31	96	92%	+46
Networks	910	997	-9%	-87	242	231	278	246	237	203	224	246	0%	+0
Iberia	640	632	1%	+8	165	173	160	133	161	156	167	156	17%	+23
Brazil	270	365	-26%	-96	77	58	118	113	76	47	57	90	-21%	-23
Client solutions & EM	474	480	-1%	-6	117	94	77	192	203	84	114	73	-62%	-119
Iberia	342	340	1%	+2	85	60	45	150	167	60	89	25	-83%	-125
Brazil	132	140	-6%	-9	32	34	32	43	36	24	25	47	10%	+4
Other	(47)	(43)	-8%	-3	9	(41)	4	(15)	(9)	(10)	7	(35)	-	-20
Consolidated EBITDA	3,950	3,731	6%	+219	927	994	755	1,055	980	891	754	1,325	26%	+270
- Adjustments (1)	293	(2)	-	-	-	-	-	(2)	0	(22)	0	315	-	+317
Recurring EBITDA	3,657	3,733	-2%	-76	927	994	755	1,057	980	914	754	1,010	-4%	-47

EBITDA 2020



EBITDA in 2020 amounted to €3,950m (+6% or +€219m YoY), including significant one-off impacts (+€295m YoY, to €293m in 2020*) and an adverse ForEx impact (-€205m), mainly driven by the 25% depreciation of BRL against Euro. Excluding one-offs and Forex impact recurring EBITDA advanced by 3% YoY to €3,657m, reflecting normalisation of hydro resources, successful hedging strategy in energy management in Iberia and higher gains from the renewables asset rotation strategy, on the one hand; lower EBITDA in wind and solar on deconsolidation of renewables assets sold during 2019, related to the asset rotation strategy, and weaker wind resources, on the other hand.

RENEWABLES (65% of EBITDA, €2,613m in 2020) – EBITDA was 14% higher YoY (+€316m YoY). Excluding one-off impacts (+€279m YoY, to €287m gain in 2020), recurring EBITDA amounted to €2,326m (+2% YoY), reflecting the strong recovery of hydro resources in Iberia (+16 p.p. but still 3% short of LT average in Portugal) along with our hedging strategy (+€84m) and higher asset rotation gains (+€120m YoY), which more than offset the de-consolidation effect of wind assets sold (-€102m) and adverse ForEx impact (-€70m, mainly driven by BRL depreciation).

NETWORKS (23% of EBITDA, €910m in 2020) – EBITDA declined by 9% YoY (-€87m YoY). Excluding one-off impacts (+€28m YoY, to €19m gain in 2020), recurring EBITDA amounted to €891m (-€115m YoY) driven by 25% depreciation of BRL against the Euro (-€90m), overshadowing local currency 7% EBITDA growth in the period backed by positive tariff updates in Brazil and tight cost control across all geographies. In Portugal, the low Portuguese government 10-year bond yields drove the rate of return on RAB in 2020 very close to the floor (4.75%), at 4.85% for High Voltage/Medium Voltage (vs. 5.13% in 2019).

CLIENT SOLUTIONS & ENERGY MANAGEMENT (12% OF EBITDA, €474m in 2020) - EBITDA decreased 1% YoY (-€6m YoY), with a negligible net impact from one-offs (+€4m YoY increase to a €6m net cost). In Iberia, our successful *hedging* strategy and price volatility in the year prompted for outstanding energy management results, while operating conditions in supply have normalised after the demand shock in 2Q20 caused by COVID lockdown. **In Brazil**, EBITDA performance largely reflected the BRL depreciation against the euro (-€44m), while local currency performance was driven by the positive impact of mark-to-market restatement of long-term contracts in supply. Ahead of its cease of operations in late Dec-20, Sines coal plant has increased production in the 2H20 as to burn the remaining coal stocks: as a result, Sines accounted for 3% of EDP's total production and 2% of EDP's revenues in 2020. **The remaining coal fired power production accounted for 6% of production in 2020 (vs. 10% in 2019) and 3% of the EDP group revenues in 2020 (vs. 6% in 2019).**

(*) *Non-recurring items: (i) -€2m in 2019, including restructuring costs (-€13m), regulatory costs (-€28m) and gain following the change in medical plan of employees in Brazil (+€30m) and reversal of an impairment at São Manoel hydro plant (+€8m); (ii) +€293m in 2020, including net gains related to portfolio reshaping (+€277m), HR restructuring costs and other HR-related items (-€53m), costs related to Sines shutdown (-€18m) and regulatory issues in Brazil and Portugal (+€87m).*

Profit & Loss Items below EBITDA

Profit & Loss Items below EBITDA (€ million)	2020	2019	Δ %	Δ Abs.	4Q19	1Q20	2Q20	3Q20	4Q20	4Q YoY	
										Δ %	Δ Abs.
EBITDA	3,950	3,731	6%	+219	1,055	980	891	754	1,325	26%	+270
Provisions	112	102	10%	+11	4	16	35	78	(17)	-	-22
Amortisations and impairments	1,632	1,766	-8%	-134	672	367	401	340	524	-22%	-148
EBIT	2,206	1,863	18%	+343	378	597	455	336	818	116%	+439
Net financial interest	(563)	(597)	6%	+34	(139)	(178)	(123)	(119)	(143)	-3%	-4
Capitalized financial costs	71	48	48%	+23	15	12	14	15	29	89%	+14
Unwinding of long term liabilities (1)	(205)	(204)	0%	-0	(51)	(49)	(50)	(55)	(50)	2%	+1
Net foreign exchange differences and derivatives	(24)	(19)	-27%	-5	(3)	(5)	(11)	(1)	(7)	-169%	-4
Other Financials	51	102	-51%	-52	53	13	9	23	6	-89%	-48
Financial Results	(671)	(670)	0%	-1	(124)	(206)	(162)	(137)	(166)	-33%	-41
Pre-tax Profit	1,535	1,194	29%	+342	254	391	293	199	652	157%	+398
Income Taxes	309	226	37%	+83	80	92	42	39	136	69%	+55
<i>Effective Tax rate (%)</i>	<i>20%</i>	<i>19%</i>			<i>32%</i>	<i>24%</i>	<i>14%</i>	<i>20%</i>	<i>21%</i>		
Extraordinary Contribution for the Energy Sector	65	68	-5%	-3	1	63	(0)	3	-	-	-1
Non-controlling Interests (Details page 27)	361	388	-7%	-27	121	90	83	49	138	14%	+17
Net Profit Attributable to EDP Shareholders	801	512	56%	+289	51	146	169	108	378	636%	+327

In 2020, **provisions** amounted to €112m, including €103m of one-offs (+€16m YoY): €30m related to the decision to anticipate the shutdown of Iberian coal plants (2Q20) and €73m booked in 3Q20 on the alleged overcompensation regarding CMEC plants participation in the ancillary services market in 2009-13.

Amortisations and impairments were 8% lower YoY, at €1,632m, mainly due to lower impairments in thermal YoY (-€61m YoY, to €236m in 2020), the de-consolidation of assets sold and held for sale and ForEx impact (-€49m).

Excluding the €70m one-off cost related to the repurchase of outstanding debt in 2020, **net financial interests improved 17% YoY** to -€493m in 2020, prompted by a 5% YoY decline in the average debt and a 60bps YoY decline in avg. cost of debt to 3.3% (vs. 3.9% in 2019). This decline was supported by the past proactive debt management, lower cost of recent issues and declining benchmark interest rates, particularly in Brazil (CDI and TJLP). The increase of **capitalised financial expenses** to €71m in 2020 was mainly related to increasing volume of works in progress in transmission in Brazil and renewables. **Other financials** were mainly impacted by last year's one-off gain on the revaluation of our equity stake in Feedzai (+€31m).

Income taxes amounted to €309m, representing an effective tax rate of 20% in 2020 following the past few quarters' specific impacts from asset rotation gains on wind offshore joint-venture.

Non-controlling interests fell 7% YoY to €361m in 2020, including €220m related to EDPR (+1% YoY) and €149m related to EDP Brasil (-16% YoY), mainly explained by the Brazilian Real depreciation (details on page 27).

Overall, net profit amounted to €801m in 2020 (+56% or +€289m YoY), penalised by net one-off* costs of €101m in 2020 (+€242m YoY*). As a result, **recurring net profit increased 6% YoY, to €901m in 2020**, driven by strong results on our energy management business in Iberia, recovery of hydro resources and strong performance on financial results. These positives more than offset the impact on our share in EDP Brasil net profit from Brazilian Real depreciation. Under tough context of Covid pandemic, EDP performance confirms its distinctive and resilient business profile.

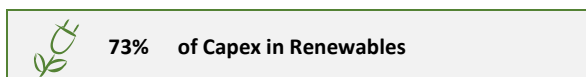
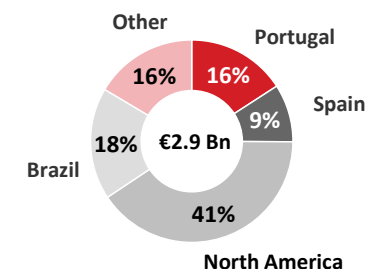
() Non-recurring items impact at net profit level: (i) -€342m in 2019, related to impairments and provisions (-€283m, mainly coal in Iberia), provision reversal at S. Manoel and the gain on the revaluation of Feedzai (+€28m), regulation related items and other (-€78m) and HR related costs (-€8m); (ii) -€101m in 2020, including the net gain from disposals and investments (+€325m), impairments (-€252m, mainly thermal in Iberia), liability management costs (-€55m), regulation related items and other (-€18m) and HR restructuring costs (-€38m).*

(1) Includes unwinding of medium, long term liabilities (TEIs, IFRS-16, dismantling & decommissioning provision for generation assets, concessions) and interest on medical care and pension fund liabilities.

Investment activity

Capex (€ million)	2020	2019	Δ %	Δ Abs.	1Q19	2Q19	3Q19	4Q19	1Q20	2Q20	3Q20	4Q20
Expansion	2,401	1,724	39%	+677	222	335	351	816	341	391	716	953
Renewables	2,101	1,121	87%	+980	158	226	212	525	271	320	639	871
Networks	289	585	-51%	-296	63	108	136	278	65	63	71	91
Other	10	18	-	-7	1	1	3	13	5	8	7	(10)
Maintenance	508	535	-5%	-27	122	146	105	161	84	103	116	205
Renewables	34	46	-27%	-13	5	8	11	22	5	4	7	18
Networks	334	326	3%	+8	91	101	59	75	57	75	80	121
Other	140	162	-14%	-22	26	37	35	64	23	24	29	65
Consolidated Capex	2,909	2,258	29%	+651	344	481	456	977	425	494	832	1,157

CAPEX 2020



Net expansion activity (€ m)	2020	2019	Δ %	Δ Abs.
Expansion Capex	2,401	1,724	39%	+677
Financial investments	806	318	153%	+488
Proceeds Asset rotation	(1,678)	(970)	-73%	-708
Proceeds from TEI in US	(305)	(186)	-63%	-118
Acquisitions and disposals	(629)	38	-	-667
Other (1)	326	244	33%	+81
Net expansion activity	922	1,168	-21%	-247

Consolidated capex increased 29% to €2,909m in 2020, 95% of which dedicated to Renewables and Grids. EDP expansion capex increased 39% to €2,401m, accounting for 83% of total capex, mostly dedicated to Renewables and Networks.

Financial investments in 2020 (€806m) were entirely concentrated in renewables: wind offshore (€380m related to the establishment of Ocean Winds, joint venture with Engie for wind offshore business, in which we own a 50% stake), solar and wind onshore projects.

Maintenance capex (€508m in 2020) was mostly dedicated to our regulated networks (66% of total), namely in Portugal, where the roll out of digitalisation continues, with 51% of supply points already with smart meters (+10p.p. YoY). In 4Q20, maintenance Capex increased 77% QoQ due to works performed to recover investments that had been postponed because of the Covid-19 pandemic.

Expansion investments (expansion capex + financial investment) in 2020 increased 58% to €3.2 Bn, largely dedicated to renewables globally (~90%):

1) €2,907m investment in new renewable capacity was distributed between North America (55%), Europe (38%) and Latam (7%). (details on page 10).

2) €289m investment in networks in Brazil (-51% YoY, significantly impacted by the BRL devaluation in the period). **In local currency, distribution capex increased 16% while capex in transmission decreased by 49% YoY to R\$1,021m following reduction in construction activity in 2Q20, related to COVID restrictions** and employees-safety. Despite some delays in construction of our transmission projects experienced during the lockdown period, the commissioning is expected ahead of regulatory schedule, until the end of 2021.

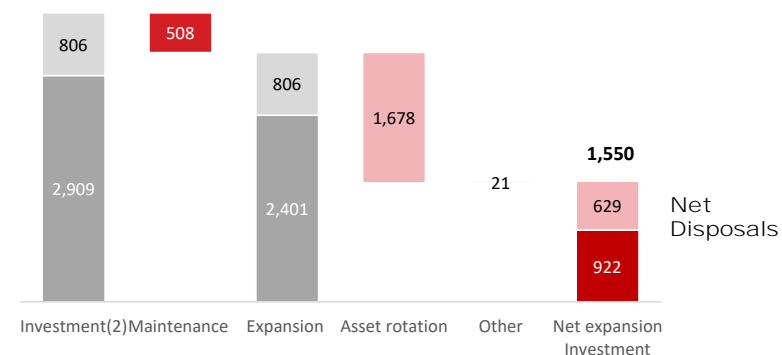
In 2020, proceeds from asset rotations amounted to €1,678m, including onshore and in Brazil (€254m, of which €132m debt de-consolidation), in Spain (€505m), in US (€423m); in Offshore (€421m related to the incorporation of JV with Engie).

All in all, expansion activity accelerated to €1,550m in 2020 (+37% YoY), reflecting (i) the acceleration of the build out activity contemplated in our Strategic Update (€3.2 Bn, +57% YoY); which was partially compensated by this year's higher proceeds from Asset rotation (€1.7 Bn), and proceeds from new Tax Equity partnerships (€305m).

Acquisitions and disposals amounted to €629m reflecting the €2.8 Bn of the disposals announced since Dec-19 (mainly hydro in Portugal and CCGT + B2C Supply in Spain) and the acquisition of Viesgo coupled with a new partnership with Macquaire funds "MIRA" which will retain 25% of the new perimeter of electricity distribution activities in Spain (€2.1 Bn). Overall, including the impact from acquisitions and disposal, net disposals, net expansion activity amounted to €921m.

Investment activity in 2020

(€ million)

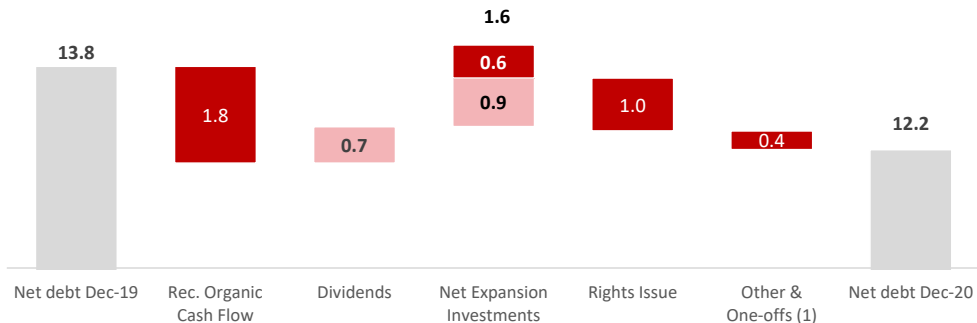


(1) Includes Proceeds from Change in WC Fixed asset suppliers, Change in consolidation perimeter, reclassification of asset rotation gain and other; (2) Includes Capex and Financial investment.

Cash Flow Statement

Net debt Evolution in 2020

(€ Billion)



Cash Flow statement (€ million)	2020	2019	Δ %	Δ Abs.
Recurring CF from Operations (2)	2,666	2,609	2%	+57
Recurring EBITDA	3,657	3,733	-2%	-76
Change in operating working capital, taxes and other	(992)	(1,124)	12%	+132
Maintenance capex (3)	(646)	(657)	2%	+11
Net interests paid	(423)	(549)	23%	+127
Payments to Institutional Partnerships US	(55)	(81)	32%	+25
Other	295	129	129%	+166
Recurring Organic Cash Flow	1,837	1,451	27%	+386
Net Expansion	(921)	(1,168)	21%	+247
Expansion capex	(2,401)	(1,724)	-39%	-677
Financial Investments	(806)	(318)	-153%	-488
Proceeds from asset rotations	1,678	970	73%	+708
Acquisition and disposals	629	(38)	-	+667
Proceeds from Institut. Partnerships in US	305	186	-	+118
Other	(326)	(244)	-33%	-81
Change in Regulatory Receivables	(48)	(65)	26%	+17
Dividends paid to EDP Shareholders	(691)	(691)	0%	-0
Effect of exchange rate fluctuations	620	(49)	-	+669
Other (including one-off adjustments)	787	200	293%	+587
Decrease/(Increase) in Net Debt	1,584	(322)	-	+1,906
Forex rate - End of Period	Dec-20	Dec-19	Δ %	Δ Abs.
EUR/USD	1.23	1.12	-8%	-0.10
BRL/EUR	6.37	4.52	-29%	-1.86

Recurring organic cash flow increased by 27% YoY, to €1.8 Bn in 2020, driven by the normalization of hydro resources, higher asset rotation gains and lower interest charges. **Recurring organic cash flow translates the cash generated and available to fulfil EDP's key strategic pillars of sustainable growth, deleveraging and shareholder remuneration.**

Maintenance capex (including payables to fixed assets suppliers), mostly related to the networks business, amounted to €646m in the period following a strong recovery QoQ in 4Q due to works performed to recover investments that has been postponed because of the Covid pandemic.

Net expansion amounted to €0.9 Bn in 2020, as the step up in expansion activity to €1.5 Bn (+37% YoY) was partially compensated by the strong execution of portfolio reshaping: in Dec-20, we completed the €2.8 Bn disposals of merchant assets (including on the one hand, 6 hydro plants in Portugal and, on a second block, a portfolio of 2 CCGTs and B2C supply in Spain) and the acquisition of Viesgo, along with a new partnership with MIRA for electricity distribution activities in Spain (€2.1bn). Our core expansion activity encompassed: (i) accelerating build out activity justifying €3.2 Bn expansion investment in 2020 (including financial investments), with a step up from 1H20 and focused in new renewable capacity and Brazil (details on page 5); (ii) €1.7 Bn proceeds from asset rotations in the period, after the closing in Dec-20 of the two deals announced in Aug/Sep-20, (iii) proceeds from institutional partnerships in US totaling €305m from 3 wind farms totaling 375 MW.

Regulatory receivables (including interests) increased by €48m in 2020, mainly Portugal, following new receivables arising from deviations between the system's real costs and ERSE's assumptions, which was mitigated by several tariff deficit sales, totaling €1.4 Bn (details on page 7).

On 14-May-20, EDP paid its **annual dividend totalling €691m (€0.19/share)**, in line with the previous year.

Effects of exchange rate fluctuations resulted in a €620m decrease on net financial debt in 2020, justified by the depreciation of USD (-8% YoY vs. the Euro) and the BRL (-29% YoY vs. the Euro).

The caption **Other** includes the €1 Bn proceeds from the rights issue concluded in Aug-20 aimed at partially finance the acquisition of Viesgo's regulated assets and -€0.2 Bn one-off impacts in 2020, mainly including CESE payment for 2019 and 2020 (€129m) and extraordinary liability management cost (€70m).

Overall, net debt declined by €1.6 Bn in 2020, to €12.2 Bn as of Dec-20.

Consolidated Financial Position

Assets (€ million)	Dec vs. Dec		
	Dec-20	Dec-19	Δ Abs.
Property, plant and equipment, net	20,163	19,676	+487
Right-of-use assets	1,030	829	+202
Intangible assets, net	4,998	4,224	+774
Goodwill	2,306	2,120	+186
Fin. investments & assets held for sale (details P. 27)	1,147	3,525	-2,378
Tax assets, deferred and current	1,806	1,889	-83
Inventories	324	368	-44
Other assets, net	8,186	8,127	+59
Collateral deposits	32	61	-29
Cash and cash equivalents	2,954	1,543	+1,412
Total Assets	42,947	42,362	+585

Equity (€ million)	Dec-20	Dec-19	Δ Abs.
Equity attributable to equity holders of EDP	9,583	8,858	+724
Non-controlling Interest (Details on page 27)	3,496	3,774	-278
Total Equity	13,078	12,632	+446

Liabilities (€ million)	Dec-20	Dec-19	Δ Abs.
Financial debt, of wich:	16,287	16,571	-285
<i>Medium and long-term</i>	<i>14,024</i>	<i>13,125</i>	<i>+899</i>
<i>Short term</i>	<i>2,263</i>	<i>3,447</i>	<i>-1,184</i>
Employee benefits (detail below)	1,342	1,312	+31
Institutional partnership liability in US	1,143	1,287	-143
Provisions	1,253	1,053	+201
Tax liabilities, deferred and current	1,336	1,121	+215
Deferred income from inst. partnerships	790	1,003	-213
Other liabilities, net	7,717	7,384	+333
Total Liabilities	29,868	29,730	+139

Total Equity and Liabilities	42,947	42,362	+585
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Employee Benefits (€ million)	Dec-20	Dec-19	Δ Abs.
Employee Benefits (bef. Tax)	1,342	1,312	+31
Pensions	630	631	-1
Medical care and other	713	681	+32
Deferred tax on Employee benefits (-)	-377	-404	+27
Employee Benefits (Net of tax)	966	908	+58

Regulatory Receivables (€ million)	Dec-20	Dec-19	Δ Abs.
Regulatory Receivables	382	370	+12
Portugal	442	366	+76
Brazil(1)	-61	4	-64
Change in Fair value (+)	-	-	-
Deferred tax on Regulat. Receivables (-)	-139	-115	-24
Regulatory Receivables (Net of tax)	242	255	-12

Total amount of **property, plant & equipment and intangible assets** increased €1.3 Bn vs. Dec-19 to €25.2 Bn as of Dec-20 mainly influenced by the additions YTD (+€2.7 Bn) and acquisition of Viesgo (€2.6 Bn) which were offset by the disposal of assets (-€1.4 Bn) and unfavourable exchange rate movements (-€1.5 Bn, mainly due to the devaluation of the BRL by 29% YoY and of the USD by 8% YoY vs. the Euro). As of Dec-20, works in progress amounted to €3.0 Bn (12% of total consolidated tangible and intangible assets): 88% at EDPR level, 2% at EDP Brasil level and the remaining 10% at Iberian level.

The book value of **financial investments & assets held for sale net of liabilities** (Incl. Equity Instruments at Fair Value) was at €1.1 Bn as of Dec-20, mainly influenced by the completion late 2020 of the portfolio reshuffle in Iberia and Asset Rotation transactions in Europe and in the US. Financial investments amount to €1.0 Bn: 51% at EDPR, 34% at EDP Brasil and 15% in Iberia (Ex-Wind). (Details on page 27)

Tax assets net of liabilities, deferred and current decreased €0.1 Bn vs. Dec-19 at €0.5 Bn in Dec-20. **Other assets (net)** was flat at €8.2 Bn vs. Dec-19. It is worth noting that Other assets (net) evolution also reflects the cash-in of €113m in 3Q20 referent to the final proceeds from sale of Naturgas as agreed in 2017.

Equity book value attributable to EDP shareholders increased by €0.7 Bn to €9.6 Bn as of Dec-20, reflecting the €0.8bn reported net profit in the 2020, the €1.0bn share capital increase executed in Aug-20, the €0.7bn annual dividend paid in May-20 and the negative Forex impact on reserves. **Non-controlling interests** decreased €0.2 bn as the establishment of the partnership with Macquarie in Spanish networks and a slight increase of our stake in EDP Brasil to 53.4% total ownership (52.6% direct stake) were offset by the negative forex impact of Brazilian Real.

Institutional partnership liabilities were down by €0.1 Bn vs Dec-19, to €1.1 Bn, as the new institutional partnerships secured were slightly outweighed by the benefits appropriated by the tax equity partners during the period, the transfer to “assets for sale” of wind onshore assets as part of the asset rotation in US closed in December and the negative exchange rate movement.

Provisions increased €0.2 Bn vs. Dec-19, at €1.3 Bn before tax. This caption includes, among others, provisions for dismantling (€567m), of which €302m related with wind farms..

Net regulatory receivables after tax amounted to **€247m as of Dec-20** (€382m before tax). The evolution during 2020 is mainly justified by unanticipated deviations vs. ERSE’s assumptions, namely lower amounts allocated to the electricity system regarding mitigation measures (+€51m).

Other liabilities (net) increased €0.3 Bn vs Dec-19, explained by Viesgo’s acquisition and new lease contracts mainly related to wind farms. The capture of Leases amounts to €0.96 Bn. Employee Benefits (net of tax) decreased €58m to €966m, namely due to a 30bps (currently at 0.6%) reduction in the discount rate applicable in the liabilities related with pensions and medical care in Portugal.

(1) Excluding the amount corresponding to the impact from the exclusion of ICMS from the calculation of PIS/COFINS from past years in our distribution companies (R\$1.5 Bn), since the receivable (recognized under current tax assets) is a pass-through to the tariff. Excludes the regulatory liability recognized against the receipt of 'Conta COVID' (R\$0.6bn), which will be recognized in the tariffs in the future

Net Financial Debt

Net Financial Debt (€ million)	Dec-20	Dec-19	Δ %	Δ Abs.
Nominal Financial Debt	15,873	16,222	-2%	-349
EDP S.A., EDP Finance BV and Other	12,654	13,618	-7%	-964
EDP Renováveis	668	769	-13%	-101
EDP Brasil	1,381	1,835	-25%	-454
EDP Espanha	1,171	-	-	+1,171
Accrued interest on Debt	256	288	-11%	-32
Fair Value of Hedged Debt	157	61	156%	+96
Derivatives associated with Debt (2)	(94)	(135)	30%	+41
Collateral deposits associated with Debt	(32)	(61)	48%	+29
Hybrid adjustment (50% equity content)	(893)	(906)	1%	+13

Total Financial Debt	15,268	15,469	-1%	-201
Cash and cash equivalents	2,954	1,543	91%	+1,412
EDP S.A., EDP Finance BV and Other	1,997	377	430%	+1,621
EDP Renováveis	474	582	-18%	-107
EDP Brasil	429	584	-27%	-155
EDP Espanha	53	-	-	+53
Financial assets at fair value through P&L	71	99	-29%	-29
EDP Consolidated Net Debt	12,243	13,827	-11%	-1,584

Credit Lines by Dec-20 (€ million)	Maximum Amount	Number of Counterparts	Available Amount	Maturity
Revolving Credit Facilities	75	1	75	Jul-21
Revolving Credit Facility	3,300	24	3,300	Oct-24
Revolving Credit Facility	2,240	17	2,240	Mar-25
Domestic Credit Lines	256	9	256	Renewable
Underwritten CP Programmes	50	1	50	Feb-21
Total Credit Lines	5,921		5,921	

Credit Ratings EDP SA & EDP Finance BV

S&P

BBB-/Stable/A-3

Moody's

Baa3/Stable/P3

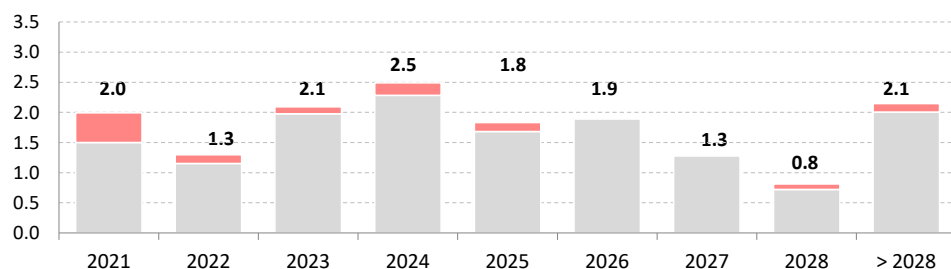
Fitch

BBB-/Positive/F3

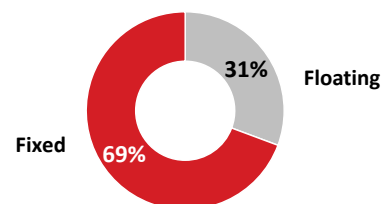
Key ratios	Dec-20	Dec-19
Net Debt / EBITDA (4)	3.2x	3.6x

Debt Maturity (€ billion) as of Dec-20 (1)

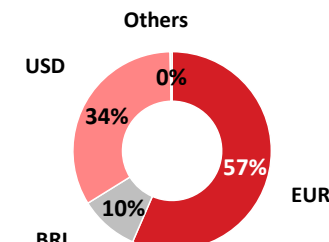
■ EDP S.A. & EDP Finance BV and Other ■ EDP Brasil



Debt by Interest Rate Type as of Dec-20 (1)



Debt by Currency as of Dec-20 (1) (3)



EDP's financial debt is mostly issued at holding level (EDP S.A. and EDP Finance B.V.), accounting for about 80% of the Group's Nominal Financial Debt. Debt for the Group is raised mostly through debt capital markets (88 %), with the remaining through bank loans and commercial paper. Following the acquisition of Viesgo (Dec-20), we have consolidated Viesgo's debt under EDP Espanha, rated at BBB (€1 Bn). EDP made its **first ever green bond issuance in Sep-18 and has since then until the end of December, issued €4.4 Bn worth of Green Bonds, corresponding to 31% of total bonds outstanding and 28% of total financial debt.**

Regarding the latest rating actions, in Feb-2020, Fitch affirmed EDP at "BBB-" and revised the outlook to positive.

Following the announcement of Viesgo acquisition deal and €1 Bn capital increase, **all 3 main rating agencies stated that the acquisition represents a strong fit with EDP's current activities.** Furthermore, it reinforces EDP's credit profile namely through the increased share of regulated/long term contracted activities in EBITDA by ~4 p.p, from 79% in 2019.

Looking at 2020's major debt maturities and early repayments in 2020:

- Repurchase of 2015 EUR750m Hybrid bond, with a 5.375% coupon;
- Maturity of USD583m bond outstanding, with a coupon of 4.125% (Jan-20);
- Maturity of EUR233m bond outstanding, with a coupon of 4.125% (Jun-20);
- Maturity of EUR462m bond outstanding, with a coupon of 4.875% (Sep-20).

In 2020, EDP completed the following operations:

- In Jan-20, €750m Green Hybrid issue, with a coupon of 1.7% (first call date in Apr-25 and final maturity in 2080 to replace the abovementioned 2015 hybrid);
- In Apr-20, €750m Green bond issue, with a coupon of 1.625% and a yield of 1.719%.
- In Sep-20, USD850m Green bond issue, with a coupon of 1.71% and a yield of 1.716%.
- During 2020, €1.4 bn of tariff deficit sales were executed in Portugal: In March €825m, in July €273m and in December €300m.

Subsequent operations:

- In Jan-21, €750m Green Hybrid issue, with a coupon of 1.875% and a yield of 1.95%(first call date in May-26 and final maturity in 2081);
- Maturity of EUR533m bond outstanding, with a coupon of 4.13% (Jan-21).
- Maturity of USD750m bond outstanding, with a coupon of 5.25% (Jan-21).

Total cash and available liquidity facilities amounted to €8.9 Bn by Dec-20, of which €5.9bn are fully available credit facilities. This liquidity position allows EDP to cover its refinancing needs beyond 2023, on a business as usual environment.

(1) Nominal Value includ. 100% of the hybrid bonds; (2) Derivatives designated for fair-value hedge of debt including accrued interest; (3) After FX-derivatives; (4) Net of regulatory receivables; net debt excluding 50% of hybrid bond issues (including interest); Based on trailing 12 months recurring EBITDA and net debt excluding 50% of hybrid bond issue (including interest).

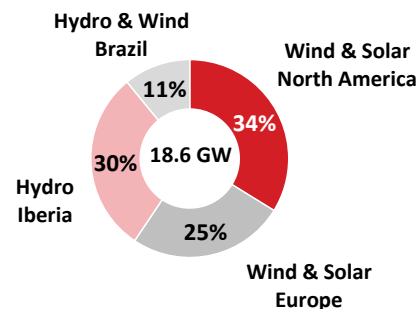


Business Segments

Renewables: Asset base & Investment activity

Installed capacity (MW)	Dec-20	Δ YTD	YoY			Under Construc.
			Δ Abs.	Additions	Reductions	
EBITDA MW	18,626	-971	-971	+1,560	-2,530	+2,051
Wind & Solar	11,500	+688	+688	+1,535	-847	+2,051
US	5,828	114	+114	+587	-473	+908
Canada	68	+38	+38	+38	-	+62
Mexico	400	+200	+200	+200	-	-
North America	6,296	+352	+352	+825	-473	+970
Spain	2,137	+163	+163	+401	-237	+85
Portugal	1,228	+64	+64	+64	-	+135
France	126	+73	+73	+73	-	+30
Belgium	10	+10	+10	+10	-	-
Poland	476	+58	+58	+58	-	+292
Romania	521	-	-	-	-	-
Italy	271	-	-	-	-	+136
Greece	-	-	-	-	-	+45
Europe	4,769	+367	+367	+605	-237	+722
Brazil	436	-32	-32	+105	-137	+359
Hydro	7,126	-1,658	-1,658	+25	-1,683	-
Iberia	5,527	-1,658	-1,658	+25	-1,683	-
Brazil	1,599	-0	-0	-	-	-
Equity MW	1,219	+118	+118	+45	+73	+390
Wind onshore & Solar	658	+108	+108	+35	+73	-
US	471	+73	+73	-	+73	-
Iberia	187	+35	+35	+35	-	-
Wind offshore	10	+10	+10	+10	-	+311
Hydro	551	-0	-0	-	-	+78
Latam	551	-0	-0	-	-	+78

Installed Capacity as of Dec-20



Assets' average life and residual life

(Years)

Hydro Iberia	35	31
Hydro Brazil	21	13
Wind & Solar Brazil	4	26
Wind & Solar Europe	10	20
Wind & Solar North America	8	22

Renewables capacity accounts for **c80% of our total installed capacity** and is our **current main growth driver**. Installed capacity as of Dec-20 totaled **19.8 GW**, including 1.2 GW Equity of wind & solar in US and Iberia, and hydro in Brazil.

In the last 12 months we added 1.6 GW of wind and solar capacity to our portfolio, including (i) in wind onshore Harvest Ridge in US (200 MW), Aventura II-V in Brazil (105 MW), and the wind onshore assets in Spain and Portugal from the Viesgo acquisition closed in Dec-20 (511 MW EBITDA + Equity), (ii) in solar the Los Cuervos plant in Mexico (200 MW) and (iii) in offshore the Windfloat project in Portugal (10 MW Equity). Also, as part of our asset rotation strategy, during 2020 we completed the sale of i) **137 MW in Brazil (Babilónia)** in Feb-20, ii) **237 MW in Spain** in Dec-20, iii) 80% shareholding position in a portfolio of **563 MW in US** in Dec-20, of which 200 MW will start operations in 2021 and the remaining position is now accounted under the equity method (73 MW), and iv) **102 MW in US (Rosewater)**, following the conclusion of the construction and the transfer of the wind farm under the Build and Transfer Agreement signed in Feb-19.

As of Dec-20, our **wind & solar capacity under construction totaled 2.4 GW**, including 2.1 GW wind onshore and solar capacity (EBITDA MW) and wind offshore capacity in UK and Belgium. In **North America**, we have currently **1.0 GW of wind onshore and solar under construction**, including Riverstart (200 MW) and Indiana Crossroads (302 MW). In **Europe**, we are building 0.7 GW of wind onshore, mainly in Poland, Portugal and Italy. In **Brazil**, we are building wind onshore and solar projects, totaling 359 MW.

Our **hydro portfolio** comprises **5,527 MW in Iberia** (c. 45% of which pumping capacity) and **1,599 MW in Brazil**. In LatAm, we additionally own equity stakes on 3 hydro plants totaling 551 MW (Jari, Cachoeira-Caldeirão and S. Manoel, all in Brazil) and own a minority stake in a hydro plant under construction in Peru (San Gaban, 78 MW net). As part of our disposal plan announced in Mar-19, we **completed the sale of 6 hydro plants in Portugal in Dec-20** (1,683 MW) for €2.2 bn. With this transaction, we reduced our exposure to hydro risk in the North of Portugal, while maintaining ~75% of our current hydro portfolio in Iberia.

All in all, **net expansion activity** worth €1,787m in 2020, almost tripled the pace of growth YoY, propelled by doubling of **expansion investment (including financial investments)**, to €2,907m in 2020 with North America accounting for ~55%. In line with our strategy since Mar-19, we closed €1,678m worth asset rotation deals, including assets in Brazil (€254m, of which €132m debt de-consolidation), in Spain (€505m), in US (€423m), the transfer of Rosewater (€74m) and in the offshore wind through our JV with Engie on OW (€421m related to the incorporation of JV with Engie).

Additionally, our expansion activity in renewables also includes €550m from the acquisition of Viesgo (511 MW EBITDA + Equity) and €305m proceeds from new TEI structures which is offset by other items (€312m), that encompass changes in consolidation perimeter (mostly related to the agreed asset rotation deals in Europe and Brazil) and the netting of asset rotation gains.

Net expansion Activity (€ million)	2020	2019	Δ %	Δ Abs.
Expansion capex	2,101	1,121	87%	+980
North America	1,189	784	52%	+405
Europe	709	307	131%	+403
Brazil & Other	203	31	562%	+173
Financial investment	806	318	153%	+488
Proceeds from asset rotations	-1,678	-970	-73%	-708
Proceeds from TEI in US	-305	-186	-63%	-118
Acquisitions/(disposals)	550	18	2954%	+532
Other (1)	312	330	-5%	-17
Net Expansion Activity	1,787	631	183%	1,156

Maintenance Capex (€ million)	2020	2019	Δ %	Δ Abs.
Iberia	29	39	-27%	-10
Brazil	5	8	-32%	-2
Maintenance capex	34	46	-27%	-13

(1) Includes Change in WC Fixed asset suppliers and changes in consolidation perimeter. Excludes asset rotation gain.

Income Statement (€ million)	2020	2019	Δ %	Δ Abs.
Gross Profit	2,416	2,409	0%	+7
OPEX	546	547	0%	-1
Other operating costs (net)	-744	-424	-76%	-320
Net Operating Costs	-198	123	-	-321
Joint Ventures and Associates	-1	11	-	-13
EBITDA	2,613	2,297	14%	+316
Amortisation, impairments; Provision	901	898	0%	+3
EBIT	1,712	1,399	22%	+313

Joint Ventures and Associates (€ million)	2020	2019	Δ %	Δ Abs.
Wind & Solar	-6	3	-	-10
Hydro Brazil	5	8	-41%	-3

Joint Ventures and Associates	-1	11	-	-13
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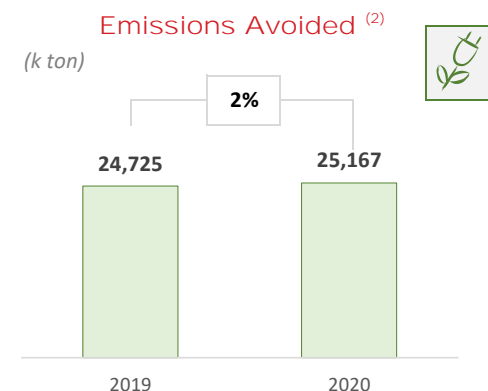
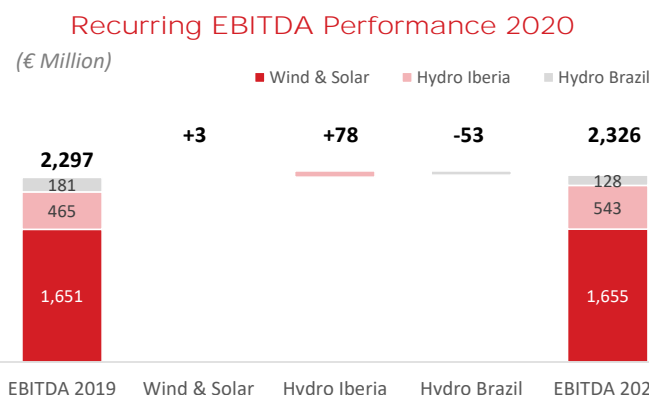
EBITDA (€ million)	2020	2019	Δ %	Δ Abs.
Wind & Solar	1,655	1,651	0%	+3
North America	777	614	26%	+162
Europe	856	917	-7%	-61
Brazil & Other	22	120	-82%	-98
Hydro	958	646	48%	+313
Iberia	764	465	64%	+299
Brazil	194	181	7%	+13

EBITDA	2,613	2,297	14%	+316
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Wind & Solar - Key Aggregate drivers	2020	2019	Δ %	Δ Abs.
Wind resources vs. LT Average (P50)	-8%	-3%	-147%	-5 p.p.
Output (GWh)	28,537	30,041	-5%	-1,503
Average selling price (€/MWh)	53	55	-3%	-1

Hydro Resources vs. LT Average	2020	2019	Δ %	Δ Abs.
Portugal	-3%	-19%	84%	16 p.p.
Brazil (1)	80%	81%	-1%	-1 p.p.

ForEx rate - Average of the period	2020	2019	Δ %	Δ Abs.
USD/EUR	1.14	1.12	-2%	0.02
BRL/EUR	5.89	4.41	-25%	1.48



In 2020, EBITDA amounted to **€2,613m (+14% YoY)**, impacted by the one-off effects on hydro, mainly (i) the gain with the sale of 6 hydro plants in Portugal closed in Dec-20 (€216m) and (ii) the gain booked in 4Q20 on GSF legal settlement in Brazil (€66m). Excluding these extraordinary impacts, **EBITDA amounted to €2,326m (+2% YoY)**, as the strong recovery of hydro resources in Iberia along with our hedging strategy and higher gains on the execution of our asset rotation strategy (+€120m YoY), more than offset the de-consolidation effect of wind assets sold (-€102m) and BRL depreciation.

Excluding the one-off gains abovementioned and in 2019, **Hydro EBITDA** increased 5% YoY to €671m (+€34m), mainly driven by Iberia. In **Iberia**, EBITDA increased €78m YoY due to the higher hydro production (+33% YoY) on the back of the recovery in hydro resources (+16p.p. to 3% short of LT average in Portugal), with the negative impact from lower average pool price being offset by a positive impact from our hedging strategy. As of Dec-20, hydro reserves in Portugal stood at 56%, 6 p.p. above LT average. In **Brazil**, hydro generation performance was impacted by the adverse effect from the energy context in 1Q20 and 4Q20, despite the significant recovery in the 2Q20 and 3Q20, and the 25% YoY BRL depreciation (-€65m).

Wind and solar EBITDA was broadly stable at €1,655m in 2020, due to the mixed impacts of:

- (i) de-consolidation of assets sold (-€102m YoY), including 997 MW in Europe (Jul-19) and 137 MW in Brazil (Feb-20);
- (ii) higher asset rotation gains (+€120m YoY to €434m): €227m on the asset rotation deals in US and Spain and the transfer of Rosewater, and €207m on the establishment of the wind offshore JV with Engie, Ocean Winds;
- (iii) lower wind resources (-5p.p YoY., 8% short of P50), particularly in Iberia and US, and lower average selling price, which were compensated by new capacity additions.

OPEX in renewables was flat, reflecting asset's deconsolidation, growth impact, tight cost control and successful implementation of ongoing savings program. In wind and solar, **Core OPEX per Avg. MW**, adjusted by asset rotations, offshore costs, service fees and forex, increased 1% given the requirements needed to accelerate growth.

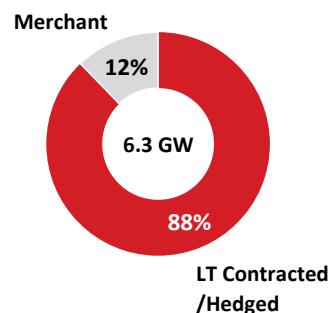
Excluding the gain with the sale of the 6 hydro plants (+€216m) and the positive impact arising from 2019 clawback value ultimately set (+€8m), **Other operating costs (net)** decreased by €97m YoY, mainly driven by higher results booked with our asset rotation strategy (+€120m). This caption includes generation taxes in Spain and clawback levy in Portugal (€39m in 2020, including the €8m positive impact abovementioned).

Renewables in North America

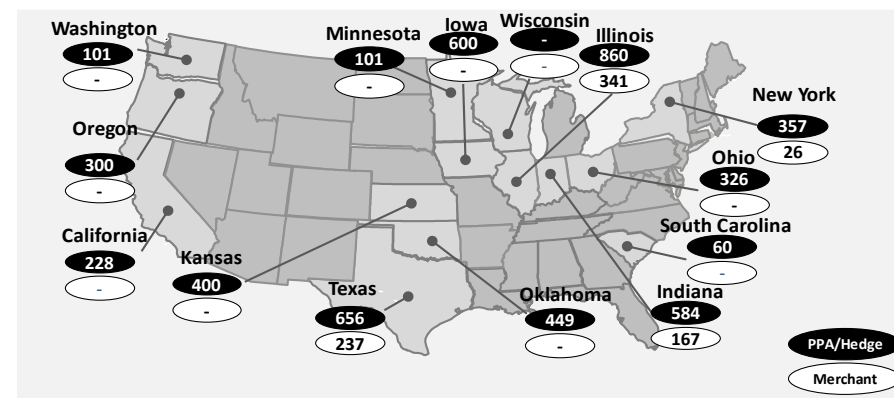
Operating data	2020	2019	Δ %	Δ Abs.
Installed capacity (MW EBITDA)	6,296	5,944	6%	+352
US PPA/Hedge	5,057	4,917	3%	+140
US Merchant	771	797	-3%	-26
Canada	68	30	126%	+38
Mexico	400	200	100%	+200
Wind resources vs. LT Average (P50)	-10%	-7%	-45%	-3 p.p.
Load Factor (%)	33%	34%	-2%	-1 p.p.
US	33%	34%	-2%	-1 p.p.
Canada	30%	27%	11%	3 p.p.
Mexico	41%	42%	-3%	-1 p.p.
Electricity Output (GWh)	17,421	16,492	6%	+928
US	16,633	15,696	6%	+937
Canada	78	70	12%	+8
Mexico	710	726	-2%	-16
Avg. Selling Price (USD/MWh)	44	45	-3%	-1
US	43	44	-3%	-1
Canada (\$CAD/MWh)	148	147	1%	+1
Mexico	67	65	2%	+2
Installed capacity (Equity MW)	471	398	18%	+73

Financial data (USD million)	2020	2019	Δ %	Δ Abs.
Adjusted Gross Profit	995	932	7%	+63
Gross Profit	765	729	5%	+36
PTC Revenues & Other	230	203	13%	+27
Joint Ventures and Associates	0	0	-	+0
EBITDA	914	688	33%	+226
EBIT	504	333	51%	+171

Installed Capacity Dec-20



USA: EBITDA MW by market - Dec-20



In North America, **installed capacity** (6.3 GW EBITDA GW) is **95% wind and 5% solar PV** (290 MW). Additionally, we own equity stakes in other wind and solar projects, equivalent to 471 MW.

In line with EDP's long term contracted growth strategy, the 825 MW additions to portfolio over the last 12 months are PPA-contracted. In 2020, **~90% of total installed capacity is PPA/Hedged contracted**.

Electricity production increased by +6% YoY, mainly reflecting the growth of average installed capacity (+8% YoY) and slightly lower average load factors. In 2020, **average wind resources** were 10% short of LT average (P50), mainly due to poorer resources in **Central and East regions**. **Average selling price** fell slightly to USD 44/MWh.

Gross profit rose to USD 765m (+5% YoY) in 2020, as benefits from the portfolio expansion largely compensated the below-the-average wind resources. **PTC Revenue & Other increased to USD 230m** (+13% YoY), reflecting new PTCs contracted and negligible impact from PTCs expiry.

EBITDA in North America increased 33% to USD 914m in 2020, following gross profit trajectory, the \$219 gain booked with the asset rotation in US and the transfer of Rosewater, as well as North America's share in the gain booked on the establishment of the JV with Engie.



- Sales can be agreed under PPAs (up to 20 years), through Hedges or Merchant prices; Green Certificates (Renewable Energy Credits, REC) subject to each state regulation;
- On Dec-19, the President signed the Taxpayer Certainty and Disaster Tax Relief Act of 2019. The act changes the phase down schedule for the PTC for onshore wind energy projects and with no changes to the solar ITC. Under prior law, the PTC phased down to 40% for projects beginning construction in 2019 and then to 0% for facilities for which construction began in 2020. The new act leaves in place the 40% PTC rate for 2019 projects, then increases the PTC to 60% for projects beginning construction in 2020. Projects beginning construction in 2021 & later will have no PTC. For 2020, PTC value is \$25/MWh.



- Feed-in Tariff for 20 years (Ontario); Renewable Energy Support Agreement (Alberta).

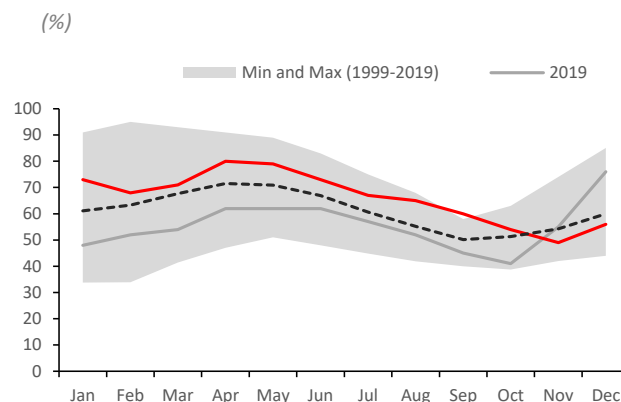


- Technological-neutral auctions (opened to all technologies) in which bidders offer a global package price for the 3 different products (capacity, electricity generation and green certificates);
- EDPR project: bilateral Electricity Supply Agreement under self-supply regime for a 25-year period.

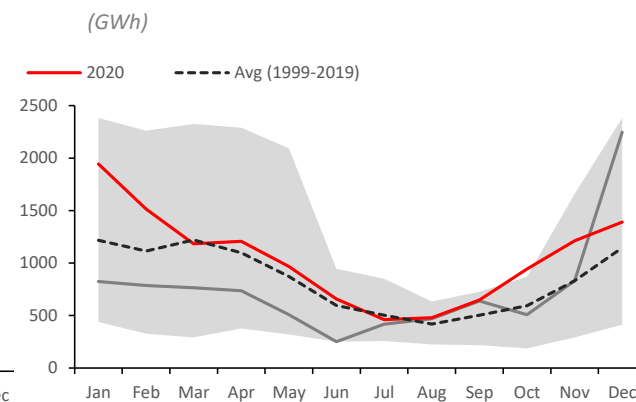
Renewables in Iberia

Operating data	2020	2019	Δ %	Δ Abs.
Installed capacity (MW EBITDA)	8,893	10,324	-14%	-1,431
Wind & Solar	3,366	3,139	7%	+227
Spain	2,137	1,974	8%	+163
Portugal	1,228	1,164	5%	+64
Hydro	5,527	7,186	-23%	-1,658
Resources vs. LT Average (Avg.=0%)				
Wind in Portugal (3)	-6%	7%	-	-13 p.p.
Hydro in Portugal (3)	-3%	-19%	84%	16 p.p.
Load Factor (%)				
Wind & Solar				
Spain	25%	28%	-11%	-3 p.p.
Portugal	26%	29%	-12%	-3 p.p.
Hydro	21%	16%	34%	5 p.p.
Electricity Output (GWh)				
Wind & Solar	6,970	8,458	-18%	-1,488
Spain	4,346	5,298	-18%	-952
Portugal	2,624	3,160	-17%	-536
Hydro	13,249	9,967	33%	+3,281
Net production (4)	11,614	8,599	35%	+3,015
Pumping	1,635	1,368	20%	+267
Avg. Selling Price (€/MWh)				
Wind & Solar				
Spain	79	71	11%	+8
Portugal	86	89	-3%	-3
Hydro (2)	42	54	-21%	-11
Installed capacity (Equity MW)	187	152	23%	+35
Financial data (€ million)				
2020	2020	2019	Δ %	Δ Abs.
Gross Profit	1,256	1,232	2%	+24
Wind & Solar (1)	575	660	-13%	-85
Spain	346	376	-8%	-30
Portugal	229	284	-19%	-54
Hydro	681	572	19%	+109
Joint Ventures and Associates	4	4	14%	+0
EBITDA	1,301	1,205	8%	+96
Wind & Solar (1)	536	740	-28%	-204
Hydro	764	465	64%	+299
EBIT	882	772	14%	+110
Wind & Solar (1)	388	578	-33%	-190
Hydro	494	194	154%	+300

Hydro reserves in Portugal vs. LT Average



Hydro production in Portugal vs. LT Average







In Iberia, installed capacity (8.9 GW) is split between **hydro (~60%)** and **wind and solar (~40%)**. In Dec-20 we completed the sale of 6 hydro plants in Portugal and the acquisition of the 511 MW (EBITDA + Equity) wind portfolio in Spain and Portugal from Viesgo.

Wind & solar output in Iberia declined by 18% YoY, to 7.0 TWh, due to the deconsolidation of capacity sold in Jul-19 (-0.8 TWh YoY) and 13p.p. YoY deterioration of wind resources, to 6% below LT average. As a result, **wind & solar gross profit** amounted to €575m (-13% YoY).

Hydro gross profit amounted to €681m. The strong performance YoY (+19% YoY) mainly reflects last year's extremely weak hydro conditions and this year's successful hedging strategy. In 2020, hydro resources posted a sharp improvement, from 19% deficit in 2019 to 3% below-the-average level in Portugal in 2020. As a result, hydro net production surged 35% YoY but pool prices were downward pressured and so was the average selling price of hydro (-21% YoY, excluding hedging effect).

Pumping activity was more intense in 2020, posting a 20% YoY increase in volume, with a unitary **pumping margin** at double digit, while contributing for hydro reserves at 56%, 6 p.p. above historical average by the end of Dec-20.

EBITDA in 2020 includes a net positive one-off impact totalling €221m, explained by the capital gain booked on the disposal of 6 hydro plants in Portugal (€216m), the impact from a lower clawback relative to 2019 ultimately set and some HR restructuring costs. Excluding these effects, **EBITDA** declined 10% YoY to €1,080 in 2020, mainly due to last year's higher gain with asset rotation strategy, the deconsolidation of assets sold (€76m) which was partly mitigated by the strong hydro performance. Additionally, generation taxes in Spain and clawback levy in Portugal amounted to €39m in 2020.

 On 22-Nov, Royal Decree Law 17/2019 was passed, introducing measures aimed at guaranteeing a stable regulatory and economic framework to encourage the development of renewable energy generation in Spain.
 The RD Law 17/2019 updates the "reasonable return" for renewable generation for the next regulatory period starting on 1 January 2020 at a level of 7.398% for assets before RDL 9/2013 and 7.09% for the new ones.
 MWs from previous regime: Feed-in Tariff inversely correlated with load factor throughout the year. Tariff monthly inflation-updated, through the later of: 15y of operation or 2020, + 7 years (cap/floor system: €74/MWh - €98/MWh);
 ENEOP portfolio: price set in an international competitive tender for 15y (or the first 33 GWh/MW) + 7y (extension cap/floor system: €74/MWh - €98/MWh). First year tariff at c.€74/MWh, CPI monthly-updated.

(1) Includes hedging adjustments; (2) Excludes mini-hydros FIT; (3) Source: REN; (4) Includes mini-hydros FIT.

Operating data	2020	2019	Δ %	Δ Abs.
Installed capacity (MW EBITDA)	1,403	1,263	11%	+140
Romania	521	521	0%	-
Poland	476	418	14%	+58
France & Belgium	136	53	157%	+83
Italy	271	271	0%	-
Load Factor (%)	27%	26%	2%	1 p.p.
Romania	26%	25%	3%	1 p.p.
Poland	29%	30%	-4%	-1 p.p.
France & Belgium	31%	22%	42%	9 p.p.
Italy	25%	27%	-7%	-2 p.p.
Electricity Output (GWh)	3,054	3,333	-8%	-279
Romania	1,186	1,151	3%	+35
Poland	1,059	1,098	-4%	-39
France & Belgium	214	533	-60%	-319
Italy	595	551	8%	+44
Avg. Selling Price (€/MWh)	78	78	0%	+0
Romania (RON/MWh)	342	323	6%	+19
Poland (PLN/MWh)	346	309	12%	+37
France & Belgium	81	92	-12%	-11
Italy	91	95	-5%	-5
ForEx rate - Average of the period				
PLN/EUR	4.44	4.30	-3%	+0.15
RON/EUR	4.84	4.75	-2%	+0.09

Financial data (€ million)	2020	2019	Δ %	Δ Abs.
Gross Profit	235	267	-12%	-32
Romania	76	83	-8%	-7
Poland	84	84	0%	+0
France & Belgium	21	49	-57%	-28
Italy	54	52	3%	+2
EBITDA	167	221	-25%	-55
EBIT	99	134	-26%	-35

In the Rest of Europe (ex-Iberia), installed capacity is mostly focused in onshore wind (1,353 MW), including also solar capacity in Romania (~50 MW). During the last 12 months, we added 140 MW to our portfolio, of which 127 MW in 2H20.

Output declined 8% YoY to 3,054 GWh, following the asset rotation transaction in Europe closed in Jul-19 (representing a 0.4 TWh output in 1H19), which outstood the benefits of stronger wind resources, justifying a 1 p.p. YoY increase in average load factor. Load factors improved YoY in France and Romania.

Average selling price remained broadly flat at €78/MWh, as lower realized prices in France and ForEx depreciation was offset by the increase of prices of green certificates in Poland.

All in all, **gross profit amounted to €235m in 2020** (-12% YoY) mainly impacted by the change in consolidation perimeter. **EBITDA reached €167m** (-25% YoY), on the back of gross profit performance and lower asset rotation gains.



• Wind assets (installed until 2013) receive 2 GC/MWh until 2017 and 1 GC/MWh after 2017 until completing 15 years. 1 out of the 2 GC earned until Mar-2017 can only be sold from Jan-2018 and until Dec-2025. Solar assets receive 6 GC/MWh for 15 years 2 out of the 6 GC earned until Dec-2020 can only be sold after Jan-2021 and until Dec-2030. GC are tradable on market under a cap and floor system (cap €35 / floor €29.4); Wind assets (installed in 2013) receive 1.5 GC/MWh until 2017 and after 0.75 GC/MWh until completing 15 years; The GCs issued starting in Apr-2017 and the GCs postponed to trading from Jul-2013 will remain valid and may be traded until Mar-2032.



• Electricity price can be established through bilateral contracts; Wind receive 1 GC/MWh which can be traded in the market. Electric suppliers have a substitution fee for non compliance with GC obligation. From Sep-17 onwards, substitution fee is calculated as 125% of the avg market price of the GC from the previous year and capped at 300PLN.

• Feed-in tariff for 15 years: (i) €82/MWh up to 10th year, inflation updated; (ii) Years 11-15: €82/MWh @2,400 hours, decreasing to €28/MWh @3,600 hours, inflation updated; Wind farms under the RC 2016 scheme receive 15-yr CfD which strike price value similar to existing FIT fee plus a management premium.

• MW <2013 are (during 15 years) under a pool + premium scheme; MW >2013 were awarded a 20 years contract through competitive auctions. According with the auction scheme, the electricity produced by these wind farms is sold on the market with CfD.

Operating data	2020	2019	Δ %	Δ Abs.
Installed capacity (MW EBITDA)	2,035	2,066	-2%	-32
Wind	436	467	-7%	-32
Hydro	1,599	1,599	0%	-0
Resources				
GSF (1)	80%	81%	-1%	-1 p.p.
Wind resources vs. LT average	-6%	-6%	-14%	-1 p.p.
Load Factor (%)				
Wind	38%	43%	-12%	-5 p.p.
Hydro	39%	29%	34%	10 p.p.
Electricity Output (GWh)	6,636	5,886	13%	+750
Wind	1,093	1,757	-38%	-665
Hydro	5,543	4,129	34%	+1,415
Avg. Selling Price (R\$/MWh)				
Wind	218	205	6%	+12
Hydro	193	170	14%	+23
Installed capacity (Equity MW)	551	551	0%	-0

Our renewable portfolio in Brazil encompasses 2.0 GW of consolidated installed capacity, 79% of which hydro majority PPA-contracted and 21% in wind onshore (PPA contracted). Additionally, EDP owns equity stakes in hydro plants, representing an attributable capacity of 551 MW.


The 41% YoY increase (+R\$354m) in hydro gross profit during 2020 to R\$1,213m is driven by the +R\$389m GSF one-off impact due to the extension of the concession of the hydro plants, as a result of the published Law 14.052/20 and respective Resolution 895/20 by ANEEL, related to the mechanism of reallocation of energy.


This positive regulatory development compensated the particularly weak hydro year, due to the combined impact of an unfavorable energy context (rainfall arrived later than usual) and adverse impact from the allocation strategy adopted, together with a lower volume of bilateral contracts established with market agents and the commercial arm (total volume sold decreased by 37% during 2020).

The deconsolidation of Babilonia wind farm in Feb-20 has impacted YoY wind operating performance providing its weight on portfolio (137 MW), higher average load factor and lower PPA price. Excluding this change in consolidation perimeter, Wind output was broadly stable at 1,093 GWh. Wind resources were 6% short of average, justifying a load factor of 38% (vs. 43% in 2019). All in all, excluding Babilonia de-consolidation effect, wind gross profit rose by 13%.

Overall, EBITDA from hydro improved by 42%, driven by the aforementioned GSF impact, while EBITDA from wind fell by 75%, driven by last year’s gain on Babilonia disposal and its de-consolidation in 2020.

Financial data (R\$ million)	2020	2019	Δ %	Δ Abs.
Gross Profit	1,428	1,187	20%	+241
Wind	215	327	-34%	-112
Hydro	1,213	859	41%	+354
Joint Ventures and Associates	-2	24	-	-26
EBITDA	1,294	1,409	-8%	-115
Wind	151	606	-75%	-454
Hydro	1,142	803	42%	+339
Lajeado & Invesco	536	431	24%	+105
Peixe Angical	381	246	55%	+134
Energest	226	126	80%	+100
EBIT	1,091	1,195	-9%	-104

- 
- Old installed capacity under a feed-in tariff program ("PROINFA")
 - Since 2008, competitive auctions awarding 20-years PPAs

- 
- Hydro capacity is either bilaterally or long term PPA contracted and are obliged to deliver a certain amount of physical guarantee of energy.

(1) Generation Scale Factor (GSF) reflects the total (real) generation, accounted as a proportion of the total volume of Physical Guarantee in the system (when has a strong volatility on quarterly basis).

Networks: Financial performance

Income Statement (€ million)	2020	2019	Δ %	Δ Abs.
Gross Profit	1,703	1,816	-6%	-114
OPEX	529	551	-4%	-22
Other operating costs (net)	266	274	-3%	-8
Net Operating Costs	795	825	-4%	-30
Joint Ventures and Associates	2	6	-57%	-3
EBITDA	910	997	-9%	-87
Amortisation, impairments; Provision	383	370	3%	+13
EBIT	527	627	-16%	-100

ForEx rate - Average of the period	2020	2019	Δ %	Δ Abs.
BRL/EUR	5.89	4.41	-25%	1.48

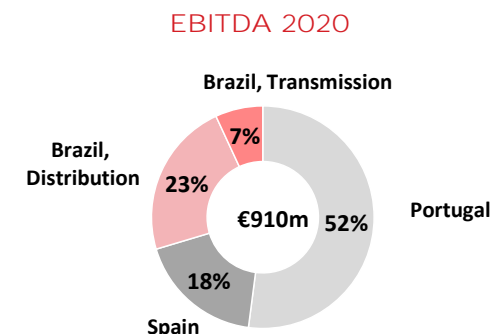
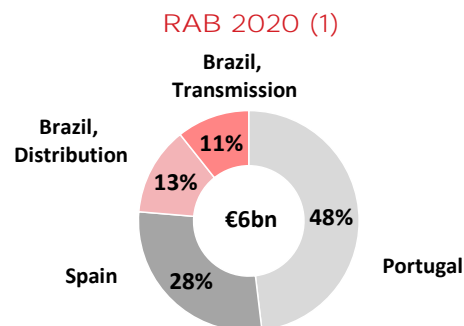
EBITDA (€ million)	2020	2019	Δ %	Δ Abs.
Portugal	474	477	-1%	-3
Spain	166	155	8%	+12
Brazil	270	365	-26%	-96
EBITDA	910	997	-9%	-87

OPEX & Capex performance	2020	2019	Δ %	Δ Abs.
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Controllable Costs (2)				
Iberia (€/Supply point)	47	52	-10%	-5
Brazil (R\$/Supply point)	190	198	-4%	-8

Capex (€ million) (3)	624	911	-32%	-287
Portugal	280	270	4%	+9
Spain	43	39	9%	+4
Brazil	301	601	-50%	-300
Maintenance	12	16	-29%	-5
Expansion	289	585	-51%	-296

Network ('000 Km)	375	341	10%	+34
Portugal	228	227	1%	+2
Spain	52	21	153%	+32
Brazil	94	93	1%	+1



Our Networks segment includes distribution of electricity in Portugal, Spain and Brazil; electricity last resort supply activity in Portugal (LRS); and the new activity of transmission, in Brazil. Overall, our regulated asset base (RAB) amounts to €6 Bn, with the transmission's financial asset base gaining track, with 11% of total base. After the acquisition of Viesgo in Spain, completed in Dec-20, the weight of Spain in the group's RAB increased to 28%, providing further regulatory visibility as the current regulatory period will be in place until 2025.

Excluding one-off impacts (+€9m in 2019, - €19m in 2020), recurring EBITDA amounted to €891m (-€115m YoY), largely reflecting the 25% depreciation of Brazilian Real against the Euro (-€90m), overshadowing local currency 7% EBITDA growth in the period backed by positive tariff updates. In Spain, recurring EBITDA amounted to €136m, reflecting the new regulatory terms in place and negligible contribution from Viesgo.

In Portugal, recurring EBITDA to €485m in 2020 (-6% YoY) reflecting lower rate of return on RAB and higher costs with vegetation management.

OPEX improved by 2% YoY, excluding one-off HR restructuring costs and favorable ForEx impact c€60m backed by the BRL depreciation (€45m), reflecting mostly tight cost control, more remote orders and lower headcount, namely in Portugal. Efficiency in operations has been improving greatly in part by the continued effort for smart meter installation and registration.

Other net operating costs fell by 3% including one-off gain related to past disposals.

Capex in 2020 declined by 32% YoY to €624m, primarily explained by lower capex in Brazil (-€300m). This, in turn, reflects: (i) interruption in construction works in new transmission lines in the 2Q20, given the Covid-19 context; (ii) heavy rainfall in some regions in Brazil in 1Q20; and (iii) BRL depreciation vs. Euro. Finally, it is worth to mention that the 4 transmission lines under construction are still ahead of the regulatory schedule, with 82% of the investment plan already executed.

Networks in Iberia

Electricity Distribution & LRS in Portugal

Income Statement (€ million)	2020	2019	Δ %	Δ Abs.
Gross Profit	1,064	1,052	1%	+11
OPEX	332	337	-1%	-5
Concession fees	262	262	0%	+0
Other operating costs (net)	-4	-23	83%	+19
Net Operating Costs	590	575	3%	+15
Joint Ventures and Associates	0	0	197%	+0
EBITDA	474	477	-1%	-3
Amortisation, impairment; Provisions	271	268	1%	+3
EBIT	203	210	-3%	-7

Key drivers	2020	2019	Δ %	Δ Abs.
Gross Profit (€ million)	1,064	1,050	1%	+14
Regulated	1,057	1,039	2%	+18
Non-regulated	7	11	-40%	-4

Distribution Grid				
Regulated revenues (€ million)	1,023	1,007	2%	+16
Electricity distributed (GWh)	44,143	45,666	-3%	-1,524
Supply Points (th)	6,302	6,277	0%	+25

Last Resort Supply				
Regulated revenues (€ million)	34	32	5%	+2
Customers supplied (th)	966	1,034	-7%	-68
Electricity sold (GWh)	2,413	2,658	-9%	-245

Electricity Distribution in Spain

Income Statement (€ million)	2020	2019	Δ %	Δ Abs.
Gross Profit	193	197	-2%	-4
OPEX	58	55	6%	+4
Other operating costs (net)	-35	-12	-	-23
Net Operating Costs	23	43	-46%	-19
Joint Ventures and Associates	-4	0	-	-4
EBITDA	166	155	8%	+12
Amortisation, impairment; Provisions	39	36	10%	+3
EBIT	127	119	7%	+8

Key drivers	2020	2019	Δ %	Δ Abs.
Gross Profit (€ million)	193	197	-2%	-4
Regulated	190	191	-0.0	-0.9
Non-regulated	4	7	-44%	-3
Electricity Supply Points (th)	1,371	668	105%	+702
Electricity Distributed (GWh)	7,559	8,262	-9%	-703

Electricity distribution and LRS in Portugal

Electricity distributed declined by 3% YoY in 2020, impacted by Covid-19 pandemic. In spite of the recovery in 3Q20 (with consumption barely flat YoY), 4Q20 was 3.3% below YoY. Note that in line with Portugal's regulatory model in place, although this contraction in consumption had a negligible impact on EBITDA, it contributed for higher regulatory receivables in the period (as detailed in page 7).

Distribution regulated revenues were €1,023m. The low Portuguese government 10-year bond yields resulted in a rate of return on RAB for 2020 very close to the floor (4.75%), at 4.85% for High Voltage/Medium Voltage (vs. 5.13% in 2019). In the **last resort electricity supply (LRS) activity, regulated revenues increased to €34m.**

Excluding one-off HR restructuring costs (+€2m YoY, to €11m in 2020), OPEX improved 2% YoY, benefitting from tight cost control and grids digitalisation. The continued roll out of smart meters, key to enhance grid digitalization, enabled a 14% rise in remote orders in Portugal and a 13% decline in the number of complaints.

Overall, excluding one-off costs (-€26m YoY, to €11m cost in 2020), **EBITDA amounted to €485m in 2020 (-6% YoY) reflecting lower rate of return on RAB** and higher costs with vegetation management.

On 15-Dec-2020, ERSE, the Portuguese energy regulator, published its **final electricity tariffs for 2021.** According to ERSE, allowed revenues for electricity distribution is €1,024m (vs €1,029m in 2020) and €34m (vs. € 32m in 2020) for last resort supplier, both excluding previous years' adjustments. Low Voltage regulated clients will see a 0.6% reduction in their tariff. Electricity distribution regulated revenues preliminarily assume a rate of return on HV/MV assets (RoRAB) of 4.85% (assuming for 2021 the same rate of 2020).

Electricity distribution in Spain

Gross profit from electricity distribution activity in Spain declined 2% YoY to €193m, mainly driven by the lower rate of return on RAB, at 6.0% in 2020 (-50bp YoY). Excluding one-off impacts (+€31m in 2020, including the reversion of contingencies relative to past disposals and HR restructuring costs), **EBITDA amounted to €136m in 2020 (-13% YoY), reflecting the new regulatory terms and lower adjustments to past year's revenues.**

As a result of the acquisition of Viesgo, completed in Dec-20, EDP more than doubled its Spanish network size to 52,492 km (+153% YoY) and the number of electricity supply points (+105% YoY) reinforcing EDP's presence in this market and the weight of regulated activities. The transaction increases our **RAB to €1.7 Bn in Spain.**

Following court decision 481/2020 on Lesividad, distribution RAB in Spain can fall from €2,051m to a minimum of €1,706m, depending on the final terms applicable yet to be known. Having said this, our **EBITDA already reflects this impact since 2017.**

Income Statement (R\$ million)	2020	2019	Δ %	Δ Abs.
Gross Profit	2,625	2,498	5%	+126
OPEX	788	664	19%	+125
Other operating costs (net)	247	211	17%	+36
Net Operating Costs	1,035	875	18%	+161
Joint Ventures and Associates	0	0	-	-
EBITDA	1,589	1,624	-2%	-34
Amortisation, impairment; Provisions	304	282	8%	+21
EBIT	1,285	1,341	-4%	-56

Distribution - Key drivers	2020	2019	Δ %	Δ Abs.
Customers Connected (th)	3,601	3,524	2.2%	+77
EDP São Paulo	1,980	1,936	2.3%	+44
EDP Espírito Santo	1,620	1,588	2.0%	+32
Electricity Distributed (GWh)	24,421	25,591	-5%	-1,170
Regulated customers	13,429	14,202	-5%	-773
Customers in Free Market	10,992	11,389	-3%	-397
Total losses (%)				
EDP São Paulo	8.6%	8.1%	5.7%	+0
EDP Espírito Santo	13.4%	12.5%	7.5%	+0
Gross Profit (R\$ million)	2,233	2,253	-1%	-20
Regulated revenues	2,051	1,869	10%	+182
Other	182	384	-52%	-201
EBITDA (R\$ million)	1,219	1,393	-12%	-174
EDP São Paulo	640	634	1%	+6
EDP Espírito Santo	579	759	-24%	-180

Transmission - Key drivers (R\$ million)	2020	2019	Δ %	Δ Abs.
Revenues	1,412	2,189	-35%	-776
Construction Revenues	1,168	2,248	-48%	-1,079
Financial Revenues	374	157	139%	+217
Other	-130	-216	40%	+86
Gross Profit	391	246	59%	+146
EBITDA	371	231	60%	+140
EBIT	370	232	59%	+137

Distributed electricity in Brazil declined 5% YoY in the 2020, mainly due to the 12% YoY fall in the 2Q20 due to the pandemic crisis, which was partially offset by a 2% YoY recovery in consumption in 4Q20, in our concession areas.

Gross profit from distribution was relatively flat YoY, at R\$2,233m, positively impacted by the tariff updates (+R\$97m YoY), factoring in a higher IGP-M index (as a result of Brazilian Real depreciation in the past year). On the other hand, last year’s update of concessions assets’ residual value in the wake of regulatory reviews explains a R\$156 m YoY decline in gross profit, despite recovery quarter-on-quarter.

Several measures were introduced by the Brazilian government to face the challenges caused by the pandemic, in particular the COVID account whereas ANEEL deemed that the over-contracting related to the pandemic was considered as involuntary, which corresponded to R\$28m for EDP Brasil in 2020.

In addition, the negative impact witnessed by demand contraction and, thus, excess supply (-R\$27m YoY) together with higher client losses (-R\$30m YoY) was partially mitigated by the gradual recovery of economic activity together with an increase in PLD witnessed in the 4Q20.

Gross profit from transmission increased by 59% YoY, reaching R\$391m, following the full commissioning of lot 11 (12 months ahead of schedule) and the evolution of construction works in the remaining lines, even taking into account some delays as a result of the pandemic.

Excluding one-off impacts (mainly last year’s R\$134m gain on social benefits related to a change in the provider of medical assistance), **OPEX** decreased by 1% YoY, due to renegotiation of contracts and reduced amount of operations. Other operating costs increased 17% YoY (+R\$36m), reflecting higher client impairments in distribution business (+R\$30m).

Overall, excluding one-off impacts mentioned above, EBITDA from networks activities increased by 7% YoY to R\$1,597m, positively impacted by a solid recovery in residential demand in the 4Q20, positive regulatory developments, as well as strong growth in transmission with the roll-out of construction works, partially offsetting the negative impact caused by the pandemic with more prominence in the 1H20.

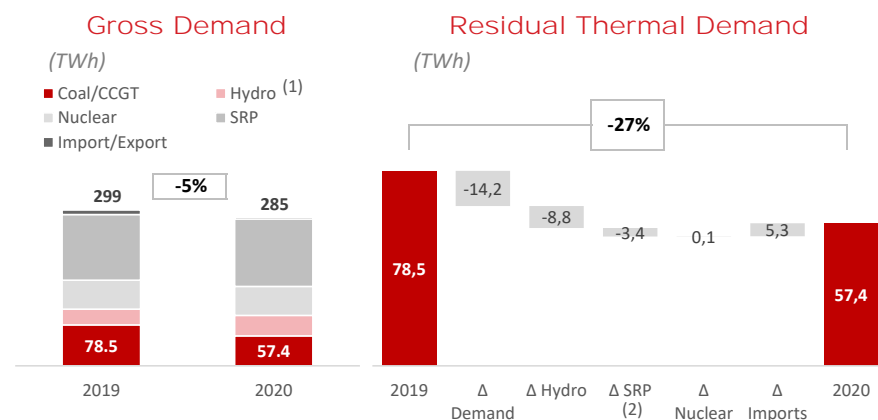


• Two distribution concessions, both 100% owned by EDP Brasil: EDP SP, in São Paulo, with 4-year regulatory period last renewed in Oct-19; EDP ES, in Espírito Santo with 3-year regulatory period last time renewed in Aug-19. The regulated WACC is currently defined at 8.09%.



• EDP operates one transmission line (since Dec-18) and part of another line (since Jan-20), while developing 4 other transmission lines, including a new one, acquired in May-19.

EDP in the Iberian market



Main Drivers (3)	2020	2019	Δ %	Δ Abs.
Electricity spot price (Spain), €/MWh	34	48	-29%	-14
Electricity final price (Spain), €/MWh (4)	42	53	-21%	-11
Iberian Electricity 1Y Fwd Price (€/MWh)	44	55	-20%	-11
CO2 allowances (EUA), €/ton	25	25	0%	-0
Coal (API2), USD/ton	50	61	-18%	-11
Mibgas, €/MWh	10	15	-34%	-5
Brent, USD/bbl	41	64	-36%	-23

Income Statement (€ million)	2020	2019	Δ %	Δ Abs.
Gross Profit	830	825	1%	+5
OPEX	397	376	6%	+22
Other operating costs (net)	89	113	-21%	-24
Net Operating Costs	486	489	0%	-2
Joint Ventures and Associates	1	4	-72%	-3
EBITDA	345	340	1%	+5
EBIT	-33	-152	78%	+119

Key financial data (€ million)	2020	2019	Δ %	Δ Abs.
Gross Profit	830	825	1%	+5
Supply (5)	404	353	14%	+51
Energy Management & Thermal	426	472	-10%	-45
EBITDA	345	340	1%	+5
Supply (5)	145	91	61%	+55
Energy Management & Thermal	199	249	-20%	-50
EBIT	-33	-152	78%	+119
Supply (5)	108	49	118%	+58
Energy Management & Thermal	-141	-201	30%	+60



Client Solutions & Energy Management segment in Iberia encompasses 4.3 GW of thermal installed capacity, ~4.1m electricity clients and energy trading activities in Iberia. These businesses are the roots for the success of our integrated portfolio management, ensuring a responsive and competitive structure capable of offering clients diversified solutions and the necessary security of supply.

Sources: EDP, REN, REE; (1) Net of pumping; (2) Special Regime Production, namely wind, solar and cogeneration; (3) Average of the period; (4) Final price reflects spot price and system costs (capacity payment, ancillary services); (5) Excludes activities carried in Italy, France and Poland (-€3m EBITDA in 2020)

Iberian electricity market context

During 2020, electricity demand in Iberia declined 5% YoY (-2% in 4Q YoY), penalised by lower economic activity due to Covid pandemic. **Residual thermal demand (RTD)**, i.e. coal and CCGT generation, decreased 27% YoY in 2020 (-21 TWh YoY), reflecting: (i) +9 TWh YoY of hydro output (net of pumping) following the recovery of hydro resources (+20% YoY but still 3% below-the-average in Portugal; +26% YoY to normalised level in Spain); (ii) a c14 TWh reduction in electricity demand in Iberia (iii) a c3 TWh increase in SRP driven by the growth in solar production. These effects were partially mitigated by a c5 TWh reduction in net imports.

Average electricity spot price declined 29% YoY, to ~€34/MWh in 2020, supported by the declining gas prices (-34% YoY), lower demand and higher hydro resources availability. Average electricity final price in Spain declined 21% YoY in 2020, to €42/MWh, reflecting higher demand for restrictions and the evolution of wholesale spot price.

EDP Performance

EBITDA rose by 1% YoY, to €345m in 2020, with a negligible net impact from one-offs (+€4m YoY increase to a €6m cost). EBITDA growth was mainly prompted by a normalization of the operating conditions in supply, particularly in 2H20: (i) demand showed signs of recovery namely in the B2C segment, following a very tough 2Q20, when demand fell short of predicted and excess energy had to be sold in the market at very depressed prices; (ii) higher services penetration, prompting an increase in revenues per customer. Additionally, the strong performance of our Energy Management & Thermal business, driven by our successful hedging strategy, was nevertheless offset by the forced burning of coal stocks in Sines during 2H20, ahead of its production ceasing in late December. Its decommissioning works started on January 15th. As a results Sines accounted for 3% of production and 2% of revenues in 2020.

In 2020, excluding Sines, EDP's coal fired electricity production in Iberia represented 2% of consolidated revenues and had a contribution below 1% to consolidated EBITDA.

In 2020, the one-off impacts (€6m) related to the forced burnt of coal at Sines and HR restructuring in Iberia were offset by the one-off positive impact related with the sale of our B2C portfolio in Spain and Castejón CCGT (+€30m net gain, completed on 1-Dec-20) and the reversal of clawback 2019 (+€13m) in line with terms ultimately set.

For 2021, we have 100% of our expected hydro and nuclear production hedged at prices close to €45/MWh (baseload price excluding ancillary services) and 100% of our expected CCGT production at mid-single digit average spread.

Supply - Key Drivers and Financials	2020	2019	Δ %	Δ Abs.
Portfolio of Clients (th)				
Electricity	4,050	5,270	-23.1%	-1,220
Portugal	4,028	4,104	-1.8%	-75
Spain	22	1,166	-98.1%	-1,145
Gas	657	1,562	-57.9%	-905
Portugal	651	659	-1.1%	-7
Spain	6	903	-99.4%	-898
Dual fuel penetration rate (%)	16.6%	30.4%	-45.4%	-0
Services to contracts ratio (%)	26.1%	18.9%	38%	+0
Volume of electricity sold (GWh)				
Residential	12,552	12,889	-2.6%	-336
Business	15,333	17,469	-12%	-2,136
Volume of gas sold (GWh)				
Residential (1)	5,159	6,470	-20%	-1,311
Business	6,384	5,748	11%	+635
Gross Profit (€ million)	404	353	14%	+51
EBITDA (€ million)	145	91	61%	+55
Capex (€ million)	56	38	46%	+18



EDP's electricity clients portfolio in Iberia (~4.1m clients), has a significant weight of residential and SME clients, corresponding to ~45% of total consumption.

EM & Thermal - Drivers and Financials	2020	2019	Δ %	Δ Abs.
Generation Output (GWh)				
CCGT	9,759	10,183	-4%	-424
Coal	4,235	7,149	-41%	-2,914
Nuclear	1,196	1,223	-2%	-27
Other	211	270	-22%	-59
Load Factors (%)				
CCGT	30%	31%	-2%	-1p.p.
Coal	20%	34%	-41%	-14p.p.
Nuclear	88%	90%	-2%	-2p.p.
Generation Costs (€/MWh) (2)				
CCGT	44	57	-23%	-13
Coal	53	51	4%	+2
Nuclear	4	5	-3%	-0
Gross Profit (€ million)	426	472	-10%	-45
EBITDA (€ million)	199	249	-20%	-50
Capex (€ million)	35	57	-38%	-22



Our thermal portfolio in Iberia encompasses 4.3 GW installed capacity, which plays an active role in ensuring the security of electricity supply: 67% in CCGT, 29% in coal, 4% in nuclear and 1% of cogeneration and waste.

Supply Iberia

Excluding the impact from the disposal of our B2C portfolio in Spain to Total, **the number of electricity clients in Portugal and Spain (B2B) slightly decreased**, as EDP maintains its focus on service quality and is leveraging on its customer portfolio to increase the share of wallet. In fact, the penetration rate of new services increased by 38% YoY to 26.1% in Dec-20, as a consequence of a 5% increase in the number of Funciona clients and also the deconsolidation of a portfolio of B2C clients with lower service penetration. EDP keeps growing into new energy solutions involving its clients in the energy transition. In this regard, in 2020, EDP did nearly 15,000 installations of distributed solar panels (+70% YoY) in Portugal B2C.

Total electricity supplied in 2020 decreased by 8% mainly driven by the B2B segment (-12%), which was heavily impacted by the slower economic activity during the Covid-19 pandemic lockdown. Demand in the B2C segment was also impacted by the deconsolidation of these assets on Dec-1st.

Excluding one-off impacts (€47m gain in 2020), EBITDA at our supply activities in Iberia rose by 7% YoY, to €99m, fully supported by the recovery in 2H20 after a harsh 2Q20, when surplus energy arising from sudden decline in demand was resold in the market at unfavourable prices. Moreover, EBITDA performance was supported by resilient demand in the B2C segment, increased installation of distributed solar and services provided. **EBITDA** performance was impacted by €19m bad debt recognition (0.8% of turnover, down 0.3 p.p. since Sep-20), of which -€1m in 4Q20.

Thermal generation & Energy management Iberia

Production in 2020 decreased 18% YoY, largely explained by the reduction in coal output (-41% YoY) leading to a 14 p.p. decrease in the load factor of our coal plants to 20% in 2020. Sines coal plant ceased production in late Dec-20, after completing the forced burning of coal stocks during 2H20. Decommissioning works started on January 15th 2021. Slightly lower CCGT output (-4% YoY) reflected the lower residual thermal demand and deconsolidation of Castejón power plants in the beginning of December.

Avg. thermal production cost posted a 16% YoY decrease (to €43/MWh in 2020), driven by lower commodity prices, particularly gas, which was slightly compensated by the higher coal-based production in 2H20.

Excluding one-off effects mentioned before, Energy Management and Thermal EBITDA reached €252 m in 2020 (+€2m YoY) reflecting a dilution of the very strong 1Q20 performance (+€121m YoY in 1Q20), driven by a normalisation of price volatility and the forced coal stock burnings in Sines.

Excluding one-off impacts, generation taxes in Spain and clawback levy in Portugal relative to 2020 declined €13m YoY, to €34m, reflecting lower CCGT production in Spain and coal production (in Portugal) and lower pool prices (in Spain).

(1) Includes SMEs; (2) Includes fuel costs, CO2 emission costs and hedging results.

Income Statement (€ million) (1)	2020	2019	Δ %	Δ Abs.
Gross Profit	162	177	-8%	-15
OPEX	34	39	-13%	-5
Other operating costs (net)	0	0	30%	+0
Joint Ventures and Associates	3	2	51%	+1
EBITDA	132	140	-6%	-9
EBIT	92	87	6%	5

ForEx rate - Average of the period	2020	2019	Δ %	Δ Abs.
BRL/EUR	5.89	4.41	-25%	+1.48

Income Statement (R\$ million)	2020	2019	Δ %	Δ Abs.
Gross Profit	955	779	22%	+175
OPEX	184	159	16%	+25
Other operating costs (net)	-5	-7	22%	+2
Joint Ventures and Associates	0	-6	-	+6
EBITDA	776	628	24%	+149
EBIT	576	428	35%	148

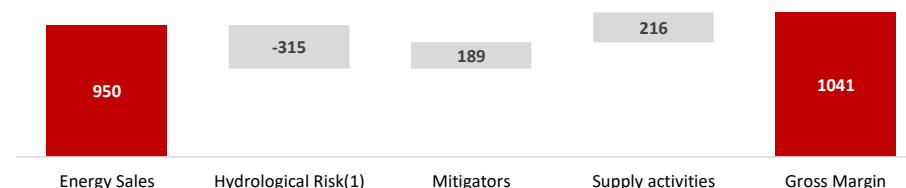
Key drivers	2020	2019	Δ %	Δ Abs.
PLD	177	227	-22%	-50
GSF (2)	80%	81%	-1%	-1p.p.

Supply & EM - Key drivers and financials	2020	2019	Δ %	Δ Abs.
Electricity sales (GWh)	25,554	24,036	6%	+1,517
Gross Profit (R\$ million)	265	160	66%	+105
EBITDA (R\$ million)	195	111	75%	+84
EBIT (R\$ million)	187	103	82%	+85

Thermal - Key drivers and financials (3)	2020	2019	Δ %	Δ Abs.
Installed Capacity (MW)	720	720	0%	-0
Electricity output (GWh)	1,586	3,707	-57%	-2,121
Availability	92%	95%	-4%	-3p.p.
Gross Profit (R\$ million)	690	619	11%	+70
EBITDA (R\$ million)	581	516	13%	+65
EBIT (R\$ million)	388	325	19%	+63

(1) For Group segment reporting purposes, Holdings and other activities at EDP Brazil level are distributed across business segments; (2) Weighted-average GSF; (3) Values of Pecém individual accounts.

EDP Energy management in Brazil 2020
(R\$ Million)



(1) Includes GSF, PLD and MRE

As part of our risk-controlled approach to its portfolio management, EDP follows a hedging strategy to mitigate the GSF/PLD risk, aiming at reducing the volatility of earnings. Therefore, supply and generation activities are managed in an integrated way, allowing the optimization of the portfolio as a whole.

At our Client Solutions & Energy Management activities in Brazil, EBITDA in EUR terms decreased by 6% to €132m, penalised by 25% YoY BRL depreciation against the euro, which offset the 22% EBITDA increase in BRL.

EBITDA from supply and energy management in Brazil improved by 75% in local currency, to R\$195m, positively impacted by an accounting change in the long-term contracts, of R\$206m due to a mark-to-market restatement of these contracts, helping to offset the reduced liquidity in the liberalized market and lower prices. Furthermore, performance in 2020 also reflected the clients' use of contracts flexibility to mitigate the adverse impact from the slump in demand.

Our thermal generation plant, Pecém I, was not dispatched from April to August, and was only dispatched during 3 days in September, as a result of lower electricity demand and better hydro conditions in the Northeast of Brazil. On the contrary, as the economy rebounded in 4Q20 amidst dry weather and activity picked-up, load factor of this plant increased to 67% in the 4Q20. Nevertheless, providing this plant is PPA remunerated based on availability, results tend to be stable and less dependent on actual production. Worth also highlighting that Pecém has a fixed monthly revenue of R\$62m, being adjusted to twelve-months IPCA, in November (+2.6% YoY).

EBITDA from thermal generation increased by +13% YoY in 2020 to R\$581m, driven by: (i) increased fixed revenues, due to annual adjustment in PPA in Nov-19; (ii) adjustment related with the downwards revision of the reference availability level of Pecém (R\$34m YoY); and (iii) better comparison YoY on variable costs.



Income Statements & Annex

2020					
(€ million)	Renewables	Networks	Clients solutions & Energy management	Corpor. Activ. & Adjustments	EDP Group
Revenues from energy sales and services and other	2,600	5,329	7,478	(2,959)	12,448
Gross Profit	2,416	1,703	992	(19)	5,092
Supplies and services	355	325	270	(94)	857
Personnel costs and employee benefits	190	204	163	109	667
Other operating costs (net)	(744)	266	89	10	(379)
Operating costs	(198)	795	522	25	1,145
Joint Ventures and Associates	(1)	2	4	(2)	3
EBITDA	2,613	910	474	(47)	3,950
Provisions	73	11	28	0	112
Amortisation and impairment (1)	828	372	390	42	1,632
EBIT	1,712	527	56	(89)	2,206

2019					
(€ million)	Renewables	Networks	Clients solutions & Energy management	Corpor. Activ. & Adjustments	EDP Group
Revenues from energy sales and services and other	2,783	6,195	8,639	(3,284)	14,333
Gross Profit	2,409	1,816	1,001	(9)	5,217
Supplies and services	365	352	285	(104)	898
Personnel costs and employee benefits	182	200	129	110	620
Other operating costs (net)	(424)	274	113	31	(6)
Operating costs	123	825	527	36	1,512
Joint Ventures and Associates	11	6	6	2	25
EBITDA	2,297	997	480	(43)	3,731
Provisions	82	14	6	(0)	102
Amortisation and impairment (1)	816	356	539	55	1,766
EBIT	1,399	627	(65)	(98)	1,863

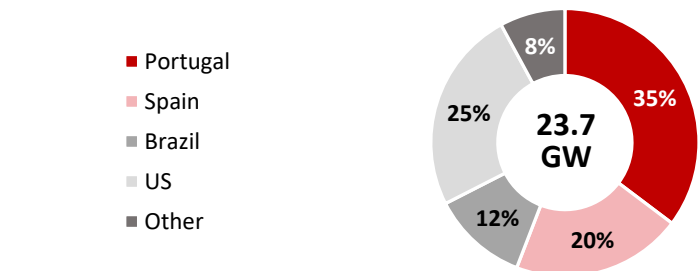
(1) Depreciation and amortisation expense net of compensation for depreciation and amortisation of subsidised assets.

Quarterly P&L (€ million)	1Q19	2Q19	3Q19	4Q19	1Q20	2Q20	3Q20	4Q20	Δ YoY %	Δ QoQ %	2019	2020	Δ %
Revenues from energy sales and services and other	3,744	3,363	3,340	3,886	3,502	2,681	2,876	3,389	-13%	18%	14,333	12,448	-13%
Cost of energy sales and other	2,383	2,123	2,131	2,479	2,027	1,499	1,757	2,074	-16%	18%	9,116	7,356	-19%
Gross Profit	1,361	1,240	1,209	1,407	1,475	1,182	1,119	1,315	-7%	17%	5,217	5,092	-2%
Supplies and services	200	221	223	253	201	201	207	248	-2%	20%	898	857	-5%
Personnel costs and Employee Benefits	159	164	156	140	165	157	143	203	45%	42%	620	667	8%
Other operating costs (net)	81	(133)	77	(31)	128	(60)	13	(460)	1405%	-3537%	(6)	(379)	-6005%
Operating costs	439	253	456	363	494	297	363	(9)	-103%	-103%	1,512	1,145	-24%
Joint Ventures and Associates	5	7	2	11	(1)	6	(2)	0	-95%	-122%	25	3	-87%
EBITDA	927	994	755	1,055	980	891	754	1,325	26%	76%	3,731	3,950	6%
Provisions	4	1	92	4	16	35	78	(17)	-501%	-122%	102	112	10%
Amortisation and impairment (1)	374	362	358	672	367	401	340	524	-22%	54%	1,766	1,632	-8%
EBIT	550	631	305	378	597	455	336	818	116%	143%	1,863	2,206	18%
Financial Results	(186)	(185)	(175)	(124)	(206)	(162)	(137)	(166)	33%	21%	(670)	(671)	0%
Profit before income tax and CESE	364	446	130	254	391	293	199	652	157%	228%	1,194	1,535	29%
Income taxes	99	38	9	80	92	42	39	136	69%	246%	226	309	37%
Extraordinary contribution for the energy sector	67	(0)	1	1	63	(0)	3	-	-100%	-	68	65	-5%
Net Profit for the period	198	408	120	173	236	252	157	517	199%	229%	899	1,161	29%
Attrib. to EDP Shareholders	100	305	55	51	146	169	108	378	636%	251%	512	801	56%
Attrib. to Non-controlling Interests	98	104	65	121	90	83	49	138	14%	180%	388	361	-7%

(1) Depreciation and amortisation expense net of compensation for depreciation and amortisation of subsidised assets.

Technology	Installed Capacity - MW (1)				Electricity Generation (GWh)				Electricity Generation (GWh)							
	Dec-20	Dec-19	Δ MW	Δ %	2020	2019	Δ GWh	Δ %	1Q19	2Q19	3Q19	4Q19	1Q20	2Q20	3Q20	4Q20
Wind	11,155	10,667	+488	5%	28,272	29,768	-1,495	-5%	8,356	7,661	5,651	8,100	7,707	6,816	5,612	8,137
US	5,738	5,624	+114	2%	16,443	15,501	+942	6%	4,196	4,113	2,975	4,217	4,453	4,239	2,957	4,793
Portugal	1,224	1,160	+64	6%	2,616	3,151	-535	-17%	832	799	549	971	710	548	543	815
Spain	2,137	1,974	+163	8%	4,346	5,298	-952	-18%	1,621	1,388	893	1,397	1,172	929	986	1,258
Brazil	436	467	-32	-7%	1,093	1,757	-665	-38%	314	384	561	499	161	227	397	308
Rest of Europe (2)	1,353	1,212	+140	12%	2,987	3,264	-277	-8%	1,160	770	498	835	1,007	655	551	774
Rest of the World (3)	267	230	+38	16%	788	796	-8	-1%	233	208	174	181	203	218	178	189
Solar	345	145	+200	138%	265	273	-8	-3%	55	85	85	48	54	86	79	46
Hydro	7,126	8,785	-1,658	-19%	18,792	14,096	+4,696	33%	4,055	2,748	2,161	5,132	6,731	4,346	2,479	5,236
Portugal	5,076	6,759	-1,683	-25%	12,571	9,087	+3,484	38%	2,395	1,523	1,539	3,629	4,692	2,866	1,594	3,419
Pumping activity	2,358	2,806	-449	-16%	-1,972	-1,824	-148	-8%	-423	-414	-363	-624	-534	-493	-465	-480
Run of the river	1,174	2,408			6,193	4,099	+2,094	51%	1,285	615	703	1,497	2,289	1,582	807	1,515
Reservoir	3,845	4,294			6,241	4,850	+1,391	29%	1,067	880	827	2,076	2,346	1,255	782	1,858
Small-Hydro	57	57			137	138	-1	-1%	43	28	10	57	57	29	6	46
Spain	451	426	+25	6%	677	880	-203	-23%	274	143	59	404	230	162	56	229
Brazil	1,599	1,599	-0	-0%	5,543	4,129	+1,415	34%	1,386	1,081	563	1,099	1,809	1,319	829	1,587
Gas/ CCGT	2,886	3,729	-843	-23%	9,759	10,183	-424	-4%	1,315	2,405	3,745	2,719	2,253	1,699	3,864	1,943
Portugal	2,031	2,031			5,653	5,837	-185	-3%	768	1,618	2,133	1,318	1,330	942	2,259	1,121
Spain	854	1,698			4,107	4,346	-239	-6%	547	786	1,612	1,400	924	757	1,605	822
Coal	1,970	3,150	-1,180	-37%	5,821	10,856	-5,035	-46%	3,778	2,645	2,307	2,126	1,160	521	1,475	2,665
Portugal	0	1,180	-1,180	-	1,832	4,020	-2,188	-54%	1,934	1,221	512	353	38	-9	788	1,015
Spain	1,250	1,250			2,403	3,129	-726	-23%	1,036	837	668	588	645	530	645	583
Brazil	720	720			1,586	3,707	-2,121	-57%	807	587	1,127	1,185	477	0	43	1,067
Nuclear - Trillo (15.5%)	156	156	-	-	1,196	1,223	-27	-2%	332	220	337	335	331	190	336	339
Other	42	49	-7	-14%	211	270	-59	-22%	82	79	64	46	49	46	53	62
Portugal	17	24			138	163	-25	-15%	49	46	36	32	34	32	35	37
Spain	25	25			73	107	-34	-32%	32	33	28	14	15	14	18	25
TOTAL	23,680	26,681	-3,001	-11%	64,318	66,670	-2,352	-4%	17,974	15,842	14,349	18,505	18,286	13,705	13,899	18,428
Of Which:																
Portugal	8,353	11,159	-2,806	-25%	22,818	22,268	+551	2%	5,981	5,210	4,772	6,305	6,806	4,382	5,222	6,409
Spain	4,873	5,529	-655	-12%	12,803	14,983	-2,181	-15%	3,843	3,407	3,597	4,137	3,317	2,582	3,647	3,256
Brazil	2,755	2,787	-32	-1%	8,222	9,593	-1,371	-14%	2,507	2,052	2,250	2,783	2,446	1,545	1,268	2,962
US	5,828	5,714	+114	2%	16,633	15,696	+937	6%	4,235	4,174	3,035	4,253	4,491	4,301	3,012	4,830

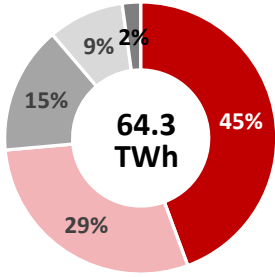
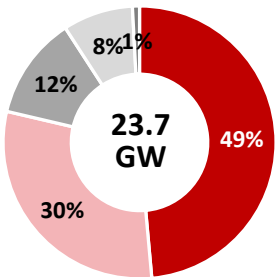
Installed capacity by Country as of Dec-20



Breakdown by Technology as of 2020

(GW Capacity & TWh of Production)

- Wind & Solar
- Hydro
- Gas
- Coal
- Other



(1) Installed capacity that contributed to the revenues in the period; (2) Includes Poland, Romania, France, Belgium and Italy; (3) Includes Canada and Mexico.

RAB (€ million)	Dec-20	Dec-19	Δ %	Δ Abs
Portugal	2,906	2,974	-2.3%	-68
High / Medium Voltage	1,754	1,816	-3.4%	-62
Low Voltage	1,152	1,157	-0.5%	-6
Spain (1)	1,706	950	79.6%	+756
Brazil (R\$ million)	9,117	7,811	16.7%	+1,306
Distribution	5,004	4,997	0.1%	+6
EDP Espírito Santo	2,581	2,656	-2.8%	-75
EDP São Paulo	2,423	2,341	3.5%	+82
Transmission (2)	4,113	2,814	46%	+1,299
TOTAL RAB	6,043	5,654	6.9%	+389

Networks	Dec-20	Dec-19	Δ %	Δ Abs.
Lenght of the networks (Km)	375,007	340,744	10.1%	+34,263
Portugal	228,349	226,823	0.7%	+1,526
Spain	52,492	20,766	152.8%	+31,725
Brazil	94,166	93,268	1.0%	+898
Distribution	93,850	93,155	0.7%	+695
Transmission	316	113	179.6%	+203

DTCs (thous.)				
Portugal	27	23	20%	+5
Spain	19	7	170%	+12

Energy Box (th)				
Portugal	3,208	2,578	24%	+630
% of Total	51%	41%	23.9%	9.8 p.p.
Spain	1,369	666	106%	+703

Customers Connected (th)	Dec-20	Dec-19	Δ %	Δ Abs.
Portugal	6,302	6,277	0.4%	+25
Very High / High / Medium Voltage	25	25	0.3%	+0
Special Low Voltage	38	37	1.0%	+0
Low Voltage	6,239	6,215	0.4%	+25
Spain	1,371	668	105.1%	+702
High / Medium Voltage	3	1	118.8%	+1
Low Voltage	1,368	667	105.0%	+701
Brazil	3,601	3,524	2.2%	+77
EDP São Paulo	1,980	1,936	2.3%	+44
EDP Espírito Santo	1,620	1,588	2.0%	+32
TOTAL	11,274	10,470	7.7%	+804

Quality of service	2020	2019	Δ %	Δ Abs.
Losses (3)				
Portugal	9.8%	9.6%	2.8%	0.3 p.p.
Spain	3.8%	3.6%	5.8%	0.2 p.p.
Brazil				
EDP São Paulo	8.6%	8.1%	5.7%	0.5 p.p.
Technical	5.5%	5.6%	-1.9%	-0.1 p.p.
Commercial	3.0%	2.5%	23.0%	0.6 p.p.
EDP Espírito Santo	13.4%	12.5%	7.5%	0.9 p.p.
Technical	8.2%	7.9%	4.8%	0.4 p.p.
Commercial	5.2%	4.6%	12.2%	0.6 p.p.

Remote orders (% of Total)				
Portugal	50%	44%	13.7%	6 p.p.
Spain	99%	100%	-0.2%	-0.2 p.p.

Telemetrying (%)				
Portugal	75%	73%	2%	1.6 p.p.
Spain	100%	100%	0%	0.1 p.p.

Electricity Distributed (GWh)	2020	2019	Δ %	Δ GWh
Portugal	44,143	45,666	-3.3%	-1,524
Very High Voltage	2,461	2,344	5.0%	118
High / Medium Voltage	20,706	21,998	-5.9%	-1,292
Low Voltage	20,976	21,325	-1.6%	-349
Spain	7,559	8,262	-8.5%	-703
High / Medium Voltage	5,427	6,032	-10.0%	-606
Low Voltage	2,132	2,229	-4.4%	-97
Brazil	24,421	25,591	-4.6%	-1,170
Free Customers	10,992	11,389	-3.5%	-397
Industrial	1,405	1,719	-18.2%	-313
Residential, Commercial & Other	12,024	12,484	-3.7%	-460
TOTAL	76,123	79,442	-4.2%	-3,319

(1) RAB post-lesividad (see note page 16); (2) Corresponds to Financial assets; (3) In Spain and Brazil, based on electricity entered the distribution grid; In Portugal, based on electricity distributed, excluding Very High Voltage.

Financial investments, Non-controlling interests and Provisions

Financial investments & Assets for Sale	Attributable Installed Capacity - MW (1)				Share of profit (2) (€ million)				Book value (€ million)			
	Dec-20	Dec-19	Δ %	Δ MW	2020	2019	Δ %	Δ Abs.	Dec-20	Dec-19	Δ %	Δ Abs.
EDP Renováveis	668	550	21%	+118	-6	3	-	-10	475	460	3%	+15
Spain	167	152										
US	471	398										
Other	30	0										
EDP Brasil	551	551	0%	-0	14	15	-12%	-2	319	464	-31%	-146
Renewables	551	551										
Networks												
Iberia (Ex-wind) & Other	10	10	0%	-	-4	6	-	-10	147	174	-15%	-27
Generation	10	10										
Networks												
Other												
Equity Instruments at Fair Value									185	171	-	+14
Assets Held for Sale (net of liabilities)									22	2,177	-	-2,155
TOTAL	1,228	1,111	11%	+117	3	25	-87%	-22	1,147	3,446	-67%	-2,299

Non-controlling interests	Attributable Installed Capacity - MW (1)				Share of profits (2) (€ million)				Book value (€ million)			
	Dec-20	Dec-19	Δ %	Δ MW	2020	2019	Δ %	Δ Abs.	Dec-20	Dec-19	Δ %	Δ Abs.
EDP Renováveis	4,192	4,112	2%	+81	220	218	1%	+2	2,518	2,547	-1%	-29
At EDPR level:	2,191	2,230	-2%	-39	127	148	-14%	-20	1,276	1,362	-6%	-86
Iberia	624	589										
North America	1,137	1,210										
Rest of Europe	269	269										
Brazil	162	162										
17.4% attributable to free-float of EDPR	2,001	1,881	6%	+120	92	70	31%	+22	1,242	1,186	5%	+57
EDP Brasil	1,725	1,734	-1%	-10	149	178	-16%	-29	943	1,267	-26%	-323
At EDP Brasil level:	598	598	0%	-0	34	35	-3%	-1	178	246	-27%	-67
Hydro	598	598										
Other	0	0										
49% attributable to free-float of EDP Brasil	1,127	1,137	-1%	-10	115	142	-19%	-28	765	1,021	-25%	-256
Iberia (Ex-wind) & Other	115	119	-3%	-4	-8	-8	4%	-0	34	-40	-	+74
TOTAL	6,032	5,965	1%	+67	361	388	-7%	-27	3,496	3,774	-7%	-278

Provisions (Net of tax)	Employees benefits (€ million)			
	Dec-20	Dec-19	Δ %	Δ Abs.
EDP Renováveis	0	0	24%	+0
EDP Brasil	93	134	-31%	-41
Iberia (Ex-wind) & Other	873	774	13%	+99
TOTAL	966	908	6%	+58

(1) MW attributable to associated companies & JVs and non-controlling interests; (2) Share of profit in JVs & associates and from non-controlling interests; assets held for sale not included;

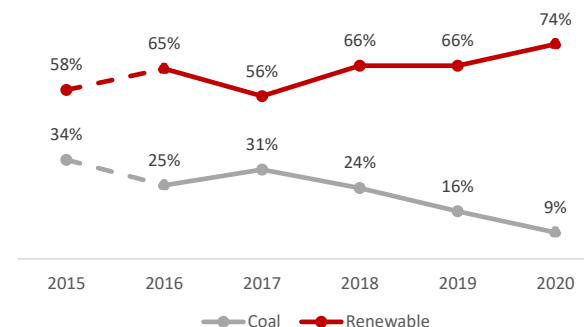
Sustainability performance

Environment	2020	2019	Δ %
Renewable generation (%)	74%	66%	11%
Greenhouse gas emissions			
Specific CO ₂ emissions (g/kWh) (1)	146	216	-33%
GHG Emission Scope 1 (ktCO _{2eq})	9,311	14,363	-35%
GHG Emission Scope 2 (ktCO _{2eq}) (2)	594	846	-30%
Air quality			
NOx emissions (kt)	6.17	10.80	-43%
SO ₂ emissions (kt)	8.23	16.31	-50%
Particulate matter emissions (kt)	0.92	1.66	-45%
Water management			
Total water withdrawn (10 ³ m ³)	602,909	996,309	-39%
Total water consumed (10 ³ m ³)	14,974	21,736	-31%
Coal & Waste management			
Coal combustion residuals generated (t)	225,430	375,167	-40%
Coal combustion residuals recycled (%)	92%	96%	-5%
Average waste recovery rate (%)	92%	96%	-4%
Environmental Matters (€ th)			
Investments	66,990	88,317	-24%
Expenses	242,069	265,880	-9%
Environmental Fees and Penalties	11.0	4.0	175%

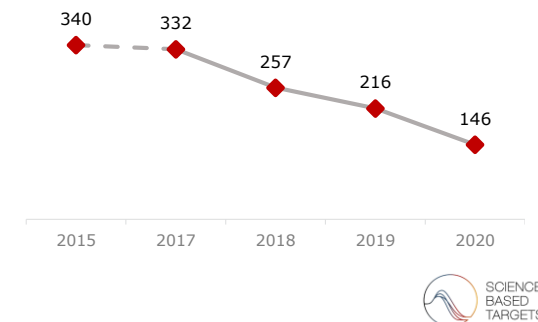
Business Model & Innovation	2020	2019	Δ %
Sustainable Mobility			
Light-duty fleet electrification (%)	11%	9%	22%
Electric charging points (#)	1,811	772	135%
Customers with electric mob. solutions (#)	18,747	10,100	86%
New market opportunities			
Smart meters in Iberian Peninsula (%)	60%	48%	25%
Energy Services Revenues / Turnover (%)	8%	7%	11%
Energy Efficiency Services Revenues (€ th)	244,573	158,376	54%
Electric load served by smart grid technol. (%)	78.2%	n.a.	n.a.
Low carbon economy			
EBITDA in Renewables (%)	66%	62%	7%
CAPEX in Renewables (%)	73%	52%	41%
Revenues from coal (%)	6%	8%	-28%

Human Capital	2020	2019	Δ %
Employment			
Employees (#)	12,180	11,660	4%
Female employees (%)	25%	25%	1%
Turnover (%)	11.5%	10.5%	9%
Training			
Total hours of training (h)	273,889	400,448	-32%
Employees with training (%)	100%	97%	3%
Direct training investment (€ th)	3,250	3,756	-13%
Health and Safety			
Accidents EDP (3)	17	29	-41%
Accidents Contractors (3)	115	82	40%
Fatal Accidents EDP	0	0	n.a.
Fatal Accidents Contractors	3	2	50%
Frequency rate EDP	0.77	1.50	-49%
Frequency rate Contractors	2.12	1.84	15%

% Renewables and Coal in generation



Specific CO₂ Emissions (g/kWh)



Sustainable Development Goals (SDG)



EDP is committed to ensuring that its activity contributes actively to 9 of the 17 United Nations SDG to be achieved by 2030.

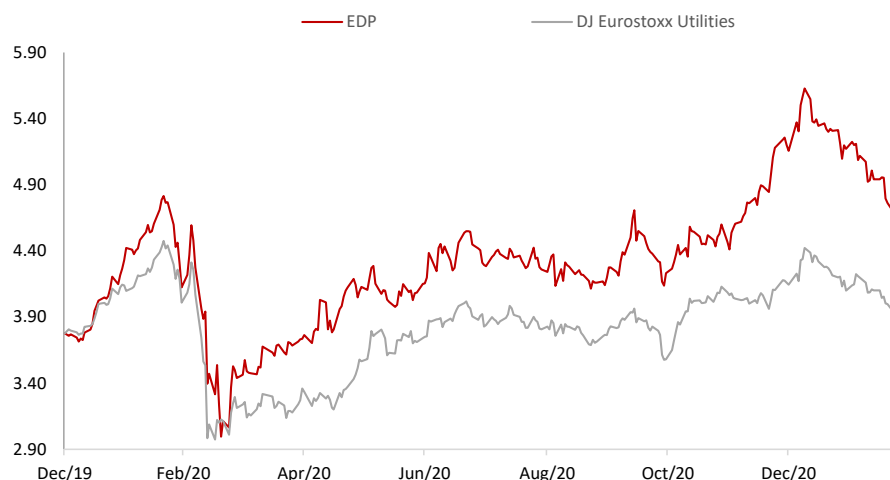
Main ESG Ratings

	Last Update	Range	Score	Ranking (4)
SAM S&P (DJSI)	2020	[0-100]	88	2º
FTSE Russel (FTSE4Good)	2020	[0-5]	5	Top 3%
VE (Euronext Vigeo)	2020	[0-100]	71	3º
ISS-Oekom (GCI)	2020	[D ⁻ -A ⁺]	B	n.a.
Sustainalytics (STOXX ESG) (5)	2020	[100-0]	22	n.a.
MSCI Research (MSCI ESG)	2020	[CCC-AAA]	AAA	Top 7%
CDP Climate Change	2020	[D ⁻ -A]	A	n.a.
CDP Water Security	2020	[D ⁻ -A]	A	n.a.
Ethisphere	2020	Y/N	Yes	n.a.

Detailed information available at: www.edp.com > Sustainability > Sustainable Investment > Sustainability Performance

(1) The stationary emissions do not include those produced by the burning of ArcelorMittal steel gases in EDP's power plant in Spain; (2) Scope 2 emissions according with GHG Protocol based location methodology; (3) Accidents leading to an absence of one more calendar day and fatalities; (4) SAM and Vigeo: the comparable peers exclude companies that manage transmission grids, only includes the ones that handle throughout the electricity value chain and electricity/gas supply; (5) Rating measures unmanaged ESG risk, distinguishing between five levels ranging from 100 (Severe) to 0 (Negligible).

EDP Stock Performance on Euronext Lisbon



EDP Stock Market Performance	YTD ¹	52W 23/02/2021	2019
EDP Share Price (Euronext Lisbon - €)			
Close	4.713	4.713	3.777
Max	5.660	5.660	3.829
Min	2.926	2.926	2.918
Average	4.187	4.178	3.355
EDP's Liquidity in Euronext Lisbon			
Turnover (€ million)	11,932	10,502	6,018
Average Daily Turnover (€ million)	41	41	24
Traded Volume (million shares)	2,850	2,514	1,794
Avg. Daily Volume (million shares)	9.69	9.78	7.04

EDP Share Data (million)	2020	2019	Δ %
Number of shares Issued (2)	3,966	3,657	8%
Treasury stock	19.6	21.4	-9%

EDP's Main Events

13-Jan: EDP secures PPA for a new solar project in Brazil
13-Jan: Cash tender offer for outstanding debt securities and new subordinated green notes issue
13-Jan: EDP prices €750 million subordinated green notes at 1.70% coupon
21-Jan: Results of the cash tender offer for outstanding hybrid at 5.375% coupon
23-Jan: EDP reached an agreement with ENGIE to create a 50:50 Joint-Venture for Offshore wind
29-Jan: EDP was awarded long term CFD at the Italian wind auction
12-Feb: EDP concludes €0.3 Bn asset rotation deal for Brazilian wind farm
26-Feb: Announcement and conclusion of Accelerated Bookbuild of CTG
28-Feb: Fitch affirms EDP at “BBB-” and revises outlook to positive
9-Mar: EDP sells Portuguese tariff deficit for €0.8 billion
7-Apr: EDP issues a €750 million 7-year Green Bond at 1.625%
16-Apr: Payment of Dividends – Year 2019
16-Apr: EDP secures a PPA for a solar plant of 200 MW in Mexico
23-Apr: The Capital Group notifies qualified shareholding in EDP of 2.05%
7-May: EDP secures a 100 MW Solar PPA in United States
18-May: EDP to sell 2 CCGT plants and B2C supply business in Spain for €515 million
19-May: Paul Elliot Singer reduces shareholding in EDP to 1.91%
25-Jun: State Street Corporation reduces shareholding in EDP to 1.74%
6-Jul: Clarification on the suspension of the CEO and Executive Board Member
14-Jul: EDP sells Portuguese tariff deficit for €0.3 billion
14-Jul: Anticipation of the shutdown process of coal power plants in Iberia
15-Jul: EDP enters into an agreement with Macquarie to acquire Viesgo and launches a rights issue
7-Aug: Results of the Offer and allocation of shares
10-Aug: EDP announces €0.5 bn asset rotation deal for wind farms in Spain
11-Aug: Commercial registry of capital increase
29-Aug: EDPB announces program of acquisition of treasury shares and dividend policy update
02-Sep: EDP announced \$0.7 bn sell down deal for wind and solar portfolio in North America
17-Sep: EDP issues a US\$850 million 7-year green bond at 1.71% coupon
13-Oct: EDP secures a PPA for two solar projects in the U.S. totalling approximately 100 MW
15-Oct: ERSE announces proposal for electricity tariffs in 2021
13-Nov: Capital Group reduces shareholding in EDP to 1.93%
1-Dec: EDP concludes the sale to total of 2 CCGT plants and B2C supply business in Spain
9-Dec: Blackrock Inc. increases shareholding in EDP to 5.06%
14-Dec: EDP was awarded long tem CFD at the Poland wind and Solar auction
15-Dec: ERSE announces the final proposal for electricity tariffs in 2021
15-Dec: EDP concludes an asset rotation deal for wind farms in Spain
16-Dec: EDP concludes the aquisition of Viesgo
17-Dec: EDP Concludes the sale of a Portfolio of 6 Hydro plants in Portugal fo €2.2 billion
21-Dec: CPPIB notifies qualified shareholding in EDP of 2.01%
28-Dec: EDP sells Portuguese tariff deficit for €0.3 billion
28-Dec: EDP concludes \$0.7 billion sell-down for wind and solar portfolio in North America
31-Dec: CPPIB reduces sahareholding in EDP to 1.89%

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Attachment 5-4

Financial Reports - ENGIE



2018 MANAGEMENT REPORT AND ANNUAL CONSOLIDATED FINANCIAL STATEMENTS



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01 MANAGEMENT REPORT

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1 ENGIE 2018 RESULTS

The previously published financial data presented hereafter have been restated to take into account (i) impacts resulting from the application of the new standards IFRS 9 – Financial Instruments and IFRS 15 – Revenue from Contracts with Customers; and (ii) the presentation in the financial statements at December 31, 2017 (for the income statement, statement of comprehensive income and statement of cash flows) of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 as "Discontinued operations", as they represent a separate major line of business under IFRS 5 – Non-current Assets Held for Sale and Discontinued Operations. A reconciliation of the reported data with the restated comparative data is presented in Note 2 "Restatement of 2017 comparative data" to the consolidated financial statements.

Main 2018 financial milestones

- **2018 results in line with targets: net recurring income Group share at €2.5 billion**, net debt/EBITDA ratio at 2.3x.
- **Stable EBITDA demonstrates ENGIE's robust business model**, with positive underlying momentum in growth segments offsetting the unfavorable impacts of unscheduled maintenance at Belgian nuclear plants, negative foreign exchange effects and dilution from disposals.
- **Solid organic⁽¹⁾ growth in EBITDA (5%)**, led by progress in the Group's key growth drivers: in particular Renewables and BtoB & BtoT Solutions.
- **Net debt reduction** (€1.4 billion vs. end 2017), due to a robust operating cash flow⁽²⁾ and disposals. The Group's financial structure is solid, as confirmed by the rating agencies which position ENGIE as an industry leader in that respect.
- **Recap of 2016-2018 strategic delivery: a reconfigured asset portfolio, reduced commodity exposure, lower carbon intensity, and an improved growth profile.** Transformation driven by portfolio rotation (€16.5 billion⁽³⁾ of disposals nearly closed), strategic investments (€14.3 billion⁽⁴⁾ of growth capex reinvested), efficiency (€1.3 billion of cost savings since 2015), customer-centric commercial capability development and accelerating momentum in Renewables.

Consistent with the strategic repositioning initiated in 2016, ENGIE continued to develop its privileged businesses. **It strengthened its positions in Client Solutions through** (i) **targeted acquisitions** in Latin America, the United States, Germany and Singapore, (ii) **new contracts** in high-growth business segments (mobility, campus management and cooling networks), (iii) **order book growth** in installation activities, and (iv) an increase in the **sale of electricity and gas market offer contracts** in France. In **Infrastructures**, storage regulation has been implemented in France, the number of smart gas meters installed in France has reached 2.5 million, and our Latin American businesses continued to grow. In **Renewables**, 1.1 GW of wind and solar capacity were added in 2018. In **Thermal contracted**, new long-term contracts were signed.

For 2019, ENGIE expects growth in net recurring income Group share to a level between €2.5 and €2.7 billion⁽⁵⁾. Looking ahead, ENGIE announces a new medium-term dividend policy, which provides for a 65%-75% targeted NRIGs payout ratio range. For the fiscal year 2019, it is ENGIE's current intention to target a dividend payout towards the upper end of this range.

(1) Gross variation without scope and foreign exchange impacts.

(2) Cash generated from operations before income tax and working capital requirement.

(3) Cumulative impacts from January 1, 2016 to December 31, 2018.

(4) Cumulative impacts from January 1, 2016 to December 31, 2018, net of DBpSO (Develop, Build, partial Sell & Operate) proceeds; excluding Capex related to E&P and upstream / midstream LNG and Corporate Capex.

(5) These targets and this indication assume average weather conditions in France, full pass through of supply costs in French regulated gas tariffs, no significant accounting changes except for IFRS 16, no major regulatory and macro-economic changes, commodity price assumptions based on market conditions as of December 31, 2018 for the non-hedged part of the production, average foreign exchange rates as follows for 2019: €/USD: 1.16; €/BRL: 4.42, and without significant impacts from disposals not already announced.

Financial data at December 31, 2018

<i>In billions of euros</i>	Dec. 31, 2018	Dec. 31, 2017	% change (reported basis)	% change (organic basis)
Revenues	60.6	59.6	+1.7%	+1.7%
EBITDA	9.2	9.2	+0.4%	+4.7%
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	5.1	5.2	-0.9%	+5.1%
Net recurring income relating to continued operations, Group share	2.5	2.2	+10.1%	+17.3%
Net income, Group share	1.0	1.3	-21.7%	
Cash Flow From Operations (CFFO)	7.3	8.5	-€1.2 bn	
Net debt	21.1	22.5	-€1.4 bn	

1.1 Analysis of 2018 financial data

1.1.1. Revenues: €60.6 billion

Revenues were €60.6 billion in 2018, up 1.7% on both a reported and organic basis versus 2017.

Reported revenue growth was impacted by an adverse foreign exchange effect (€929 million), mainly due to the depreciation of the Brazilian real and US dollar against the euro, offset by an aggregate positive scope effect (€955 million). Changes to the scope of consolidation primarily included acquisitions in Client Solutions (Keepmoat Regeneration in the United Kingdom, MCI in France, and Talen and Unity in the United States), as well as two new hydro power concessions acquired in Brazil. These positive impacts were partly offset by the disposal of thermal generation businesses in the United Kingdom and Poland in 2017 and of the Loy Yang B coal-fired power plant in Australia in early 2018.

Organic revenue growth was primarily driven by tariff increases and new power supply contracts in Latin America, growth in hydro power sales in France and Brazil, higher retail power sales in France, higher energy sales in the United Kingdom, Romania and Australia, and improved business volumes in BtoB and BtoT Solutions in France and the rest of Europe. Revenue growth was partly offset by the new accounting treatment of long-term gas supply contracts in Europe since the end of 2017 (no impact on EBITDA), as well as a decrease in gas sales in France.

1.1.2. EBITDA: €9.2 billion

EBITDA was €9.2 billion, up 0.4% on a reported basis and up 4.7% on an organic basis versus 2017.

Reported EBITDA growth includes an adverse foreign exchange effect (€258 million), mainly due to the depreciation of the Brazilian real and, to a lesser extent, the US dollar against the euro, and a negative scope effect (€113 million). This scope effect stems chiefly from the sale of the Loy Yang B coal-fired power plant in Australia in early 2018 and of thermal generation assets in the United Kingdom at the end of 2017, partly offset by two hydro concessions acquired in Brazil in late 2017 and by various acquisitions in BtoB and BtoT Solutions, mainly in the United States and the Middle East.

Organic EBITDA growth was mainly driven by revenue-related developments. Additional contributions have come from energy management activities (due to favorable European markets and a new management model for certain long term contracts), the *Lean* 2018 performance program and the positive impact of new French gas storage regulation. These more than offset the negative impact of major unscheduled maintenance operations and a decrease in captured prices in the Belgian nuclear business.

Organic EBITDA performance by segment:

<i>In billions of euros</i>	Dec. 31, 2018	Dec. 31, 2017	% change (reported basis)	% change (organic basis)
North America	0.2	0.2	+0,1%	-7,5%
Latin America	1.8	1.7	+3,8%	+11,1%
Africa/Asia	1.1	1.3	-11,7%	+6,0%
Benelux	(0.2)	0.5	-133,7%	-133,5%
France	1.7	1.5	+14,2%	+14,2%
Europe excluding France & Benelux	0.7	0.6	+4,6%	+6,5%
Infrastructures Europe	3.5	3.4	+3,3%	+3,3%
GEM	0.2	(0.2)	NA	NA
Other	0.2	0.1	+56,6%	NA
TOTAL	9.2	9.2	+0,4%	+4,7%

- **North America** reported a 7.5% organic reduction in EBITDA due to 2017 and 2018 one-offs creating tough comparison and an increase in the cost of wind and solar development platforms expected to contribute as of 2019. These negative impacts were partly offset by growth in thermal and renewable power generation activities due to favorable climate conditions in the United States and Canada and to the contribution of the Holman solar farm in Texas commissioned in the second half of 2017.
- **Latin America** delivered strong 11.1% organic EBITDA growth, driven mainly by an improvement in power generation in Brazil (better hydrology and commissioning of new windfarms), tariff increases in gas infrastructures in Mexico and Argentina and new long-term power purchase agreements (PPA) in Chile, partly offset by the expiration of long term PPAs in Peru at the end of 2017.
- **Africa/Asia** reported buoyant 6.0% organic growth in EBITDA, driven mainly by the solar business in India and gas distribution business in Thailand.
- **Benelux** reported a very significant 134% organic decrease in EBITDA, mainly due to nuclear activities which were severely affected by unscheduled outages, leading to a very low availability rate in 2018 (52%), and by a decrease in captured prices.
- **France** delivered strong 14.2% organic EBITDA growth, driven primarily by a sharp increase in renewable hydro power generation, significant gains on partial disposals of wind and solar assets, and an increase in margins on BtoB and BtoT Solutions. These positive impacts were partly offset by declining margins in the retail gas market.
- **Europe excluding France & Benelux** reported 6.5% organic EBITDA growth, due mainly to improved performance in Client Solutions in the United Kingdom, Romania and Spain.
- **Infrastructures Europe** delivered 3.3% organic EBITDA growth following the introduction of gas storage regulation on January 1, 2018.
- **GEM (Global Energy Management)** delivered very strong organic EBITDA growth, driven by excellent performance in a favorable market environment (versus a weaker early 2017 comparable due to supply difficulties in southern France) and by a change of management model for some long-term contracts.
- In the **Other segment**, strong organic growth in EBITDA was driven by corporate cost savings under the Lean 2018 performance program and positive one-off items in the thermal generation business in Europe (favorable outcome of litigations), which offset the less favorable market conditions in 2018 compared with 2017.

EBITDA performance by activity:

<i>In billions of euros</i>	Dec. 31, 2018	Dec. 31, 2017	% change (reported basis)	% change (organic basis)
Client Solutions	2.4	2.2	+9%	+5%
Of which BtoC	0.7	0.7	-1%	+0%
Of which BtoB and BtoT	1.7	1.5	+13%	+7%
Infrastructures	3.9	3.8	+4%	+5%
Renewables and Thermal contracted	2.8	2.5	+9%	+15%
Of which Renewables	1.6	1.4	+17%	+25%
Of which Thermal contracted	1.1	1.1	-1%	+4%
Merchant	0.5	0.8	-29%	-29%
Of which Nuclear	(0.5)	0.1	NA	NA
Of which Merchant excluding Nuclear	1.1	0.6	+76%	+77%
Others ⁽¹⁾	(0.4)	(0.1)	NA	NA
TOTAL	9.2	9.2	+0.4%	+4.7%

(1) Including activities sold or in the process of being sold.

Apart from Nuclear, all activities delivered reported and organic growth, despite a significant adverse foreign exchange effect.

- In **Client Solutions**, 9% reported EBITDA growth was driven by a strong overall performance in BtoB and BtoT Solutions and a stable performance in BtoC. BtoB and BtoT Solutions delivered 13% reported EBITDA growth, driven mainly by contributions from new acquisitions, good services volume and margin performance in Europe, and from gas and electricity sales to businesses in Europe and Latin America. BtoC was stable compared with 2017, with a decrease in gas volumes and margins in France offset by an increase in the electricity client portfolio in France and Australia and by positive one-offs in Europe.
- **Infrastructure** delivered 5% organic EBITDA growth despite an unfavorable temperature effect in France. Growth was driven primarily by the implementation of the French gas storage regulation on January 1, 2018, Mexican gas transportation tariff increases and gas distribution activities in Argentina and Thailand. These positive impacts were partly offset by the introduction of new contractual provisions in gas transportation business for low calorific gas conversion in the north of France.
- **Renewables and Thermal contracted** delivered 9% reported EBITDA growth and a strong 15% organic growth. The negative impact of the depreciation of the Brazilian real and, to a lesser extent, of the US dollar against the euro was partly offset by the contribution of the two hydro concessions in Brazil acquired at the end of 2017. Renewable power generation delivered strong 25% organic growth, driven primarily by a large number of wind and solar farm partial disposals in 2018 (DBpSO⁽¹⁾ model) and by growth in hydro power generation in France. **Thermal Contracted** power delivered 4% organic growth even though there were more significant positive one-offs in 2017 than in 2018. Growth was driven by new long-term PPAs obtained in Chile and the commissioning of the Safi power plant in Morocco, which more than offset the expiration of long-term PPAs in Peru.
- The **Nuclear** business reported a very significant decrease due to unscheduled outages leading to a very low availability rate of 52% in 2018 and due to a decrease in captured prices.
- **Merchant business excluding Nuclear** delivered very strong 76% growth in reported EBITDA and 77% organically, driven mainly by a good performance from Global Energy Management (GEM) and thermal power generation in Europe.

(1) Develop, Build, partial Sell & Operate.

1.1.3. Current operating income after share in net income of entities accounted for using the equity method: €5.1 billion

Current operating income after share in net income of entities accounted for using the equity method amounted to €5.1 billion, down 0.9% on a reported basis and up 5.1% on an organic basis compared with 2017, in line with EBITDA growth.

1.1.4. Net recurring income relating to continued operations, Group share of €2.5 billion and Net income Group share of €1.0 billion

Net recurring income Group share relating to continued operations amounted to €2.5 billion in 2018, a sharp increase of 10.1% compared with the previous year, driven by the continued improvement in current operating income after share in net income of entities accounted for using the equity method, coupled with an improvement in the recurring effective tax rate.

Net income Group share amounted to €1.0 billion compared with €1.3 billion in 2017. It includes mainly impairment losses, partially offset by the gain on disposal of the upstream LNG business ("Discontinued operations").

1.1.5. Net financial debt: €21.1 billion

Net financial debt stood at €21.1 billion, down €1.4 billion compared with December 31, 2017. This variation is mainly due to (i) cash flow from operations (€7.3 billion), (ii) the impacts of the portfolio rotation program (€4.4 billion, including the closing of the sale of the exploration-production and upstream LNG businesses, the Loy Yang B coal-fired power plant in Australia and the distribution business in Hungary, as well as the classification of Glow, a power plant operator in the Asia-Pacific region, as "Assets classified as held for sale"). These items were partially offset by (i) gross capital expenditure over the period (€7.6 billion⁽¹⁾), and (ii) dividends paid to ENGIE SA shareholders (€1.7 billion) and to non-controlling interests (€0.8 billion).

Cash flow from operations (CFFO) amounted to €7.3 billion, down €1.2 billion compared with 2017. The decrease stems chiefly from the return to a normal level in working capital (€1.5 billion negative impact) and from a decrease in financial cash flows, partly offset by an increase in operating cash flow and lower tax expense.

At end December 2018, **net financial debt to EBITDA ratio** amounted to 2.3x, below the target of less than or equal to 2.5x. The average cost of gross debt was 2.68%, up very slightly compared with 2017.

Economic net debt⁽²⁾ to EBITDA ratio stood at 3.85x, stable compared with end 2017. Taking into account the future impact of IFRS 16 at EBITDA⁽³⁾ level, the ratio stands at 3.66x.

1.2 Successful strategic repositioning for ENGIE

ENGIE successfully continued its strategic repositioning and reached the targets set in 2016:

- the disposal of its interest in Glow in Asia-Pacific (announced in June 2018) will reduce ENGIE's consolidated net debt by €3.2 billion. It will enable the Group to **complete its portfolio rotation program** initiated three years ago. To date €16.5 billion⁽⁴⁾ of disposals were announced, of which €14.0 billion already booked.

(1) Net of disposal proceeds from DBpSO operations.

(2) Net economic debt amounted to €35.6 billion at the end of December 2018 (compared with €36.4 billion at the end of December 2017); it includes in particular nuclear provisions and post-employment benefits; details of its calculation are provided in the notes to the financial statements (see Note 6.7).

(3) Leases commitments included in economic net debt are restated in EBITDA (for approximately €0.5 billion), reflecting the implementation of IFRS 16 from 2019 onwards.

(4) Cumulative impacts from January 1, 2016 to December 31, 2018.

- the **capital expenditure program** has also been completed, with €14.3 billion⁽¹⁾ of growth investments since 2016, mainly in Renewables and Thermal contracted (48%), but also in Client Solutions (33%) and Infrastructure (15%).
- the **Lean 2018 performance program** achieved €1.3 billion in net gains at EBITDA level at the end of 2018, versus an initial cost reduction target of €1.0 billion.

In addition, this successful strategic repositioning also led to an improvement in the Group's capital efficiency and profitability, with in particular an increase in ROCEp⁽²⁾ of more than 90 bps over the period 2016-2018 and an increase in Client Solutions current operating income margins of 30bps in 2018.

1.3 2019 financial targets

ENGIE anticipates for 2019 **a net recurring income Group share between €2.5 and €2.7 billion**. This guidance is based on an indicative range for EBITDA of €9.9 to 10.3 billion, after IFRS 16 – Leases⁽³⁾ implementation.

For 2019, ENGIE anticipates:

- a net financial debt/EBITDA ratio below or equal to 2.5x, and
- an “A” category credit rating.

In order to monitor and communicate performance of this objective, segment information will be complemented from 2019 onwards. In accordance with the project, internal organization will need to be adapted, which will be announced shortly.

1.4 Dividend policy

For **fiscal year 2018**, ENGIE confirms the payment of a **0.75 euro per share dividend, payable in cash**.

From 2020⁽⁴⁾, the annual dividend will be paid in one time, at the end of the Ordinary General Meeting (OGM) approving the annual accounts.

In order to offset the impact of this transition on shareholders in 2019, ENGIE will submit for shareholder approval at its OGM on May 17, an exceptional dividend of €0.37 per share, which will bring the total distribution decided by this General Meeting to €1.12 per share.

Looking ahead, ENGIE announces a **new medium-term dividend policy, in the range of 65 to 75% NRIs payout ratio**. For the fiscal year 2019, ENGIE is aiming for a dividend at the upper end of this range.

(1) Cumulative impacts from January 1, 2016 to December 31, 2018, net of DBpSO proceeds; excluding Capex related to E&P and upstream/midstream LNG and Corporate Capex.

(2) Return on Productive Capital Employed, excluding non-productive capital employed and with NOPAT restated for share of entities accounted for using the equity method in non-recurring items.

(3) Impact of around €0.5 billion (without any impact on NRIs).

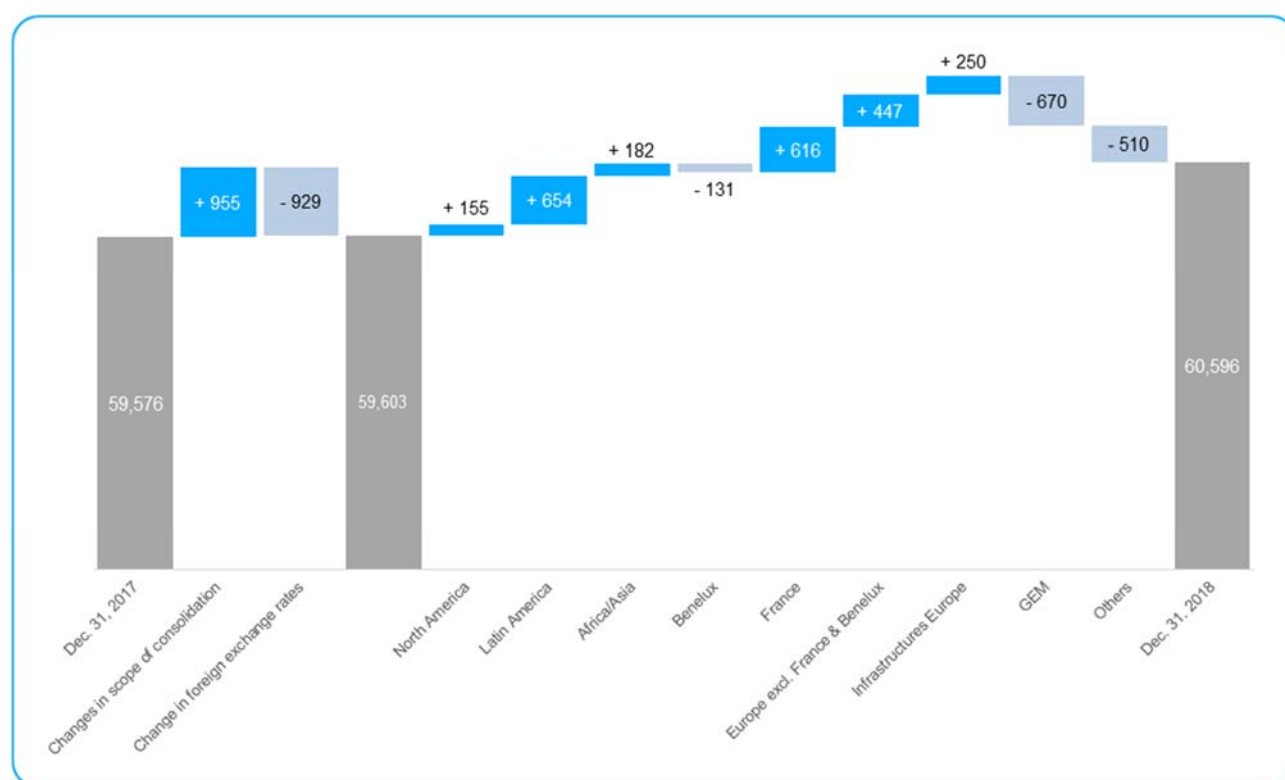
(4) Based on the distributable amount for the year ended December 31, 2019 for the dividend paid in 2020.

2 REPORTABLE SEGMENT BUSINESS TRENDS

<i>In millions of euros</i>	Dec. 31, 2018	Dec 31, 2017	% change (reported basis)	% change (organic basis)
Revenues	60,596	59,576	+1.7%	+1.7%
EBITDA	9,236	9,199	+0.4%	+4.7%
Net depreciation and amortization/Other	(4,110)	(4,027)		
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	5,126	5,172	-0.9%	+5.1%

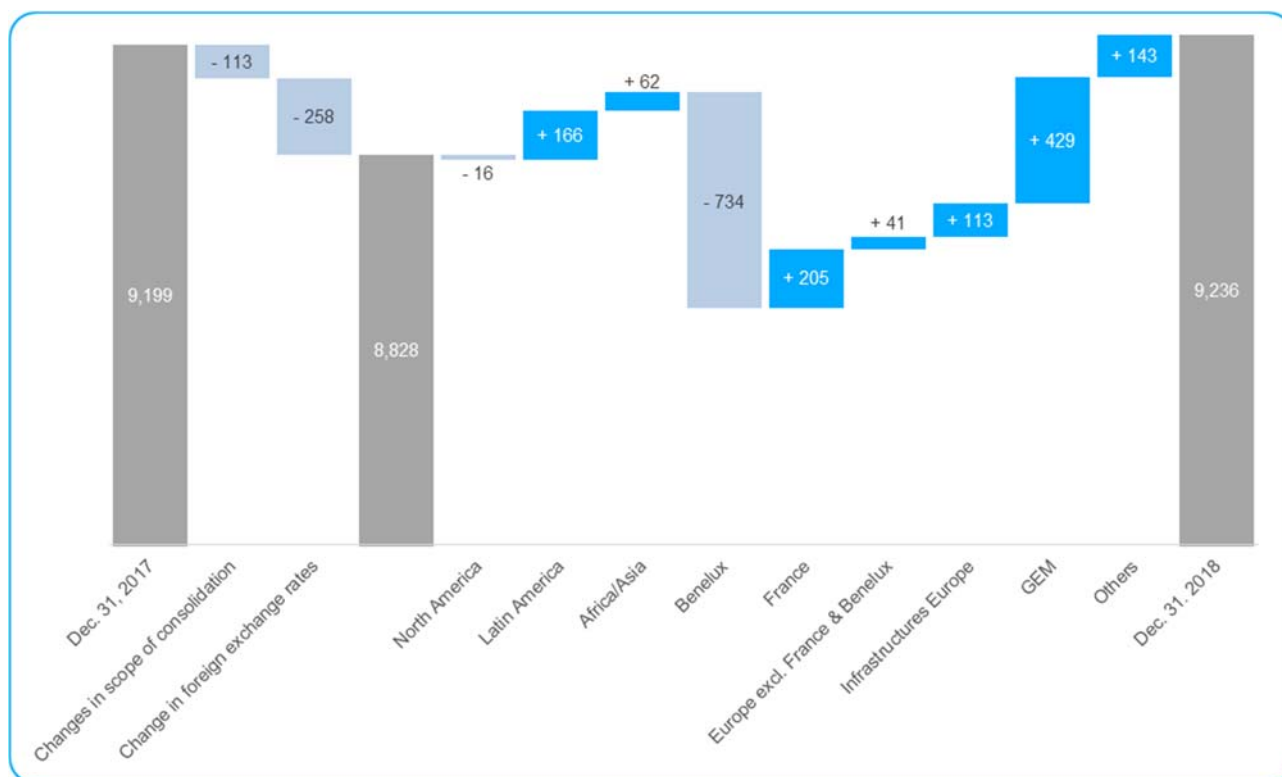
REVENUE TRENDS

In millions of euros



EBITDA TRENDS

In millions of euros



2.1 North America

In millions of euros	Dec. 31, 2018	Dec. 31, 2017	% change (reported basis)	% change (organic basis)
Revenues	3,383	2,964	+14.1%	+5.5%
EBITDA	224	224	+0.1%	-7.5%
Net depreciation and amortization/Other	(73)	(50)		
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	151	174	-13.1%	-20.1%

Revenues for the North America segment totaled €3,383 million, up 14.1%. The negative foreign exchange effect was more than offset by positive scope effects mainly arising from the acquisition of the service activities of Talen in September 2017, Unity in March 2018 and Donnelly in August 2018. On an organic basis, the 5.5% revenue increase was mainly driven by higher prices and volumes achieved by the residual LNG activity.

EBITDA totaled €224 million, stable compared with 2017 but down 7.5% organically adjusted for the contribution of new acquisitions. Growth in thermal and renewable generation activities was mainly attributable to favorable weather conditions in the Northeast region of the United States and in Canada, and to the commissioning of Holman solar assets in the second half of 2017. These effects were more than offset by significant non-recurring items in 2018 and by an increase in the costs of wind and solar projects, the largest of which are expected to make a contribution in 2019.

Current operating income after share in net income of entities accounted for using the equity method amounted to €151 million, down 20% on an organic basis, due to the one-off positive effect on net depreciation and amortization charges recorded in 2017.

2.2 Latin America

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017	% change (reported basis)	% change (organic basis)
Revenues	4,639	4,383	+5.8%	+17.1%
EBITDA	1,775	1,709	+3.8%	+11.1%
Net depreciation and amortization/Other	(419)	(433)		
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	1,355	1,277	+6.2%	+12.9%

Revenues for the Latin America segment totaled €4,639 million, up 5.8% on a reported basis and 17.1% organically. Reported revenues were negatively impacted by the strong depreciation of the Brazilian real (-16%) and, to a lesser extent, the US dollar (-4%), but these negative effects were more than offset by the scope effect of the new hydro concessions in Brazil (Jaguara and Miranda) acquired at the end of 2017 and by the organic revenue increase. In Brazil, organic growth was mainly driven by higher hydro sales in the spot market and the commissioning of new wind farms. In Mexico and Argentina, revenues benefited from price increases in gas distribution activities. In Chile, business was positively impacted by the start of new PPAs with distribution companies, while in Peru it was affected by the end of some high margin PPAs in 2017.

Electricity sales increased by 3.3 TWh to 62.6 TWh and gas sales increased by 5.4 TWh to 34.3 TWh.

EBITDA totaled €1,775 million, up 11.1% on an organic basis, mainly due to the above change in revenues.

Current operating income after share in net income of entities accounted for using the equity method amounted to €1,355 million, up 12.9% on an organic basis in line with the change in EBITDA.

2.3 Africa/Asia

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017	% change (reported basis)	% change (organic basis)
Revenues	4,014	3,939	+1.9%	+5.0%
EBITDA	1,122	1,272	-11.7%	+6.0%
Net depreciation and amortization/Other	(229)	(256)		
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	893	1,016	-12.1%	+6.0%

Revenues for the Africa/Asia region totaled €4,014 million, up 1.9% on a reported basis and up 5.0% organically. On a reported basis, revenues were impacted by the negative exchange rate effect relating to the US dollar, the Australian dollar and the Turkish lira. The net scope effect was slightly positive, as the negative impact of the sale of the Loy Yang B coal-fired power plant in Australia in January 2018 was more than offset by the positive contribution from several acquisitions in Client Solutions in South Africa, Morocco, Ivory Coast, Uganda, Zambia and Australia. The organic increase mainly reflects higher sales in retail activities in Australia and higher volumes of thermal contracted power generation in Thailand. These effects were partially offset by the impacts of the closure of the Hazelwood coal-fired power plant in Australia in March 2017.

Electricity sales decreased by 9.7 TWh to 35.2 TWh, with reduced volumes mostly due to the Hazelwood closure and the sale of Loy Yang B.

EBITDA totaled €1,122 million, down 11.7% on a reported basis but up 6.0% organically. Reported EBITDA was negatively impacted by the foreign exchange effects mentioned above and by the sale of Loy Yang B, partly offset by the positive contribution from Tabreed (cooling networks) in the United Arab Emirates. Organic growth was driven mainly by a higher contribution from the solar business in India and PTT NGD's gas distribution business in Thailand.

Current operating income after share in net income of entities accounted for using the equity method amounted to €893 million, up 6% on an organic basis primarily for the same reasons as those given above for EBITDA, although the

lower depreciation charges following the classification of the thermal generation business in Thailand as “Discontinued operations” only partially offset the impact of impairment charges related to equity-accounted entities.

2.4 Benelux

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017	% change (reported basis)	% change (organic basis)
Revenues	6,690	6,771	-1.2%	-1.9%
EBITDA	(186)	550	-133.7%	-133.5%
Net depreciation and amortization/Other	(579)	(561)		
CURRENT OPERATING INCOME/(LOSS) AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	(765)	(11)	NA	NA

Revenues for the Benelux segment amounted to €6,690 million, down 1.2% on a reported basis compared with 2017. This decrease is due to nuclear power generation activities, which are affected both by a decline in volumes due to more shutdowns in 2018 than in 2017 (in particular at Doel 3 from September 22, 2017 until August 5, 2018 and Tihange 3 since March 31, 2018) and by a decrease in captured prices. These negative impacts were partially offset by the positive volume impacts recorded in energy retail activities and by the contribution from 2018 of revenues from the Cozie service activities.

In Belgium and Luxembourg, power generation amounts to 27.5 TWh, representing a decrease of 10.5 TWh. In the Netherlands, electricity sales amounted to 10.7 TWh, representing an increase of 0.9 TWh.

Natural gas sales in Benelux totaled 52 TWh, representing an increase of 2.5 TWh compared with 2017, due to a favorable climate effect in the first quarter of 2018 and net customer gains.

EBITDA was down by €736 million to a negative €186 million due to the nuclear power business which was severely affected by unscheduled outages leading to a very low availability rate of 52% in 2018, and by a decrease in captured prices.

Current operating income/(loss) after share in net income of entities accounted for using the equity method amounted to a negative €765 million, down €754 million compared with 2017 in line with the change in EBITDA.

2.5 France

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017	% change (reported basis)	% change (organic basis)
Revenues	15,183	14,157	+7.2%	+4.4%
EBITDA	1,669	1,461	+14.2%	+14.2%
Net depreciation and amortization/Other	(635)	(592)		
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	1,034	869	+19.0%	+18.3%

Volumes sold

<i>In TWh</i>	Dec. 31, 2018	Dec. 31, 2017	% change (reported basis)
Gas sales	88.3	94.7	-6.8%
Electricity sales	39.0	34.3	+14.0%

France climatic adjustment

<i>In TWh</i>	Dec. 31, 2018	Dec. 31, 2017	Total change in TWh
Climate adjustment volumes (negative figure = warm climate, positive figure = cold climate)	(3.0)	(0.3)	(2.7)

Revenues for the France segment totaled €15,183 million, up 7.2% on a reported basis and 4.4% on an organic basis. Reported growth includes the impact of the acquisition of several service companies in the BtoB segment (MCI at end-December 2017, Icomera in June 2017, CNN MCO in September 2017 and Eras in March 2018). Organic growth was driven primarily by a sharp increase in hydro power generation thanks to better runoff in 2018, growth in retail electricity sales and buoyant business in BtoB et BtoT services.

Natural gas sales fell by 6.4 TWh following the loss of retail customers due to competitive pressure (3.7 TWh) and an unfavorable temperature effect (2.7 TWh). Electricity sales were up 4.8 TWh thanks to the continued development of retail offers (up 2.9 TWh) and growth in sales of hydro power (up 1.9 TWh).

EBITDA amounted to €1,669 million, up 14.2% on an organic basis, driven primarily by a large number of wind and solar farm disposals in 2018 (mainly the Compagnie du Vent facilities and offshore wind projects at Yeu-Noirmoutiers and Dieppe-Le Tréport), growth in hydro power generation, and improved margins in service activities.

Current operating income after share in net income of entities accounted for using the equity method amounted to €1,034 million, up 18.3% on an organic basis in line with the change in EBITDA.

2.6 Europe excluding France & Benelux

In millions of euros	Dec. 31, 2018	Dec. 31, 2017	% change (reported basis)	% change (organic basis)
Revenues	9,527	8,831	+7.9%	+5.1%
EBITDA	679	650	+4.6%	+6.5%
Net depreciation and amortization/Other	(207)	(216)		
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	473	434	+9.0%	+11.6%

Revenues for the Europe excluding France & Benelux segment amounted to €9,527 million, up 7.9% on a reported basis and 5.1% on an organic basis, driven mainly by Client Solutions. Reported growth includes the impact of the acquisition of housing regeneration company Keepmoat Regeneration in the United Kingdom in April 2017. The 5.1% organic growth was driven by the start-up of the retail energy business in the United Kingdom in June 2017, the development of Keepmoat over a nine-month period, a positive price effect in the gas and electricity retail business in Romania, and growth in service activities in Spain.

Electricity sales amounted to 29 TWh, representing a decrease of 1.1 TWh compared to 2017, mainly in the BtoB segment in Germany. Gas sales were down 0.4 TWh to 70.6 TWh.

EBITDA totaled €679 million, representing an increase of 6.5% on an organic basis, mainly for the same reasons as given above for revenues, coupled with good hydrological conditions in Spain. These items were partly offset by a lower performance in hydro power generation in the United Kingdom due to regulatory and market conditions.

Current operating income after share in net income of entities accounted for using the equity method amounted to €473 million, up 11.6% on an organic basis, slightly higher than EBITDA growth due to the improvement in the contribution from equity-accounted entities in Germany.

2.7 Infrastructures Europe

In millions of euros	Dec. 31, 2018	Dec. 31, 2017	% change (reported basis)	% change (organic basis)
Revenues	5,694	5,446	+4.6%	+4.6%
Total revenues (incl. intra-group transactions)	6,859	6,712	+2.2%	
EBITDA	3,499	3,386	+3.3%	+3.3%
Net depreciation and amortization/Other	(1,482)	(1,444)		
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	2,016	1,941	+3.9%	+3.8%

Revenues for the Infrastructures Europe segment amounted to €5,694 million, up 4.6% on a reported basis compared with 2017. The increase was mainly due to price increases in the transportation networks in France, LNG terminal business, which delivered a strong commercial performance, and the development of own account storage sales in the United Kingdom. Growth was partly offset by negative temperature effect of 8.1 TWh, representing €51.8 million.

EBITDA amounted to €3,499 million, up 3.3% driven mainly by the introduction of gas storage regulation on January 1, 2018 in France, partly offset by the introduction of new contractual provisions for L-gas conversion in Northern France at GRTgaz.

Current operating income after share in net income of entities accounted for using the equity method amounted to €2,016 million for the period, an increase of 3.9% in line with EBITDA growth.

2.8 GEM

In millions of euros	Dec. 31, 2018	Dec. 31, 2017	% change (reported basis)	% change (organic basis)
Revenues	6,968	7,638	-8.8%	-8.8%
EBITDA	240	(188)	NA	NA
Net depreciation and amortization/Other	(41)	(40)		
CURRENT OPERATING INCOME/(LOSS) AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	199	(229)	NA	NA

Revenues for the GEM segment amounted to €6,968 million, down 8.8% compared with 2017. The decrease was mainly due to the change of accounting treatment for long-term gas supply contracts and transport and storage capacity contracts⁽¹⁾.

EBITDA amounted to €240 million, up sharply compared with the prior-year period, driven by an excellent performance from the energy management activities in favorable market conditions in 2018 (whereas the first quarter of 2017 had suffered from supply difficulties in the south of France), coupled with the positive impact on EBITDA of the change of management model for certain long term contracts.

Current operating income after share in net income of entities accounted for using the equity method amounted to €199 million in 2018, representing growth on both a reported and an organic basis, in line with EBITDA trends.

2.9 Other

In millions of euros	Dec. 31, 2018	Dec. 31, 2017	% change (reported basis)	% change (organic basis)
Revenues	4,498	5,445	-17.4%	-10.2%
EBITDA	213	136	+56.6%	NA
Net depreciation and amortization/Other	(444)	(436)		
CURRENT OPERATING INCOME/(LOSS) AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	(232)	(300)	+22.8%	+37.1%

(1) Since October 1, 2017, these contracts have been managed individually based on market conditions rather than as part of a portfolio. As a result, fair value accounting is mostly applied. The segment's results therefore include the realized and unrealized gains and losses relating to these contracts, which are now measured at fair value through profit or loss and included in the net margin presented in revenues.

Volumes sold

In TWh	Dec. 31, 2018	Dec 31, 2017	% change (reported basis)
Gas sales in France	36.9	42.4	-12.9%
Electricity sales	34.9	46.1	-24.9%

France climatic adjustment

In TWh	Dec. 31, 2018	Dec. 31, 2017	Total change in TWh
Climate adjustment volumes (negative figure = warm climate, positive figure = cold climate)	(0.7)	(0.1)	(0.6)

The Other segment mainly comprises the activities of the Generation Europe, Tractebel and GTT business units, the *Entreprises & Collectivités* activities, and the Group's holding and corporate activities, which notably include the entities centralizing the Group's financing requirements and the equity-accounted contribution of SUEZ.

Revenues amounted to €4,498 million, down 17.4% on a reported basis and 10.2% on an organic basis. The reported decrease mainly reflects the 2017 disposal of the thermal power generation business in the United Kingdom and Poland. The organic decrease mainly reflects lower downstream gas sales in France and less favorable market conditions for power generation in Europe.

Gas sales fell by 5.4 TWh as a result of strong competitive pressure, with a slightly negative climate effect. ENGIE's share of the BtoB market was 18% compared with 21% at end-2017.

Electricity sales totaled 34.9 TWh, representing a decrease of 11.2 TWh compared with 2017. The decrease was mainly due to the disposal of thermal generation assets in the United Kingdom and Poland, and the end of the Rosen power station contract in Italy.

EBITDA totaled €213 million, up on both a reported and organic basis compared with 2017, mainly due to one-off positive items in the thermal power generation business in Europe (mainly the favorable outcome of certain disputes), the development of ancillary activities, and the contribution from the Lean 2018 program, which more than offset the less favorable market conditions in 2018.

Current operating loss after share in net income/(loss) of entities accounted for using the equity method amounted to a negative €232 million for the period, representing an increase on both a reported and an organic basis in line with EBITDA.

3 OTHER INCOME STATEMENT ITEMS

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾	% change (reported)
Current operating income after share in net income of entities accounted for using the equity method	5,126	5,172	-0.9%
Mark to market on commodity contracts other than trading instruments	(223)	29	
Impairment losses	(1,798)	(1,298)	
Restructuring costs	(162)	(669)	
Changes in scope of consolidation	(150)	752	
Other non-recurring items	(147)	(1,252)	
Income/(loss) from operating activities	2,645	2,735	-3.3%
Net financial income/(loss)	(1,381)	(1,388)	
Income tax benefit/(expense)	(704)	395	
NET INCOME/(LOSS) RELATING TO CONTINUED OPERATIONS	560	1,741	
NET INCOME/(LOSS) RELATING TO DISCONTINUED OPERATIONS	1,069	366	
NET INCOME/(LOSS)	1,629	2,108	-22.7%
Net income/(loss) Group share	1,033	1,320	
Of which Net income/(loss) relating to continued operations, Group share	(12)	1,047	
Of which Net income/(loss) relating to discontinued operations, Group share	1,045	273	
Non-controlling interests	595	788	
Of which Non-controlling interests relating to continued operations	572	695	
Of which Non-controlling interests relating to discontinued operations	24	93	

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

Income from operating activities amounted to €2,645 million in 2018, representing a decrease compared with 2017, mainly due to (i) losses on asset disposals, (ii) higher impairment losses in 2018, (iii) the negative impact of fair value adjustments to commodity hedges, and (iv) the decrease in current operating income after share in net income of companies accounted for using the equity method, partly offset by (v) the non-recurring charge recognized in 2017 related to the change in the accounting treatment of long-term gas supply contracts and transport and storage contracts implemented by the GEM business unit, and (vi) lower restructuring costs.

Income from operating activities was also affected by:

- changes in the fair value of commodity derivatives relating to operating items, which had a negative impact of €223 million (reflecting transactions not eligible for hedge accounting), compared with a positive impact of €29 million in 2017. The impact for the period results chiefly from negative overall price effects on these positions, combined with the net negative impact of unwinding positions with a positive market value at December 31, 2017;
- net impairment losses of €1,798 million, compared with €1,298 million the previous year.
At December 31, 2018, the Group recognized net impairment losses of €14 million against goodwill, €1,576 million against property, plant and equipment and intangible assets, and €209 million against financial assets and investments in entities accounted for using the equity method. These impairment losses related mainly to the Benelux, Other (primarily the Generation Europe business unit), Africa/Asia, Infrastructures and Latin America reportable segments. After taking into account the deferred tax effects and the share of impairment losses attributable to non-controlling interests, the impact of these impairment losses on net income Group share for 2018 amounts to €1,540 million. These impairment losses are described in Note 10.2 "Impairment losses" to the consolidated financial statements. In 2017, the Group recognized net impairment losses of €481 million against goodwill, €787 million against property, plant and equipment and intangible assets, and €30 million against financial assets and investments in entities accounted for using the equity method. These impairment losses related mainly to the Infrastructures (storage), and Other (primarily the Generation Europe business unit) reportable segments;
- restructuring costs of €162 million (compared with €669 million the previous year) including notably costs related to decisions to shut down operations and close some entities and sites, as well as costs related to various staff reduction plans;

- negative scope effects of €150 million, mainly comprising a €87 million loss on the sale of the Loy Yang B thermal power plant in Australia, primarily in respect of items of other comprehensive income recycled to the income statement;
- other non-recurring items totaling a negative €147 million, mainly including asset scrapping and costs related to site closures.

The **net financial loss** was stable and amounted to €1,381 million in 2018, compared with €1,388 million the previous year (see Note 11).

The **income tax** charge for 2018 amounted to €704 million (versus a €395 million benefit in 2017). It includes an income tax benefit of €125 million arising on non-recurring operating and financial income/(loss) (versus €1,462 million in 2017), mainly comprising non-recurring taxable charges in France and deferred tax assets on impairment losses in Germany and Latin America. In 2017, non-recurring items included the reduction in the tax rate in France pursuant to the 2018 Finance Act and the refund of the 3% tax on dividends previously paid by French companies. Adjusted for these non-recurring items, the effective recurring tax rate was 23.7%, lower than the 2017 rate of 29.6% due mainly to the recognition of deferred tax assets in several countries where the Group's prospects have improved.

Net income relating to continued operations attributable to non-controlling interests amounted to €572 million, compared with €695 million in 2017. The decrease was mainly due to the change in impairment losses, coupled with the sale of the Loy Yang B coal-fired power plant.

4 CHANGES IN NET DEBT

Net financial debt stood at €21.1 billion, down €1.4 billion compared with December 31, 2017. This variation is mainly due to (i) cash flow from operations (€7.3 billion), (ii) the impacts of the portfolio rotation program (€4.4 billion, including the closing of the sale of the exploration-production and upstream LNG businesses, the Loy Yang B coal-fired power plant in Australia and the distribution business in Hungary, as well as the classification of Glow, a power plant operator in the Asia-Pacific region, as “Assets classified as held for sale”). These items were partially offset by (i) gross capital expenditure over the period (€7.6 billion⁽¹⁶⁾), and (ii) dividends paid to ENGIE SA shareholders (€1.7 billion) and to non-controlling interests (€0.8 billion).

Changes in net debt break down as follows:

In millions of euros



(1) See Note 19.2.1 “Issuance of deeply-subordinated perpetual notes”.

	Maintenance investments
	Development investments
	Financial investments

The net debt (excluding internal debt of discontinued operations) to EBITDA ratio came out at 2.28 at December 31, 2018.

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017
Net debt (excluding internal debt of discontinued operations)	21,102	20,788
EBITDA	9,236	9,199
NET DEBT/EBITDA RATIO	2.28	2.26

(16) Net of DBSO proceeds.

The economic net debt (excluding internal debt of discontinued operations) to EBITDA ratio stood at 3.85 at December 31, 2018.

In millions of euros	Dec. 31, 2018	Dec. 31, 2017
Economic net debt (excluding internal debt of discontinued operations)	35,590	35,127
EBITDA	9,236	9,199
ECONOMIC NET DEBT/EBITDA RATIO ⁽¹⁾	3.85	3.82

(1) The 2018 ratio comes to 3.7 once lease payments relating to operating lease commitments included in economic net debt have been restated for EBITDA (around €0.5 billion), thus reflecting expected impacts as from 2019 of the application of IFRS 16 – Leases.

4.1 Cash flow from operations (CFFO)

Cash flow from operations (CFFO) amounted to €7.3 billion, down €1.2 billion compared with 2017. The decrease stems chiefly from the return to a normal level in working capital (€1.5 billion negative impact) and from a decrease in financial cash flows, partly offset by an increase in operating cash flow and lower tax expense.

4.2 Net investments

Gross investments during the period amounted to €8,169 million and included:

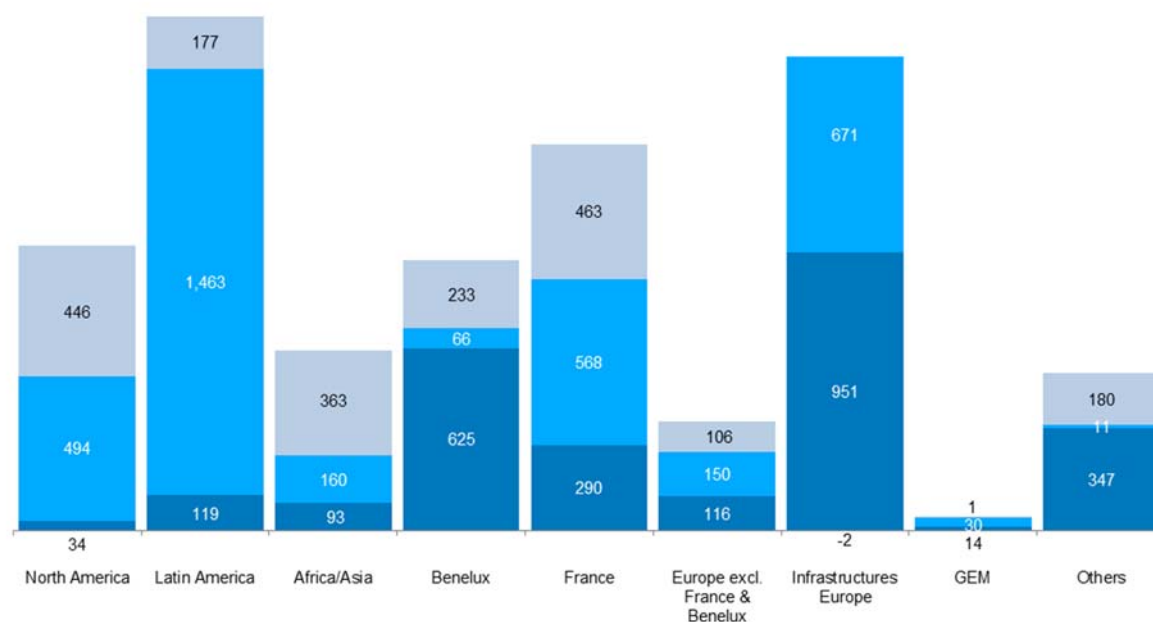
- financial investments for €1,967 million, relating primarily to (i) the acquisition of renewable energy companies (wind and solar) and services companies (micro-power grid, heating and cooling network) in North America (€446 million), wind power and service companies in Africa (€193 million) and the Langa group in France (€174 million), (ii) financing of the construction of the Safi thermal power plant in Morocco (€149 million), and (iii) a €188 million increase in Synatom investments;
- development investments totaling €3,613 million, including (i) €1,463 million invested in the Latin America segment to build thermal power plants and develop wind and photovoltaic farms in Brazil and Chile, (ii) €671 million invested in the Infrastructures Europe segment (blending projects and development of the natural gas distribution and transportation network in France), (iii) €494 million invested in the North America segment (mainly to develop wind power projects), and (iv) €568 million invested in the France segment (mainly in renewable projects);
- maintenance investments for an amount of €2,589 million.

Disposals represented a cash inflow of €2,755 million and mainly included the Group's divestment of its LNG activities, its 70% holding in its subsidiary ENGIE E&P International (EPI), the Loy Yang B coal-fired power plant in Australia and the gas distribution business in Hungary.

Taking into account changes in the scope of consolidation for the period relating to acquisitions and disposals of subsidiaries (€2,290 million negative impact), the impact on net debt of investments net of proceeds from disposals amounted to €3,124 million.

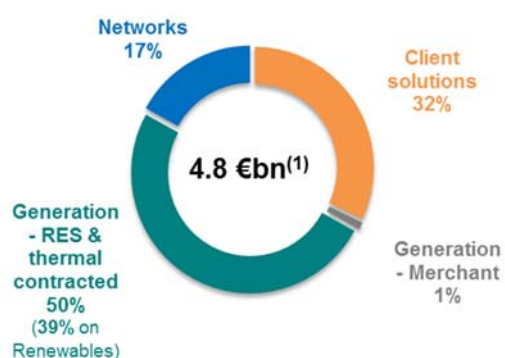
Capital expenditures break down as follows by segment:

In millions of euros



■ Maintenance investments
■ Development investments
■ Financial investments

Growth capital expenditures break down as follows by activity:



Main projects

Low CO₂

Brésil - wind (Campo Largo, Umburranas) & solar	~	0.7
North America - Wind (including Infinity platform)	~	0.5
Latin America - Mexican wind & solar projects	~	0.2
France - Langa group acquisition	~	0.2
Australia - Willogoleche (wind)	~	0.1

Networks

GRDF	~	0.4
GRTgaz	~	0.2

Client Solutions

North America - client solutions acquisitions (including Donnelly, Unity, Socore, Plymouth & Longwood)	~	0.4
Electro Power Systems	~	0.1
Europe excluding France & Benelux - Piora acquisition	~	0.1
Latin America - CAM, Transantiago acquisitions	~	0.1
France BtoB - tuck-in acquisitions	~	0.1

(1) Net of partial disposals under DBSO operations, excluding Corporate, and Synatom reallocated to maintenance expenditure.

4.3 Dividends and movements in treasury stock

Dividends and movements in treasury stock during the period amounted to €2,554 million and included:

- €1,739 million in dividends paid by ENGIE SA to its shareholders, which corresponds to the balance of the 2017 dividend (€0.35 per share for shares with rights to an ordinary dividend or €0.42 per share for shares with rights to a dividend mark-up) paid in May 2018 and to an interim dividend (€0.37 per share) paid in October 2018;
- dividends paid by various subsidiaries to their non-controlling shareholders in an amount of €796 million, the payment of interest on hybrid debt for €123 million and movements in treasury stock.

4.4 Net debt at December 31, 2018

Excluding amortized cost but including the impact of foreign currency derivatives, at December 31, 2018 a total of 75% of net debt was denominated in euros and 18% in US dollars.

Including the impact of financial instruments, 81% of net debt is at fixed rates.

The average maturity of the Group's net debt is 10.9 years.

At December 31, 2018, the Group had total undrawn confirmed credit lines of €13.2 billion.

5 OTHER ITEMS IN THE STATEMENT OF FINANCIAL POSITION

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017	Net change
Non-current assets	91,716	92,412	(696)
<i>Of which goodwill</i>	<i>17,809</i>	<i>17,285</i>	<i>525</i>
<i>Of which property, plant and equipment and intangible assets, net</i>	<i>55,635</i>	<i>57,566</i>	<i>(1,931)</i>
<i>Of which investments in entities accounted for using the equity method</i>	<i>7,846</i>	<i>7,606</i>	<i>240</i>
Current assets	61,986	57,729	4,257
<i>Of which assets classified as held for sale</i>	<i>3,798</i>	<i>6,687</i>	<i>(2,889)</i>
Total equity	40,941	42,122	(1,181)
Provisions	21,813	21,715	98
Borrowings	32,178	33,467	(1,289)
Other liabilities	58,769	52,836	5,933
<i>Of which liabilities directly associated with assets classified as held for sale</i>	<i>2,130</i>	<i>3,371</i>	<i>(1,241)</i>

The carrying amount of **property, plant and equipment and intangible assets** was €55.6 billion, down €1.9 billion compared with December 31, 2017. The decrease was primarily the result of the classification of Glow in Thailand, some of Langa's solar farms in France, and renewable energy assets in Mexico as "Assets classified as held for sale" (€2.6 billion negative impact) (see Note 5.2), depreciation and amortization charges (€3.8 billion negative impact), impairment losses (€1.6 billion negative impact) and translation adjustments (€0.1 billion negative impact), partly offset by capital expenditure during the period (€6.3 billion positive impact).

Goodwill increased by €0.5 billion to €17.8 billion, mainly due to acquisitions made by the North America business unit (€0.2 billion positive impact) and the France Renewable business unit (€0.2 billion positive impact), offset by the goodwill on the holding in Thai company Glow and Langa's operating assets following their classification as "Assets classified as held for sale" (€0.2 billion negative impact).

Total equity amounted to €40.9 billion, a decrease of €0.5 billion compared with December 31, 2017. The decrease stemmed mainly from the payment of the cash dividend (€2.6 billion negative impact, including €1.7 billion of dividends paid by ENGIE SA to its shareholders and €0.9 billion paid to non-controlling interests), partly offset by net income for the period (€1.6 billion positive impact).

Provisions amounted to €21.8 billion, stable compared with December 31, 2017.

At December 31, 2018, assets and liabilities reclassified to "**Assets classified as held for sale**" and "**Liabilities directly associated with assets classified as held for sale**" correspond to Glow in Thailand, some of Langa's solar farms in France and renewable energy assets in Mexico, and at December 31, 2017, to the exploration-production activities and the Loy Yang B power plant in Australia (see Note 5.1).

6 PARENT COMPANY FINANCIAL STATEMENTS

The figures provided below relate to the financial statements of ENGIE SA, prepared in accordance with French GAAP and applicable regulations.

Revenues for ENGIE SA in 2018 totaled €27,833 million, driven mainly by positive price and volume effects on sales to other gas operators.

The net operating loss was €1,058 million, relatively stable compared with a loss of €1,358 million in 2017. Revenue growth (€7,248 million) was offset by an increase in gas purchase costs (€7,471 million). The electricity business was up slightly from €4,602 million in 2017 to €4,683 million in 2018, representing an increase of 2% driven by new electricity customers (approximately 450,000 new customers), partly offset by an increase in supply costs.

Net financial income amounted to €3,718 million compared with €3,849 million in 2017.

Non-recurring items represented a loss of €2,107 million, mainly comprising impairment of equity investments.

The income tax benefit amounted to €549 million compared to a benefit of €1,001 million in 2017, mainly comprising a tax consolidation benefit of €343 million, a net tax provision reversal of €124 million and various other net tax credits of €82 million. The 2017 figure included a €422 million refund by the French State of the 3% tax on dividends, which was held unconstitutional by the French Constitutional Court.

Net income for the year came out at €1,102 million.

Shareholders' equity amounted to €36,616 million at end-2018 compared with €37,191 million at end-2017. The €575 million decrease was due in large part to the difference in net income between 2017 and 2018 (negative €319 million) and the appropriation of 2017 net income (negative €333 million).

At December 31, 2018, net debt stood at €36,080 million, and cash and cash equivalents totaled €8,032 million (of which €5,216 relating to subsidiaries' current accounts).

Information relating to payment deadlines

Pursuant to the application of Article D.441-4 of the French Commercial Code, companies whose annual financial statements are certified by a Statutory Auditor must publish information regarding supplier and customer payment deadlines. The purpose is to demonstrate that there is no significant failure to respect settlement deadlines.

Information relating to supplier and customer payment deadlines mentioned in Article D.441-4 of the French Commercial Code

	Article D. 441 I.- 1°: Invoices received, unpaid and overdue at the reporting date						Article D. 441 I.- 2°: Invoices issued, unpaid and overdue at the reporting date					
	0 days (indicative)	1 to 30 days	31 to 60 days	61 to 90 days	91 days or more	Total (1 day or more)	0 days (indicative)	1 to 30 days	31 to 60 days	61 to 90 days	91 days or more	Total (1 day or more)
<i>In millions of euros</i>												
(A) By aging category												
Number of invoices	-					18,871	-					548,749
Aggregate invoice amount (incl. VAT)	-	448.3	40.3	0.5	113.8	602.9	-	602.5	32.6	14.9	177.4	917.3
Percentage of total amount of purchases (incl. VAT) for the period	-	1.34%	0.12%	0.00%	0.34%	1.81%						
Percentage of total revenues (incl. VAT) for the period							-	2.11%	0.10%	0.05%	0.54%	2.79%
(B) Invoices excluded from (A) relating to disputed or unrecognized receivables and payables												
Number of excluded invoices					226							-
Aggregate amount of excluded invoices					9.9							-
(C) Standard payment terms used (contractual or legal terms - Article L. 441-6 or Article L. 443-1 of the French Commercial Code)												
Payment terms used to calculate late payments	Legal payment terms: 30 days						Contractual payment terms: 14 days					
							Legal payment terms: 30 days					

02 CONSOLIDATED FINANCIAL STATEMENTS

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INCOME STATEMENT

<i>In millions of euros</i>	Notes	Dec. 31, 2018	Dec. 31, 2017 ⁽¹⁾
Revenues from contracts with customers	8	56,388	53,073
Revenues from other contracts		4,208	6,503
REVENUES		60,596	59,576
Purchases		(32,190)	(31,465)
Personnel costs	9.1	(10,624)	(10,051)
Depreciation, amortization and provisions	9.2	(3,586)	(3,787)
Other operating expenses		(10,981)	(10,978)
Other operating income		1,550	1,455
CURRENT OPERATING INCOME		4,765	4,750
Share in net income of entities accounted for using the equity method	4	361	422
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	10	5,126	5,172
Mark-to-market on commodity contracts other than trading instruments	10.1	(223)	29
Impairment losses	10.2	(1,798)	(1,298)
Restructuring costs	10.3	(162)	(669)
Changes in scope of consolidation	10.4	(150)	752
Other non-recurring items	10.5	(147)	(1,252)
INCOME/(LOSS) FROM OPERATING ACTIVITIES	10	2,645	2,735
Financial expenses		(1,981)	(2,127)
Financial income		600	739
NET FINANCIAL INCOME/(LOSS)	11	(1,381)	(1,388)
Income tax benefit/(expense)	12	(704)	395
NET INCOME/(LOSS) RELATING TO CONTINUED OPERATIONS		560	1,741
NET INCOME/(LOSS) RELATING TO DISCONTINUED OPERATIONS		1,069	366
NET INCOME/(LOSS)		1,629	2,108
Net income/(loss) Group share		1,033	1,320
Of which Net income/(loss) relating to continued operations, Group share		(12)	1,047
Of which Net income/(loss) relating to discontinued operations, Group share		1,045	273
Non-controlling interests		595	788
Of which Non-controlling interests relating to continued operations		572	695
Of which Non-controlling interests relating to discontinued operations		24	93
BASIC EARNINGS/(LOSS) PER SHARE (EUROS)	13	0.37	0.49
Of which Basic earnings/(loss) relating to continued operations per share		(0.07)	0.38
Of which Basic earnings/(loss) relating to discontinued operations per share		0.44	0.11
DILUTED EARNINGS/(LOSS) PER SHARE (EUROS)	13	0.37	0.49
Of which Diluted earnings/(loss) relating to continued operations per share		(0.07)	0.38
Of which Diluted earnings/(loss) relating to discontinued operations per share		0.43	0.11

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

STATEMENT OF COMPREHENSIVE INCOME

<i>In millions of euros</i>	Notes	Dec. 31, 2018	Dec. 31, 2018 Owners of the parent	Dec. 31, 2018 Non- controlling interests	Dec. 31, 2017 ⁽¹⁾	Dec. 31, 2017 Owners of the parent ⁽¹⁾	Dec. 31, 2017 Non- controlling interests ⁽¹⁾
NET INCOME/(LOSS)		1,629	1,033	595	2,108	1,320	788
Debt instruments ⁽²⁾	17	29	29	-	(406)	(406)	-
Net investment hedges	18	7	7	-	327	327	-
Cash flow hedges (excl. commodity instruments)	18	(175)	(184)	9	441	422	19
Commodity cash flow hedges	18	(18)	7	(26)	(136)	(126)	(11)
Deferred tax on items above	12	48	43	5	(161)	(159)	(2)
Share of entities accounted for using the equity method in recyclable items, net of tax		201	201	-	74	74	-
Translation adjustments		22	(54)	77	(2,516)	(2,155)	(361)
Recyclable items relating to discontinued operations, net of tax		36	39	(3)	(121)	(68)	(53)
TOTAL RECYCLABLE ITEMS		150	88	62	(2,498)	(2,091)	(407)
Equity instruments	17	42	42	-	3	3	-
Actuarial gains and losses	21	(245)	(247)	1	96	93	2
Deferred tax on items above	12	58	58	-	(97)	(92)	(4)
Share of entities accounted for using the equity method in non-recyclable items from actuarial gains and losses, net of tax		(43)	(45)	2	32	32	-
Non-recyclable items relating to discontinued operations, net of tax		(3)	(1)	(2)	5	3	2
TOTAL NON-RECYCLABLE ITEMS		(192)	(193)	2	39	39	-
TOTAL COMPREHENSIVE INCOME/(LOSS)		1,586	928	659	(351)	(732)	381

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

(2) Comparative data at December 31, 2017 of debt instruments integrate variations of available-for-sale financial assets, within the meaning of IAS 39.

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

STATEMENT OF FINANCIAL POSITION

ASSETS

<i>In millions of euros</i>	Notes	Dec. 31, 2018	Dec. 31, 2017 ⁽¹⁾	Jan. 1, 2017 ⁽¹⁾
Non-current assets				
Goodwill	14	17,809	17,285	17,372
Intangible assets, net	15	6,718	6,504	6,640
Property, plant and equipment, net	16	48,917	51,061	57,775
Other financial assets	17	6,193	5,586	5,243
Derivative instruments	17	2,693	2,949	3,603
Investments in entities accounted for using the equity method	4	7,846	7,606	6,815
Other non-current assets	27	474	566	430
Deferred tax assets	12	1,066	854	1,297
TOTAL NON-CURRENT ASSETS		91,716	92,412	99,175
Current assets				
Other financial assets	17	2,290	2,010	1,746
Derivative instruments	17	10,679	7,378	9,047
Trade and other receivables, net	8	15,613	13,127	14,160
Assets from contracts with customers	8	7,411	6,930	6,529
Inventories	27	4,158	4,161	3,663
Other current assets	27	9,337	8,508	10,697
Cash and cash equivalents	17	8,700	8,929	9,810
Assets classified as held for sale	5	3,798	6,687	3,506
TOTAL CURRENT ASSETS		61,986	57,729	59,157
TOTAL ASSETS		153,702	150,141	158,332

(1) Comparative data at December 31, 2017 and at January 1, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

LIABILITIES

<i>In millions of euros</i>	Notes	Dec. 31, 2018	Dec. 31, 2017 ⁽¹⁾	Jan. 1, 2017 ⁽¹⁾
Shareholders' equity		35,551	36,283	39,253
Non-controlling interests	3	5,391	5,840	5,784
TOTAL EQUITY	19	40,941	42,122	45,037
Non-current liabilities				
Provisions	20	19,194	18,434	19,466
Long-term borrowings	17	26,434	25,292	24,405
Derivative instruments	17	2,785	2,980	3,410
Other financial liabilities	17	46	32	200
Liabilities from contracts with customers	8	36	258	265
Other non-current liabilities	27	960	1,007	1,180
Deferred tax liabilities	12	5,415	5,215	6,782
TOTAL NON-CURRENT LIABILITIES		54,869	53,218	55,709
Current liabilities				
Provisions	20	2,620	3,281	2,693
Short-term borrowings	17	5,745	8,175	12,544
Derivative instruments	17	11,510	8,720	9,228
Trade and other payables	17	19,759	16,404	17,042
Liabilities from contracts with customers	8	3,598	3,317	2,545
Other current liabilities	27	12,529	11,531	13,233
Liabilities directly associated with assets classified as held for sale	5	2,130	3,371	300
TOTAL CURRENT LIABILITIES		57,891	54,800	57,586
TOTAL EQUITY AND LIABILITIES		153,702	150,141	158,332

(1) Comparative data at December 31, 2017 and at January 1, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

STATEMENT OF CHANGES IN EQUITY

<i>In millions of euros</i>	Number of shares	Share capital	Addi- tional paid- in capital	Consoli- dated reserves	Deeply- subor- dinated perpetual notes	Changes in fair value and other	Transla- tion adjust- ments	Treasury stock	Sharehol- ders' equity	Non- controlling interests	Total
EQUITY AT DECEMBER 31, 2016	2,435,285,011	2,435	32,506	1,967	3,273	(1,137)	1,296	(761)	39,578	5,870	45,447
IFRS 9 & 15 impact (see Note 2)	-	-	-	(20)	-	(305)	-	-	(325)	(86)	(411)
EQUITY AT JANUARY 1, 2017⁽¹⁾	2,435,285,011	2,435	32,506	1,947	3,273	(1,442)	1,296	(761)	39,253	5,784	45,037
Net income/(loss)				1,320					1,320	788	2,108
Other comprehensive income/(loss)				39		257	(2,349)		(2,052)	(407)	(2,459)
TOTAL COMPREHENSIVE INCOME/(LOSS)				1,359	-	257	(2,349)	-	(732)	381	(351)
Employee share issues and share-based payment				37					37	-	37
Dividends paid in cash				(2,049)					(2,049)	(680)	(2,729)
Purchase/disposal of treasury stock				(19)				(122)	(140)	-	(140)
Coupons of deeply-subordinated perpetual notes					(144)				(144)	-	(144)
Transactions between owners				60					60	131	191
Transactions with impacts on non-controlling interests				(3)					(3)	(1)	(4)
Transactions between owners within entities accounted for using the equity method				(1)					(1)		(1)
Share capital increases subscribed by non-controlling interests									-	226	226
Other changes				2					2	(3)	(1)
EQUITY AT DECEMBER 31, 2017⁽¹⁾	2,435,285,011	2,435	32,506	1,333	3,129	(1,184)	(1,053)	(883)	36,282	5,840	42,122

(1) Comparative data at January 1, 2017 and December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

<i>In millions of euros</i>	Number of shares	Share capital	Additional paid-in capital	Consolidated reserves	Deeply-subordinated perpetual notes	Changes in fair value and other	Translation adjustments	Treasury stock	Shareholders' equity	Non-controlling interests	Total
EQUITY AT DECEMBER 31, 2017	2,435,285,011	2,435	32,506	1,455	3,129	(915)	(1,088)	(883)	36,639	5,938	42,577
IFRS 9 & 15 impact (see Note 2)	-	-	-	(122)	-	(270)	36	-	(357)	(99)	(455)
Reclassification of premiums and coupons relating deeply-subordinated perpetual notes ⁽¹⁾	-	-	-	(570)	570	-	-	-	-	-	-
EQUITY AT JANUARY 1, 2018⁽²⁾	2,435,285,011	2,435	32,506	763	3,699	(1,184)	(1,053)	(883)	36,282	5,840	42,122
Net income/(loss)				1,033					1,033	595	1,629
Other comprehensive income/(loss)				(193)		165	(78)		(106)	63	(42)
TOTAL COMPREHENSIVE INCOME/(LOSS)				840	-	165	(78)	-	928	659	1,586
Employee share issues and share-based payment		6	60	80					146	1	146
Cancellation of treasury stock		(6)	-	(75)				81	-	-	-
Dividends paid in cash				(1,739)					(1,739)	(882)	(2,621)
Purchase/disposal of treasury stock				(236)				342	105	-	105
Deeply-subordinated perpetual notes ⁽¹⁾				(11)	1,000				989	-	989
Reclassification under debt of deeply-subordinated perpetual notes ⁽¹⁾				(24)	(949)				(973)	-	(973)
Interest on deeply-subordinated perpetual notes				(123)	-				(123)	-	(123)
Transactions between owners				(34)					(34)	10	(24)
Transactions with impact on non-controlling interests ⁽³⁾				-					-	(229)	(229)
Share capital increases and decreases subscribed by non-controlling interests									-	(6)	(6)
Other changes				(29)	-	-			(29)	(2)	(31)
EQUITY AT DECEMBER 31, 2018	2,435,285,011	2,435	32,565	(590)	3,750	(1,019)	(1,130)	(460)	35,551	5,391	40,941

(1) For clarity's sake, it has been decided to present deeply-subordinated perpetual notes for their nominal value instead of their net value (premiums and coupons deducted). This reclassification has no impact on equity. Transactions for the period are presented in Note 19.2.1 "Deeply-subordinated perpetual notes".

(2) Comparative data at January 1, 2017 and December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

(3) Mainly relating to the deconsolidation of the ENGIE E&P International following its disposal (see Note 5.1.2) and the change in consolidation method of Hazelwood (see Note 3.1).

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

STATEMENT OF CASH FLOWS

<i>In millions of euros</i>	Notes	Dec. 31, 2018	Dec. 31, 2017 ⁽¹⁾
NET INCOME/(LOSS)		1,629	2,108
- Net income/(loss) relating to discontinued operations		1,069	366
NET INCOME/(LOSS) RELATING TO CONTINUED OPERATIONS		560	1,741
- Share in net income of entities accounted for using the equity method		(361)	(422)
+ Dividends received from entities accounted for using the equity method		572	466
- Net depreciation, amortization, impairment and provisions		5,077	6,217
- Impact of changes in scope of consolidation and other non-recurring items		198	(858)
- Mark-to-market on commodity contracts other than trading instruments		223	(29)
- Other items with no cash impact		105	43
- Income tax expense		704	(395)
- Net financial income/(loss)		1,387	1,387
Cash generated from operations before income tax and working capital requirements		8,464	8,150
+ Tax paid		(757)	(905)
Change in working capital requirements	26.1	149	1,613
CASH FLOW FROM OPERATING ACTIVITIES RELATING TO CONTINUED OPERATIONS		7,857	8,858
CASH FLOW FROM OPERATING ACTIVITIES RELATING TO DISCONTINUED OPERATIONS		17	476
CASH FLOW FROM OPERATING ACTIVITIES		7,873	9,335
Acquisitions of property, plant and equipment and intangible assets	5.5	(6,202)	(5,778)
Acquisitions of controlling interests in entities, net of cash and cash equivalents acquired	5.5	(983)	(692)
Acquisitions of investments in entities accounted for using the equity method and joint operations	5.5	(338)	(1,311)
Acquisitions of equity and debt instruments	5.5	(283)	(247)
Disposals of property, plant and equipment, and intangible assets		114	90
Loss of controlling interests in entities, net of cash and cash equivalents sold		2,865	3,211
Disposals of investments in entities accounted for using the equity method and joint operations		2	283
Disposals of equity and debt instruments		186	126
Interest received on financial assets		26	75
Dividends received on equity instruments		52	171
Change in loans and receivables originated by the Group and other	5.5	(251)	(856)
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES RELATING TO CONTINUED OPERATIONS		(4,813)	(4,928)
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES RELATING TO DISCONTINUED OPERATIONS		(1,282)	(242)
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES		(6,095)	(5,171)
Dividends paid ⁽²⁾		(2,659)	(2,871)
Recovery from the French State of the 3% tax on dividends		-	389
Repayment of borrowings and debt		(5,328)	(7,738)
Change in financial assets held for investment and financing purposes		(289)	(197)
Interest paid		(727)	(744)
Interest received on cash and cash equivalents		79	107
Cash flow on derivatives qualifying as net investment hedges and compensation payments on derivatives and on early buyback of borrowings		(152)	(156)
Increase in borrowings		4,724	6,356
Increase/decrease in capital		70	486
Hybrid issue of subordinated perpetual notes		989	-
Purchase and/or sale of treasury stock		104	(140)
Changes in ownership interests in controlled entities	5.5	(18)	1
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES RELATING TO CONTINUED OPERATIONS		(3,207)	(4,506)
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES RELATING TO DISCONTINUED OPERATIONS		1,279	(228)
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES		(1,928)	(4,734)
Effects of changes in exchange rates and other relating to continued operations		(78)	(286)
Effects of changes in exchange rates and other relating to discontinued operations		(1)	(11)
TOTAL CASH FLOW FOR THE PERIOD		(229)	(867)
Reclassification of cash and cash equivalents relating to discontinued operations		-	(16)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD		8,929	9,813
CASH AND CASH EQUIVALENTS AT END OF PERIOD		8,700	8,929

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

(2) The line "Dividends paid" includes the coupons paid to owners of the deeply subordinated perpetual notes for an amount of €123 million at December 31, 2018 and €144 million at December 31, 2017.

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

03 NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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ENGIE SA, the parent company of the Group, is a French *société anonyme* with a Board of Directors that is subject to the provisions of Book II of the French Commercial Code (*Code de Commerce*), as well as to all other provisions of French law applicable to French commercial companies. It was incorporated on November 20, 2004 for a period of 99 years.

It is governed by current and future laws and by regulations applicable to *sociétés anonymes* and its bylaws.

The Group is headquartered at 1 place Samuel de Champlain, 92400 Courbevoie (France).

ENGIE shares are listed on the Paris, Brussels and Luxembourg stock exchanges.

On February 27, 2019, the Group's Board of Directors approved and authorized for issue the consolidated financial statements of the Group for the year ended December 31, 2018.

NOTE 1 ACCOUNTING FRAMEWORK AND BASIS FOR PREPARING THE CONSOLIDATED FINANCIAL STATEMENTS

1.1 Accounting standards

Pursuant to European Regulation (EC) 809/2004 on prospectuses dated April 29, 2004, financial information concerning the assets, liabilities, financial position, and profit and loss of ENGIE has been provided for the last two reporting periods (ended December 31, 2017 and 2018). This information was prepared in accordance with European Regulation (EC) 1606/2002 "on the application of international accounting standards" dated July 19, 2002. The Group's consolidated financial statements for the year ended December 31, 2018 have been prepared in accordance with IFRS Standards as published by the International Accounting Standards Board and endorsed by the European Union⁽¹⁾.

The accounting standards applied in the consolidated financial statements for the year ended December 31, 2018 are consistent with the policies used to prepare the consolidated financial statements for the year ended December 31, 2017, except for those described in § 1.1.1 below.

1.1.1 IFRS Standards, amendments or IFRIC Interpretations applicable in 2018

- IFRS 9 – *Financial instruments*

In accordance with the transition principles of IFRS 9, the new standard is applied retrospectively for the classification and measurement of financial assets and liabilities as well as for impairment losses, and prospectively for hedge accounting with the exception of the provisions relating to the recognition of the time value of derivative instruments. For these, as from January 1, 2017, the Group has decided to recognize changes in the fair value of the time component in other comprehensive income, for hedging relationships in which only the 'spot' element had previously been designated as hedging instrument.

For further details on the impact of IFRS 9 on the consolidated financial statements, please refer to Notes 2, 17 and 18.

- IFRS 15 – *Revenue from Contracts with Customers*

The first-time application has been implemented under the full retrospective method requiring comparative information to be restated at the date of initial application. In addition, ENGIE has decided to apply the practical expedients provided for by the standard regarding completed contracts or contracts modified as at January 1, 2017.

(1) Available on the European Commission's website: http://ec.europa.eu/internal_market/accounting/ias/index_en.htm.

For further details on the impact of IFRS 15 on the consolidated financial statements, please refer to Notes 2 and 18.

- Amendments to IFRS 2 – *Share-based payment: Classification and measurement of share-based payment transactions*
- IFRIC 22 – *Foreign Currency Transactions and Advance Consideration*
- Annual Improvements to IFRS Standards 2014-2016 Cycle⁽¹⁾

The impact of the application of IFRS 9 and IFRS 15 is presented in the Notes mentioned above.

The other amendments, interpretations and improvements have no significant impact on the Group's consolidated financial statements.

1.1.2 IFRS Standards, amendments or IFRIC Interpretations effective in 2019 and that the Group has elected not to early adopt

- IFRS 16 - *Leases*

In January 2016, the IASB has issued a new standard on leases. Under the new standard, all lease commitments will be recognized on the face of the statement of financial position, without distinguishing between operating leases and finance leases.

The main impact we expect on the consolidated statement of financial position is an increase in the "right-of-use assets" on the assets side and an increase of the lease liabilities on the liabilities side, regarding leases where the Group acts as lessee and which are currently qualified as operating leases. They concern mainly real estate and vehicles. In the consolidated income statement, reversal of the rental expenses of these operating leases will lead to an increase in EBITDA and in depreciation and financial expenses.

Having concluded the stage of identifying leases throughout the Group, their analyzes under the criteria of the new standard have been realized (identifying a lease, assessing the term of the lease, measuring and determining the discount rates, etc.). They are now identified on an ongoing basis so as to update the Group database. The IT tool able to deal with processing a large number of leases, has been deployed throughout the Group.

Transition

Analyzing the impact of the transition under the modified retrospective approach is being finalized. The Group has elected to apply some of the transition options of the new standard as at January 1, 2019. Amongst others, it has elected to include in the Group database the leases for which the lease term ends within 12 months of the transition date, to adjust the "right-of-use assets" by the amount of the provisions for onerous leases recognized in the statement of financial position as at December 31, 2018 (instead of impairing them) and to apply the grand-fathering clause.

Commitments relating to operating leases are presented in Note 23.1 "Operating leases for which ENGIE acts as lessee" (please refer to Note 22 for finance leases). Consistently with the amount of these off-balance sheet commitments, these leases are expected to have an impact amounting from €2.1 billion to €2.3 billion on the Group's debt as from 2019.

- Amendments to IFRS 9 – *Financial Instruments: Prepayment features with negative compensation*
- Amendments to IAS 28 – *Investments in Associates and Joint Ventures: Long-term interests in Associates and Joint Ventures*⁽²⁾
- Amendments to IAS 19 – *Employee benefits: Plan Amendment, Curtailment or Settlement*⁽²⁾

⁽¹⁾ The improvements of this cycle relating to IFRS 1 and IAS 28 are applicable as from 2018.

- IFRIC 23 – *Uncertainty over income tax treatments*
- Annual Improvements to IFRS Standards 2015-2017 Cycle⁽¹⁾.

The impact of the application of these other amendments, interpretations and improvements is currently being assessed.

1.1.3 IFRS Standards, amendments or IFRIC Interpretations effective after 2019

- IFRS 17 – *Insurance contracts*⁽²⁾
- Amendments to IFRS 3 – *Business Combinations: Definition of a Business*⁽¹⁾
- Amendments to IAS 1 – *Presentation of Financial Statements* and IAS 8 – *Accounting Policies, Changes in Accounting Estimates and Errors: Definition of Material* ⁽¹⁾.

The impact of the application of these standards and amendments is currently being assessed.

1.2 Measurement and presentation basis

1.2.1 Historical cost convention

The Group's consolidated financial statements are presented in euros and have been prepared using the historical cost convention, except for financial instruments that are accounted for under the financial instrument categories defined by IFRS 9.

1.2.2 Chosen options

1.2.2.1 Reminder of IFRS 1 transition options

The Group used some of the options available under IFRS 1 for its transition to IFRS in 2005. The options that continue to have an effect on the consolidated financial statements are:

- translation adjustments: the Group elected to reclassify cumulative translation adjustments within consolidated equity at January 1, 2004;
- business combinations: the Group elected not to restate business combinations that took place prior to January 1, 2004 in accordance with IFRS 3.

1.2.2.2 Business combinations

Business combinations carried out prior to January 1, 2010 were accounted for in accordance with IFRS 3 prior to the revision. In accordance with IFRS 3 revised, these business combinations have not been restated.

Since January 1, 2010, the Group applies the purchase method as defined in IFRS 3 revised, which consists in recognizing the identifiable assets acquired and liabilities assumed at their fair values at the acquisition date, as well as any non-controlling interests in the acquiree. Non-controlling interests are measured either at fair value or at the entity's proportionate interest in the net identifiable assets of the acquiree. The Group determines on a case-by-case basis which measurement option to be used to recognize non-controlling interests.

(1) These standards and amendments have not yet been adopted by the European Union.

(2) These standards and amendments have not yet been adopted by the European Union.

1.2.2.3 Consolidated statement of cash flows

The consolidated statement of cash flows is prepared using the indirect method starting from net income.

“Interest received on non-current financial assets” is classified within investing activities because it represents a return on investments. “Interest received on cash and cash equivalents” is shown as a component of financing activities because the interest can be used to reduce borrowing costs. This classification is consistent with the Group’s internal organization, where debt and cash are managed centrally by the Group treasury department.

As impairment losses on current assets are considered to be definitive losses, changes in current assets are presented net of impairment.

Cash flows relating to the payment of income tax are presented on a separate line.

1.2.3 Foreign currency transactions

1.2.3.1 Translation of foreign currency transactions

Foreign currency transactions are recorded in the functional currency at the exchange rate prevailing on the date of the transaction.

Functional currency is the currency of the primary economic environment in which an entity operates, which in most cases corresponds to local currency. However, certain entities may have a functional currency different from the local currency when that other currency is used for an entity’s main transactions and better reflects its economic environment.

At each reporting date:

- monetary assets and liabilities denominated in foreign currencies are translated at year-end exchange rates. The resulting translation gains and losses are recorded in the consolidated statement of income for the year to which they relate;
- non-monetary assets and liabilities denominated in foreign currencies are recognized at the historical cost applicable at the date of the transaction.

1.2.3.2 Translation of the financial statements of subsidiaries with a functional currency other than the euro (the presentation currency)

The statements of financial position of these subsidiaries are translated into euros at the official year-end exchange rates. Income statement and cash flow statement items are translated using the average exchange rate for the year. Any differences arising from the translation of the financial statements of these subsidiaries are recorded under “Translation adjustments” as other comprehensive income.

Goodwill and fair value adjustments arising on the acquisition of foreign entities are classified as assets and liabilities of those foreign entities and are therefore denominated in the functional currencies of the entities and translated at the year-end exchange rate.

1.2.4 Use of estimates and judgments

1.2.4.1 Estimates

The preparation of consolidated financial statements requires the use of estimates and assumptions to determine the value of assets and liabilities and contingent assets and liabilities at the reporting date, as well as income and expenses reported during the period.

Developments in the economic and financial environment prompted the Group to step up its risk oversight procedures and include an assessment of these risks in measuring financial instruments and performing impairment tests. The Group's estimates used in business plans and determination of discount rates used in impairment tests and for calculating provisions, take into account the environment and the important market volatility.

Accounting estimates are made in a context which remains sensitive to energy market developments, therefore making it difficult to apprehend medium-term economic prospects.

Due to uncertainties inherent in the estimation process, the Group regularly revises its estimates in light of currently available information. Final outcomes could differ from those estimates.

The key estimates used in preparing the Group's consolidated financial statements relate mainly to:

- measurement of the fair value of assets acquired and liabilities assumed in a business combination (*see Note 5*);
- measurement of revenue not yet metered, so called un-metered revenue (*see Note 8*);
- measurement of recognized tax loss carry-forwards (*see Note 12*);
- measurement of the recoverable amount of goodwill (*see Note 14*), other intangible assets (*see Note 15*) and property, plant and equipment (*see Note 16*);
- financial instruments (*see Notes 17 and 18*);
- measurement of provisions, particularly for back-end of nuclear fuel cycle, dismantling obligations, disputes, pensions and other employee benefits (*see Notes 20 and 21*).

1.2.4.2 Judgment

As well as relying on estimates, Group management also makes judgments to define the appropriate accounting policies to apply to certain activities and transactions, particularly when the effective IFRS Standards and IFRIC Interpretations do not specifically deal with the related accounting issues.

In particular, the Group exercised its judgment in assessing:

- the type of control (*see Note 3*);
- the performance obligations of sales contracts (*see Note 8*);
- how revenue is recognized for distribution or transmission services invoiced to clients (*see Note 8*);
- the identification of "own use contracts" as defined by IFRS 9 within non-financial purchase and sales contracts (electricity, gas, etc.) (*see Note 18*);
- the classification of arrangements which contain a lease (*see Notes 22 and 23*).

Entities for which judgment on the nature of control has been exercised are listed in Note 3 "Main subsidiaries at December 31, 2018" and Note 4 "Investments in entities accounted for using the equity method".

Accounting standards

From now on, accounting standards are presented above the Notes to which they relate in order to improve the clarity of these consolidated financial statements.

NOTE 2 RESTATEMENT OF 2017 COMPARATIVE DATA

The previously published financial statements presented hereafter have been restated to take into account:

- impacts resulting from the application of the new standards IFRS 9 – *Financial Instruments* and IFRS 15 – *Revenue from Contracts with Customers*; and
- the presentation in the financial statements at December 31, 2017 (the income statement, statement of comprehensive income and statement of cash flows) as “Discontinued operations” of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018, as they represent a separate major line of business under IFRS 5 – *Non-current Assets Held for Sale and Discontinued Operations*.

It should be noted that the exploration-production activities (ENGIE E&P International) were already classified as discontinued operations in the consolidated financial statements at December 31, 2017.

2.1 Impacts of applying IFRS 9 and IFRS 15 to the comparative 2017 financial statements

2.1.1 Impacts on the statement of financial position at December 31, 2017

2.1.1.1 Summary of the main impacts

<i>In millions of euros</i>	Dec. 31, 2017 reclassified	IFRS 9 impacts	IFRS 15 impacts	Dec. 31, 2017 restated
Other financial assets	7,632	(35)	-	7,596
Investments in entities accounted for using the equity method	7,702	(79)	(16)	7,606
Trade and other receivables, net	13,247	(126)	4	13,126
Assets from contracts with customers	6,946	(16)	-	6,930
Other current and non-current assets	114,761	37	83	114,882
TOTAL ASSETS	150,287	(217)	70	150,140
Shareholders' equity	36,639	(224)	(132)	36,283
Non-controlling interests	5,938	(11)	(87)	5,840
TOTAL EQUITY	42,577	(235)	(219)	42,122
Provisions	21,720	3	(8)	21,715
Liabilities from contracts with customers	3,278	-	298	3,575
Other current and non-current liabilities	82,712	15	(1)	82,727
TOTAL EQUITY AND LIABILITIES	150,287	(217)	70	150,140

2.1.1.2 Reclassifications to adapt the presentation of the statement of financial position following the application of the two new standards

The main impacts concern, for IFRS 9, the reclassification of financial assets that were previously classified as "Available-for-sale securities" and measured at fair value through other comprehensive income, and, for IFRS 15, the separate presentation of contract assets and contract liabilities.

In millions of euros	Dec. 31, 2017 published	Reclassifications						Dec. 31, 2017 reclassified
Assets								
Available-for-sale securities	2,656	(2,656)						-
Loans and receivables at amortized cost	3,576	(3,576)						-
Other financial assets	-	2,656	3,576	85	(293)	1,608		7,632
Equity instruments at fair value through other comprehensive income	-	745						745
Equity instruments at fair value through income	-	379						379
Debt instruments at fair value through other comprehensive income	-	882				901		1,783
Debt instruments at fair value through income	-	650				213		863
Loans and receivables at	-		3,576	85	(293)	494		3,861
Investments in entities accounted for using the equity method	7,409				293			7,702
Other current and non-current assets	9,059				22			9,081
Trade and other receivables, net	20,311			(74)	(46)	(6,951)	7	13,247
Assets from contracts with customers	-			(4)		6,951		6,947
Financial assets at fair value through income	1,608					(1,608)		-
Cash and cash equivalents	8,931			(7)				8,924
Liabilities								
Provisions	21,768				(48)			21,720
Trade and other payables, net	16,432					(7)	(18)	16,408
Liabilities from contracts with customers	-				2	3,276		3,278
Other current and non-current liabilities	15,765				22	(3,269)	25	12,542

2.1.1.3 IFRS 9 – Financial Instruments: impacts on the statement of financial position at December 31, 2017

The main impacts of the first-time application of IFRS 9 on the statement of financial position are summarized below for each of the three phases of the new standard.

- **Classification and measurement of financial assets and liabilities**

IFRS 9 requires financial assets to be classified and measured based on their type, their contractual cash flow characteristics and their business model. The new standard does not significantly change how financial liabilities are classified and measured.

For the Group, the main impact concerns the reclassification of financial assets which were previously presented as "Available-for-sale securities" and measured at fair value through other comprehensive income. A summary of the reclassifications is shown in the table above (see Note 2.1.1.2).

- **Impairment**

IFRS 9 rules regarding impairment require the recognition of expected credit losses on initial recognition of receivables, or as from the time when loans are granted or financial guarantees given.

The first-time application of IFRS 9 resulted in an increase in impairment. The increase mainly concerns trade receivables and assets from contracts with customers (increase in impairment of €134 million at end-2017 out of a total gross amount of €20 billion), as well as long-term receivables (increase in impairment of €26 million at end-2017 out of a total gross amount of €4 billion).

The impacts of changes in impairment following the first-time application of IFRS 9 are summarized in the table below.

<i>in millions of euros</i>	Dec. 31, 2017 reclassified	IFRS 9 impacts	Dec. 31, 2017 restated before IFRS 15 impacts
Other financial assets	7,632	(35)	7,596
Equity instruments at fair value through other comprehensive income	745	(12)	733
Gross	578	(3)	575
Fair value	167	(9)	158
Equity instruments at fair value through income	379	14	393
Gross	466	(2)	464
Fair value	(87)	16	(71)
Debt instruments at fair value through other comprehensive income	1,783	3	1,786
Gross	1,741	-	1,741
Fair value	42	4	46
Debt instruments at fair value through income	863	(6)	857
Gross	908	(2)	906
Fair value	(46)	(3)	(49)
Loans and receivables at amortized cost	3,861	(35)	3,826
Gross	4,084	(8)	4,076
Fair value	19	-	19
Impairment	(242)	(26)	(269)
Trade and other receivables, net	13,247	(126)	13,122
Gross	14,221	-	14,221
Impairment	(973)	(126)	(1,099)
Assets from contracts with customers	6,946	(16)	6,930
Gross	6,950	(8)	6,943
Impairment	(4)	(8)	(12)

- **Hedge accounting**

The new standard aims to better align hedge accounting with risk management, without substantially changing hedge accounting principles.

The Group, which applies hedge accounting primarily to hedge net debt risk, did not observe any material impact as a result of the transition in this respect.

For the three phases, the first-time application of IFRS 9 had a total negative €235 million impact on consolidated equity at December 31, 2017 (including a negative €79 million impact on the measurement of the share in net assets of entities accounted for using the equity method).

2.1.1.4 IFRS 15 – Revenue from Contracts with Customers: impacts on the statement of financial position at December 31, 2017

The main impacts of the first-time application of IFRS 15 on the Group's statement of financial position concern:

- the separate presentation of contract assets and contract liabilities, which results in certain trade receivables being reclassified as contract assets and certain other current liabilities as contract liabilities (see summary table of reclassifications in section 2.1.1.2 above);
- the measurement of the revenues to be recognized, for which more explicit rules are set out in the new standard, notably depending on how the performance obligations identified are satisfied, and has modified the timing of revenue recognition and the margin profile for certain contracts.

The second point, this mainly affects contracts for the operation and maintenance of power plants or the provision of production capacities, with a potential increase in contract liabilities reflecting the delay between the price received and the completion of the services.

As a consequence, applying IFRS 15 had a negative €219 million impact on equity at December 31, 2017 whereas the impact on the rhythm of revenue recognition in the income statement for these contracts was not material, given their term.

2.1.2 Impacts on income statement at December 31, 2017

2.1.2.1 Summary of the main impacts

In millions of euros	Dec. 31, 2017 published	IFRS 9 impacts	IFRS 15 impacts	Dec. 31, 2017 restated excluding IFRS 5 impacts relating to
Revenues from contracts with customers	64,280	-	(9,898)	54,381
Revenues from other contracts	749	-	5,805	6,555
REVENUES	65,029	-	(4,093)	60,936
Purchases	(36,740)	-	3,980	(32,760)
Other operating income and expenses	(9,636)	-	78	(9,558)
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	5,273	(23)	(39)	5,211
INCOME/(LOSS) FROM OPERATING ACTIVITIES	2,819	(27)	(39)	2,752
NET FINANCIAL INCOME/(LOSS)	(1,296)	(100)	(11)	(1,407)
Income tax expense	425	37	11	473
NET INCOME/(LOSS)	2,238	(92)	(38)	2,108

2.1.2.2 IFRS 9 – Financial instruments: impacts on income statement at December 31, 2017

The impact of the application of IFRS 9 on net income Group share amounted to a negative €92 million (negative €129 million before tax) at December 31, 2017.

The impact on net income was primarily due to a one-off transition effect resulting from the application of IFRS 9, paragraph 7.2.1, which requires assets that were derecognized in 2017, particularly trade receivables, to continue to be accounted for under IAS 39 rather than IFRS 9. As a result, the recognition of expected credit losses on the initial

recognition of new receivables (mainly trade receivables) in 2017 had a one-off negative impact of €113 million on gross income for the period, presented in non-recurring income.

It should be noted that after transition, recurring income may be impacted primarily by significant changes in the credit rating of our counterparties, for example in the event of a financial crisis

2.1.2.3 IFRS 15 – Revenue from Contracts with Customers: impacts on income statement at December 31, 2017

The main impacts on the Group's consolidated revenues are related to presentation. The impact of the new standard on current operating income is not material.

The three main issues concerning the Group are presented below. The first two, which represent €9,526 million are related to presentation and have no impact on the Group's current operating income:

- in certain countries where the Group acts as energy provider without being in charge of energy distribution, the analysis under IFRS 15 may lead to recognizing only energy sales as revenues. In some situations, the accounting treatment under IFRS 15 leads to a decrease in revenues corresponding to distribution without any impact on the energy margin, since the related expenses are decreased accordingly. At December 31, 2017, the related revenue restatement amounted to a negative €3,803 million, with operating expenses decreasing by the same amount. The countries that are most concerned are Belgium (for the distribution of gas and electricity as well as for the transportation of electricity) and France (for the distribution of electricity). Even if there is no impact at Group level for gas in France, there is an impact on the revenue breakdown by reportable segment: under IFRS 15, the revenues on gas distribution are no longer recognized by the provider (in the France reportable segment) but by the distributor (in the Europe Infrastructures reportable segment). At December 31, 2017, these revenues amounted to €1,957 million;
- commodities sales transactions which are within the scope of IFRS 9 – *Financial Instruments*, are outside the scope of IFRS 15. The sales under the related contracts that result in a physical delivery are therefore presented on a separate line from IFRS 15 revenues. At December 31, 2017, these sales amounted to €5,723 million;
- the new standard has modified the timing of revenue recognition for certain types of activities (such as operation and maintenance of power plants or provision of production capacities). However, this did not have a material impact on income at December 31, 2017.

2.2 Classification of upstream liquefied natural gas (LNG) activities as "Discontinued operations"

On July 13, 2018, the Group finalized the disposal of its upstream liquefied natural gas (LNG) activities to Total (see Note 5.1.4 "Disposal of ENGIE's liquefied natural gas (LNG) activities").

In accordance with IFRS 5, the upstream LNG activities are presented as "Discontinued operations" in the Group's income statement, statement of comprehensive income and statement of cash flows at December 31, 2017

Other assets held for sale at December 31, 2018 do not meet the definition of "Discontinued operations" and therefore have not been restated.

2.3 2017 comparative financial statements

2.3.1 Income statement at December 31, 2017

<i>In millions of euros</i>	Dec. 31, 2017 published	IFRS 9 impacts	IFRS 15 impacts	IFRS 5 - LNG	Dec. 31, 2017 restated
Revenues from contracts with customers	64,280	-	(9,898)	(1,308)	53,073
Revenues from other contracts	749	-	5,805	(52)	6,503
REVENUES	65,029	-	(4,093)	(1,360)	59,576
Purchases	(36,740)	-	3,980	1,296	(31,465)
Personnel costs	(10,082)	-	-	31	(10,051)
Depreciation, amortization and provisions	(3,736)	(14)	(3)	(35)	(3,787)
Other operating expenses	(11,077)	-	61	37	(10,978)
Other operating income	1,441	-	16	(2)	1,455
CURRENT OPERATING INCOME	4,835	(13)	(39)	(33)	4,750
Share in net income of entities accounted for using the equity method	437	(10)	-	(6)	422
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	5,273	(23)	(39)	(39)	5,172
Mark-to-market on commodity contracts other than trading instruments	(307)	(32)	-	368	29
Impairment losses	(1,317)	18	-	1	(1,298)
Restructuring costs	(671)	-	-	2	(669)
Changes in scope of consolidation	752	-	-	-	752
Other non-recurring items	(911)	9	-	(350)	(1,252)
INCOME/(LOSS) FROM OPERATING ACTIVITIES	2,819	(27)	(39)	(17)	2,735
NET FINANCIAL INCOME/(LOSS)	(1,296)	(100)	(11)	19	(1,388)
Income tax expense	425	37	11	(79)	395
NET INCOME/(LOSS) RELATING TO CONTINUED OPERATIONS	1,948	(91)	(38)	(77)	1,741
NET INCOME/(LOSS) RELATING TO DISCONTINUED OPERATIONS	290	(1)	-	77	366
NET INCOME/(LOSS)	2,238	(92)	(38)	-	2,108
Net income/(loss) Group share	1,423	(80)	(23)	-	1,320
<i>of which Net income/(loss) relating to continued operations, Group share</i>	<i>1,226</i>	<i>(80)</i>	<i>(23)</i>	<i>(77)</i>	<i>1,047</i>
<i>of which Net income/(loss) relating to discontinued operations, Group share</i>	<i>196</i>	<i>-</i>	<i>-</i>	<i>77</i>	<i>273</i>
Non-controlling interests	815	(11)	(16)	-	788
<i>of which Non-controlling interests relating to continued operations</i>	<i>722</i>	<i>(11)</i>	<i>(16)</i>	<i>-</i>	<i>695</i>
<i>of which Non-controlling interests relating to discontinued operations</i>	<i>93</i>	<i>-</i>	<i>-</i>	<i>-</i>	<i>93</i>
BASIC EARNINGS/(LOSS) PER SHARE (EUROS)	0.53	(0.03)	(0.01)	-	0.49
<i>of which Basic earnings/(loss) relating to continued operations per share</i>	<i>0.45</i>	<i>(0.03)</i>	<i>(0.01)</i>	<i>(0.03)</i>	<i>0.38</i>
<i>of which Basic earnings/(loss) relating to discontinued operations per share</i>	<i>0.08</i>	<i>-</i>	<i>-</i>	<i>0.03</i>	<i>0.11</i>
DILUTED EARNINGS/(LOSS) PER SHARE (EUROS)	0.53	(0.03)	(0.01)	-	0.49
<i>of which Diluted earnings/(loss) relating to continued operations per share</i>	<i>0.45</i>	<i>(0.03)</i>	<i>(0.01)</i>	<i>(0.03)</i>	<i>0.38</i>
<i>of which Diluted earnings/(loss) relating to discontinued operations per share</i>	<i>0.08</i>	<i>-</i>	<i>-</i>	<i>0.03</i>	<i>0.11</i>

2.3.2 Statement of comprehensive income at December 31, 2017

<i>In millions of euros</i>	Published figures of Déc. 31, 2017	Impact of IFRS 9	Impact of IFRS 15	IFRS 5 - LNG	Restated figures of Dec. 31, 2017
NET INCOME/(LOSS)	2,238	(92)	(38)	-	2,108
Equity instruments	(379)	(27)	-	-	(406)
Net investment hedges	327	-	-	-	327
Cash flow hedges (excl. commodity instruments)	419	22	-	-	441
Commodity cash flow hedges	(20)	14	-	(131)	(136)
Deferred tax on items above	(184)	(24)	-	47	(161)
Share of entities accounted for using the equity method in recyclable items, net of tax	13	51	-	10	74
Translation adjustments	(2,583)	21	27	19	(2,516)
Recyclable items relating to discontinued operations, net of tax	(177)	1	-	55	(121)
TOTAL RECYCLABLE ITEMS	(2,583)	58	27	-	(2,498)
Equity instruments	-	3	-	-	3
Actuarial gains and losses	96	-	-	-	96
Deferred tax on items above	(97)	(2)	-	2	(97)
Share of entities accounted for using the equity method in non-recyclable items from actuarial gains and losses, net of tax	32	-	-	-	32
Non-recyclable items relating to discontinued operations, net of tax	7	-	-	(2)	5
TOTAL NON-RECYCLABLE ITEMS	38	1	-	-	39
TOTAL COMPREHENSIVE INCOME/(LOSS)	(307)	(32)	(11)	-	(351)
<i>Of which owners of the parent</i>	<i>(701)</i>	<i>(22)</i>	<i>(7)</i>	<i>-</i>	<i>(732)</i>
<i>Of which non-controlling interests</i>	<i>394</i>	<i>(9)</i>	<i>(4)</i>	<i>-</i>	<i>381</i>

2.3.3 Statement of financial position at January 1, 2017

<i>In millions of euros</i>	Jan 1, 2017 published	IFRS 9 & IFRS 15 classification	Jan 1, 2017 reclassified	IFRS 9 impacts	IFRS 15 impacts	Jan 1, 2017 restated
Non-current assets						
Goodwill	17,372	-	17,372	-	-	17,372
Intangible assets, net	6,639	1	6,640	-	-	6,640
Property, plant and equipment, net	57,739	-	57,739	(3)	39	57,775
Available-for-sale securities	2,997	(2,997)	-	-	-	-
Loans and receivables at amortized cost	2,250	(2,250)	-	-	-	-
Other financial assets	-	5,249	5,249	(6)	-	5,243
Derivative instruments	3,603	-	3,603	-	-	3,603
Assets from contracts with customers	-	-	-	-	-	-
Investments in entities accounted for using the equity method	6,624	348	6,972	(141)	(16)	6,815
Other non-current assets	431	(1)	430	-	-	430
Deferred tax assets	1,250	-	1,250	7	40	1,297
TOTAL NON-CURRENT ASSETS	98,905	351	99,255	(143)	62	99,175
Current assets						
Loans and receivables at amortized cost	595	(595)	-	-	-	-
Other financial assets	-	1,768	1,768	(22)	-	1,746
Derivative instruments	9,047	-	9,047	-	-	9,047
Trade and other receivables, net	20,835	(6,666)	14,169	(19)	10	14,160
Assets from contracts with customers	-	6,536	6,536	(6)	(1)	6,529
Inventories	3,656	-	3,656	-	7	3,663
Other current assets	10,692	5	10,697	1	(1)	10,697
Financial assets at fair value through income	1,439	(1,439)	-	-	-	-
Cash and cash equivalents	9,825	(7)	9,819	(9)	-	9,810
Assets classified as held for sale	3,506	-	3,506	-	-	3,506
TOTAL CURRENT ASSETS	59,595	(397)	59,198	(55)	15	59,157
TOTAL ASSETS	158,499	(47)	158,453	(198)	77	158,332
Shareholders' equity	39,578		39,578	(203)	(122)	39,253
Non-controlling interests	5,870		5,870	(2)	(83)	5,784
TOTAL EQUITY	45,447		45,447	(206)	(205)	45,037
Non-current liabilities						
Provisions	19,461	-	19,461	5	-	19,466
Long-term borrowings	24,411	(6)	24,405	-	-	24,405
Derivative instruments	3,410	-	3,410	-	-	3,410
Other financial liabilities	200	-	200	-	-	200
Liabilities from contracts with customers	-	53	53	-	212	265
Other non-current liabilities	1,203	(23)	1,180	-	-	1,180
Deferred tax liabilities	6,775	-	6,775	-	7	6,782
TOTAL NON-CURRENT LIABILITIES	55,461	23	55,484	5	220	55,709
Current liabilities						
Provisions	2,747	(49)	2,698	-	(5)	2,693
Short-term borrowings	12,539	6	12,544	-	-	12,544
Derivative instruments	9,228	-	9,228	-	-	9,228
Trade and other payables, net	17,075	(24)	17,051	-	(9)	17,042
Liabilities from contracts with customers	-	2,454	2,454	(2)	94	2,545
Other current liabilities	15,702	(2,456)	13,246	4	(17)	13,233
Liabilities directly associated with assets classified as held for sale	300	-	300	-	-	300
TOTAL CURRENT LIABILITIES	57,591	(70)	57,521	2	62	57,586
TOTAL EQUITY AND LIABILITIES	158,499	(47)	158,453	(198)	77	158,332

2.3.4 Statement of financial position at December 31, 2017

In millions of euros	Dec. 31, 2017 published	IFRS 9 & IFRS 15 classification	Dec. 31, 2017 reclassified	IFRS 9 impacts	IFRS 15 impacts	Dec. 31, 2017 restated
Non-current assets						
Goodwill	17,285	-	17,285	-	-	17,285
Intangible assets, net	6,504	1	6,504	-	-	6,504
Property, plant and equipment, net	51,024	-	51,024	-	38	51,061
Available-for-sale securities	2,656	(2,656)	-	-	-	-
Loans and receivables at amortized cost	2,976	(2,976)	-	-	-	-
Other financial assets	-	5,598	5,598	(12)	-	5,586
Derivative instruments	2,948	(2)	2,946	3	-	2,949
Assets from contracts with customers	-	-	-	-	-	-
Investments in entities accounted for using the equity method	7,409	293	7,702	(79)	(16)	7,606
Other non-current assets	567	(1)	566	-	-	566
Deferred tax assets	803	(21)	782	27	45	854
TOTAL NON-CURRENT ASSETS	92,171	236	92,407	(61)	66	92,412
Current assets						
Loans and receivables at amortized cost	599	(599)	-	-	-	-
Other financial assets	-	2,033	2,033	(23)	-	2,010
Derivative instruments	7,378	(4)	7,374	4	-	7,378
Trade and other receivables, net	20,311	(7,064)	13,247	(126)	4	13,126
Assets from contracts with customers	-	6,946	6,946	(16)	-	6,930
Inventories	4,155	-	4,155	-	7	4,161
Other current assets	8,492	23	8,515	(1)	(6)	8,508
Financial assets at fair value through income	1,608	(1,608)	-	-	-	-
Cash and cash equivalents	8,931	(7)	8,924	5	-	8,929
Assets classified as held for sale	6,687	-	6,687	-	-	6,687
TOTAL CURRENT ASSETS	58,161	(280)	57,881	(157)	4	57,728
TOTAL ASSETS	150,332	(45)	150,287	(218)	70	150,140
Shareholders' equity	36,639		36,639	(224)	(132)	36,283
Non-controlling interests	5,938		5,938	(11)	(87)	5,840
TOTAL EQUITY	42,577		42,577	(235)	(219)	42,122
Non-current liabilities						
Provisions	18,428	1	18,429	5	-	18,434
Long-term borrowings	25,292	-	25,292	-	-	25,292
Derivative instruments	2,980	-	2,980	-	-	2,980
Other financial liabilities	32	-	32	-	-	32
Liabilities from contracts with customers	-	33	33	-	225	258
Other non-current liabilities	1,009	(3)	1,006	-	2	1,007
Deferred tax liabilities	5,220	(27)	5,193	14	8	5,215
TOTAL NON-CURRENT LIABILITIES	52,960	4	52,964	19	235	53,218
Current liabilities						
Provisions	3,340	(49)	3,291	(2)	(8)	3,281
Short-term borrowings	8,176	-	8,175	-	-	8,175
Derivative instruments	8,720	-	8,720	-	-	8,720
Trade and other payables, net	16,432	(24)	16,408	-	(4)	16,404
Liabilities from contracts with customers	-	3,245	3,245	-	72	3,317
Other current liabilities	14,756	(3,220)	11,536	1	(7)	11,530
Liabilities directly associated with assets classified as held for sale	3,371	-	3,371	-	-	3,371
TOTAL CURRENT LIABILITIES	54,795	(49)	54,746	(1)	55	54,799
TOTAL EQUITY AND LIABILITIES	150,332	(45)	150,287	(217)	70	150,140

2.3.5 Statement of cash flows at December 31, 2017

In millions of euros	Dec. 31, 2017 published	IFRS 9 impacts	IFRS 15 impacts	IFRS 5 - LNG	Dec. 31, 2017 restated
NET INCOME/(LOSS)	2,238	(92)	(38)	-	2,108
- Net income/(loss) relating to discontinued operations	290	(1)	-	77	366
NET INCOME/(LOSS) RELATING TO CONTINUED OPERATIONS	1,948	(91)	(38)	(77)	1,741
- Share in net income of entities accounted for using the equity method	(437)	10	-	6	(422)
+ Dividends received from entities accounted for using the equity method	466	-	-	-	466
- Net depreciation, amortization, impairment and provisions	6,203	(19)	(2)	35	6,217
- Impact of changes in scope of consolidation and other non-recurring items	(1,096)	(111)	-	350	(858)
- Mark-to-market on commodity contracts other than trading instruments	307	32	-	(368)	(29)
- Other items with no cash impact	44	-	-	-	43
- Income tax expense	(425)	(37)	(11)	79	(395)
- Net financial income/(loss)	1,296	99	11	(19)	1,387
Cash generated from operations before income tax and working capital	8,305	(117)	(41)	5	8,150
+ Tax paid	(894)	-	-	(11)	(905)
Change in working capital requirements	1,251	121	63	177	1,613
CASH FLOW FROM OPERATING ACTIVITIES RELATING TO CONTINUED OPERATIONS	8,662	4	22	171	8,858
CASH FLOW FROM OPERATING ACTIVITIES RELATING TO DISCONTINUED OPERATIONS	647	-	-	(171)	476
CASH FLOW FROM OPERATING ACTIVITIES	9,309	4	22	-	9,335
Acquisitions of property, plant and equipment and intangible assets	(5,779)	-	(3)	5	(5,778)
Acquisitions of controlling interests in entities, net of cash and cash equivalents acquired	(690)	(2)	-	1	(692)
Acquisitions of investments in entities accounted for using the equity method and joint operations	(1,446)	-	-	135	(1,311)
Acquisitions of equity and debt instruments	(258)	10	-	-	(247)
Disposals of property, plant and equipment and intangible assets	90	-	-	-	90
Loss of controlling interests in entities, net of cash and cash equivalents sold	3,203	8	-	-	3,211
Disposals of investments in entities accounted for using the equity method and joint operations	283	-	-	-	283
Disposals of equity and debt instruments	538	-	-	(412)	126
Interest received on financial assets	83	2	(11)	1	75
Dividends received on equity instruments	170	-	-	-	171
Change in loans and receivables originated by the Group and other	(838)	(10)	(8)	-	(856)
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES RELATING TO CONTINUED OPERATIONS	(4,645)	9	(22)	(270)	(4,928)
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES RELATING TO DISCONTINUED OPERATIONS	(512)	-	-	270	(242)
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES	(5,157)	9	(22)	-	(5,171)
Dividends paid	(2,871)	-	-	-	(2,871)
Recovery from the French State of the 3% tax on dividends	389	-	-	-	389
Repayment of borrowings and debt	(7,738)	-	-	-	(7,738)
Change in financial assets held for investment and financing purposes	(181)	(16)	-	-	(197)
Interest paid	(745)	-	-	1	(744)
Interest received on cash and cash equivalents	100	7	-	-	107
Cash flow on derivatives qualifying as net investment hedges and compensation payments on derivatives and on early buyback of borrowings	(156)	-	-	-	(156)
Increase in borrowings	6,356	-	-	-	6,356
Increase/decrease in capital	224	-	-	262	486
Purchase and/or sale of treasury stock	(140)	-	-	-	(140)
Changes in ownership interests in controlled entities	1	-	-	-	1
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES RELATING TO CONTINUED OPERATIONS	(4,761)	(9)	-	263	(4,506)
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES RELATING TO DISCONTINUED OPERATIONS	36	-	-	(263)	(228)
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES	(4,725)	(9)	-	-	(4,734)
Effects of changes in exchange rates and other relating to continued operations	(294)	7	-	-	(286)
Effects of changes in exchange rates and other relating to discontinued operations	(10)	-	-	(1)	(11)
TOTAL CASH FLOW FOR THE PERIOD	(877)	11	-	(1)	(867)
Reclassification of cash and cash equivalents relating to discontinued operations	(16)	-	-	-	(16)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	9,825	(13)	-	-	9,813
CASH AND CASH EQUIVALENTS AT END OF PERIOD	8,931	(2)	-	-	8,929

2.3.6 Impacts on key indicators

<i>In millions of euros</i>	Dec. 31, 2017 published	IFRS 9 impacts	IFRS 15 impacts	IFRS 5 - LNG	Dec. 31, 2017 restated
EBITDA	9,316	(25)	(39)	(54)	9,199
NET RECURRING INCOME	3,550	(120)	(38)	-	3,392
Net recurring income/(loss) relating to continued operations	3,135	(127)	(38)	10	2,979
Net recurring income/(loss) relating to discontinued operations	415	8	-	(10)	413
NET RECURRING INCOME/(LOSS), GROUP SHARE	2,662	(122)	(23)	-	2,518
Net recurring income/(loss) relating to continued operations, Group share	2,372	(127)	(23)	11	2,233
Net recurring income/(loss) relating to discontinued operations, Group share	291	5	-	(11)	285
NET RECURRING INCOME/(LOSS) ATTRIBUTABLE TO NON-CONTROLLING INTERESTS	887	2	(16)	-	874
Net recurring income/(loss) relating to continued operations attributable to non-controlling interests	762	-	(16)	-	746
Net recurring income/(loss) relating to discontinued operations attributable to non-controlling interests	125	3	-	-	128
CASH FLOW FROM OPERATIONS (CFFO)	8,311	6	11	181	8,509

NOTE 3 MAIN SUBSIDIARIES AT DECEMBER 31, 2018

Accounting standards

Controlled entities (subsidiaries) are fully consolidated in accordance with IFRS 10 – *Consolidated Financial Statements*. An investor (the Group) controls an entity and therefore must consolidate it if all of the following three criteria are met:

- it has the ability to direct the relevant activities of the entity;
- it has the rights and is exposed to variable returns from its involvement with the entity;
- it has the ability to use its power over the entity to affect the investor's return.

3.1 List of main subsidiaries at December 31, 2018

The following lists are made available by the Group to third parties, pursuant to Regulation No. 2016-09 of the French accounting standards authority (ANC) issued on December 2, 2016:

- list of companies included in consolidation;
- list of companies excluded from consolidation because their individual and cumulative incidence on the Group's consolidated accounts is not material. They correspond to entities deemed not significant as regards the Group's main key figures (revenues, total equity, etc), shell companies or entities that have ceased all activities and are undergoing liquidation/closure proceedings;
- list of main non-consolidated interests.

This information is available on the Group's website (www.engie.com, Investors/Regulated information section). Non-consolidated companies are classified under non-current financial assets (see Note 17.1.1.1) under "Equity instruments at fair value".

The list of the main subsidiaries presented below was determined, as regards operating entities, based on their contribution to Group revenues, EBITDA, net income and net debt. The main equity-accounted investments (associates and joint ventures) are presented in Note 4 "Investments in entities accounted for using the equity method".

"FC" indicates the full consolidation method.

Some entities such as ENGIE SA, ENGIE Energie Services SA or Electrabel SA comprise both operating activities and headquarters functions which report to management teams of different reportable segments. In the following tables, these operating activities and headquarters functions are shown within their respective reportable segments under their initial company name followed by a (*) sign.

North America

Company name	Activity	Country	% interest		Consolidation method	
			Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
ENGIE North America	Electricity distribution and generation/Natural gas/LNG/Energy services	United States	100.0	100.0	FC	FC
ENGIE Holding Inc.	Holding - parent company	United States	100.0	100.0	FC	FC
Distrigas of Massachusetts	LNG terminals	United States	-	100.0	-	FC
ENGIE Gas & LNG LLC	Natural gas/LNG	United States	-	100.0	-	FC
ENGIE Infinity Renewables ⁽¹⁾	Electricity distribution and generation	United States	100.0	-	FC	-
SoCore Energy LLC ⁽²⁾	Electricity distribution and generation	United States	100.0	-	FC	-
ENGIE Resources Inc.	Energy sales	United States	100.0	100.0	FC	FC
Engie Insight Service	Energy services	United States	100.0	100.0	FC	FC

(1) Acquisition on February 20, 2018.

(2) Acquisition on April 16, 2018.

Latin America

Company name	Activity	Country	% interest		Consolidation method	
			Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
ENGIE Energia Chile Group	Electricity distribution and generation	Chile	52.8	52.8	FC	FC
ENGIE Energia Perú	Electricity distribution and generation	Peru	61.8	61.8	FC	FC
ENGIE Brasil Energia Group	Electricity distribution and generation	Brazil	68.7	68.7	FC	FC

Africa/Asia

Company name	Activity	Country	% interest		Consolidation method	
			Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
Glow Group ⁽¹⁾	Electricity distribution and generation	Thailand	69.1	69.1	FC	FC
Hazelwood Power Partnership ⁽²⁾	Electricity generation	Australia	72.0	72.0	Joint Operation	FC
Loy Yang B Group ⁽³⁾	Electricity generation	Australia	-	70.0	FC	FC
Simply Energy	Energy sales	Australia	72.0	72.0	FC	FC
Baymina Enerji A.S.	Electricity generation	Turkey	95.0	95.0	FC	FC

(1) Assets classified as "Assets held for sale" on December 31, 2018 (see Note 5 "Main change in Group structure").

(2) Change in consolidation method in 2018 further to the implementation of a new governance as part of the dismantling of the site.

(3) The Loy Yang B coal-fired power plant in Australia was sold on January 15, 2018 (see Note 5 "Main changes in Group structure").

Benelux

Company name	Activity	Country	% interest		Consolidation method	
			Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
Electrabel SA (*)	Electricity generation/Energy sales	Belgium	100.0	100.0	FC	FC
Synatom	Managing provisions relating to power plants and nuclear fuel	Belgium	100.0	100.0	FC	FC
Cofely Fabricom SA	Systems, facilities and maintenance services	Belgium	100.0	100.0	FC	FC
ENGIE Energie Nederland N.V. (*)	Energy sales	Netherlands	100.0	100.0	FC	FC
ENGIE Services Nederland N.V.	Energy services	Netherlands	100.0	100.0	FC	FC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 3 MAIN SUBSIDIARIES AT DECEMBER 31, 2018

France

Company name	Activity	Country	% interest		Consolidation method	
			Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
ENGIE SA (*)	Energy sales	France	100.0	100.0	FC	FC
ENGIE Energie Services SA (*)	Energy services/Networks	France	100.0	100.0	FC	FC
Axima Concept	Systems, facilities and maintenance services	France	100.0	100.0	FC	FC
Endel Group	Systems, facilities and maintenance services	France	100.0	100.0	FC	FC
INEO Group	Systems, facilities and maintenance services	France	100.0	100.0	FC	FC
Compagnie Nationale du Rhône	Electricity distribution and generation	France	49.9	49.9	FC	FC
ENGIE Green	Electricity distribution and generation	France	100.0	100.0	FC	FC
CPCU	Urban heating networks	France	66.5	64.4	FC	FC

Europe excluding France & Benelux

Company name	Activity	Country	% interest		Consolidation method	
			Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
ENGIE Energielösungen GmbH	Energy services	Germany	100.0	100.0	FC	FC
ENGIE Deutschland GmbH	Energy services	Germany	100.0	100.0	FC	FC
ENGIE Italia S.p.A (*)	Energy sales	Italy	100.0	100.0	FC	FC
Engie Servizi S.p.A	Energy services	Italy	100.0	100.0	FC	FC
ENGIE Romania	Natural gas distribution/Energy sales	Romania	51.0	51.0	FC	FC
ENGIE Supply Holding UK Limited	Energy sales	United Kingdom	100.0	100.0	FC	FC
ENGIE Retail Investment UK Limited	Holding	United Kingdom	100.0	100.0	FC	FC
First Hydro Holdings Company	Electricity generation	United Kingdom	75.0	75.0	FC	FC
Keepmoat Regeneration	Energy services	United Kingdom	100.0	100.0	FC	FC
ENGIE Services Holding UK Ltd	Energy services	United Kingdom	100.0	100.0	FC	FC
ENGIE Services Limited	Energy services	United Kingdom	100.0	100.0	FC	FC

Infrastructures Europe

Company name	Activity	Country	% interest		Consolidation method	
			Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
GRDF	Natural gas distribution	France	100.0	100.0	FC	FC
GRTgaz Group (excluding Elengy)	Natural gas transportation	France	74.6	74.8	FC	FC
Elengy	Natural gas/LNG	France	74.6	74.8	FC	FC
Fosmax LNG	Natural gas/LNG	France	54.1	54.2	FC	FC
Storengy Deutschland GmbH	Underground natural gas storage	Germany	100.0	100.0	FC	FC
Storengy SA	Underground natural gas storage	France	100.0	100.0	FC	FC

GEM (2018) / GEM & LNG (2017)⁽¹⁾

Company name	Activity	Country	% interest		Consolidation method	
			Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
Electrabel SA (*)	Energy management trading	France/Belgium	100.0	100.0	FC	FC
ENGIE Global Markets	Energy management trading	France/Belgium/Singapore	100.0	100.0	FC	FC
ENGIE Energy Management (*)	Energy management trading	France/Belgium/Italy/United Kingdom	100.0	100.0	FC	FC
ENGIE Energy Management	Holding	Switzerland	100.0	100.0	FC	FC
ENGIE SA (*)	Energy management trading/Energy sales/LNG	France	100.0	100.0	FC	FC

(1) The disposal of upstream LNG activities was completed on July 13, 2018. As a result, the reportable segment "GEM & LNG" has been renamed "GEM" and from now on only includes the activities of the GEM Business Unit.

E&P⁽¹⁾

Company name	Activity	Country	% interest		Consolidation method	
			Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
ENGIE E&P International Group	Exploration-production	France and other countries	-	70.0	-	FC
ENGIE E&P International	Holding - parent company	France	-	70.0	-	FC
ENGIE E&P Nederland B.V.	Exploration-production	Netherlands	-	70.0	-	FC
ENGIE E&P Deutschland GmbH	Exploration-production	Germany	-	70.0	-	FC
ENGIE E&P Norge AS	Exploration-production	Norway	-	70.0	-	FC
ENGIE E&P UK Ltd.	Exploration-production	United Kingdom	-	70.0	-	FC

(1) The disposal of ENGIE E&P International was completed on February 15, 2018 (see Note 5 "Main changes in Group structure").

Others

Company name	Activity	Country	% interest		Consolidation method	
			Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
ENGIE SA (*)	Holding - parent company	France	100.0	100.0	FC	FC
Electrabel SA (*)	Holding/Electricity generation	Belgium	100.0	100.0	FC	FC
ENGIE Energie Services SA (*)	Holding	France	100.0	100.0	FC	FC
International Power Limited	Holding	United Kingdom	100.0	100.0	FC	FC
ENGIE CC	Financial subsidiaries/Central functions	Belgium	100.0	100.0	FC	FC
ENGIE FINANCE SA	Financial subsidiaries	France	100.0	100.0	FC	FC
ENGIE Solar	Solar EPC	France	100.0	100.0	FC	FC
ENGIE Energie Nederland N.V. (*)	Electricity generation	Netherlands	100.0	100.0	FC	FC
ENGIE Cartagena	Electricity generation	Spain	100.0	100.0	FC	FC
ENGIE Deutschland AG (*)	Electricity generation	Germany	100.0	100.0	FC	FC
ENGIE Kraftwerk Wilhelmshaven GmbH & Co. KG	Electricity generation	Germany	57.0	57.0	FC	FC
ENGIE Thermique France	Electricity generation	France	100.0	100.0	FC	FC
Gaztransport & Technigaz (GTT)	Engineering	France	40.4	40.4	FC	FC
Tractebel Engineering	Engineering	Belgium	100.0	100.0	FC	FC

3.2 Significant judgments exercised when assessing control

The Group primarily considers the following information and criteria when determining whether it has control over an entity:

- governance arrangements: voting rights and whether the Group is represented in the governing bodies, majority rules and veto rights;
- whether substantive or protective rights are granted to shareholders, particularly in relation to the entity's relevant activities;
- the consequences of a "deadlock" clause;
- whether the Group is exposed, or has rights, to variable returns from its involvement with the entity.

The Group exercised its judgment regarding the entities and sub-groups described below.

Entities in which the Group has the majority of the voting rights

GRTgaz (Infrastructures Europe): 74.6%

In addition to the analysis of the shareholder agreement with Société d'Infrastructures Gazières, a subsidiary of *Caisse des Dépôts et Consignations* (CDC), which owns 24.8% of the share capital of GRTgaz, the Group also assessed the rights granted to the French Energy Regulatory Commission (*Commission de régulation de l'énergie* – CRE). As a regulated activity, GRTgaz has a dominant position on the gas transportation market in France. Accordingly, since the transposition of the Third European Directive of July 13, 2009 into French law (Code de l'énergie -Energy Code) of May 9, 2011, GRTgaz has been subject to independence rules as concerns its directors and senior management team. The French Energy Code confers certain powers on the CRE in the context of its duties to control the proper functioning of the gas markets in France, including verifying the independence of the members of the Board of Directors and senior management and assessing the

choice of investments. The Group considers that it exercises control over GRTgaz and its subsidiaries (including Elengy) in view of its current ability to appoint the majority of the members of the Board of Directors and take decisions about the relevant activities, especially in terms of the level of investment and planned financing.

Entities in which the Group does not have the majority of the voting rights

In the entities in which the Group does not have a majority of the voting rights, judgment is exercised with regard to the following items, in order to assess whether there is a situation of *de facto* control:

- dispersion of the shareholding structure: number of voting rights held by the Group relative to the number of rights held respectively by the other vote holders and their dispersion;
- voting patterns at shareholders' meetings: the percentages of voting rights exercised by the Group at shareholders' meetings in recent years;
- governance arrangements: representation in the governing body with strategic and operational decision-making power over the relevant activities;
- rules for appointing key management personnel;
- contractual relationships and material transactions.

The main fully consolidated entities in which the Group does not have the majority of the voting rights are Compagnie Nationale du Rhône (49.98%) and Gaztransport & Technigaz (40.4%).

Compagnie Nationale du Rhône ("CNR" – France): 49.98%

The Group holds 49.98% of the share capital of CNR, with CDC holding 33.2%, and the balance (16.82%) being dispersed among around 200 local authorities. In view of the current provisions of the French "Murcef" law, under which a majority of CNR's share capital must remain under public ownership, the Group is unable to hold more than 50% of the share capital. However, the Group considers that it exercises *de facto* control as it holds the majority of the voting rights exercised at shareholders' meetings due to the widely dispersed shareholding structure and the absence of evidence of the minority shareholders acting in concert.

Gaztransport & Technigaz ("GTT" – Others): 40.4%

Since GTT's initial public offering in February 2014, ENGIE has been the largest shareholder in the company with a 40.4% stake, the free float representing around 49% of the share capital. The Group holds the majority of the voting rights exercised at shareholders' meetings in view of the widely dispersed shareholding structure and the absence of evidence of minority shareholders acting in concert. ENGIE also holds the majority of the seats on the Board of Directors. The Group considers that it exercises *de facto* control over GTT, based on an IFRS 10 criteria.

3.3 Subsidiaries with material non-controlling interests

The following table shows the non-controlling interests in Group entities that are deemed to be material, the respective contributions to equity and net income at December 31, 2018 and December 31, 2017, as well as the dividends paid to non-controlling interests of these significant subsidiaries:

Corporate name	Activity	Percentage interest of non-controlling interests		Net income/(loss) of non-controlling interests		Equity of non-controlling interests		Dividends paid to non-controlling interests	
		Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
In millions of euros									
GRTgaz Group (Infrastructures Europe, France)	Regulated gas transportation activities and management of LNG terminals	25.4	25.2	99	99	1,133	981	158	97
ENGIE Energía Chile Group (Latin America, Chile) ⁽¹⁾	Electricity distribution and generation - thermal power plants	47.2	47.2	49	45	913	842	25	27
Glow Group (Africa/Asia, Thailand) ⁽²⁾	Electricity distribution and generation - hydroelectric, wind and thermal power plants	30.9	30.9	96	87	512	465	75	87
ENGIE Brasil Energia Group (Latin America, Brazil) ⁽¹⁾	Electricity distribution and generation	31.3	31.3	170	174	473	563	206	154
ENGIE Romania Group (Europe excluding France & Benelux, Romania)	Distribution of natural gas/Energy sales	49.0	49.0	43	36	512	491	18	12
ENGIE E&P International Group (E&P, France and other countries) ⁽³⁾	Portfolio of exploration-production assets and oil and gas field operation assets	NA	30.0	24	93	NA	363	38	-
ENGIE Energía Perú (Latin America, Peru) ⁽¹⁾	Electricity distribution and generation - thermal and hydroelectric power plants	38.2	38.2	34	45	376	337	11	17
Gaztransport & Technigaz (Other, France) ⁽¹⁾	Naval engineering, cryogenic membrane containment systems for LNG transportation	59.6	59.6	63	47	339	335	59	59
Other subsidiaries with non-controlling interests				18	162	1,131	1,464	294	227
TOTAL				595	788	5,391	5,840	882	680

(1) The ENGIE Energía Chile, ENGIE Energía Brasil and Glow groups, as well as Gaztransport & Technigaz and ENGIE Energía Perú are listed on the stock markets in their respective countries.

(2) Assets classified as "Assets held for sale" at December 31, 2018 (see Note 5 "Main changes in Group structure").

(3) The disposal of ENGIE E&P International group was finalized on February 15, 2018 (see Note 5 "Main changes in Group structure").

3.3.1 Condensed financial information on subsidiaries with material non-controlling interests

The condensed financial information concerning these subsidiaries presented in the table below is based on a 100% interest and is shown before intragroup eliminations.

	GRTgaz Group		ENGIE Energía Chile Group		Glow Group ⁽¹⁾		ENGIE Brasil Energia Group	
<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
Income statement								
Revenues	2,298	2,266	1,028	895	1,354	1,287	2,017	1,935
Net income/(loss)	389	461	94	85	262	225	544	555
Net income/(loss) Group share	283	342	45	40	165	138	374	381
Other comprehensive income/(loss) – Owners of the parent	(13)	(4)	49	(122)	41	(51)	(119)	(178)
TOTAL COMPREHENSIVE INCOME/(LOSS) – OWNERS OF THE PARENT	270	339	94	(82)	206	87	255	203
Statement of financial position								
Current assets	918	777	364	343	3,278	584	1,045	998
Non-current assets	10,404	10,481	2,700	2,562	(257)	2,330	4,232	3,895
Current liabilities	(921)	(885)	(271)	(303)	(950)	(359)	(907)	(1,460)
Non-current liabilities	(6,198)	(5,910)	(910)	(871)	(835)	(1,363)	(2,983)	(1,759)
TOTAL EQUITY	4,204	4,462	1,882	1,732	1,237	1,191	1,388	1,673
TOTAL NON-CONTROLLING INTERESTS	1,133	1,196	913	842	512	465	473	563
Statement of cash flows								
Cash flow from operating activities	1,213	1,074	249	190	421	487	875	797
Cash flow from (used in) investing activities	(493)	(915)	(248)	(428)	(132)	(142)	(851)	(1,551)
Cash flow from (used in) financing activities	(740)	(149)	(15)	55	(534)	(316)	89	770
TOTAL CASH FLOW FOR THE PERIOD⁽²⁾	(20)	10	(14)	(183)	(245)	29	113	16

(1) Assets classified as “Assets held for sales” at December 31, 2018 (see Note 5 “Main changes in Group structure”).

(2) Excluding effects of changes in exchange rates and other.

	ENGIE Romania Group		ENGIE Energía Perú		Gaztransport & Technigaz	
<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
Income statement						
Revenues	1,231	1,051	427	502	246	237
Net income/(loss)	87	74	88	117	106	78
Net income/(loss) Group share	44	38	55	72	43	32
Other comprehensive income/(loss) – Owners of the parent	(3)	(13)	27	(66)	-	-
TOTAL COMPREHENSIVE INCOME/(LOSS) – OWNERS OF THE PARENT	41	25	81	6	43	32
Statement of financial position						
Current assets	626	517	255	224	319	232
Non-current assets	787	769	1,728	1,678	491	530
Current liabilities	(312)	(240)	(174)	(259)	(166)	(122)
Non-current liabilities	(64)	(57)	(824)	(764)	(74)	(79)
TOTAL EQUITY	1,037	989	985	879	570	562
TOTAL NON-CONTROLLING INTERESTS	512	491	376	337	339	335
Statement of cash flows						
Cash flow from operating activities	109	120	195	323	168	116
Cash flow from (used in) investing activities	(58)	(38)	(19)	(73)	(9)	(6)
Cash flow from (used in) financing activities	(54)	(67)	(144)	(242)	(94)	(95)
TOTAL CASH FLOW FOR THE PERIOD⁽¹⁾	(3)	15	33	8	66	14

(1) Excluding effects of changes in exchange rates and other.

NOTE 4 INVESTMENTS IN ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD

Accounting standards

The Group accounts for its investments in associates (entities over which the Group has significant influence) and joint ventures using the equity method. Under IFRS 11 – Joint Arrangements, a joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement.

The respective contributions of associates and joint ventures in the statement of financial position, the income statement and the statement of comprehensive income at December 31, 2018 and December 31, 2017 are as follows:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Statement of financial position		
Investments in associates	4,590	5,118
Investments in joint ventures	3,256	2,488
INVESTMENTS IN ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	7,846	7,606
Income statement		
Share in net income/(loss) of associates	88	263
Share in net income/(loss) of joint ventures	273	159
SHARE IN NET INCOME/(LOSS) OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	361	422
Statement of comprehensive income		
Share of associates in "Other comprehensive income/(loss)"	132	113
Share of joint ventures in "Other comprehensive income/(loss)"	26	(7)
SHARE OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD IN "OTHER COMPREHENSIVE INCOME/(LOSS)"	158	106

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

Significant judgments

The Group primarily considers the following information and criteria in determining whether it has joint control or significant influence over an entity:

- governance arrangements: whether the Group is represented in the governing bodies, majority rules and veto rights;
- whether substantive or protective rights are granted to shareholders, particularly in relation to the entity's relevant activities:
This can be difficult to determine in the case of "project management" or "one-asset" entities, as certain decisions concerning the relevant activities are made upon the creation of the joint arrangement and remain valid throughout the project. Accordingly, the decision-making analysis relates to the relevant residual activities of the entity (those that significantly affect the variable returns of the entity);
- the consequences of a "deadlock" clause;
- whether the Group is exposed, or has rights, to variable returns from its involvement with the entity:
This can also involve analyzing the Group's contractual relations with the entity, in particular the conditions in which these contracts are entered into, their duration as well as the management of conflicts of interest that may arise when the entity's governing body casts votes.

The Group exercised its judgment regarding the following entities and sub-groups:

Project management entities in the Middle East

The significant judgments made in determining the consolidation method to be applied to these project management entities concerned the risks and rewards relating to contracts between ENGIE and the entity concerned, as well as an analysis of the residual relevant activities over which the entity retains control after its creation. The Group considers that it has significant influence or joint control over these entities, since the decisions taken throughout the term of the project about the relevant activities such as refinancing, or the renewal or amendment of significant contracts (sales, purchases, operating and maintenance services) require, depending on the case, the unanimous consent of two or more parties sharing control.

SUEZ Group (32.06%)

With effect from July 22, 2013, the date on which the SUEZ shareholders' agreement expired, ENGIE no longer controls SUEZ but exercises significant influence over the company. In particular, this is because: (i) the Group does not have a majority of members on SUEZ's Board of Directors, (ii) at Shareholders' Meetings, although SUEZ's shareholder base is fragmented and ENGIE holds a large interest, past voting shows that ENGIE alone did not have the majority at Ordinary and Extraordinary Shareholders' Meetings between 2010 and 2018 and (iii) the operational transition agreements (essentially relating to a framework agreement governing purchases and IT) were entered into on an arm's length basis.

Joint ventures in which the Group holds an interest of more than 50%

Tihama (60%)

ENGIE holds a 60% stake in the Tihama cogeneration plant in Saudi Arabia and its partner Saudi Oger holds 40%. The Group considers that it has joint control over Tihama since the decisions about its relevant activities, including for example the preparation of the budget and amendments to major contracts, etc., require the unanimous consent of the parties sharing control.

Joint control – difference between joint ventures and joint operations

Classifying a joint arrangement requires the Group to use its judgment to determine whether the entity in question is a joint venture or a joint operation. IFRS 11 requires an analysis of "other facts and circumstances" when determining the classification of jointly controlled entities.

The IFRS Interpretations Committee (IFRS IC) (November 2014) decided that for an entity to be classified as a joint operation, other facts and circumstances must give rise to direct enforceable rights to the assets, and obligations for the liabilities, of the joint arrangement.

In view of this position and its application to our analyses, the Group has no material joint operations at December 31, 2018.

4.1 Investments in associates

4.1.1 Contribution of material associates and of associates that are not material to the Group taken individually

The table hereafter shows the contribution of each material associate along with the aggregate contribution of associates deemed not material taken individually, in the consolidated statement of financial position, income statement, statement of comprehensive income, and the "Dividends received from companies accounted for using the equity method" line of the statement of cash flows.

The Group used qualitative and quantitative criteria to determine material associates. These criteria include the contribution to the consolidated line items "Share in net income/(loss) of associates" and "Investments in associates", the total assets

NOTE 4 INVESTMENTS IN ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD

of associates in Group share, and associates carrying major projects in the study or construction phase for which the related investment commitments are material.

Corporate name	Activity	Capacity	Percentage interest of investments in associates		Carrying amount of investments in associates		Share in net income/(loss) of associates		Other comprehensive income/(loss) of associates		Dividends received from associates	
			Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
In millions of euros												
SUEZ Group (Other)	Water and waste processing		32.06	31.96	1,968	2,083	55	100	21	99	130	119
Energia Sustentável Do Brasil (Latin America, Brazil)	Hydro power plant	3,750 MW	40.00	40.00	646	784	(57)	(23)	-	-	-	-
Project management entities in the Middle East (Africa/Asia, Saudi Arabia, Bahrain, Qatar, United Arab Emirates, Oman, Kuwait) ⁽¹⁾	Gas-fired power plants and seawater desalination facilities				1,004	868	97	157	96	(16)	97	96
GASAG (Europe excluding France & Benelux, Germany)	Gas and heat networks		31.57	31.57	261	247	18	14	1	4	4	2
Other investments in associates that are not material taken individually					710	1,136	(25)	14	14	26	104	60
INVESTMENTS IN ASSOCIATES					4,590	5,118	88	263	132	113	334	278

- (1) Investments in associates operating gas-fired power plants and seawater desalination facilities in the Arabian Peninsula have been grouped together under "Project management entities in the Middle East". This includes around 40 associates operating thermal power plants with a total installed capacity of 28,020 MW (at 100%) and a further 1,507 MW (at 100%) in capacity under construction. These associates have fairly similar business models and joint arrangements: the project management entities selected as a result of a competitive bidding process develop, build and operate power generation plants and seawater desalination facilities. The entire output of these facilities is sold to government-owned companies under power and water purchase agreements, over periods generally spanning 20 to 30 years.
- In accordance with their contractual arrangements, the corresponding plants are recognized as property, plant and equipment or as financial receivables whenever substantially all of the risks and rewards associated with the assets are transferred to the buyer of the output. This treatment complies with IFRIC 4 and IAS 17. The shareholding structure of these entities systematically includes a government-owned company based in the same country as the project management entity. The Group's percentage interest and percentage voting rights in each of these entities varies between 20% and 50%.

The share in net income/(loss) of associates includes a net non-recurring loss for a total amount of €155 million in 2018 (compared to a net non-recurring loss of €43 million in 2017), mainly including changes in the fair value of derivative instruments and disposal gains and losses, net of tax (see Note 6.2 "Net recurring income Group share").

4.1.2 Financial information regarding material associates

The tables below provide condensed financial information for the Group's main associates. The amounts shown have been determined in accordance with IFRS, before the elimination of intragroup items and after (i) adjustments made in line with Group accounting policies and (ii) fair value measurements of the assets and liabilities of the associate performed at the date of acquisition at the level of ENGIE, as required by IAS 28. All amounts are presented based on a 100% interest with the exception of "Total equity attributable to ENGIE".

<i>In millions of euros</i>	Revenues	Net income/(loss)	Other comprehensive income/(loss)	Total comprehensive income/(loss)	Current assets	Non-current assets	Current liabilities	Non-current liabilities	Total equity	% interest of Group	Total equity attributable to ENGIE
AT DECEMBER 31, 2018											
SUEZ Group ⁽¹⁾	17,331	335	(103)	232	10,872	22,681	11,664	12,896	8,993	32.06	1,968
Energia Sustentável Do Brasil	564	(142)	-	(142)	199	4,388	544	2,428	1,615	40.00	646
Project management entities in the Middle East	4,254	467	406	873	2,572	21,401	3,775	16,263	3,934		1,004
GASAG	1,196	56	3	59	798	1,733	1,508	196	827	31.57	261
AT DECEMBER 31, 2017											
SUEZ Group ⁽¹⁾	15,783	296	(195)	101	10,314	22,517	10,920	12,889	9,022	31.96	2,083
Energia Sustentável Do Brasil	789	(58)	(1)	(58)	269	4,976	591	2,695	1,960	40.00	784
Project management entities in the Middle East	4,147	633	87	720	2,512	20,958	3,979	16,219	3,272		868
GASAG	1,106	46	12	58	780	1,676	1,500	173	782	31.58	247

(1) The data indicated in the table for SUEZ correspond to financial information published by SUEZ. Total SUEZ equity attributable to the Group amounts to €6,392 million based on the published financial statements of SUEZ and €6,139 million based on the financial statements of ENGIE. The difference in these amounts mainly reflects the non-inclusion of the share in deeply-subordinated perpetual notes issued by SUEZ in total equity attributable to ENGIE, partly offset by the fair value measurement of the assets and liabilities of SUEZ at the date the Group changed its consolidation method (July 22, 2013).

SUEZ is the only material listed associate. Based on the closing share price at December 31, 2018, the market value of this interest was €2,297 million.

4.1.3 Transactions between the Group and its associates

The data below set out the impact of transactions with associates on the Group's 2018 consolidated financial statements.

<i>In millions of euros</i>	Purchases of goods and services	Sales of goods and services	Net financial income (excluding dividends)	Trade and other receivables	Loans and receivables at amortized cost	Trade and other payables	Borrowings and debt
Project management entities in the Middle East	-	237	(3)	33	69	4	-
Contassur ⁽¹⁾	-	-	-	167	2	-	-
Energia Sustentável Do Brasil	126	-	-	-	76	10	-
Other	29	4	8	17	182	2	1
AT DECEMBER 31, 2018	154	241	4	217	329	16	1

(1) Contassur is a life insurance company accounted for using the equity method. Contassur offers insurance contracts, chiefly with pension funds that cover post-employment benefit obligations for Group employees and also employees of other companies mainly engaged in regulated activities in the electricity and gas sector in Belgium. Insurance contracts entered into by Contassur represent reimbursement rights recorded within "Other assets" in the statement of financial position. These reimbursement rights totaled €168 million at December 31, 2018 (€159 million at December 31, 2017).

4.2 Investments in joint ventures

4.2.1 Contribution of material joint ventures and of joint ventures that are not material to the Group taken individually

The table below shows the contribution of each material joint venture along with the aggregate contribution of joint ventures deemed not material taken individually to the consolidated statement of financial position, income statement, statement of comprehensive income, and the "Dividends received from entities accounted for using the equity method" line of the statement of cash flows.

The Group used qualitative and quantitative criteria to determine material joint ventures. These criteria include the contribution to the line items "Share in net income/(loss) of joint ventures" and "Investments in joint ventures", the Group's share in total assets of joint ventures, and joint ventures conducting major projects in the study or construction phase for which the related investment commitments are material.

Corporate name	Activity	Capacity	Percentage interest of investments in joint ventures		Carrying amount of investments in joint ventures		Share in net income/(loss) of joint ventures		Other comprehensive income/(loss) of joint ventures		Dividends received from joint ventures	
			Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
In millions of euros												
National Central Cooling Company "Tabreed" (Africa/Asia, Abu Dhabi)	District cooling networks		40.00	40.00	710	656	40	13	-	-	39	-
EcoEléctrica (North America, Puerto Rico)	Combined-cycle gas-fired power plant and LNG terminal	507 MW	50.00	50.00	416	470	34	44	-	-	104	-
Portfolio of power generation assets in Portugal (Europe excluding France & Benelux, Portugal)	Electricity generation	2,895 MW	50.00	50.00	325	329	44	40	1	3	49	135
WSW Energie und Wasser AG (Europe excluding France & Benelux, Germany)	Electricity distribution and generation	229 MW	33.10	33.10	204	192	11	7	-	-	3	3
Tihama Power Generation Co (Africa/Asia, Saudi Arabia)	Electricity generation	1,599 MW	60.00	60.00	163	122	34	2	1	1	-	-
Ohio State Energy Partners (North America)	Services		50.00	50.00	129	117	5	3	5	(2)	4	1
Megal GmbH (Infrastructures Europe, Germany)	Gas transmission network		49.00	49.00	91	98	6	4	-	-	13	12
Transmisora Eléctrica del Norte (Latin America, Chile)	Electricity transmission line		50.00	50.00	85	66	7	1	-	-	-	-
Other investments in joint ventures that are not material taken individually					1,134	438	92	44	18	(9)	31	36
INVESTMENTS IN JOINT VENTURES					3,256	2,488	273	159	26	(7)	244	188

The share in net income/(loss) of joint ventures includes non-recurring income of €6 million in 2018 (non-recurring income of €18 million in 2017), resulting chiefly from changes in the fair value of derivatives, impairment losses and disposal gains and losses, net of tax (see Note 6.2 "Net recurring income Group share").

4.2.2 Financial information regarding material joint ventures

The amounts shown have been determined in accordance with IFRS before the elimination of intragroup items and after (i) adjustments made in line with Group accounting policies and (ii) fair value measurements of the assets and liabilities of the joint venture performed at the date of acquisition at the level of ENGIE, as required by IAS 28. All amounts are

presented based on a 100% interest with the exception of "Total equity attributable to ENGIE" in the statement of financial position.

Information on the income statement and statement of comprehensive income

<i>In millions of euros</i>	Revenues	Deprecia-tion and amortization on intangible assets and property, plant and equipment	Net financial income/(loss) ⁽¹⁾	Income tax expense	Net income/(loss)	Other comprehensive income/(loss)	Total comprehensive income/(loss)
AT DECEMBER 31, 2018							
National Central Cooling Company "Tabreed"	335	(34)	(37)	-	100	-	100
EcoEléctrica	280	(63)	2	(3)	68	-	68
Portfolio of power generation assets in Portugal	749	(65)	(31)	(37)	106	3	109
WSW Energie und Wasser AG	856	(11)	(3)	(19)	35	-	35
Tihama Power Generation Co	111	(5)	(24)	(8)	56	1	57
Ohio State Energy Partners	52	-	(33)	-	10	11	21
Megal GmbH	124	(63)	(4)	2	12	-	12
Transmisora Eléctrica del Norte	75	-	(33)	(5)	14	16	30
AT DECEMBER 31, 2017							
National Central Cooling Company "Tabreed" ⁽²⁾	121	(12)	(15)	-	34	-	34
EcoEléctrica	301	(72)	(2)	(4)	89	-	89
Portfolio of power generation assets in Portugal	760	(66)	(36)	(20)	100	12	112
WSW Energie und Wasser AG	879	(13)	(5)	(16)	21	1	23
Tihama Power Generation Co	120	(5)	(26)	(5)	3	2	4
Ohio State Energy Partners	27	-	(16)	-	6	(5)	1
Megal GmbH	115	(59)	(4)	2	9	-	9
Transmisora Eléctrica del Norte	7	-	4	(1)	3	(8)	(5)

(1) Interest income is not material.

(2) These data correspond to the amount at 100% from the date acquisition by ENGIE (August 16, 2017).

Information on the statement of financial position

<i>In millions of euros</i>	Cash and cash equivalents	Other current assets	Non-current assets	Short-term borrowings	Other current liabilities	Long-term borrowings	Other non-current liabilities	Total equity	% interest of Group	Total equity attributable to ENGIE
AT DECEMBER 31, 2018										
National Central Cooling Company "Tabreed"	65	124	2,574	-	173	816	-	1,775	40.00	710
EcoEléctrica	24	107	755	3	27	-	23	833	50.00	416
Portfolio of power generation assets in Portugal ⁽¹⁾	231	568	1,305	287	178	763	115	761	50.00	325
WSW Energie und Wasser AG ⁽²⁾	12	148	778	55	84	101	103	596	33.10	204
Tihama Power Generation Co	129	140	488	61	40	370	15	271	60.00	163
Ohio State Energy Partners	16	8	1,039	(6)	7	804	-	257	50.00	129
Megal GmbH	-	13	752	10	55	446	70	185	49.00	91
Transmisora Eléctrica del Norte	66	30	773	75	3	621	-	170	50.00	85
AT DECEMBER 31, 2017										
National Central Cooling Company "Tabreed"	101	108	2,351	-	160	760	-	1,641	40.00	656
EcoEléctrica	97	112	773	3	16	-	23	940	50.00	470
Portfolio of power generation assets in Portugal	245	741	1,275	315	168	886	130	762	50.00	329
WSW Energie und Wasser AG	13	117	769	40	98	105	97	560	33.10	192
WSW Energie und Wasser AG	77	20	626	50	52	404	14	204	60.00	122
Tihama Power Generation Co	25	0	931	717	1	6	-	234	50.00	117
Megal GmbH	5	6	765	4	50	446	77	200	49.00	98
Transmisora Eléctrica del Norte	21	103	849	2	5	836	-	131	50.00	66

(1) Equity Group share amounts to €649 million for the Portuguese sub-group. The share of this €649 million attributable to ENGIE is therefore €325 million.

(2) Equity Group share amounts to €586 million for the WSW Energie und Wasser AG sub-group. The share of this €586 million attributable to ENGIE is therefore €193million. This amount is increased by an additional share of €11 million in respect of a non-controlling interest held directly by ENGIE in a subsidiary of this sub-group (and is therefore not included in the €586 million in equity attributable to the owners of the parent).

4.2.3 Transactions between the Group and its joint ventures

The data below set out the impact of transactions with joint ventures on the Group's 2018 consolidated financial statements.

<i>In millions of euros</i>	Purchases of goods and services	Sales of goods and services	Net financial income (excluding dividends)	Trade and other receivables	Loans and receivables at amortized cost	Trade and other payables	Borrowings and debt
EcoEléctrica	-	123	-	-	-	23	-
Portfolio of power generation assets in Portugal	-	-	-	-	128	-	-
WSW Energie und Wasser AG	1	43	-	6	-	-	-
Megal GmbH	65	-	-	-	-	5	-
Futures Energies Investissements Holding	2	17	4	-	157	-	-
Other	36	21	6	10	116	3	8
AT DECEMBER 31, 2018	104	205	10	17	400	32	8

4.3 Other information on investments accounted for using the equity method

4.3.1 Unrecognized share of losses of associates and joint ventures

Cumulative unrecognized losses of associates (corresponding to the cumulative amount of losses exceeding the carrying amount of investments in the associates concerned) including other comprehensive income/(loss), amounted to €171 million in 2018 (€218 million in 2017). Unrecognized losses relating to fiscal year 2018 amounted to €18 million.

These unrecognized losses mainly correspond to (i) the negative fair value of derivative instruments designated as interest rate and commodity hedges ("Other comprehensive income/(loss)") contracted by associates in Asia Pacific in connection with the financing of construction projects for power generation plants and (ii) cumulative losses arising on the Tirreno Power joint venture.

4.3.2 Commitments and guarantees given by the Group in respect of entities accounted for using the equity method

At December 31, 2018, the main commitments and guarantees given by the Group in respect of entities accounted for using the equity method concern the following two companies and groups of companies:

- Energia Sustentável do Brasil ("Jirau"), for an aggregate amount of BRL 4,341 million (€975 million).

At December 31, 2018, the amount of loans granted by Banco Nacional de Desenvolvimento Econômico e Social, the Brazilian Development Bank, to Energia Sustentável do Brasil amounted to BRL 10,852 million (€2,439 million). Each partner stands as guarantor for this debt to the extent of its ownership interest in the consortium;

- the project management entities in the Middle East and Africa, for an aggregate amount of €1,035 million.

Commitments and guarantees given by the Group in respect of these project management entities chiefly correspond to:

- an equity contribution commitment (capital/subordinated debt) for €147 million. These commitments only concern entities acting as holding companies for projects in the construction phase,
- letters of credit to guarantee debt service reserve accounts for an aggregate amount of €237 million. The project financing set up in certain entities can require those entities to maintain a certain level of cash within the company (usually enough to service its debt for six months). This is particularly the case when the financing is without recourse. This level of cash may be replaced by letters of credit,
- collateral given to lenders in the form of pledged shares in the project management entities, for an aggregate amount of €261million,
- performance bonds and other guarantees for an amount of €390 million.

NOTE 5 MAIN CHANGES IN GROUP STRUCTURE

Accounting standards

In accordance with IFRS 5 - *Non-Current Assets Held for Sale and Discontinued Operations*, assets or groups of assets held for sale are presented separately on the face of the statement of financial position and are measured at the lower of their carrying amount and fair value less costs to sell.

An asset is classified as "held for sale" when its sale is highly probable within twelve months from the date of classification, when it is available for immediate sale under its present condition and when the management is committed to a plan to sell the asset and an active program to locate a buyer and complete the plan has been initiated. To assess whether a sale is highly probable, the Group takes into consideration among other things indications of interest and offers received from potential buyers as well as specific execution risks attached to certain transactions.

Assets or group of assets are presented as discontinued operations in the Group's consolidated financial statements when they are classified as "held for sale" and represent a separate major line of business under IFRS 5.

5.1 Disposals carried out in 2018

As part of its transformation plan, on February 25, 2016, the Group presented a €15 billion asset disposal program in order to reduce its exposure to high CO₂ emitting activities and merchant activities over the 2016-2018 period.

The table below shows the impact of the main disposals and sale agreements of 2018 on the Group's net debt, excluding partial disposals with respect to DBSO⁽¹⁾ activities:

<i>In millions of euros</i>	Disposal price	Reduction in net debt
Disposal of the Loy Yang B coal power plant (Australia)	471	330
Disposal of the exploration-production activities	921	1,913
Disposal of gas distribution activities (Hungary)	147	198
Disposal of LNG activities	1,202	1,144
Other disposals that are not material taken individually	285	353
Classification of Glow activities under "Assets held for sale" - Thailand	-	723
Classification of Langa activities under "Assets held for sale" - France	-	270
TOTAL	3,026	4,931

The €4,931 million reduction in net debt at December 31, 2018 is in addition to the €8,976 million decrease previously recognized at December 31, 2017 as part of the asset disposal program, representing a total of €13,907 million to date. Additional disposals in the process of completion at December 31, 2018 are described in Note 5.2.

5.1.1 Disposal of the Loy Yang B coal-fired power plant (Australia)

On January 15, 2018, the Group completed the sale of the Loy Yang B coal-fired power plant in Australia, for which it received a payment of €471 million corresponding to the sale price of the entire interest in Loy Yang B. An amount corresponding to 30% of this price was paid to Mitsui in the form of dividends.

The transaction reduced the Group's net debt by €624 million (the impact of the derecognition of Loy Yang B's net debt totaling €294 million following its classification under "Assets held for sale" at December 31, 2017, plus the payment of €330 million received in 2018 for the 70% interest sold). The loss on disposal totaled €87 million for 2018, mainly

(1) Develop, Build, Share and Operate.

corresponding to the reclassification from other comprehensive income to the income statement of translation adjustments and net investment hedges relating to the portfolio.

5.1.2 Disposal of the exploration-production business

On February 15, 2018, the Group completed the sale of its 70% interest in ENGIE E&P International (EPI) to Neptune Energy and received a payment of €921 million, corresponding to the sale price of all of its shares.

The combined effects of the transaction and of the cash generated by these activities since January 1, 2018 have reduced the Group's net debt by €1,913 million. The disposal gain before tax, recognized in "Net income/(loss) relating to discontinued operations" (see Note 5.2.3), amounted to €65 million in 2018.

Following the transaction, the Group still holds a residual 46% interest in ENGIE E&P Touat B.V. (Other sector), which holds a 65% stake in the Touat gas field under development in Algeria. This interest is now accounted for using the equity method.

5.1.3 Disposal of the gas distribution business (Hungary)

On January 11, 2018, following the success of the negotiations initiated in the second half of 2015 with the Hungarian State, the Group completed the sale of its entire interest in its Hungarian gas distribution subsidiary Égaz-Dégaz to Nemzeti Közművek Zártkörűen Működő Részvénytársaság (NKM) - a Hungarian state-owned company. The transaction reduced the Group's net debt by €198 million, with no material disposal gain.

5.1.4 Disposal of ENGIE's liquefied natural gas (LNG) activities

On July 13, 2018, the Group completed the sale of its upstream LNG activities to Total: liquefaction, shipping (including the Gazocéan subsidiary) and international LNG trading operations.

The combined effects of the transaction and of the cash generated by these LNG upstream activities since January 1, 2018 have reduced the Group's net debt by €1,144 million excluding any additional future payments to be received. The disposal gain before tax, recognized in "Net income/(loss) relating to discontinued operations" (see Note 5.2.3), amounted to €1,193 million at December 31, 2018.

5.2 Assets held for sale and discontinued operations

Total "Assets classified as held for sale" and total "Liabilities directly associated with assets classified as held for sale" amounted to €3,798 million and €2,130 million, respectively, at December 31, 2018.

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017
Property, plant and equipment, net	2,661	5,307
Other assets	1,137	1,380
TOTAL ASSETS CLASSIFIED AS HELD FOR SALE	3,798	6,687
<i>of which Assets relating to discontinued operations</i>	-	5,471
Borrowings and debt	1,019	418
Other liabilities	1,111	2,953
TOTAL LIABILITIES DIRECTLY ASSOCIATED WITH ASSETS CLASSIFIED AS HELD FOR SALE	2,130	3,371
<i>of which Liabilities directly associated with assets relating to discontinued operations</i>	-	2,705

All assets classified as held for sale at December 31, 2017 (exploration-production activities and the Loy Yang B power plant in Australia) were sold in 2018 (see Note 5.1, Disposals carried out in 2018).

At December 31, 2018 these assets and liabilities related to Glow's activities in Thailand, the solar parks run by Langa group in France and renewable energy assets in Mexico.

5.2.1 Disposal of ENGIE's interest in Glow

On June 20, 2018, ENGIE signed a share purchase agreement with Thailand-based Global Power Synergy Public Company Ltd. (GPSC) for the sale of its 69.1% interest in Glow, an independent power producer listed on the Stock Exchange of Thailand (Africa/Asia segment) and the Group classified it as an asset held for sale at the same date. The transaction translates into net proceeds of €2.5 billion for ENGIE and is expected to result in a total €3.2 billion reduction in ENGIE's consolidated net debt.

This reclassification under "Assets held for sale" reduced the Group's net debt by €723 million at December 31, 2018. Given the expected capital gain from the sale, no value adjustments were made at December 31, 2018. Glow's contribution to "Net income/(loss) Group share" was €165 million for 2018 and €138 million for 2017.

The transaction is expected to be completed during first-half 2019. The disposal gain is expected to be in the range of €1.5 billion.

5.2.2 Langa group asset disposal program

On December 21, 2018, the Group signed a sale agreement with Predica for the solar parks operated or under construction by Langa (France segment) to FEIH2 (a joint venture 80%-owned by Predica and 20%-owned by the ENGIE Group).

At December 31, 2018, the Group considered that the sale of these assets was highly probable in view of the progress made in the divestiture process and, as a result, classified the assets under "Assets held for sale". In view of the expected disposal gain, no value adjustments were recorded at December 31, 2018.

This reclassification under "Assets held for sale" reduced the Group's net debt by €270 million at December 31, 2018. The assets' contribution to net income Group share in 2018 was marginal.

The transaction is expected to be completed in fourth-quarter 2019.

5.2.3 Financial information on discontinued operations

Income from discontinued operations

<i>In millions of euros</i>	Dec 31, 2018	Dec 31, 2017
Revenues from contracts with customers	2,163	5,021
Revenues from other contracts	65	52
REVENUES	2,229	5,073
Purchases	(2,102)	(3,326)
Personnel costs	(35)	(237)
Depreciation, amortization and provisions	(18)	(86)
Other operating expenses	(44)	(322)
Other operating income	(5)	16
CURRENT OPERATING INCOME	25	1,119
Share in net income of entities accounted for using the equity method	2	11
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	27	1,130
Mark-to-market on commodity contracts other than trading instruments	(221)	(381)
Impairment losses	(1)	(138)
Restructuring costs	-	(3)
Changes in scope of consolidation	1,258	(15)
Other non-recurring items	(2)	369
INCOME/(LOSS) FROM OPERATING ACTIVITIES	1,062	961
Financial expenses	(20)	(88)
Financial income	7	27
NET FINANCIAL INCOME/(LOSS)	(14)	(61)
Income tax expense	21	(533)
NET INCOME/(LOSS) RELATING TO DISCONTINUED OPERATIONS	1,069	366
Net income/(loss) relating to discontinued operations, Group share	1,045	273
Non-controlling interests relating to discontinued operations	24	93

Income from discontinued operations relates to ENGIE's upstream LNG activities (see Note 5.1.4) and to exploration production activities, including the disposal gain (see Note 5.1.2).

Revenues generated by discontinued operations (LNG and EPI) with ENGIE Group companies totaled €880 million in 2018 (versus €1,959 million in 2017).

As required by IFRS 5, ENGIE has no longer recognized any depreciation and amortization expense on the property, plant and equipment and intangible assets of LNG activities (as of April 1, 2018) and of EPI activities (as of May 11, 2017). The savings generated by this change amounted to €36 million before tax (primarily relating to EPI) in 2018.

Net income relating to discontinued operations also includes €22 million of costs incurred specifically in connection with the LNG transaction.

Comprehensive income from discontinued operations

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2018 Owners of the parent	Dec. 31, 2018 Non- controlling interests	Dec. 31, 2017	Dec. 31, 2017 Owners of the parent	Dec. 31, 2017 Non- controlling interests
NET INCOME/(LOSS) RELATING TO DISCONTINUED OPERATIONS	1,069	1,045	24	366	273	93
Commodity cash flow hedges	80	52	28	246	211	34
Deferred tax on items above	(43)	(33)	(10)	(88)	(76)	(12)
Share of entities accounted for using the equity method in recyclable items, net of tax	46	46	-	(10)	(10)	-
Translation adjustments	(43)	(23)	(19)	(268)	(193)	(75)
TOTAL RECYCLABLE ITEMS	37	39	(3)	(121)	(68)	(53)
Actuarial gains and losses	(2)	-	(2)	(2)	(2)	(1)
Deferred tax on items above	(1)	(1)	-	7	5	3
TOTAL NON-RECYCLABLE ITEMS	(3)	(2)	(2)	5	3	2
TOTAL COMPREHENSIVE INCOME/(LOSS) RELATING TO DISCONTINUED OPERATIONS	1,102	1,083	19	250	208	42

Comprehensive income from discontinued operations relates to ENGIE's upstream LNG activities (see Note 5.1.4) and to exploration-production activities (see Note 5.1.2).

Cash flows from discontinued operations

<i>In millions of euros</i>	Dec 31, 2018	Dec 31, 2017
NET INCOME/(LOSS)	1,069	366
Cash generated from operations before income tax and working capital requirements	42	1,224
Tax paid	(53)	(460)
Change in working capital requirements	28	(288)
CASH FLOW FROM OPERATING ACTIVITIES	17	476
Acquisitions of property, plant and equipment and intangible assets	(51)	(601)
Loss of controlling interests in entities, net of cash and cash equivalent sold	(522)	-
Disposals of equity and debt instruments	-	412
Other	(710)	(53)
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES	(1,282)	(242)
Cash flow from (used in) financing activities excluding intercompany transactions	1,284	(49)
Intercompany transactions with ENGIE on borrowings	(7)	(223)
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES	1,278	(272)
Effects of changes in exchange rates and other	3	(11)
TOTAL CASH FLOW FOR THE PERIOD	15	(49)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	15	65
CASH AND CASH EQUIVALENTS AT END OF PERIOD	-	15

Cash flows from discontinued operations relate to ENGIE's upstream LNG activities (see Note 5.1.4) and to exploration-production activities (see Note 5.1.2).

5.3 Acquisitions carried out in 2018

Various other acquisitions, equity transactions and disposals took place in 2018. They included the purchase of (i) companies in the renewable energy sector (wind and solar power) and in the services sector (microgrid, heating and cabling network) in the United States, (ii) the Langa group (an independent producer in solar, wind, biogas and biomass power in the renewable energy sector) as well as the purchase of a majority interest in Electro Power Systems (EPS, a company listed on Euronext which specializes in energy storage solutions and microgrids that enable intermittent renewable sources to be transformed into a stable power source) in France, and (iii) Piora FM SA (an airport services company) in Switzerland. In addition, on December 6, 2018, the Group finalized its acquisition of Compañía Americana de Multiservicios (CAM), the leading installation, operation and maintenance services provider in the electricity and telecommunications sectors in Latin America.

NOTE 6 FINANCIAL INDICATORS USED IN FINANCIAL COMMUNICATION

The purpose of this note is to present the main non-GAAP financial indicators used by the Group as well as their reconciliation with the aggregates of the IFRS consolidated financial statements.

6.1 EBITDA

The reconciliation between EBITDA and current operating income after share in net income of entities accounted for using the equity method is as follows:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017 ⁽¹⁾
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	5,126	5,172
Net depreciation and amortization/Other	3,882	3,966
Share-based payments (IFRS 2)	79	37
Non-recurring share in net income of entities accounted for using the equity method	149	24
EBITDA	9,236	9,199

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

6.2 Net recurring income Group share

Net recurring income Group share is a financial indicator used by the Group in its financial reporting to present net income Group share adjusted for unusual or non-recurring items.

This financial indicator therefore excludes:

- all items presented between the lines "Current operating income after share in net income of entities accounted for using the equity method" and "Income/(loss) from operating activities", i.e. "Mark-to-market on commodity contracts other than trading instruments", "Impairment losses", "Restructuring costs", "Changes in scope of consolidation" and "Other non-recurring items". These items are defined in Note 10 "Income/(loss) from operating activities"
- the following components of net financial income/(loss): the impact of debt restructuring, compensation payments on the early unwinding of derivative instruments net of the reversal of the fair value of these derivatives that were settled early, changes in the fair value of derivative instruments which do not qualify as hedges under IFRS 9 – *Financial Instruments: Recognition and Measurement*, as well as the ineffective portion of derivative instruments that qualify as hedges;
- the income tax impact of the items described above, determined using the statutory income tax rate applicable to the relevant tax entity;
- the recovery from the French State of the 3% tax on dividends in 2017 and the impact of tax rate changes in France and in the United States and other non-recurring measures in 2017 (see Note 12.1.2);
- net non-recurring items included in "Share in net income of entities accounted for using the equity method". The excluded items correspond to the non-recurring items as defined above.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 6 FINANCIAL INDICATORS USED IN FINANCIAL COMMUNICATION

The reconciliation of net income/(loss) with net recurring income Group share is as follows:

In millions of euros	Notes	Dec. 31, 2018	Dec. 31, 2017 ⁽¹⁾
NET INCOME/(LOSS) GROUP SHARE		1,033	1,320
NET INCOME/(LOSS) RELATING TO DISCONTINUED OPERATIONS, GROUP SHARE		1,045	273
NET INCOME/(LOSS) RELATING TO CONTINUED OPERATIONS, GROUP SHARE		(12)	1,047
Non-controlling interests relating to continued operations		572	695
NET INCOME/(LOSS) RELATING TO CONTINUED OPERATIONS		560	1,741
Reconciliation items between CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD and INCOME/(LOSS) FROM OPERATING ACTIVITIES			
		2,481	2,437
Mark-to-market on commodity contracts other than trading instruments	10	223	(29)
Impairment losses	10	1,798	1,298
Restructuring costs	10	162	669
Changes in scope of consolidation	10	150	(752)
Other non-recurring items	10	147	1,252
Other adjusted items		207	(1,198)
Ineffective portion of derivatives qualified as fair value hedges	11.3	3	2
Gains/(losses) on debt restructuring and early unwinding of derivative financial instruments	11.2	(7)	98
Change in fair value of derivatives not qualified as hedges and ineffective portion of derivatives qualified as cash flow hedges	11.3	183	187
Non recurring income/(loss) from debt instruments and equity instruments	11.3	26	-
Recovery from the French State of the 3% tax on dividends		-	(408)
Tax rate changes in France, in the United States and other non-recurring measures		-	(479)
Other adjusted tax impacts		(147)	(622)
Non-recurring income included in share in net income of entities accounted for using the equity method		149	24
NET RECURRING INCOME RELATING TO CONTINUED OPERATIONS		3,248	2,980
Net recurring income relating to continued operations attributable to non-controlling interests		790	746
NET RECURRING INCOME RELATING TO CONTINUED OPERATIONS, GROUP SHARE		2,458	2,233
Net recurring income relating to discontinued operations, Group share ⁽²⁾		(33)	285
NET RECURRING INCOME GROUP SHARE		2,425	2,518

- (1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").
- (2) The reconciliation of "net income/(loss) relating to discontinued operations, Group share" with "net recurring income relating to discontinued operations, Group share" at December 31, 2018 is mainly due to the gain on the disposal of the exploration-production activities, to the MtM on commodity contracts other than trading instruments recorded by upstream LNG activities and to miscellaneous disposal costs.

6.3 Industrial capital employed

The reconciliation of industrial capital employed with items in the statement of financial position is as follows:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
(+) Property, plant and equipment and intangible assets, net	55,635	57,566
(+) Goodwill	17,809	17,285
(-) <i>Goodwill Gaz de France - SUEZ and International Power⁽²⁾</i>	(7,610)	(7,715)
(+) IFRIC 4 and IFRIC 12 receivables	1,550	1,548
(+) Investments in entities accounted for using the equity method	7,846	7,606
(-) <i>Goodwill arising on the International Power combination⁽²⁾</i>	(151)	(144)
(+) Trade and other receivables, net	15,613	13,127
(-) <i>Margin calls^(2, 3)</i>	(1,669)	(1,110)
(+) Inventories	4,158	4,161
(+) Assets from contracts with customers	7,411	6,930
(+) Other current and non-current assets	9,811	9,073
(+) Deferred tax	(4,349)	(4,361)
(+) <i>Cancellation of deferred tax on other recyclable items⁽²⁾</i>	(247)	(236)
(-) Provisions	(21,813)	(21,715)
(+) <i>Actuarial gains and losses in shareholders' equity (net of deferred tax)⁽²⁾</i>	2,637	2,438
(-) Trade and other payables	(19,759)	(16,404)
(+) <i>Margin calls^(2, 3)</i>	1,681	473
(-) Liabilities from contracts with customers	(3,634)	(3,575)
(-) Other current and non-current liabilities	(13,507)	(12,579)
INDUSTRIAL CAPITAL EMPLOYED	51,412	52,370

- (1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").
- (2) For the purpose of calculating industrial capital employed, the amounts recorded in respect of these items have been adjusted from those appearing in the statement of financial position.
- (3) Margin calls included in "Trade and other receivables, net" and "Trade and other payables" correspond to advances received or paid as part of collateralization agreements set up by the Group to reduce its exposure to counterparty risk on commodity transactions.

6.4 Cash flow from operations (CFFO)

The reconciliation of cash flow from operations (CFFO) with items in the statement of cash flows is as follows:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Cash generated from operations before income tax and working capital requirements	8,464	8,150
Tax paid	(757)	(905)
Change in working capital requirements	149	1,613
Interest received on non-current financial assets	26	75
Dividends received on non-current financial assets	52	171
Interest paid	(727)	(744)
Interest received on cash and cash equivalents	79	107
Change in financial assets at fair value through income	(289)	(197)
(+) <i>Change in financial assets at fair value through income recorded in the statement of financial position and other</i>	303	238
CASH FLOW FROM OPERATIONS (CFFO)	7,300	8,509

- (1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

6.5 Capital expenditures (CAPEX)

The reconciliation of capital expenditures (CAPEX) with items in the statement of cash flows is as follows:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Acquisitions of property, plant and equipment and intangible assets	6,202	5,778
Acquisitions of controlling interests in entities, net of cash and cash equivalents acquired	983	692
(+) <i>Cash and cash equivalents acquired</i>	83	30
Acquisitions of investments in entities accounted for using the equity method and joint operations	338	1,311
Acquisitions of equity and debt instruments	283	247
Change in loans and receivables originated by the Group and other	251	856
(+) <i>Other</i>	11	3
Change in ownership interests in controlled entities	18	(1)
(+) <i>Payments received in respect of the disposal of non-controlling interests</i>	-	222
TOTAL CAPITAL EXPENDITURE (CAPEX)	8,169	9,137

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

6.6 Net debt

Net debt is presented in Note 17.3 "Net debt".

6.7 Economic net debt

Economic net debt is as follows:

<i>In millions of euros</i>	Notes	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
NET DEBT	17	21,102	22,520
Internal debt of discontinued operations	17	-	1,732
NET DEBT (excluding internal debt of discontinued operations)		21,102	20,788
Future minimum operating lease payments	23	2,087	3,463
(-) <i>discontinued operations</i>		-	(1,132)
Provisions for back-end of the nuclear fuel cycle	20	6,170	5,914
Provisions for dismantling of plant and equipment	20	6,081	5,728
Provisions for site rehabilitation	20	222	313
Post-employment benefit - Pension	21	1,970	1,763
(-) <i>discontinued operations</i>		-	(14)
(-) <i>Infrastructures regulated companies</i>		60	40
Post-employment benefit - Reimbursement rights	21	(167)	(158)
Post-employment benefit - Others benefits	21	4,293	4,278
(-) <i>discontinued operations</i>		-	(34)
(-) <i>Infrastructures regulated companies</i>		(2,572)	(2,420)
Deferred tax assets for pension and related obligations	12	(1,374)	(1,318)
(-) <i>discontinued operations</i>		-	11
(-) <i>Infrastructures regulated companies</i>		601	578
Plan assets relating to nuclear provisions, inventories of uranium and a receivable of Electrabel towards EDF Belgium	17 & 27	(2,883)	(2,672)
ECONOMIC NET DEBT		35,590	35,127

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

NOTE 7 SEGMENT INFORMATION

7.1 Operating segments and reportable segments

ENGIE is organized into 23 Business Units (BUs) or operating segments primarily based on a region-centered approach within a single country or group of countries. Each Business Unit corresponds to an "operating segment" whose operational and financial performance is regularly reviewed by the Group's Executive Committee, which is the Group's "chief operating decision maker" within the meaning of IFRS 8.

These operating segments are grouped into nine reportable segments to present the Group's segment information: North America, Latin America, Africa/Asia, Benelux, France, Europe excluding France & Benelux, Infrastructures Europe, GEM & LNG and Other.

Exploration & Production (E&P) and LNG have been sold (see Note 5 "*Main changes in Group structure*"). As a result, the reportable segment "GEM & LNG" has been renamed "GEM" and from now on only includes the activities of the GEM Business Unit.

7.1.1 Description of reportable segments

- **North America:** includes power generation, energy services and natural gas and electricity sales activities in the United States, Canada and Puerto Rico.
- **Latin America:** groups together the activities of (i) the Brazil BU and (ii) the Latin America BU (Argentina, Chile, Mexico and Peru). The subsidiaries concerned are involved in the centralized power generation and gas chain businesses, and energy services.
- **Africa/Asia:** groups together the activities of the following BUs: (i) Asia-Pacific (Australia, New Zealand, Thailand, Singapore, Indonesia and Laos), (ii) China, (iii) Africa (Morocco, South Africa) and (iv) the Middle East, South and Central Asia and Turkey (including India and Pakistan). In all of these regions, the Group is active in electricity generation and sales, gas distribution and sales, energy services and seawater desalination in the Arabian peninsula.
- **Benelux:** includes the Group's activities in Belgium, the Netherlands and Luxembourg: (i) power generation using its nuclear power plants and renewable power generation facilities, (ii) natural gas and electricity sales and (iii) energy services.
- **France:** groups together the activities of the following BUs: (i) France BtoB: energy sales and services for buildings and industry, cities and regions and major infrastructures, (ii) France BtoC: sales of energy and related services to individual and professional customers, (iii) France Renewable Energy: development, construction, financing, operation and maintenance of all renewable power generation assets in France, and (iv) France Networks, which designs, finances, builds and operates decentralized energy production and distribution facilities (heating and cooling networks).
- **Europe excluding France & Benelux:** groups together the activities of the following BUs: (i) United Kingdom (management of renewable power generation assets and the portfolio of distribution assets, supply of energy services and solutions, etc.) and (ii) North, South and Eastern Europe (sales of natural gas and electricity and related energy services and solutions, operation of renewable power generation assets, management of distribution networks).
- **Infrastructures Europe:** groups together the GRDF, GRTgaz, Elengy and Storengy BUs, which operate natural gas transportation, storage and distribution networks and facilities, and LNG terminals, mainly in France and Germany. They also sell access rights to these infrastructures to third parties.
- **GEM:** the aim of the GEM BU is to manage and optimize the Group's portfolios of physical and contractual assets (excluding gas infrastructures), particularly on the European market, on behalf of the BUs that hold power generation assets. It is also responsible for sales of energy to major pan-European and national industrial clients, and leverages its expertise in the energy-related financial markets to provide solutions to third parties.
- **Other:** includes the activities of the following BUs: (i) Generation Europe, comprising the Group's thermal power generation activities in Europe, (ii) Tractebel (engineering companies specializing in energy, hydraulics and infrastructures), (iii) GTT (specialized in the design of cryogenic membrane confinement systems for sea

transportation and storage of LNG, both on land and at sea), as well as the Group's holding and corporate activities which include the entities centralizing the Group's financing requirements, energy sales to BtoB in France (*Entreprises & Collectivités*) and the contribution of the associate SUEZ.

The main commercial relationships between the reportable segments are as follows:

- relationships between the "Infrastructures Europe" reportable segment and the users of these infrastructures, i.e. the "GEM", "France" and "Other" (E&C) reportable segments: services relating to the use of the Group's gas infrastructures in France are billed based on regulated fees applicable to all network users;
- relationships between the "GEM" reportable segment and the "France", "Benelux" and "Europe excluding France & Benelux" reportable segments: the "GEM" reportable segment manages the Group's natural gas supply contracts and sells gas at market prices to commercial companies within the "Other" (E&C), "France", "Benelux" and "Europe excluding France & Benelux" reportable segments. As regards electricity, GEM manages and optimizes the power stations and sales portfolios on behalf of entities that hold power generation assets and deducts a percentage of the energy margin in return for providing these services. The revenues and margins related to power generation activities (minus the percentage deducted by GEM) are reported by the segments that hold power generation assets ("France", "Benelux", "Europe excluding France & Benelux" and "Generation Europe" within the "Other" reportable segment);
- relationships between the "Generation Europe" segment, which is part of the "Other" reportable segment, and the commercial entities in the "France", "Benelux" and "Europe excluding France & Benelux" reportable segments: a portion of the power generated by thermal assets within the "Generation Europe" BU is sold to commercial entities from these segments at market prices.

Due to the variety of its businesses and their geographical location, the Group serves a very diverse range of situations and customer types (industry, local authorities and individual customers). Accordingly, no external customer represents individually 10% or more of the Group's consolidated revenues.

7.2 Key indicators by reportable segment

Key indicators by reportable segments (except for 2017 industrial capital employed), presented hereafter, no longer take into account the contribution of activities classified as "Discontinued activities" in accordance with IFRS 5 (see Note 5 "Main changes in Group structure"). In addition, comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

REVENUES

In millions of euros	Dec. 31, 2018			Dec. 31, 2017		
	External revenues	Intra-Group Revenues	Total	External revenues	Intra-Group Revenues	Total
North America	3,383	62	3,445	2,964	51	3,015
Latin America	4,639	-	4,639	4,383	-	4,383
Africa/Asia	4,014	1	4,016	3,939	-	3,940
Benelux	6,690	450	7,140	6,771	976	7,748
France	15,183	2	15,185	14,157	(86)	14,072
Europe excluding France & Benelux	9,527	128	9,655	8,831	155	8,986
Infrastructures Europe	5,694	1,166	6,859	5,446	1,267	6,712
GEM	6,968	6,077	13,045	7,638	7,128	14,766
Others	4,498	1,943	6,440	5,445	1,836	7,281
Elimination of internal transactions	-	(9,829)	(9,829)	-	(11,328)	(11,328)
TOTAL REVENUES	60,596	-	60,596	59,576	-	59,576

EBITDA

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017
North America	224	224
Latin America	1,775	1,709
Africa/Asia	1,122	1,272
Benelux	(186)	550
France	1,669	1,461
Europe excluding France & Benelux	679	650
Infrastructures Europe	3,499	3,386
GEM	240	(188)
Others	213	136
TOTAL EBITDA	9,236	9,199

DEPRECIATION AND AMORTIZATION

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017
North America	(72)	(53)
Latin America	(416)	(432)
Africa/Asia	(134)	(244)
Benelux	(576)	(558)
France	(628)	(606)
Europe excluding France & Benelux	(201)	(201)
Infrastructures Europe	(1,479)	(1,444)
GEM	(39)	(38)
Others	(337)	(391)
TOTAL DEPRECIATION AND AMORTIZATION	(3,882)	(3,966)

SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017
North America	75	78
Latin America	(25)	(17)
Africa/Asia	166	191
Benelux	7	5
France	1	8
Europe excluding France & Benelux	45	36
Infrastructures Europe	12	9
GEM	(5)	(4)
Others	84	116
<i>Of which share in net income of SUEZ</i>	55	100
TOTAL SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	361	422

Associates and joint ventures account for €88 million and €273 million respectively of share in net income of entities accounted for using the equity method at December 31, 2018 (compared to €263 million and €159 million at December 31, 2017).

CURRENT OPERATING INCOME/(LOSS) AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017
North America	151	174
Latin America	1,355	1,277
Africa/Asia	893	1,016
Benelux	(765)	(11)
France	1,034	869
Europe excluding France & Benelux	473	434
Infrastructures Europe	2,016	1,941
GEM	199	(229)
Others	(232)	(300)
TOTAL CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	5,126	5,172

INDUSTRIAL CAPITAL EMPLOYED

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017
North America	2,494	1,718
Latin America	9,897	9,281
Africa/Asia	3,553	5,186
Benelux	(3,759)	(3,019)
France	6,300	5,890
Europe excluding France & Benelux	5,092	5,022
Infrastructures Europe	19,802	19,914
GEM (2018) / GEM & LNG (2017)	1,102	929
Others	6,930	7,447
<i>Of which SUEZ equity value</i>	<i>2,018</i>	<i>2,110</i>
TOTAL INDUSTRIAL CAPITAL EMPLOYED	51,412	52,370

CAPITAL EXPENDITURE (CAPEX)

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017
North America	974	316
Latin America	1,758	2,241
Africa/Asia	616	887
Benelux	925	694
France	1,322	1,067
Europe excluding France & Benelux	372	636
Infrastructures Europe	1,619	1,718
GEM	45	346
Others	538	1,232
TOTAL CAPITAL EXPENDITURE (CAPEX)	8,169	9,136

7.3 Key indicators by geographic area

The amounts set out below are analyzed by:

- destination of products and services sold for revenues;
- geographic location of consolidated companies for industrial capital employed.

<i>In millions of euros</i>	Revenues		Industrial capital employed	
	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
France	24,983	25,251	30,542	30,310
Belgium	5,961	5,921	(3,254)	(2,233)
Other EU countries	15,448	14,583	7,188	7,250
Other European countries	820	1,100	386	425
North America	3,865	3,499	2,881	2,188
Asia, Middle East & Oceania	4,936	4,913	3,329	5,264
South America	4,197	4,040	9,523	9,091
Africa	385	271	816	74
TOTAL	60,596	59,576	51,412	52,370

NOTE 8 REVENUES

8.1 Revenues

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Revenues from contracts with customers	56,388	53,073
Revenues from other contracts	4,208	6,503
REVENUES	60,596	59,576

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

Realized but not yet metered revenues (so called un-metered revenues) mainly relate to France and Belgium for an amount of €3,108 million at December 31, 2018 (€3,034 at December 31, 2017).

8.1.1 Revenues from contracts with customers

Accounting standards

Revenues from contracts with customers concern revenues from contracts that fall within the scope of IFRS 15. Revenues are recognized when the customer obtains control of goods or services promised in the contract, for the amount of consideration to which an entity expects to be entitled in exchange for said promised goods or services.

A contractual analysis of the Group's sale contracts has led to the application of the following revenue recognition principles.

- Gas, electricity and other energies**
 Revenues from sales of gas, electricity and other energies are recognized upon delivery of the power to the retail, business or industrial customer.
 Power deliveries are monitored in real time or on a deferred basis for those customers whose energy consumption is metered during the accounting period, in which case the portion of not yet metered revenues "in the meter" is estimated on the closing date.
- Gas, electrical and other energy infrastructures**
 Revenues derived by gas and electricity infrastructure operators upon providing transportation or distribution or storage capacities, are recognized on a straight-line basis over the contract term.
 In the countries where the Group acts as an energy provider (supplier) without being in charge of its distribution or transportation, mainly in France and Belgium, an analysis of the energy sales contracts and of the related regulatory frame is carried out to determine whether the distribution or transportation services invoiced to the customers have to be excluded from the revenue recognized under IFRS 15.
 Judgment may be exercised by the Group for this analysis in order to determine whether the energy provider acts as an agent or a principal for the gas or electricity distribution or transportation services re-invoiced to the customers. The main criteria used by the Group to exercise its judgment and conclude, in certain countries, that the energy provider acts as an agent of the infrastructure operator are: who is primarily responsible for fulfillment of the distribution or transportation services? Has the energy provider the ability to commit to capacity reservation contracts towards the infrastructure operator? To what extent does the energy provider have discretion in establishing the price for the distribution or transportation services?
- Constructions, installations, Operations and Maintenance (O&M), facility management (FM) and other services**
 Constructions and installations contracts mainly concern assets built on the premises of customers such as cogeneration units, heaters or other energy-efficiency assets. The related revenues are usually recognized according to the percentage of completion on the basis of the costs incurred.

O&M contracts generally require the Group to perform services ensuring the availability of assets generating energy. These services are performed over time and the related revenues are recognized according to the percentage of completion on the basis of the costs incurred.

FM generally involves managing and integrating a great number of different services, outsourced by the customers. The consideration due to FM suppliers can either be fixed or variable depending on the number of hours or on another indicator, irrespective of the nature of the services provided. Hence, the related revenues are recognized according to the percentage of completion on the basis of the costs incurred or of the number of hours performed.

The table below shows a breakdown of revenues by type of accounting principles:

<i>In millions of euros</i>	Sales of gas	Sales of electricity and other energies	Sales of services linked to infrastructures	Constructions, installations, O&M, FM and other services	Revenues from contracts with customers	Revenues from other contracts	Dec. 31, 2018
North America	592	1,858	-	900	3,350	33	3,383
Latin America	461	3,522	322	197	4,501	138	4,639
Africa/Asia	452	2,605	31	806	3,894	121	4,014
Benelux	1,341	2,143	14	3,038	6,537	153	6,690
France	3,164	4,040	105	7,675	14,983	200	15,183
Europe excluding France & Benelux	1,901	3,425	233	3,798	9,357	170	9,527
Infrastructures Europe	155	-	5,092	200	5,447	247	5,694
GEM	2,938	1,135	113	-	4,186	2,782	6,968
Others	1,113	1,925	167	927	4,133	365	4,498
TOTAL REVENUES	12,116	20,654	6,077	17,540	56,388	4,208	60,596

<i>In millions of euros</i>	Sales of gas	Sales of electricity and other energies	Sales of services linked to infrastructures	Constructions, installations, O&M, FM and other services	Revenues from contracts with customers	Revenues from other contracts	Dec. 31, 2017
North America	411	1,913	1	604	2,928	36	2,964
Latin America	399	3,477	279	144	4,300	83	4,383
Africa/Asia	455	2,405	53	695	3,608	332	3,939
Benelux	1,210	1,984	33	2,935	6,162	609	6,771
France	3,296	3,302	91	7,177	13,866	292	14,157
Europe excluding France & Benelux	1,756	3,044	303	3,377	8,480	351	8,831
Infrastructures Europe	227	-	4,668	269	5,165	281	5,446
GEM	2,375	1,450	176	3	4,003	3,635	7,638
Others	1,422	2,085	85	971	4,562	883	5,445
TOTAL REVENUES	11,551	19,659	5,688	16,176	53,073	6,503	59,576

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

8.1.2 Revenues from other contracts

Accounting standards

If it is not possible to conclude from the contractual analysis that the contract falls within the scope of IFRS 15, the revenues are then accounted for as non-IFRS 15 revenues.

Non-IFRS 15 revenues are presented on a separate line of the income statement. They include the following items:

- commodity sales transactions within the scope of IFRS 9 – *Financial Instruments* and give rise to a physical delivery;
- proprietary trading transactions and energy trading carried out on behalf of customers, shown on a net basis after netting sales and purchases;

- lease or concession income, as well as any financing component of operational services.

In 2018, commodities sales transactions within the scope of IFRS 9 and giving rise to physical deliveries amounted to €3,408 million (€5,712 million in 2017). Revenues generated on other transactions which are not in the scope of IFRS 15 were not material.

8.2 Trade and other receivables, assets and liabilities from contracts with customers

Accounting standards

On initial recognition, trade and other receivables are recorded at their transaction price as defined in IFRS 15.

A contract asset is an entity's right to consideration in exchange for goods or services that have been transferred to a customer but for which payment is not yet due or is contingent on the satisfaction of a specific condition stipulated in the contract. When an amount becomes due, it is transferred to receivables.

A receivable is recorded when the entity has an unconditional right to consideration. A right to consideration is unconditional if only the passage of time is required before payment of that consideration.

A contract liability is an entity's obligation to transfer goods or services to a customer for which the entity has already received consideration from the customer. The liability is derecognized upon recognition of the corresponding revenue.

Trade and other receivables and contract assets are tested for impairment in accordance with the provisions of IFRS 9 on expected credit losses.

The impairment model for financial assets is based on the expected credit loss model. To calculate expected losses, the Group uses a matrix approach for trade receivables and contract assets, for which the change in credit risk is monitored on a portfolio basis. An individual approach is used for large customers and other large counterparties, for which the change in credit risk is monitored on an individual basis.

See Note 18 "Risks arising from financial instruments" for the Group's assessment of counterparty risk.

8.2.1 Trade and other receivables, assets and from contracts with customers

En millions d'euros	Dec. 31, 2018			Dec. 31, 2017 ⁽¹⁾		
	Non-current	Current	Total	Non-current	Current	Total
Trade and other receivables, net	-	15,613	15,613	-	13,127	13,127
of which IFRS 15	-	7,552	7,552	-	7,009	7,009
of which non-IFRS15	-	8,060	8,060	-	6,118	6,118
Assets from contracts with customers	-	7,411	7,411	-	6,930	6,930

(1) Comparative data at December 31, 2017 and at January 1, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

The table below shows expected credit losses on trade and other receivables and contract assets:

In millions of euros	Dec. 31, 2018			Dec. 31, 2017 ⁽¹⁾		
	Gross	Allowances and expected credit losses	Net	Gross	Allowances and expected credit losses	Net
Trade and other receivables, net	16,689	(1,076)	15,613	14,208	(1,081)	13,127
Assets from contracts with customers	7,419	(8)	7,411	6,943	(12)	6,930
TOTAL	24,108	(1,085)	23,023	21,150	(1,094)	20,057

(1) Comparative data at December 31, 2017 and at January 1, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

Expected impairment and credit losses on trade and other receivables and contract assets amounted to €1,085 million in 2018 (€1,094 million in 2017).

Information on the age of receivables past due but not impaired and on counterparty risk are provided in Note 18.2 "Counterparty risk".

Current assets from contracts with customers include accrued income and unbilled revenues (for €6,377 million at December 31, 2018) and delivered, un-metered and unbilled gas and electricity ("energy in the meter") (for €1,034 million at December 31, 2018, mainly in France, Benelux and Latin America, representing 1.7% of annual revenues). The reportable segments that reported the greatest amounts of contract assets at December 31, 2018 are France (€2,730 million), Europe excluding France & Benelux (€1,436 million), Benelux (€859 million) and GEM (€556 million).

For customers whose energy consumption is metered during the accounting period, particularly customers supplied with low-voltage electricity or low-pressure gas, the gas supplied but not yet metered at the reporting date is estimated based on historical data, consumption statistics and estimated selling prices.

For sales on networks used by a large number of grid operators, the Group are allocated a certain volume of energy transiting through the networks by the grid managers. As the final allocations are sometimes only known several months down the line, revenue figures cannot be determined with absolute certainty. However, the Group has developed measuring and modeling tools allowing it to estimate revenues with a reasonable degree of accuracy and subsequently ensure that risks of error associated with estimating quantities sold and the related revenues can be considered as immaterial.

In France and Belgium, un-metered revenues ("gas in the meter") is calculated using a direct method taking into account customers' estimated consumption based on the last invoice or metering not yet billed. These estimates are in line with the volume of energy allocated by the grid managers over the same period. The average price is used to measure "gas in the meter" and takes account of the category of customer and the age of the delivered unbilled "gas in the meter". The portion of unbilled revenues at the reporting date varies according to the assumptions about volume and average price.

"Electricity in the meter" is also determined using a direct allocation method similar to that used for gas, but taking into account specific factors related to electricity consumption. It is also measured on a customer-by-customer basis or by customer type.

8.2.2 Liabilities from contracts with customers

In millions of euros	Dec. 31, 2018			Dec. 31, 2017 ⁽¹⁾		
	Non-current	Current	Total	Non-current	Current	Total
Liabilities from contracts with customers	36	3,598	3,634	258	3,317	3,575

(1) Comparative data at December 31, 2017 and at January 1, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

Current liabilities from contracts with customers include advances and downpayments received for €1,713 million at December 31, 2018 and deferred revenues for €1,885 million.

The segments reporting the greatest amounts of contract liabilities are France (€2,048 million) – particularly BtoB (€1,172 million) – Europe excluding France & Benelux (€626 million) and Benelux (€387 million). These are the segments for which revenues are recognized over time, thereby generating a difference in timing between the payments received and the completion of the services.

The classification of Glow in Thailand under "assets held for sale" reduced contract liabilities by €291 million.

8.3 Revenues relating to performance obligations not yet satisfied

Revenues relating to performance obligations only partially satisfied at December 31, 2018 amounted to €10,886 million.

They mainly concern the United Kingdom (€6,102 million) and France BtoB (€2,902 million) BUs. These BUs handle a large number of construction, installation, maintenance and facility management contracts under which revenues are recognized over time. The Benelux, Tractebel Engineering and NECST BUs will also be recognizing revenues over the next three years for performance obligations satisfied over time.

NOTE 9 OPERATING EXPENSES

9.1 Personnel costs

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Short-term benefits	(9,998)	(9,510)
Share-based payments (see Note 24)	(86)	(44)
Costs related to defined benefit plans (see Note 21.3.4)	(407)	(355)
Costs related to defined contribution plans (see Note 21.4)	(133)	(142)
PERSONNEL COSTS	(10,624)	(10,051)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

9.2 Depreciation, amortization and provisions

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Depreciation and amortization (see Notes 15 and 16)	(3,882)	(3,966)
Net change in write-downs of inventories, trade receivables and other assets	-	(67)
Net change in provisions (see Note 20)	296	245
DEPRECIATION, AMORTIZATION AND PROVISIONS	(3,586)	(3,787)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

At December 31, 2018, depreciation and amortization mainly break down as €837 million for intangible assets and €3 048 million for property, plant and equipment.

NOTE 10 FROM CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD TO INCOME/(LOSS) FROM OPERATING ACTIVITIES

Accounting standards

Current operating income is an indicator used by the Group to present “a level of operational performance that can be used as part of an approach to forecast recurring performance” (this complies with ANC Recommendation 2013-03 on the format of financial statements of entities applying IFRS). Current operating income is a sub-total which helps in better understanding the Group’s performance because it excludes items which are inherently difficult to predict due to their unusual, abnormal or non-recurring nature. For the Group, such items relate to mark-to-market on commodity contracts other than trading instruments, impairment losses, restructuring costs, scope effect transactions and other non-recurring items and are defined as follows:

- “Mark-to-market on commodity contracts other than trading instruments” corresponds to the changes in the fair value (mark-to-market) of financial instruments related to commodities, such as gas and electricity, which do not qualify as either trading or hedging instruments. These contracts are used in economic hedges of operating transactions in the energy sector. The changes in the fair value of these instruments have to be recognized through profit or loss under IFRS 9. Since they can be material and difficult to predict, they are presented on a separate line of the consolidated income statement;
- “Impairment losses” include impairment losses on goodwill, other intangible assets, property, plant and equipment and investments in entities consolidated using the equity method of accounting;
- “Restructuring costs” concern costs corresponding to a restructuring program planned and controlled by management that materially changes either the scope of a business undertaken by the entity, or the manner in which that business is conducted, based on the criteria set out in IAS 37;
- “Changes in the scope of consolidation”. This line includes:
 - direct costs related to acquisitions of controlling interests,
 - in a business combination achieved in stages, remeasurement at fair value at the acquisition date of the previously held interest,
 - subsequent changes in the fair value of contingent consideration,
 - gains or losses from disposals of investments which result in a change of consolidation method, as well as any impact from the remeasurement of retained interests with the exception of gains and losses arising from transactions realized in the framework of “*Develop, Build, Share & Operate*” (DBSO) or “*Develop, Share, Build & Operate*” (DSBO) business models. These transactions on renewable activities are recognized in the current operating income as they are part of the recurring rotation of the Group’s capital employed;
- “Other non-recurring items” notably include gains and losses on disposals of non-current assets.

NOTE 10 FROM CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD TO INCOME/(LOSS) FROM OPERATING ACTIVITIES

The transition from Current operating income after share in net income of entities accounted for using the equity method to Income/(loss) from operating activities is detailed hereunder:

In millions of euros	Dec. 31, 2018	Dec. 31, 2017 ⁽¹⁾
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	5,126	5,172
Mark-to-market on commodity contracts other than trading instruments	(223)	29
Impairment losses	(1,798)	(1,298)
Restructuring costs	(162)	(669)
Changes in scope of consolidation	(150)	752
Other non-recurring items	(147)	(1,252)
INCOME/(LOSS) FROM OPERATING ACTIVITIES	2,645	2,735

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

10.1 Mark-to-market on commodity contracts other than trading instruments

In 2018, this item represents a net expense of €223 million, compared with net income of €29 million in 2017. It mainly reflects the changes in the fair value of (i) electricity and natural gas sale and purchase contracts falling within the scope of IFRS 9 and (ii) financial instruments used as economic hedges but not eligible for hedge accounting.

This expense is due to (i) a negative price effect related to changes in the forward prices of the underlying commodities, notably in gas, coupled with (ii) the negative impact of the settlement of positions over the period with a positive fair value at December 31, 2017.

10.2 Impairment losses

In millions of euros	Dec. 31, 2018	Dec. 31, 2017 ⁽¹⁾
Impairment losses:		
Goodwill (see Note 14.1)	(14)	(481)
Property, plant and equipment and other intangible assets (see Notes 15 and 16)	(1,609)	(952)
Investments in entities accounted for using the equity method and related provisions	(209)	(31)
TOTAL IMPAIRMENT LOSSES	(1,831)	(1,463)
Reversal of impairment losses:		
Property, plant and equipment and other intangible assets	33	165
Financial assets	-	1
TOTAL REVERSALS OF IMPAIRMENT LOSSES	33	166
TOTAL	(1,798)	(1,298)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

Net impairment losses amounted to €1,798 million in 2018 and related primarily to property, plant and equipment. After taking into account the deferred tax effects and the share of impairment losses attributable to non-controlling interests, the impact of these impairment losses on net income Group share for 2018 amounted to €1,540 million.

Impairment tests are performed in accordance with the conditions described in Note 14.3.

10.2.1 Impairment losses recognized in 2018

Net impairment losses amounted to €1,798 million in 2018 and mainly concerned:

- **Generation Europe CGU assets**

In 2018, the Group recognized €646 million in net impairment losses against thermal power generation assets in Europe, owing to the downward revision of cash flow projections for certain portfolio assets in an unfavorable

economic environment. The main assumptions and key estimates used to determine the value of assets are discount rates, estimated demand for electricity and changes in the price of CO₂, fuel and electricity beyond the liquidity period, in addition to the regulatory environment and the operating life of the assets concerned.

Coal-fired power plants in Europe have been subject to unfavorable conditions, including the expected impact of the stricter regulatory environment, which has resulted in lower captured margins over the long term, impacting the profitability of these assets.

- **Belgian nuclear power assets**

Further developments in 2018 led the Group to now distinguish nuclear power plants where there is no longer any possibility of extending their operating life from those whose operating life may still be extended beyond 2025. In view of this backdrop accentuated by the prolonged outages at certain power plants and the changes to the management methods of the plants as the end of their operating lives draws near, the Group has aligned its forecasts with the nuclear plants' maintenance schedule, as updated for the next three years. Consequently, the Group recognized impairment losses of €615 million in 2018 against plants whose operating life may no longer be extended.

- **Other impairment losses**

Other impairment losses recognized by the Group mainly concern:

- an investment in the Africa/Asia segment in respect of which an impairment loss of €209 million was recognized based on the revised forecasts;
- gas infrastructure facilities in Europe, in respect of which an €87 million impairment loss was recognized after the life expectancy of certain facilities was revised and their dismantling date consequently brought forward;
- thermal power generation assets in Latin America, in respect of which a €71 million impairment loss was recognized after their operating lives were revised.

10.2.2 Impairment losses recognized in 2017

Net impairment losses amounted to €1,298 million in 2017, and mainly concerned:

- the Storengy CGU for €494 million, including €338 million against goodwill following the regulation of storage activities in France;
- thermal power generation assets in Europe for €317 million, mainly due to the expected impact of a stricter regulatory environment for coal-fired power plants.

After taking into account the deferred tax effects and the share of impairment losses attributable to non-controlling interests, the impact of these impairment losses on net income Group share for 2017 amounted to €1,129 million.

10.3 Restructuring costs

Restructuring costs totaled €162 million in 2018, mainly including:

- costs related to various staff reduction plans (€54 million);
- costs related to decisions to relinquish several premises, restructure agencies and close facilities (€63 million);
- various other restructuring costs (€45 million).

In 2017, restructuring costs totaled €669 million, including €509 million related to staff reduction plans as part of the Group's transformation plan as well as measures to adapt to economic conditions, €108 million related to the shutdown of production and closure of some facilities and €53 million in other miscellaneous restructuring costs.

10.4 Changes in scope of consolidation

The impact of changes in the scope of consolidation in 2018 was a negative €150 million and mainly comprised (i) the €87 million negative impact of the sale of the Loy Yang B thermal power plant in Australia, primarily in respect of items of other comprehensive income recycled to the income statement, and (ii) the €27 million negative impact of the sale of LNG operations in the United States.

The impact of changes in the scope of consolidation in 2017 was a positive €752 million, and mainly comprised gains on the disposal of (i) the thermal merchant power plant portfolio in the United States for €540 million, (ii) the Group's interest in NuGen for €93 million, (iii) a thermal power plant portfolio in the United Kingdom for €61 million, and (iv) the Polaniec power plant in Poland for €57 million.

10.5 Other non-recurring items

Other non-recurring items totaling a negative €147 million in 2018, mainly included asset scrapping, costs related to site closures and other miscellaneous costs.

In 2017, other non-recurring items mainly included the €1,243 million expense corresponding to the change in the accounting treatment of long-term gas supply contracts and transport and storage contracts implemented by the GEM BU.

NOTE 11 NET FINANCIAL INCOME/(LOSS)

In millions of euros	Dec. 31, 2018			Dec. 31, 2017 ⁽¹⁾		
	Expense	Income	Total	Expense	Income	Total
Cost of net debt	(713)	85	(628)	(812)	134	(678)
Gains and losses on debt restructuring transactions and from the early unwinding of derivative financial instruments	(108)	115	7	(181)	83	(98)
Other financial income and expenses	(1,161)	400	(761)	(1,134)	522	(611)
NET FINANCIAL INCOME/(LOSS)	(1,981)	600	(1,381)	(2,127)	739	(1,388)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

11.1 Cost of net debt

The main items of the cost of net debt break down as follows:

In millions of euros	Expense	Income	Total	
			Dec. 31, 2018	Dec. 31, 2017 ⁽¹⁾
Interest expense on gross debt and hedges	(844)	-	(844)	(915)
Foreign exchange gains/losses on borrowings and hedges	-	4	4	21
Ineffective portion of derivatives qualified as fair value hedges	(3)	-	(3)	(2)
Gains and losses on cash and cash equivalents and liquid debt instruments held for cash investment purposes	-	81	81	113
Capitalized borrowing costs	134	-	134	104
COST OF NET DEBT	(713)	85	(628)	(678)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

The decrease in the cost of net debt is mainly due to a slight reduction in the volume of average debt since the end of 2017, to the positive impacts of debt financing transactions realized by the Group and to active interest-rate management (see Note 17.3.3 "Financial instruments – Main events of the period").

At December 31, 2018, the average cost of debt after hedging came out at 2.68% compared with 2.63% at December 31, 2017.

11.2 Gains and losses on debt restructuring transactions and from the early unwinding of derivative financial instruments

The main effects of debt restructuring break down as follows:

In millions of euros	Expense	Income	Dec. 31, 2018	Dec. 31, 2017 ⁽¹⁾
Impact of early unwinding of derivative financial instruments on the income statement	(108)	102	(6)	-
Of which cash payments made on the unwinding of swaps	(108)	-	(108)	(83)
Of which reversal of the negative fair value of these derivatives that were settled early	-	102	102	83
Impact of debt restructuring transactions on the income statement	-	13	13	(98)
Of which early refinancing transactions expenses	-	13	13	(98)
GAINS AND LOSSES ON DEBT RESTRUCTURING TRANSACTIONS AND THE EARLY UNWINDING OF DERIVATIVE FINANCIAL INSTRUMENTS	(108)	115	7	(98)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

The Group carried out a number of early refinancing transactions (see Note 17.3.3. "Financial instruments – Main events of the period").

11.3 Other financial income and expenses

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Other financial expenses		
Income/(loss) from debt instruments and equity instruments	(84)	(12)
Change in fair value of derivatives not qualified as hedges	(183)	(187)
Gains and losses on the designation and inefficiency of economic hedges on other financial items	(2)	(1)
Unwinding of discounting adjustments to other long-term provisions	(538)	(493)
Net interest expense on post-employment benefits and other long-term benefits	(112)	(118)
Interest on trade and other payables	(39)	(48)
Other financial expenses	(203)	(275)
TOTAL	(1,161)	(1,134)
Other financial income		
Income/(loss) from debt instruments and equity instruments	73	77
Interest income on trade and other receivables	52	29
Interest income on loans and receivables at amortized cost	111	151
Other financial income	164	265
TOTAL	400	522
OTHER FINANCIAL INCOME AND EXPENSES, NET	(761)	(611)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

At December 31, 2017, "Other financial income" notably included interest relating to the recovery from the French State of the 3% tax on dividends as well as interest relating to the dispute opposing Electrabel and E.ON in respect of the Belgian and German nuclear contribution payments for an amount of €87 million.

NOTE 12 INCOME TAX EXPENSE

Accounting standards

The Group calculates taxes in accordance with prevailing tax legislation in the countries where income is taxable.

In accordance with IAS 12, deferred taxes are recognized according to the liability method on temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and their tax bases, using tax rates that have been enacted or substantively enacted by the reporting date. However, under the provisions of IAS 12, no deferred tax is recognized for temporary differences arising from goodwill for which impairment losses are not deductible for tax purposes, or from the initial recognition of an asset or liability in a transaction which (i) is not a business combination and (ii) at the time of the transaction, affects neither accounting income nor taxable income. In addition, deferred tax assets are only recognized to the extent that it is probable that taxable income will be available against which the deductible temporary differences can be utilized.

A deferred tax liability is recognized for all taxable temporary differences associated with investments in subsidiaries, associates, joint ventures and branches, except if the Group is able to control the timing of the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

Net balances of deferred taxes are calculated based on the tax position of each company or on the total income of companies included within the relevant consolidated tax group, and are presented in assets or liabilities for their net amount per tax entity.

Deferred taxes are reviewed at each reporting date to take into account factors including the impact of changes in tax laws and the prospects of recovering deferred tax assets arising from deductible temporary differences.

Deferred tax assets and liabilities are not discounted.

Tax effects relating to coupon payments on deeply-subordinated perpetual notes are recognized in profit or loss.

12.1 Actual income tax expense recognized in the income statement

12.1.1 Breakdown of actual income tax expense recognized in the income statement

The tax expense recognized in the income statement for 2018 amounts to €704 million (€395 million income tax income in 2017). It breaks down as follows:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Current income taxes	(712)	(367)
Deferred taxes	9	761
TOTAL INCOME TAX BENEFIT/(EXPENSE) RECOGNIZED IN INCOME	(704)	395

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

12.1.2 Reconciliation of theoretical income tax expense with actual income tax expense

A reconciliation of theoretical income tax expense with the Group's actual income tax expense is presented below:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Net income/(loss)	1,629	2,108
Share in net income of entities accounted for using the equity method	361	422
Net income from discontinued operations	1,069	366
Income tax expense	(704)	395
Income/(loss) before income tax expense and share in net income of associates (A)	903	925
Of which French companies	1,434	(744)
Of which companies outside France	(531)	1,669
Statutory income tax rate of the parent company (B)	34.4%	34.4%
THEORETICAL INCOME TAX EXPENSE (C) = (A) X (B)	(311)	(318)
Reconciling items between theoretical and actual income tax expense		
Difference between statutory tax rate applicable to the parent and statutory tax rate in force in jurisdictions in France and abroad	42	112
Permanent differences ⁽²⁾	(72)	(287)
Income taxed at a reduced rate or tax-exempt ⁽³⁾	123	460
Additional tax expense ⁽⁴⁾	(74)	(241)
Effect of unrecognized deferred tax assets on tax loss carry-forwards and other tax-deductible temporary differences ⁽⁵⁾	(968)	(564)
Recognition or utilization of tax income on previously unrecognized tax loss carry-forwards and other tax-deductible temporary differences ⁽⁶⁾	370	241
Impact of changes in tax rates ⁽⁷⁾	54	518
Tax credits and other tax reductions ⁽⁸⁾	185	506
Other ⁽⁹⁾	(53)	(32)
INCOME TAX BENEFIT/(EXPENSE) RECOGNIZED IN INCOME	(704)	395

- (1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").
- (2) Includes mainly the disallowable impairment losses on goodwill, the disallowable operating expenses, the deduction of interest expenses arising from hybrid debts and effects relating to the cap on allowable interest on borrowings in France.
- (3) Reflects notably capital gains on disposals of securities exempt from tax or taxed at a reduced rate in some tax jurisdictions, the impact of the specific tax regimes used by some entities, the disallowable impairment losses and capital losses on securities, and the impact of the untaxed income from remeasuring previously-held (or retained) equity interests in connection with acquisitions and changes in consolidation methods.
- (4) Includes mainly tax on dividends resulting from the parent company tax regime, the exceptional income tax to compensate the reimbursement from the French State of the 3% tax on the dividends in 2017, the withholding tax on dividends and interest levied in several tax jurisdictions, allocations to provisions for income tax, and regional and flat-rate corporate taxes.
- (5) Includes (i) the cancellation of the net deferred tax asset position for some tax entities in the absence of sufficient profit being forecast and (ii) the impact of disallowable impairment losses on the assets.
- (6) Includes the impact of the recognition of net deferred tax asset positions for some tax entities.
- (7) Includes mainly the impact of tax rate changes on the deferred tax balances in France (see below) and in the United States in 2017.
- (8) Includes notably the reversals of provisions for tax litigation, tax credits in France and other tax reductions and the impact of deductible notional interest in Belgium. In 2017, includes the refund of €376 million relating to the 3% tax on dividends paid previously in cash by the French companies.
- (9) Includes mainly the correction of previous tax charges.

The 2018 French Finance Law approved on December 30, 2017 plans a tax rate decrease to 25.82% as of 2022 for all French tax entities (tax rate of 25.00%, plus the 3.3% social contribution). Deferred tax recorded by the French entities which is expected to reverse after 2022 was re-measured at this new rate in the December 31, 2017 accounts. This resulted in a positive impact of €550 million on non-recurring income and a negative impact of €91 million on deferred tax recognized in the statement of comprehensive income. However, the deferred tax balances, which expire in 2019, have been maintained at the 32.02% rate, without taking into consideration the fact that the 34.43% rate will be maintained for 2019, as already announced but not yet approved by Parliament at December 31, 2018.

12.1.3 Analysis of the deferred tax income/(expense) recognized in the income statement, by type of temporary difference

In millions of euros	Impact in the income statement	
	Dec. 31, 2018	Dec. 31, 2017 (1)
Deferred tax assets:		
Tax loss carry-forwards and tax credits	302	(118)
Pension and related obligations	2	(68)
Non-deductible provisions	(77)	(25)
Difference between the carrying amount of PP&E and intangible assets and their tax bases	(141)	(240)
Measurement of financial instruments at fair value (IAS 32/IFRS 9)	845	(288)
Other	38	(72)
TOTAL	969	(811)
Deferred tax liabilities:		
Difference between the carrying amount of PP&E and intangible assets and their tax bases	(249)	671
Measurement of financial instruments at fair value (IAS 32/IFRS 9)	(751)	741
Other	116	125
TOTAL	(884)	1,537
DEFERRED TAX INCOME/(EXPENSE)	85	726
Of which continued activities	9	761

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

The deferred tax income recorded in 2017 derives notably from the future tax rate decrease approved in France.

12.2 Deferred tax income/(expense) recognized in "Other comprehensive income"

Net deferred tax income/(expense) recognized in "Other comprehensive income" is broken down by component as follows:

In millions of euros	Dec. 31, 2018	Dec. 31, 2017 (1)
Equity and debt instruments	(1)	37
Actuarial gains and losses	68	(95)
Net investment hedges	(14)	(86)
Cash flow hedges on other items	71	(116)
Cash flow hedges on net debt	(10)	2
TOTAL EXCLUDING SHARE OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	114	(257)
Share of entities accounted for using the equity method	(20)	3
Discontinued operations	(81)	(81)
TOTAL	13	(336)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

12.3 Deferred taxes presented in the statement of financial position

12.3.1 Change in deferred taxes

Changes in deferred taxes recognized in the statement of financial position, after netting deferred tax assets and liabilities by tax entity, break down as follows:

<i>In millions of euros</i>	Assets	Liabilities	Net position
At December 31, 2017⁽¹⁾	854	(5,215)	(4,361)
Impact on net income for the year	969	(884)	85
Impact on other comprehensive income items	127	(128)	(1)
Impact of changes in scope of consolidation	(207)	199	(9)
Impact of translation adjustments	(3)	(24)	(27)
Transfers to assets and liabilities classified as held for sale	(222)	161	(60)
Other	28	(4)	24
Impact of netting by tax entity	(481)	481	-
AT DECEMBER 31, 2018	1,066	(5,415)	(4,349)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

12.3.2 Analysis of the net deferred tax position recognized in the statement of financial position (before netting deferred tax assets and liabilities by tax entity), by type of temporary difference

Accounting standards

Measurement of recognized tax loss carry-forwards

Deferred tax assets are recognized on tax loss carry-forwards when it is probable that taxable profit will be available against which the tax loss carry-forwards can be utilized. The probability that taxable profit will be available against which the unused tax losses can be utilized, is based on taxable temporary differences relating to the same taxation authority and the same taxable entity and estimates of future taxable profits. These estimates and utilizations of tax loss carry-forwards were prepared on the basis of profit and loss forecasts over a six-year tax projection period as included in the medium-term business plan validated by the Management, unless exception justified by a particular context and, if necessary, on the basis of additional forecasts.

<i>In millions of euros</i>	Statement of financial position at	
	Dec. 31, 2018	Dec. 31, 2017 ⁽¹⁾
Deferred tax assets:		
Tax loss carry-forwards and tax credits	1,765	1,652
Pension obligations	1,374	1,318
Non-deductible provisions	371	312
Difference between the carrying amount of PP&E and intangible assets and their tax bases	787	974
Measurement of financial instruments at fair value (IAS 32/IFRS 9)	3,398	2,736
Other	545	555
TOTAL	8,239	7,547
Deferred tax liabilities:		
Difference between the carrying amount of PP&E and intangible assets and their tax bases	(8,773)	(8,657)
Measurement of financial instruments at fair value (IAS 32/IFRS 9)	(3,343)	(2,629)
Other	(472)	(623)
TOTAL	(12,588)	(11,908)
NET DEFERRED TAX ASSETS/(LIABILITIES)	(4,349)	(4,361)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

12.4 Unrecognized deferred taxes

At December 31, 2018, the tax effect of tax losses and tax credits eligible for carry-forward but not utilized and not recognized in the statement of financial position amounted to €3,216 million (€3,144 million at December 31, 2017). Most of these unrecognized tax losses relate to companies based in countries which allow losses to be carried forward indefinitely (mainly Belgium and Luxembourg) or up to nine years in the Netherlands. These tax loss carry-forwards did not give rise to the recognition of deferred tax due to the absence of sufficient profit forecasts in the medium term.

The tax effect of other tax-deductible temporary differences not recorded in the statement of financial position was €1,364 million at end-December 2018 versus €1,246 million at end-December 2017.

NOTE 13 EARNINGS PER SHARE

Accounting standards

Basic earnings per share is calculated by dividing net income Group share for the year by the weighted average number of ordinary shares outstanding during the year. The average number of ordinary shares outstanding during the year is the number of ordinary shares outstanding at the beginning of the year, adjusted by the number of ordinary shares bought back or issued during the year.

For diluted earnings per share calculation, the weighted average number of shares and basic earnings per share are adjusted to take into account the impact of the conversion or exercise of any dilutive potential ordinary shares (options, warrants and convertible bonds, etc.).

	Dec. 31, 2018	Dec. 31, 2017 ⁽¹⁾
Numerator (in millions of euros)		
Net income/(loss) Group share	1,033	1,320
<i>Of which Net income/(loss) relating to continued activities, Group share</i>	<i>(12)</i>	<i>1,047</i>
Interest from deeply-subordinated perpetual notes	(145)	(144)
Net income used to calculate earnings per share	889	1,176
<i>Of which Net income/(loss) relating to continued activities, Group share, used to calculate earnings per share</i>	<i>(156)</i>	<i>903</i>
Impact of dilutive instruments	-	-
Diluted net income/(loss) Group share	889	1,176
Denominator (in millions of shares)		
Average number of outstanding shares	2,396	2,396
Impact of dilutive instruments:		
Bonus share plans reserved for employees	11	9
Diluted average number of outstanding shares	2,407	2,405
Earnings per share (in euros)		
Basic earnings/(loss) per share	0.37	0.49
<i>Of which Basic earnings/(loss) Group share relating to continued activities per share</i>	<i>(0.07)</i>	<i>0.38</i>
Diluted earnings/(loss) per share	0.37	0.49
<i>Of which Diluted earnings/(loss) Group share relating to continued activities per share</i>	<i>(0.06)</i>	<i>0.38</i>

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

In compliance with IAS 33 – *Earnings per Share*, earnings per share and diluted earnings per share are based on net income/(loss) Group share after deduction of payments to bearers of deeply-subordinated perpetual notes (see Note 19.2.1).

The Group's dilutive instruments included in the calculation of diluted earnings per share include bonus shares and performance shares granted in the form of ENGIE securities.

NOTE 14 GOODWILL

Accounting standards

Recognition of goodwill

Goodwill is measured as the excess of the aggregate of:

- (i) the consideration transferred;
- (ii) the amount of any non-controlling interests in the acquiree; and
- (iii) in a business combination achieved in stages, the acquisition-date fair value of the previously held equity interest in the acquiree;

over the net acquisition-date fair value of the identifiable assets acquired and liabilities assumed. The key assumptions and estimates used to determine the fair value of assets acquired and liabilities assumed include the market outlook for the measurement of future cash flows as well as applicable discount rates. These assumptions reflect management's best estimates.

The amount of goodwill recognized at the acquisition date cannot be adjusted after the end of the measurement period.

Goodwill relating to interests in associates is recorded under "Investments in entities accounted for using the equity method".

Risk of impairment

Goodwill is not amortized but tested for impairment each year in accordance with IAS 36, or more frequently where an indication of impairment is identified. Impairment tests are carried out at the level of cash-generating units (CGUs) or groups of CGUs which constitute groups of assets which generate cash flows that are largely independent from cash flows generated by other CGUs.

The method used to carry out these impairment tests are described in paragraph 14.3.

Impairment losses in relation to goodwill cannot be reversed and are shown as "Impairment losses" in the income statement.

Indicators of impairment (goodwill, intangible assets and property plant and equipment)

The main indicators of impairment used by the Group are:

- Using external sources of information
 - A decline in an asset's value over the period that is significantly more than would be expected from the passage of time or normal use;
 - Significant adverse changes that have taken place over the period, or will take place in the near future, in the technological market, economic or legal environment in which the entity operates or in the market to which an asset is dedicated;
 - An increase over the period in market interest rates or other market rates of return on investments if such increase is likely to affect the discount rate used in calculating an asset's value in use and decrease its recoverable amount materially;
 - The carrying amount of the net assets of the entity exceeds its market capitalization;
- Using internal sources of information
 - Evidence of obsolescence or physical damage to an asset
 - Significant changes in the extent to which, or manner in which, an asset is used or is expected to be used, that have taken place in the period or soon hereafter and that will have an adverse effect on it. These

changes include the asset becoming idle, plans to dispose of an asset sooner than expected, reassessing its useful life as finite rather than indefinite or plans to restructure the operations for which the asset belong;

- Internal reports that indicate that the economic performance of an asset is, or will be, worse than expected.

14.1 Movements in the carrying amount of goodwill

<i>In millions of euros</i>	Net amount
At December 31, 2016	17,372
Impairment losses	(481)
Changes in scope of consolidation and Other	775
Transfer to Assets classified as held for sale	(32)
Translation adjustments	(350)
At December 31, 2017⁽¹⁾	17,285
Impairment losses	(14)
Changes in scope of consolidation and Other	745
Transfer to Assets classified as held for sale	(216)
Translation adjustments	9
AT DECEMBER 31, 2018	17,809

(1) Comparative data at December 31, 2017 and at January 1, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

The impact of changes in the scope of consolidation at December 31, 2018 relates primarily to:

- the recognition of goodwill arising on the acquisition of Langa Group (€241 million), Infinity Renewables (€94 million) and Electro Power System (€57 million);
- the derecognition of goodwill in an amount of €109 million relating to the disposal of wind and solar fields in France (negative impact of €71 million), and gas distribution activities in Hungary (negative impact of €29 million).

Following the classification of the Company's interest in Glow, the electricity production project in Thailand, as assets held for sale (see Note 5.2 "Assets held for sale and discontinued operations"), the carrying amount of the corresponding goodwill was transferred to "Assets classified as held for sale" in the statement of financial position.

The decrease in this caption in 2017 related chiefly to the recognition of impairment losses against goodwill totaling €481 million, including €338 million against the Storengy CGU and €141 million allocated to the group of assets held for sale which comprises the Loy Yang B power plant, the derecognition of goodwill relating to assets sold for €127 million, translation adjustments for €350 million, offset by the recognition of goodwill arising on the acquisitions for €674 million and the increase in the fair value of the financial liability representing the put option granted by the Group on non-controlling interests in La Compagnie du Vent, with a matching entry of €131 million in goodwill.

14.2 Goodwill CGUs

The table below shows “material” goodwill CGUs at December 31, 2018:

<i>In millions of euros</i>	Operating segment	Dec. 31, 2018
MATERIAL CGUs		
Benelux	Benelux	4,258
GRDF	Infrastructures Europe	4,009
France Renewable Energy	France	1,085
United Kingdom	Europe excl. France & Benelux	1,045
France BtoC	France	1,044
OTHER SIGNIFICANT CGUs		
North America	North America	875
France BtoB	France	731
Northern, Southern and Central Europe	Europe excl. France & Benelux	644
Generation Europe	Other	629
OTHER CGUs		3,490
TOTAL		17,809

14.3 Impairment testing of goodwill CGUs

All goodwill CGUs are tested for impairment based on data as of end-June, completed by a review of events arisen in the second half of the year. In most cases, the recoverable amount of CGUs is determined by reference to a value in use that is calculated using cash flow projections drawn up on the basis of the 2019 budget and the 2020-2021 medium-term business plan, as approved by the Executive Committee and the Board of Directors, and on extrapolated cash flows beyond that time frame.

Cash flow projections are determined on the basis of macroeconomic assumptions (inflation, exchange rates and growth rates) and price forecasts resulting from the Group's reference scenario for 2022-2040. The forecasts that feature in the reference scenario were approved by the Executive Committee in December 2018. The forecasts and projections included in the reference scenario were determined on the basis of the following inputs:

- forward market prices over the liquidity period for fuel (coal, oil and gas), CO₂ and electricity on each market;
- beyond this period, medium- and long-term energy prices were determined by the Group based on macroeconomic assumptions and fundamental supply and demand equilibrium models, the results of which are regularly compared against forecasts prepared by external energy sector specialists. Long-term projections for CO₂ prices are those presented in the “Canfin, Grandjean et Mestrallet” report published in July 2016. More specifically, medium- and long-term electricity prices were determined by the Group using electricity demand forecasting models, medium- and long-term forecasts of fuel and CO₂ prices, and expected trends in installed capacity and in the technology mix of the production assets within each power generation system.

The discount rates used correspond to the weighted average cost of capital, which is adjusted in order to reflect the business, market, country and currency risk relating to each goodwill CGU reviewed. The discount rates used are consistent with available external information sources. The post-tax rates used in 2018 to measure the value in use of the goodwill CGUs for discounting future cash flows ranged between 3.7% and 11.3%, compared with a range of between 4.7% and 12.5% in 2017. The discount rates used for the main goodwill CGUs are shown in Notes 14.3.1 “Material CGUs” and 14.3.2 “Other significant CGUs”, below.

14.3.1 Material CGUs

This section presents the method for determining value in use, the key assumptions underlying the valuation, and the sensitivity analyses for the impairment tests on CGUs where the amount of goodwill represents more than 5% of the Group's total goodwill at December 31, 2018.

14.3.1.1 Benelux CGU

The goodwill allocated to the Benelux CGU amounted to €4,258 million at December 31, 2018. The Benelux CGU includes the Group's activities in Belgium, the Netherlands and Luxembourg: (i) power generation activities using its nuclear power plants and wind farms, (ii) natural gas and electricity sales activities, and (iii) energy services activities, as well as drawing rights on the Chooz B and Tricastin power plants in France.

Key assumptions used for the impairment test

The cash flow projections for the Benelux CGU are based on a large number of key assumptions, such as the long-term prices for fuel and CO₂, expected trends in gas and electricity demand and in electricity prices, the market outlook, and changes in the regulatory environment (especially concerning nuclear capacities in Belgium and the extension of drawing rights agreements for French nuclear plants). The key assumptions also include the discount rate used to calculate the value in use of this goodwill CGU.

The 2018 value in use of the activities included in this CGU was calculated using the cash flow projections drawn up on the basis of the 2019 budget and the 2020-2021 medium-term business plan. Cash flow projections for the period beyond the medium-term business plan were determined as described below:

Activities	Assumptions applied beyond the term of the business plan ⁽¹⁾
Nuclear power generation in Belgium	For Doel 1, Doel 2 and Tihange 1, cash flow projection over the residual useful life of 50 years. For the second generation reactors Doel 3 and Tihange 2, cash flow projection over the residual useful life of 40 years. For the second generation reactors Doel 4 and Tihange 3, extension of the operating life for a period of 20 years.
Drawing rights on Chooz B et Tricastin power plants	Cash flow projection over the remaining term of existing contract plus assumption that drawing rights will be extended for a further 10 years.
Energy retail and service activities	Cash flow projection over the duration of the business plan at mid term, plus application of a terminal value based on a normative cash flow using a long-term growth rate of 1.9%

(1) Assumptions unchanged from December 31, 2017.

The discount rates applied to these cash flows ranged from 5.8% to 8.5%, depending on the risk profiles of each business activity.

The most important assumptions concerning the Belgian regulatory environment relate to the operating life of existing nuclear reactors and the level of royalties and nuclear contributions paid to the Belgian State.

The impairment test took into account the 10-year extension (through 2025) of the operating life of Tihange 1, Doel 1 and Doel 2, as well as the capital expenditure required for the extension of Doel 1 and Doel 2, annual royalties totaling €20 million in respect of said extension and the new conditions for determining the nuclear contribution that will apply to second-generation reactors (Doel 3 and 4, Tihange 2 and 3) through their 40th year of operation, as defined in the December 29, 2016 law.

As regards second-generation reactors, the principle of a gradual phase-out of nuclear power and the schedule for this phase-out, with the shutdown of the reactors Doel 3 in 2022, Tihange 2 in 2023 and Tihange 3 and Doel 4 in 2025, after 40 years of operation, were reaffirmed in the law of June 18, 2015 and by the energy pact approved by the government on March 30, 2018. The pact is supplemented by a federal energy strategy based on four objectives: the safeguarding of supplies, the impact on climate, the impact on energy prices, and the safety of power plants. A monitoring committee has been set up and will meet each year to evaluate the achievement of these objectives and, where applicable, make recommendations to policymakers so that corrective action may be taken.

However, in view of (i) the extension of the operating life of Tihange 1, Doel 1 and Doel 2 beyond 40 years, (ii) the importance of nuclear power generation in the Belgian energy mix, (iii) the lack of a sufficiently detailed and attractive industrial plan enticing energy utilities to invest in replacement thermal capacity, and (iv) CO₂ emissions reduction targets, the Group considers that nuclear power will still be needed to guarantee the energy equilibrium in Belgium after 2025. Accordingly, in calculating value in use, the Group assumes a 20-year extension of the operating life of half of its second generation reactors, while taking into account a mechanism of nuclear contributions to be paid to the Belgian government. Should the circumstances described above change in the future, the Group may adapt its industrial scenarios accordingly.

In France, the Group included an assumption that its drawing rights on the Tricastin and Chooz B nuclear plants expiring in 2021 and 2037, respectively, would be extended by 10 years. Although no such decision has been taken by the government and the nuclear safety authority, the Group considers that extending the reactors' operating life is the most credible and likely scenario at this point in time. This is also consistent with the expected French energy mix featured in the Group's reference scenario.

Results of the impairment test

At December 31, 2018, the recoverable amount of the goodwill CGU was higher than its carrying amount. Furthermore, the Group recognized impairment losses of €615 million against nuclear reactors (see Note 10.2 "Impairment losses").

Sensitivity analyses

A decrease of €10/MWh in electricity prices for nuclear power generation would lead to an additional impairment loss of around €1,200 million. Conversely, an increase of €10/MWh in electricity prices would have a positive impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU.

An increase of 50 basis points in the discount rates used would have a negative 49% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 53% impact on the calculation.

Various transformational scenarios were considered concerning nuclear power generation in Belgium:

- the disappearance of the entire nuclear component from the portfolio in 2025 after 50 years of operation in the case of Tihange 1, Doel 1 and Doel 2, and 40 years of operation for the second-generation reactors would have a strongly adverse impact on the results of the test, with the recoverable amount falling significantly below the carrying amount. In this scenario, the impairment risk would represent around €1,700 million;
- if the life of half of the second-generation reactors were to be extended by ten years and the entire nuclear component subsequently disappear, the recoverable amount would fall below the carrying amount and the impairment risk would represent €547 million.

14.3.1.2 GRDF CGU

The total amount of goodwill allocated to the GRDF CGU was €4,009 million at December 31, 2018. The GRDF CGU groups together the Group's regulated natural gas distribution activities in France.

The value in use of the GRDF CGU was calculated using the cash flow projections drawn up on the basis of the 2019 budget, the 2020-2021 medium-term business plan, and cash flow projections for the 2022-2024 period. The terminal value corresponds to the expected Regulated Asset Base (RAB) with no premium at the end of 2024. The RAB is the value assigned by the French Energy Regulation Commission (CRE) to the assets operated by the distributor. It is the sum of the future pre-tax cash flows, discounted at a rate that equals the pre-tax rate of return guaranteed by the regulator.

The cash flow projections are drawn up based on the tariff for public natural gas distribution networks, known as the "ATRD 5 tariff", which entered into effect for a period of four years on July 1, 2016, and on the overall level of investments agreed by the CRE as part of its decision on the ATRD 5 tariff.

Given the regulated nature of the businesses grouped within the GRDF CGU, a reasonable change in any of the valuation inputs would not result in the recoverable amount falling below the carrying amount.

14.3.1.3 France Renewable Energy CGU

The goodwill allocated to the France Renewable Energy CGU amounted to €1,085 million at December 31, 2018. The France Renewable Energy CGU groups together the development, construction, financing, operation and maintenance of all of the renewable power generation assets in France (hydraulic, wind and photovoltaic).

The value in use of these activities was calculated using the cash flow projections drawn up on the basis of the 2019 budget and the 2020-2021 medium-term business plan. For the hydraulics business, a terminal value was calculated by extrapolating the cash flows beyond that period based on the reference scenario adopted by the Group.

The main assumptions and key estimates relate primarily to discount rates, assumptions on the renewal of the hydropower concession agreements and changes in the sales prices of electricity beyond the liquidity period.

The discount rates applied are between 5.1% and 8.3%, depending on whether they relate to regulated assets or merchant activities.

Value in use of the Compagnie Nationale du Rhône and SHEMA was calculated based on assumptions including the extension or renewal of a tender process for the concession agreements, as well as on the conditions of a potential extension.

The cash flows for the periods covered by the renewal of the concession agreements are based on a number of assumptions relating to the economic and regulatory conditions for operating these assets (royalty rates, required level of investment, etc.) during this period.

A decrease of €10/MWh in electricity prices for hydropower generation would have a negative 47% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. Conversely, an increase of €10/MWh in electricity prices would have a positive 47% impact on the calculation.

An increase of 50 basis points in the discount rates used would have a negative 47% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 63% impact on the calculation.

If the Compagnie Nationale du Rhône hydropower concession agreements are not renewed beyond 2023, this would have a strong adverse impact on the results of the test, with the recoverable amount falling significantly below the carrying amount. In this scenario, the impairment risk would represent around €0.9 billion.

14.3.1.4 United Kingdom CGU

The goodwill allocated to the United Kingdom CGU amounted to €1,045 million at December 31, 2018. The United Kingdom CGU includes activities in (i) renewable power generation (hydraulic, wind and solar), (ii) gas and electricity sales, and (iii) services to individual and professional customers in the United Kingdom.

The value in use of these activities was calculated using the cash flow projections drawn up on the basis of the 2019 budget and the 2020-2021 medium-term business plan. A terminal value was calculated for the services and energy sales businesses by extrapolating the cash flows beyond that period using a long-term growth rate of 2% per year.

The main assumptions and key estimates relate primarily to discount rates and changes in price beyond the liquidity period.

The discount rates applied are between 5.7% and 9.0%.

An increase of 50 basis points in the discount rates used would have a negative 44% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 60% impact on the calculation.

A decrease of 10% in the margin captured by power generation assets would have a negative 69% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. An increase of 10% in the margin captured would have a positive 69% impact on this calculation.

14.3.1.5 France BtoC CGU

The goodwill allocated to the France BtoC CGU amounted to €1,044 million at December 31, 2018. The France BtoC CGU groups together sales of energy and related services to individual and professional customers in France.

The value in use of these activities was calculated using the cash flow projections drawn up on the basis of the 2019 budget and the 2020-2021 medium-term business plan. A terminal value was calculated by extrapolating the cash flows beyond that period using a long-term growth rate of 1.8%.

The main assumptions and key estimates relate primarily to discount rates, expected trends in gas and electricity demand in France, changes in the Group's market share and sales margin forecasts.

The discount rates applied are between 6.5% and 8.5%.

An increase of 50 basis points in the discount rates used would have a negative 22% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 29% impact on the calculation.

A decrease of 5% in the margin on gas and electricity sales activities would have a negative 14% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. Conversely, an increase of 5% in the margin on gas and electricity sales activities would have a positive 14% impact on the calculation.

14.3.2 Other significant CGUs

The table below sets out the assumptions used to determine the recoverable amount of the other main CGUs.

CGU	Reportable segment	Measurement	Discount rate
North America	North America	DCF + DDM	4.0% - 11.3%
Generation Europe	Other	DCF + DDM	3.7% - 9.1%
Northern, Southern and Eastern Europe	Europe excl. France & Benelux	DCF + DDM	4.8% - 10.9%
France BtoB	France	DCF + DDM	7.1% - 7.7%

DDM refers to the discounted dividend model.

14.3.2.1 North America CGU

The goodwill allocated to the North America CGU amounted to €875 million at December 31, 2018. The North America CGU mainly comprises:

- Canada, which includes activities in (i) renewable, thermal power generation (wind and biomass), (ii) services to individual and professional customers;
- The United States, which includes activities in (i) gas and electricity sales, (ii) services to individual and professional customers and (iii) thermal power generation;
- Puerto Rico, which includes an investment in EcoElectrica, a key energy industry player in Puerto Rico's economy (see Note 4.2 "Investments in joint ventures"). Despite the difficult financial environment in Puerto Rico, ENGIE does not have any information at December 31, 2018 on the basis of which the Group would modify its valuation assumptions regarding its share in these assets.

The wind and solar energy production activities acquired in the United States in 2018 make up an independent goodwill CGU.

The value in use of these activities was calculated using the cash flow projections drawn up on the basis of the 2019 budget and the 2020-2021 medium-term business plan. A terminal value was calculated for the services and energy sales businesses using EBITDA multiples as a basis.

The main assumptions and key estimates relate primarily to discount rates and changes in captured margins beyond the liquidity period.

The discount rates applied are between 4.0% and 11.3%.

An increase of 50 basis points in the discount rates used would have a negative impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain slightly above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive impact on the calculation.

A decrease of 5% in the margin on gas and electricity sales activities would have a negative 45% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. Conversely, an increase of 5% in the margin on gas and electricity sales activities would have a positive 45% impact on the calculation.

A decrease of 5% in service activities would have a negative 37% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. Conversely, an increase of 5% in the margin on gas and electricity sales activities would have a positive 37% impact on the calculation.

14.3.2.2 Generation Europe CGU

The goodwill allocated to the Generation Europe CGU amounted to €629 million at December 31, 2018. The Generation Europe CGU groups together the thermal power generation activities in Europe.

The value in use of these activities was calculated using the cash flow projections drawn up on the basis of the 2019 budget and the 2020-2021 medium-term business plan. Beyond this three-year period, cash flows were projected over the useful lives of the assets based on the reference scenario adopted by the Group.

The discount rates applied to these cash flow projections ranged between 3.7% and 9.1%.

The main assumptions and key estimates relate primarily to discount rates, estimated demand for electricity and changes in the price of CO₂, fuel and electricity beyond the liquidity period.

Results of the impairment test

At December 31, 2018, the recoverable amount of the Generation Europe goodwill CGU was higher than its carrying amount.

Sensitivity analyses

An increase of 50 basis points in the discount rates used would have a negative 13% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 13% impact on the calculation.

A decrease of 10% in the margin captured by thermal power plants would have a negative 17% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. An increase of 10% in the margin captured would have a positive 17% impact on this calculation.

14.3.2.3 Other significant goodwill CGUs

For the other significant goodwill CGUs, there is a considerable difference between their recoverable amount and their carrying amount at December 31, 2018.

14.4 Goodwill segment information

The carrying amount of goodwill can be analyzed as follows by operating segment:

<i>In millions of euros</i>	Dec. 31, 2018
North America	997
Latin America	740
Africa-Asia	649
Benelux	4,258
France	3,273
Europe excl. France & Benelux	1,689
Infrastructures Europe	5,000
Other	1,203
TOTAL	17,809

NOTE 15 INTANGIBLE ASSETS

Accounting standards

Initial measurement

Intangible assets are carried at cost less any accumulated amortization and any accumulated impairment losses.

Amortization

Intangible assets are amortized on the basis of the expected pattern of consumption of the estimated future economic benefits embodied in the asset. Amortization is calculated mainly on a straight-line basis over the following useful lives:

Main depreciation periods (years)	Useful life	
	Minimum	Maximum
Concession rights	10	30
Customer portfolio	10	40
Other intangible assets	1	50

Intangible assets with an indefinite useful life are not amortized but are tested for impairment annually.

Risk of impairment

In accordance with IAS 36, impairment tests are carried out on items of property, plant and equipment and intangible assets where there is an indication that the assets may be impaired. Such indications may be based on events or changes in the market environment, or on internal sources of information. Intangible assets that are not amortized are tested for impairment annually.

Impairment indicators

Property, plant and equipment and intangible assets with finite useful lives are only tested for impairment when there is an indication that they may be impaired. This is generally the result of significant changes in the environment in which the assets are operated or when economic performance is lower than expected.

Main impairment indicators used by the Group are described in Note 14 "Goodwill".

Impairment

Items of property, plant and equipment and intangible assets are tested for impairment at the level of the individual asset or cash-generating unit (CGU), as appropriate and, determined in accordance with IAS 36. If the recoverable amount of an asset is lower than its carrying amount, the carrying amount is written down to the recoverable amount by recording an impairment loss. Upon recognition of an impairment loss, the depreciable amount and possibly the useful life of the asset concerned is revised.

Impairment losses recorded in relation to property, plant and equipment or intangible assets may be subsequently reversed if the recoverable amount of the asset increases to exceed the carrying amount. The increased carrying amount of an item of property, plant or equipment following the reversal of an impairment loss may not exceed the carrying amount that would have been determined (net of depreciation/amortization) had no impairment loss been recognized in prior periods.

Measurement of recoverable amount

In order to review the recoverable amount of property, plant and equipment and intangible assets, the assets are grouped, where appropriate, into CGUs and the carrying amount of each CGU is compared with its recoverable amount.

For operating entities which the Group intends to hold on a long-term and going concern basis, the recoverable amount of a CGU corresponds to the higher of its fair value less costs to sell and its value in use. Value in use is primarily determined based on the present value of future operating cash flows including a terminal value. Standard valuation techniques are used based on the following main economic assumptions:

- market perspectives and developments in the regulatory framework;
- discount rates based on the specific characteristics of the operating entities concerned;
- terminal values in line with available market data specific to the operating segments concerned and growth rates associated with these terminal values, not to exceed the inflation rate.

Discount rates are determined on a post-tax basis and applied to post-tax cash flows. The recoverable amounts calculated on the basis of these discount rates are the same as the amounts obtained by applying the pre-tax discount rates to cash flows estimated on a pre-tax basis, as required by IAS 36.

For operating entities which the Group has decided to sell, the related recoverable amount of the assets concerned is based on market value less costs of disposal. Where negotiations are ongoing, this value is determined based on the best estimate of their outcome as of the reporting date.

In the event of a decline in value, the impairment loss is recorded in the consolidated income statement under "Impairment losses".

15.1 Movements in intangible assets

<i>In millions of euros</i>	Intangible rights arising on concession contracts	Capacity entitlements	Others	Total
GROSS AMOUNT				
At December 31, 2016	3,205	2,565	11,614	17,384
Acquisitions	179	-	1,026	1,205
Disposals	(32)	-	(224)	(256)
Translation adjustments	(57)	-	(261)	(318)
Changes in scope of consolidation	1	-	27	28
Transfer to "Assets classified as held for sale"	-	-	(1,075)	(1,075)
Other	343	116	(439)	20
At December 31, 2017⁽¹⁾	3,640	2,681	10,668	16,988
Acquisitions	120	17	912	1,048
Disposals	(9)	(19)	(149)	(177)
Translation adjustments	(52)	-	10	(42)
Changes in scope of consolidation	1	-	(290)	(289)
Transfer to "Assets classified as held for sale"	-	-	(98)	(98)
Other	55	40	(54)	41
AT DECEMBER 31, 2018	3,753	2,719	11,000	17,472
ACCUMULATED AMORTIZATION AND IMPAIRMENT				
At December 31, 2016	(1,259)	(1,988)	(7,497)	(10,744)
Amortization	(117)	(56)	(603)	(776)
Impairment	(7)	-	(219)	(227)
Disposals	20	-	219	239
Translation adjustments	5	-	149	154
Changes in scope of consolidation	-	-	(3)	(3)
Transfer to "Assets classified as held for sale"	-	-	880	880
Other	(26)	-	19	(7)
At December 31, 2017⁽¹⁾	(1,385)	(2,045)	(7,054)	(10,484)
Amortization	(144)	(61)	(632)	(837)
Impairment	-	-	(16)	(16)
Disposals	7	19	129	155
Translation adjustments	4	-	2	6
Changes in scope of consolidation	-	-	434	434
Transfer to "Assets classified as held for sale"	-	-	46	46
Other	(32)	-	(26)	(57)
AT DECEMBER 31, 2018	(1,550)	(2,087)	(7,117)	(10,754)
CARRYING AMOUNT				
At December 31, 2017⁽¹⁾	2,255	636	3,613	6,504
AT DECEMBER 31, 2018	2,204	632	3,883	6,718

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

Following the classification of the Group's interest in Glow (power generation in Thailand) under "Assets held for sale" (see Note 5.2 "Assets held for sale and discontinued operations"), the carrying amount of the corresponding intangible assets was transferred to "Assets classified as held for sale" in the statement of financial position at December 31, 2018.

15.1.1 Intangible rights arising on concession contracts

Accounting standards

IFRIC 12 – *Service concession arrangements* deals with the treatment to be applied by the concession operator in respect of certain concession arrangements.

For a concession arrangement to fall within the scope of IFRIC 12, usage of the infrastructure must be controlled by the concession grantor. This requirement is satisfied when the following two conditions are met:

- the grantor controls or regulates what services the operator must provide with the infrastructure, to whom it must provide them, and at what price; and
- the grantor controls any residual interest in the infrastructure at the end of the term of the arrangement, for example retains the right to take back the infrastructure at the end of the concession.

The intangible asset model according to IFRIC 12§17 applies if the operator receives a right (a license) to charge the users, or the grantor, depending on the use made of the public service. There is no unconditional right to receive cash as the amounts depend on the extent to which the public uses the service.

Concession infrastructures that do not meet the requirements of IFRIC 12 are presented as property, plant and equipment. This is the case of the distribution infrastructures of gas in France. The related assets are recognized in accordance with IAS 16, given that GRDF operates its network under long-term concession arrangements, most of which are mandatorily renewed upon expiration pursuant to French law No. 46-628 of April 8, 1946.

15.1.2 Capacity entitlements

The Group has acquired capacity entitlements from power stations operated by third parties. These power station capacity rights were acquired in connection with transactions or within the scope of the Group's involvement in financing the construction of certain power stations. In consideration, the Group received the right to purchase a share of the production over the useful life of the underlying assets. These rights are amortized over the useful life of the underlying assets, not to exceed 50 years. The Group currently holds entitlements in the Chooz B and Tricastin power plants in France and in the virtual power plant (VPP) in Italy.

15.1.3 Others

At December 31, 2018, this caption mainly relates to software and licenses for €985 million, as well as to intangible assets (client portfolio) acquired as a result of business combinations and capitalized acquisition costs for customer contracts for €1,000 million.

15.2 Information regarding research and development costs

Accounting standards

Research costs are expensed as incurred.

Development costs are capitalized when the asset recognition criteria set out in IAS 38 are met. Capitalized development costs are amortized over the useful life of the intangible asset recognized.

Research and development activities primarily relate to various studies regarding technological innovation, improvements in plant efficiency, safety, environmental protection, service quality, and the use of energy resources.

Research and development costs, excluding technical assistance costs, totaled €182 million in 2018, of which €25 million expenses related to in-house projects in the development phase that meet the criteria for recognition as an intangible asset as defined in IAS 38.

NOTE 16 PROPERTY, PLANT AND EQUIPMENT

Accounting standards

Initial recognition and subsequent measurement

Items of property, plant and equipment are recognized at historical cost less any accumulated depreciation and any accumulated impairment losses.

The carrying amount of these items is not revalued as the Group has elected not to apply the allowed alternative method, which consists of regularly revaluing one or more categories of property, plant and equipment.

Investment subsidies are deducted from the gross value of the assets concerned.

In accordance with IAS 16, the initial cost of the item of property, plant and equipment includes an initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, when the entity has a present, legal or constructive obligation to dismantle the item or restore the site. A corresponding provision for this obligation is recorded for the amount of the asset component.

Property, plant and equipment acquired under finance leases are carried in the consolidated statement of financial position at the lower of market value and the present value of the related minimum lease payments, in accordance with IAS 17. The corresponding liability is recognized under borrowings. These assets are depreciated using the same methods and useful lives as set out below.

Borrowing costs that are directly attributable to the construction of the qualifying asset are capitalized as part of the cost of that asset.

Cushion gas

“Cushion” gas injected into underground storage facilities is essential for ensuring that reservoirs can be operated effectively, and is therefore inseparable from these reservoirs. Unlike “working” gas which is included in inventories (see Note 27.2 “Inventories”), cushion gas is reported in Other Property, Plant and Equipment.

Depreciation

In accordance with the components approach, each significant component of an item of property, plant and equipment with a different useful life from that of the main asset to which it relates is depreciated separately over its own useful life.

Property, plant and equipment is depreciated mainly using the straight-line method over the following useful lives:

Main depreciation periods (years)	Useful life	
	Minimum	Maximum
Plant and equipment		
• Storage - Production - Transport - Distribution	5	60 ^(*)
• Installation - Maintenance	3	10
• Hydraulic plant and equipment	20	65
Other property, plant and equipment	2	33

(*)Excluding cushion gas.

The range of useful lives is due to the diversity of the assets in each category. The minimum periods relate to smaller equipment and furniture, while the maximum periods concern network infrastructures and storage facilities. In accordance with the law of January 31, 2003 adopted by the Belgian Chamber of Representatives with respect to the gradual phase-out of nuclear energy for the industrial production of electricity, the useful lives of nuclear power stations were reviewed and adjusted prospectively to 40 years as from 2003, except for Tihange, Doel 1 and Doel 2 for which the operating lives have been extended by 10 years.

Fixtures and fittings relating to hydro plants operated by the Group are depreciated over the shorter of the contract term and the useful life of the assets, taking into account the renewal of the concession period if such renewal is considered to be reasonably certain.

Risk of impairment

See Note 15 "Intangible assets".

Impairment indicators

See Note 14 "Goodwill".

16.1 Movements in property, plant and equipment

<i>In millions of euros</i>	Land	Buildings	Plant and equipment	Vehicles	Dismantling costs	Assets in progress	Other	Total
GROSS AMOUNT								
At December 31, 2016	756	5,687	95,555	451	3,030	6,462	1,174	113,115
Acquisitions	7	24	918	39	-	4,015	58	5,062
Disposals	(10)	(84)	(851)	(40)	(34)	(110)	(208)	(1,337)
Translation adjustments	(22)	(119)	(2,466)	(11)	(41)	(414)	(16)	(3,090)
Changes in scope of consolidation	3	(23)	(1,614)	3	(4)	99	-	(1,535)
Transfer to "Assets classified as held for sale"	(26)	(67)	(11,698)	(7)	(742)	(1,160)	(14)	(13,714)
Other	9	98	3,702	9	11	(4,039)	11	(197)
At December 31, 2017⁽¹⁾	717	5,517	83,547	444	2,220	4,853	1,005	98,303
Acquisitions	9	42	545	51	-	4,593	61	5,302
Disposals	(17)	(38)	(635)	(40)	(3)	(6)	(59)	(797)
Translation adjustments	(5)	31	114	2	6	(53)	8	103
Changes in scope of consolidation	(1)	(3)	(1,678)	(39)	(12)	(59)	(4)	(1,797)
Transfer to "Assets classified as held for sale"	(19)	(12)	(3,866)	(6)	(1)	(206)	(29)	(4,138)
Other	(14)	138	3,589	6	233	(3,652)	34	334
AT DECEMBER 31, 2018	671	5,676	81,615	419	2,444	5,469	1,015	97,309
ACCUMULATED DEPRECIATION AND IMPAIRMENT								
At December 31, 2016	(145)	(2,925)	(48,534)	(337)	(1,324)	(1,195)	(878)	(55,337)
Depreciation	(9)	(123)	(2,929)	(40)	(187)	-	(96)	(3,384)
Impairment	2	(31)	(670)	(1)	2	(19)	(2)	(719)
Disposals	1	68	692	36	46	96	202	1,140
Translation adjustments	6	16	1,226	10	24	59	10	1,352
Changes in scope of consolidation	1	18	825	(1)	2	26	1	871
Transfer to "Assets classified as held for sale"	15	35	7,785	5	518	208	11	8,577
Other	-	7	(388)	(2)	(9)	625	26	258
At December 31, 2017⁽¹⁾	(129)	(2,937)	(41,992)	(330)	(929)	(199)	(725)	(47,241)
Depreciation	(8)	(119)	(2,600)	(42)	(189)	-	(90)	(3,048)
Impairment	(1)	(82)	(1,006)	(1)	(250)	(219)	(3)	(1,561)
Disposals	-	23	551	37	-	1	53	665
Translation adjustments	4	(5)	(108)	(2)	(4)	4	(6)	(119)
Changes in scope of consolidation	2	1	1,277	43	12	21	7	1,363
Transfer to "Assets classified as held for sale"	-	5	1,552	5	-	2	23	1,588
Other	2	(60)	56	(1)	(58)	24	(2)	(39)
AT DECEMBER 31, 2018	(130)	(3,175)	(42,270)	(290)	(1,418)	(367)	(742)	(48,391)
CARRYING AMOUNT								
At December 31, 2017⁽¹⁾	588	2,579	41,554	115	1,291	4,653	280	51,062
AT DECEMBER 31, 2018	541	2,501	39,345	129	1,026	5,102	273	48,917

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement financial information").

In 2018, the net decrease in “Property, plant and equipment” takes into account:

- the classification under “Assets held for sale” (see Note 5.2 “Assets held for sale and discontinued operations”) for a negative €2,550 million of the Group’s interest in Glow (power generation in Thailand), the Langa group’s operating wind farms in France and solar fields in Mexico. The carrying amount of these property, plant and equipment, has been transferred to “Assets classified as held for sale” in the statement of financial position at December 31, 2018;
- depreciation for a total negative amount of €3,048 million;
- impairment losses amounting to €1,561 million, mainly related to thermal power generation assets in Europe (€1,268 million) and Latin America (€71 million), and gas infrastructure sites in France (€87 million);
- changes in the scope of consolidation for a negative €434 million, mainly resulting from the DBSO⁽¹⁾ activities relating to wind and solar farms in France (negative impact of €411 million), gas distribution activities in Hungary (negative impact of €155 million), LNG activities (negative impact of €110 million euros), slightly offset by the acquisition of the Langa group in France (€206 million);
- partly offset by maintenance and development investments for a total amount of €5,302 million mainly relating to the construction of plants and development of wind and solar farms in Latin America and France, the extension of transportation and distribution networks in the Infrastructures Europe segment.

In 2017, the net increase in “Property, plant and equipment” mainly resulted from:

- the transfer of the carrying amount of property, plant and equipment to “Assets held for sale” of Loy Yang B assets in the process being sold at December 31, 2017 and of exploration-production activities under discontinued operations for a negative total amount of €5,137 million;
- maintenance and development investments for a total amount of €5,062 million mainly related to the construction of plants and development of wind and solar farms in Latin America and France, and the extension of transportation and distribution networks in the Infrastructures Europe segment;
- depreciation for a total negative amount of €3,384 million;
- negative net translation adjustments of €1,738 million, mainly resulting from the US dollar (negative impact of €963 million) and the Brazilian real (negative impact of €439 million);
- impairment losses amounting to €719 million, mainly related to thermal power generation assets (€510 million) and gas storage facilities in Germany (€156 million);
- changes in the scope of consolidation for a negative €664 million, mainly resulting from the DBSO activities relating to wind and solar fields in France (negative impact of €277 million), and the disposal of power generation plants in the United-Kingdom (negative impact of €186 million).

16.2 Pledged and mortgaged assets

Items of property, plant and equipment pledged by the Group to guarantee borrowings and debt amounted to €1,298 million at December 31, 2018 compared to €2,185 million at December 31, 2017.

The decrease mainly related to the classification of Glow assets in Thailand under “Assets held for sale”. The secured debt, on the other hand, was classified as “Liabilities held for sale” (see Note 5.2).

16.3 Contractual commitments to purchase property, plant and equipment

In the ordinary course of their operations, some Group companies have entered into commitments to purchase, and the related third parties to deliver, property, plant and equipment. These commitments relate mainly to orders for equipment, and material related to the construction of energy production units and to service agreements.

(1) Develop Build Share and Operate.

Investment commitments made by the Group to purchase property, plant and equipment totaled €1,415 million at December 31, 2018 compared to €1,988 million at December 31, 2017.

16.4 Other information

Borrowing costs for 2018 included in the cost of property, plant and equipment amounted to €134 million at December 31, 2018 compared to €104 million at December 31, 2017.

NOTE 17 FINANCIAL INSTRUMENTS

17.1 Financial assets

Accounting standards

In accordance with the principles of IFRS 9 - *Financial Instruments*, financial assets are recognized and measured either at amortized cost, at fair value through equity or at fair value through profit or loss based on the following two criteria:

- a first criterion relating to the contractual cash flows characteristics of the financial asset. The analysis of the contractual cash flows characteristics allows to determine whether these cash flows are “only payments of principal and interest on the outstanding amounts” (known as “SPPI” test or Solely Payment of Principal and Interest);
- a second criterion relating to the business model used by the Group to manage its financial assets. IFRS 9 defines three different business models. A first business model whose objective is to hold assets in order to collect contractual cash flows (hold to collect), a second model whose objective is achieved by both collecting contractual cash flows and selling financial assets (hold to collect and sell) and other business models.

The identification of the business model and the analysis of the contractual cash flows characteristics require judgment to ensure that the financial assets are classified in the appropriate category.

Where the financial asset is an investment in an equity instrument and is not held for trading, the Group may irrevocably elect to present the gains and losses on that investment in other comprehensive income.

Except for trade receivables, which are measured at their transaction price in accordance with IFRS 15, financial assets are measured, on initial recognition, at their fair value plus, in the case of a financial asset not at fair value through profit or loss, transaction costs that are directly attributable to their acquisition.

At each reporting period, financial assets measured using the amortized cost method or at fair value through other comprehensive income (with a recycling mechanism) are subject to an impairment test based on the expected credit losses method.

Financial assets also include derivatives that are measured at fair value in accordance with IFRS 9.

In accordance with IAS 1, the Group presents current and non-current assets and current and non-current liabilities separately in the statement of financial position. In view of the majority of the Group's activities, it was considered that the criterion to be used to classify assets is the expected time to realize the asset or settle the liability: the asset is classified as current if this period is less than 12 months and as non-current if it is more than 12 months after the reporting period.

The following table presents the Group's different categories of financial assets, broken down into current and non-current items:

In millions of euros	Notes	Dec. 31, 2018			Dec. 31, 2017 ⁽¹⁾		
		Non-current	Current	Total	Non-current	Current	Total
Other financial assets	17.1	6,193	2,290	8,483	5,586	2,010	7,596
Equity instruments at fair value through other comprehensive income		742	-	742	733	-	733
Equity instruments at fair value through income		365	-	365	393	-	393
Debt instruments at fair value through other comprehensive income		1,108	840	1,947	844	942	1,786
Debt instruments at fair value through income		600	233	832	647	210	857
Loans and receivables at amortized cost		3,378	1,218	4,596	2,968	858	3,826
Trade and other receivables	8.2	-	15,613	15,613	-	13,127	13,127
Assets from contracts with customers	8.2	-	7,411	7,411	-	6,930	6,930
Cash and cash equivalent	17.1	-	8,700	8,700	-	8,929	8,929
Derivative instruments	17.4	2,693	10,679	13,372	2,949	7,378	10,326
TOTAL		8,886	44,692	53,578	8,535	38,374	46,908

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

17.1.1 Other financial assets

17.1.1.1 Equity instruments at fair value

Accounting standards

Equity instruments at fair value through other comprehensive income (OCI)

Under IFRS 9 an irrevocable election can be made to present in other comprehensive income subsequent changes in the fair value of an investment in an equity instrument that is not held for trading. This choice is made on an instrument-by-instrument basis. Amounts presented in other comprehensive income should not be transferred to profit or loss including proceeds of disposals. However, IFRS 9 authorizes the transfer of the accumulated profits and losses to another component of equity. Dividends from such investments are recognized in profit or loss unless the dividend clearly represents the recovery of a portion of the cost of the investment.

The equity instruments recognized under this line item mainly concern investments in companies that are not controlled by the Group and for which OCI measurement has been selected given their strategic and long-term nature.

Upon initial recognition, these equity instruments are recognized at fair value, which is generally their acquisition cost, plus transaction costs.

At each reporting date, for listed securities, the fair value is determined based on the quoted market price at the reporting date. For unlisted securities, fair value is measured using valuation models based primarily on the latest market transactions, the discounting of dividends or cash flows and the net asset value.

Equity instruments at fair value through profit or loss

Equity instruments that are held for trading or for which the Group has not elected for measurement at fair value through other comprehensive income are measured at fair value through profit or loss.

This category mainly includes investments in companies not controlled by the Group.

Upon initial recognition, these equity instruments are recognized at fair value, which is generally their acquisition cost.

At each reporting date, for listed and unlisted securities, the same measurement method as described above should be applied.

<i>In millions of euros</i>	Equity instruments at fair value through other comprehensive income	Equity instruments at fair value through income	Total
At December 31, 2017⁽¹⁾	733	393	1,127
Increase	50	170	220
Decrease	(62)	(118)	(179)
Changes in fair value	35	(46)	(10)
Changes in scope of consolidation, foreign exchange translation and other	(15)	(34)	(50)
AT DECEMBER 31, 2018	742	365	1,107

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

Equity instruments amounted to €1,107 million at December 31, 2018 of which €62 million in listed securities relating to equity instruments at fair value through other comprehensive income.

At December 31, 2018 the net book value of equity instruments at fair value through other comprehensive income amounted to €742 million. This amount mainly includes shares held by the group as minority interest in Nord Stream AG for an amount of €478 million.

In 2018, the Group received €55 million of dividends including €38 million from equity instruments at fair value through other comprehensive income (of which €1 million from shares sold in 2018) and €15 million from equity instruments at fair value through income (of which €3 million from shares sold in 2018).

17.1.1.2 Debt instruments at fair value

Accounting standards

Debt instruments at fair value through other comprehensive income

Financial assets that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets and for which the contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the outstanding amount (SPPI), are measured at fair value through OCI (with recycling mechanism). This involves a measurement through profit or loss for interest (at amortized cost using the effective interest method), depreciations and foreign exchange gains and losses, and through OCI (with recycling mechanism) for other gains or losses.

This category mainly includes bonds and financial deposits (step-up deposits).

Fair value gains and losses on these instruments are recognized in other comprehensive income, except for the following items which are recognized in profit or loss:

- interest income using the effective interest method;
- expected credit losses and reversals;
- foreign exchange gains and losses.

When the financial asset is derecognized, the cumulative gain or loss that was previously recognized in other comprehensive income is reclassified from equity to profit or loss.

Debt instruments at fair value through profit or loss

Financial assets whose contractual cash flows do not consist solely of payments of principal and interest on the amount outstanding (SPPI) or that are held in view of an "other" business model are measured at fair value through profit or loss.

The Group's investments in UCITS are accounted for in this caption. They are considered as debt instruments, according to IAS 32 - *Financial Instruments: Presentation*, given the existence of an obligation for the issuer to redeem units, on

simple request of the holder. They are measured at fair value through profit or loss because the contractual cash flows characteristics do not meet the SPPI test.

<i>In millions of euros</i>	Debt instruments at fair value through other comprehensive income	Debt instruments at fair value through income	Liquid debt instruments held for cash investment purposes at fair value through other comprehensive income	Liquid debt instruments held for cash investment purposes at fair value through income	Total
At December 31, 2017⁽¹⁾	884	621	902	236	2,643
Increase	139	(73)	170	65	300
Decrease	(9)	(2)	(145)	-	(156)
Changes in fair value	33	(23)	-	3	14
Changes in scope of consolidation, foreign exchange translation and other	(22)	3	(5)	3	(22)
AT DECEMBER 31, 2018	1,025	525	922	307	2,779

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

At December 31, 2018, the debt instruments at fair value amounted to €2,779 million including €1,947 million of debt instruments at fair value through other comprehensive income and €832 million of debt instruments at fair value through income (respectively €1,786 million and €857 million at December 31, 2017).

Debt instruments at fair value at December 31, 2018 include bonds and money market funds held by Synatom for €1,492 million and liquid instruments deducted from gross debt for €1,229 million (respectively €1,441 million and €1,138 million at December 31, 2017).

17.1.1.3 Loans and receivables at amortized cost

Accounting standards

Loans and receivables held by the Group under a business model consisting in holding the instrument in order to collect the contractual cash flows, and whose contractual cash flows consist solely of payments of principal and interest on the principal amount outstanding (SPPI test) are measured at amortized cost. Interest is calculated using the effective interest method.

The following items are recognized in profit or loss:

- interest income using the effective interest method;
- expected credit losses and reversals;
- foreign exchange gains and losses.

Leasing security deposits are presented in this caption and recognized at their nominal value.

<i>In millions of euros</i>	Dec. 31, 2018			Dec. 31, 2017 ⁽¹⁾		
	Non-current	Current	Total	Non-current	Current	Total
Loans granted to affiliated companies	1,498	121	1,619	990	97	1,087
Other receivables at amortized cost	675	241	916	672	107	779
Amounts receivable under concession contracts	544	68	612	571	82	653
Amounts receivable under finance leases	661	89	750	735	72	807
Margin calls on derivatives hedging borrowings - assets	-	699	699	-	500	500
TOTAL	3,378	1,218	4,596	2,968	858	3,826

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

The increase in “Loans and receivables at amortized cost” in 2018 includes the €247 million loan granted to Neptune Energy as part of the sale of the exploration-production business. This item also includes the financing of the Nord Stream 2 pipeline project for a nominal amount of €298 million (excluding capitalized interests and expected credit losses).

The table below shows impairment and expected credit losses on loans and receivables at amortized cost:

In millions of euros	Dec. 31, 2018				Dec. 31, 2017 ⁽¹⁾			
	Gross	Amortized cost	Impairment and expected credit losses ⁽²⁾	Net	Gross	Amortized cost	Impairment and expected credit losses ⁽²⁾	Net
Loans granted to affiliated companies	1,808	86	(275)	1,619	1,293	19	(225)	1,087
Other receivables at amortized cost	924	1	(10)	916	789	-	(10)	779
Amounts receivable under concession contracts	614	-	(1)	612	655	-	(2)	653
Amounts receivable under finance leases	783	1	(34)	750	839	1	(33)	807
Margin calls on derivatives hedging borrowings - assets	699	-	-	699	500	-	-	500
TOTAL	4,827	88	(319)	4,596	4,076	21	(270)	3,826

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 “Restatement of 2017 comparative data”).

(2) Including impairment on the Argentine State receivables, attributable to SUEZ (see Note 28.1.1 “Concessions in Buenos Aires and Santa Fe”).

Information on the age of past due receivables and on counterparty risk associated with loans and receivables at amortized cost are provided in Note 18.2 “Counterparty risk”.

Net gains and losses recognized in the income statement relating to loans and receivables at amortized cost break down as follows:

In millions of euros	Interest income	Post-acquisition measurement	
		Foreign currency translation	Expected credit loss
At December 31, 2018	263	(21)	(41)
At December 31, 2017 ⁽¹⁾	248	(13)	(8)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as “Discontinued operations” of ENGIE’s upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 “Restatement of 2017 comparative data”).

No material expected credit losses were recognized against loans and receivables at amortized cost at December 31, 2018 and December 31, 2017.

17.1.2 Trade and other receivables, assets from contracts with customers

Information on trade and other receivables and assets from contracts with customers are provided in Note 8.2.

17.1.3 Cash and cash equivalents

Accounting principles

This item includes cash equivalents as well as short-term investments that are considered to be readily convertible into a known amount of cash and where the risk of a change in their value is deemed to be negligible based on the criteria set out in IAS 7.

Bank overdrafts are not included in the calculation of cash and cash equivalents and are recorded under “Short-term borrowings”.

Cash and cash equivalent items are subject to impairment tests in accordance with the expected credit losses model of IFRS 9.

Cash and cash equivalents totaled €8,700 million at December 31, 2018 (€8,929 million at December 31, 2017).

This amount included funds related to the green bond issues, which remain unallocated to the funding of eligible projects (see section 5 of the Registration Document).

This amount also included at December 31, 2018 €121 million in cash and cash equivalents subject to restrictions (€141 million at December 31, 2017). Cash and cash equivalents subject to restrictions include notably €62 million of cash equivalents set aside to cover the repayment of borrowings and debt as part of project financing arrangements in certain subsidiaries.

Gains recognized in respect of "Cash and cash equivalents" amounted to €73 million at December 31, 2018 compared to €104 million at December 31, 2017.

17.1.4 Financial assets set aside to cover the future costs of dismantling nuclear facilities and managing radioactive fissile material

As indicated in Note 20.2 "Nuclear dismantling liabilities", the Belgian law of April 11, 2003, amended by the law of April 25, 2007, granted the Group's wholly-owned subsidiary Synatom responsibility for managing and investing funds received from operators of nuclear power plants in Belgium and designed to cover the costs of dismantling nuclear power plants and managing radioactive fissile material.

Pursuant to the law, Synatom may lend up to 75% of these funds to operators of nuclear plants provided that they meet certain financial criteria – particularly in terms of credit quality. The funds that cannot be lent to operators are either lent to entities meeting the credit quality criteria set by the law or invested in financial assets such as bonds and money market funds.

Loans to entities outside the Group and other cash investments are shown in the table below:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Loans to third parties	512	516
Loan to Eso/Elia	454	454
Loan to Ores Assets	40	41
Loan to Sibelga	18	22
Others loans and receivables at amortized cost	163	23
Debt instruments - restricted cash	163	23
Equity and debt instruments at fair value	1,539	1,483
Equity instruments at fair value through other comprehensive income	47	41
Debt instruments at fair value through other comprehensive income	1,025	861
Debt instruments at fair value through income	467	580
TOTAL	2,214	2,022

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

Loans to entities outside the Group and the cash subject to restriction held by money market funds are shown in the statement of financial position as "Loans and receivables at amortized cost". Bonds and money market funds held by Synatom are shown as "equity instruments at fair value through other comprehensive income", "debt instruments at fair value through other comprehensive income" or "debt instruments at fair value through income" (see Note 17.1 "Financial assets").

17.1.5 Transfer of financial assets

At December 31, 2018, the outstanding amount of transferred financial assets (as well as the risks to which the Group remains exposed following the transfer of those financial assets) as part of transactions leading to either (i) all or part of

those assets being retained in the statement of financial position, or (ii) their full deconsolidation while retaining a continuing involvement in these financial assets, was not material in terms of the Group's indicators.

In 2018, the Group carried out disposals without recourse to financial assets as part of transactions leading to full derecognition, for an outstanding amount of €872 million at December 31, 2018.

17.1.6 Financial assets and equity instruments pledged as collateral for borrowings and debt

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017
Financial assets and equity instruments pledged as collateral	3,447	3,602

This item mainly includes the carrying amount of equity instruments pledged as collateral for borrowings and debt.

17.2 Financial liabilities

Accounting standards

Borrowings and other financial liabilities are measured at amortized cost using the effective interest rate method.

On initial recognition, any issue or redemption premiums and discounts and issuing costs are added to/deducted from the nominal value of the borrowings concerned. These items are taken into account when calculating the effective interest rate and are therefore recorded in the consolidated income statement over the life of the borrowings using the amortized cost method.

As regards structured debt instruments that do not have an equity component, the Group may be required to separate an “embedded” derivative instrument from its host contract. When an embedded derivative is separated from its host contract, the initial carrying amount of the structured instrument is broken down into an embedded derivative component, corresponding to the fair value of the embedded derivative, and a financial liability component, corresponding to the difference between the amount of the issue and the fair value of the embedded derivative. The separation of components upon initial recognition does not give rise to any gains or losses.

The debt is subsequently recorded at amortized cost using the effective interest method while the derivative is measured at fair value, with changes in fair value recognized in profit or loss.

Financial liabilities are recognized either:

- as “Amortized cost liabilities” for borrowings, trade payables and other creditors, and other financial liabilities;
- as “Liabilities measured at fair value through profit or loss” for derivative financial instruments and for financial liabilities designated as such.

The following table presents the Group’s different financial liabilities at December 31, 2018, broken down into current and non-current items:

In millions of euros	Notes	Dec. 31, 2018			Dec. 31, 2017 ⁽¹⁾		
		Non-current	Current	Total	Non-current	Current	Total
Borrowings and debt	17.2	26,434	5,745	32,178	25,292	8,175	33,467
Trade and other payables	17.2	-	19,759	19,759	-	16,404	16,404
Liabilities from contracts with customers	8.2	36	3,598	3,634	258	3,317	3,575
Derivative instruments	17.4	2,785	11,510	14,295	2,980	8,720	11,700
Other financial liabilities	17.2	46	-	46	32	-	32
TOTAL		29,301	40,612	69,913	28,562	36,617	65,179

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 “Restatement of 2017 comparative data”).

17.2.1 Trade and other payables

In millions of euros	Dec. 31, 2018	Dec. 31, 2017 ⁽¹⁾
Trade payables	19,192	15,983
Payable on fixed assets	568	422
TOTAL	19,759	16,404

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 “Restatement of 2017 comparative data”).

The carrying amount of these financial liabilities represents a reasonable estimate of their fair value.

17.2.2 Liabilities from contracts with customers

Information on liabilities from contracts with customers are provided in Note 8.2.

17.2.3 Borrowings and debt

In millions of euros	Dec. 31, 2018			Dec. 31, 2017 ⁽¹⁾		
	Non-current	Current	Total	Non-current	Current	Total
Bond issues	21,444	1,202	22,645	20,062	2,175	22,237
Bank borrowings	4,272	349	4,620	4,231	928	5,159
Negotiable commercial paper	-	2,894	2,894	-	3,889	3,889
Drawdowns on credit facilities	33	33	66	26	21	47
Liabilities under finance leases	262	118	380	330	152	483
Other borrowings	74	51	125	65	56	121
TOTAL BORROWINGS	26,084	4,647	30,731	24,714	7,221	31,935
Bank overdrafts and current accounts	-	464	464	-	466	466
OUTSTANDING BORROWINGS AND DEBT	26,084	5,111	31,195	24,714	7,688	32,401
Impact of measurement at amortized cost	13	228	241	242	47	289
Impact of fair value hedges	337	2	339	336	29	365
Margin calls on derivatives hedging borrowings - carried in liabilities	-	404	404	-	412	412
BORROWINGS AND DEBT	26,434	5,745	32,178	25,292	8,175	33,467

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

The fair value of gross borrowings and debt amounted to €33,651 million at December 31, 2018, compared with a carrying amount of €32,178 million.

Financial income and expenses relating to borrowings and debt are detailed in Note 11 "Net financial income/(loss)".

Borrowings and debt are analyzed in Note 17.3 "Net debt".

17.2.4 Other financial liabilities

At December 31, 2018, other financial liabilities amounted to €46 million (compared to €32 million at December 31, 2017), mainly corresponding to debt resulting from uncalled share capital of entities accounted for using the equity method.

17.3 Net debt

17.3.1 Net debt by type

In millions of euros	Dec. 31, 2018			Dec. 31, 2017 ⁽¹⁾		
	Non-current	Current	Total	Non-current	Current	Total
Outstanding borrowings	26,084	5,111	31,195	24,714	7,688	32,401
Impact of measurement at amortized cost	13	228	241	242	47	289
Impact of fair value hedge ⁽²⁾	337	2	339	336	29	365
Margin calls on derivatives hedging borrowings - carried in liabilities	-	404	404	-	412	412
BORROWINGS AND DEBT	26,434	5,745	32,178	25,292	8,175	33,467
Derivatives hedging borrowings - carried in liabilities ⁽³⁾	259	66	325	293	59	352
GROSS DEBT	26,692	5,811	32,503	25,585	8,234	33,819
Assets related to financing	(53)	(1)	(53)	(59)	(1)	(60)
Margin calls on derivatives hedging borrowings - carried in assets	-	(699)	(699)	-	(500)	(500)
ASSETS RELATED TO FINANCING AND MARGIN CALLS	(53)	(700)	(752)	(59)	(501)	(559)
Cash and cash equivalents	-	(8,700)	(8,700)	-	(8,929)	(8,929)
Derivatives hedging borrowings - carried in assets ⁽³⁾	(678)	(42)	(720)	(610)	(63)	(673)
NET CASH	(678)	(8,742)	(9,420)	(610)	(8,992)	(9,602)
Liquid debt instruments held for cash investment purposes	(235)	(995)	(1,230)	(30)	(1,108)	(1,138)
LIQUID DEBT INSTRUMENTS HELD FOR CASH INVESTMENT PURPOSES	(235)	(995)	(1,230)	(30)	(1,108)	(1,138)
NET DEBT	25,727	(4,625)	21,102	24,887	(2,367)	22,520
Outstanding borrowings	26,084	5,111	31,195	24,714	7,688	32,401
Assets related to financing	(53)	(1)	(53)	(59)	(1)	(60)
Liquid debt instruments held for cash investment purposes	(235)	(995)	(1,230)	(30)	(1,108)	(1,138)
Cash and cash equivalents	-	(8,700)	(8,700)	-	(8,929)	(8,929)
NET DEBT EXCLUDING THE IMPACT OF AMORTIZED COST, DERIVATIVE INSTRUMENTS AND MARGIN CALLS	25,796	(4,584)	21,212	24,626	(2,351)	22,275

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

(2) This item corresponds to the revaluation of the interest rate component of debt in a qualified fair value hedging relationship.

(3) This item represents the interest rate component of the fair value of derivatives hedging borrowings in a designated fair value hedging relationship. It also represents the exchange rate and outstanding accrued interest rate components of the fair value of all debt-related derivatives irrespective of whether or not they qualify as hedges.

Net debt excluding internal debt of discontinued operations amounted to €20,788 million at December 31, 2017 (see Notes 5.1.2 "Disposal of the exploration-production business" and 5.1.4 "Disposal of ENGIE's liquefied natural gas (LNG) activities").

17.3.2 Reconciliation between net debt and cash flow from (used in) financing activities

In millions of euros	Dec. 31, 2017 ⁽¹⁾	Cash flow from financing activities	Cash flow from operating and investing activities and variation of cash and cash equivalents	Change in fair value	Translation adjustments	Change in scope of consolidation and others	Dec. 31, 2018
Outstanding borrowings	32,401	(589)	-	-	41	(658)	31,195
Impact of measurement at amortized cost	289	(20)	-	19	(12)	(35)	241
Impact of fair value hedge	365	-	-	(26)	-	-	339
Margin calls on derivatives hedging borrowings - carried in liabilities	412	(8)	-	-	-	-	404
BORROWINGS AND DEBT	33,467	(617)	-	(7)	29	(694)	32,178
Derivatives hedging borrowings - carried in liabilities	352	(76)	-	-	51	(2)	325
GROSS DEBT	33,819	(693)	-	(7)	80	(696)	32,503
Assets related to financing	(60)	-	-	-	6	-	(53)
Margin calls on derivatives hedging borrowings - carried in assets	(500)	(199)	-	-	-	-	(699)
ASSETS RELATED TO FINANCING AND MARGIN CALLS	(559)	(199)	-	-	6	-	(752)
Cash and cash equivalents	(8,929)	-	(449)	-	93	585	(8,700)
Derivatives hedging borrowings - carried in assets	(673)	89	-	29	(160)	(4)	(720)
NET CASH	(9,602)	89	(449)	29	(67)	580	(9,420)
Liquid debt instruments held for cash investment purposes	(1,138)	(90)	-	(4)	-	3	(1,230)
LIQUID DEBT INSTRUMENTS HELD FOR CASH INVESTMENT PURPOSES	(1,138)	(90)	-	(4)	-	3	(1,230)
NET DEBT	22,520	(894)	(449)	18	19	(113)	21,102

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

17.3.3 Main events of the period

17.3.3.1 Impact of changes in the scope of consolidation and in exchange rates on net debt

In 2018, changes in exchange rates resulted in a €19 million increase in net debt, including a €124 million decrease in relation to the Brazilian real, which was offset by a €151 million increase in debt denominated in US dollars.

Changes in the scope of consolidation (including the cash impact of acquisitions and disposals) led to a €2,605 million decrease in net debt, reflecting:

- disposals of assets over the period, which reduced net debt by €3,938 million, notably including the disposal of the exploration-production business, upstream liquefied natural gas (LNG) activities, the Loy Yang B power plant in Australia and the gas distribution business in Hungary (see Note 5.1 "Disposals carried out in 2018");
- the classification of Glow under "Assets held for sale" (see Note 5.2.1 "Disposal of ENGIE's interest in Glow") and assets held by the Langa group (see Note 5.2.2 "Disposal of Langa group asset disposal program") which reduced net debt by €993 million;
- acquisitions carried out in 2018 (chiefly in the United States with the purchase of companies in the renewable energy and services sectors and in France with the purchase of the Langa group, Priora FM SA and a majority interest in Electro Power Systems), which increased net debt by €2,326 million (see Note 5.3 "Acquisitions carried out in 2018").

17.3.3.2 Financing and refinancing transactions

The Group carried out the following main transactions in 2018:

- on June 22, 2018, ENGIE SA issued €750 million worth of bonds maturing in June 2028 with a 1.421% coupon;
- on September 19, 2018, ENGIE SA issued €1 billion worth of bonds:
 - a €500 million tranche maturing in September 2025 with a 0.875% coupon,
 - a €500 million tranche maturing in September 2033 with a 1.875% coupon;
- the redemption of the following bonds, which matured in 2018:
 - ENGIE SA redeemed the €644 million worth of bonds that matured on February 18, 2018 with a 5.125% coupon,
 - ENGIE SA redeemed the €729 million worth of bonds that matured on June 1, 2018 with a 2.25% coupon,
 - ENGIE SA redeemed the €150 million worth of bonds that matured on October 17, 2018 with a 3.046% coupon;
- on July 5, July 11 and October 16, 2018, ENGIE SA carried out private issues in the amounts of €75 million, AUD 85 million (€53 million) and €50 million, maturing in 2038, 2033 and 2027 respectively;
- on June 6, 2018, ENGIE gave notice that it had exercised the annual prepayment option for the €600 million tranche of deeply-subordinated notes (representing a total amount of €621 million including the accrued coupon) that had previously been recognized in equity in an amount of €584 million. ENGIE SA redeemed the bonds on July 10, 2018;
- on December 5, 2018, ENGIE gave notice that it had exercised the annual prepayment option for the GBP 300 million tranche of deeply-subordinated notes (representing a total amount of €352 million including the accrued coupon) that had previously been recognized in equity in an amount of €340 million;
- on December 12, 2018, Electrabel SA repaid the €300 million bank loan with a variable 3-month Euribor coupon;
- ENGIE Brasil Energia carried out the following transactions:
 - on June 28, 2018, ENGIE Brasil Energia carried out four bond issues totaling BRL 1,802 million (€401 million). BRL 782 million of these issues will mature in 2023 and BRL 1,020 million in 2027;
 - on July 25, 2018, ENGIE Brasil Energia carried out two bond issues totaling BRL 746 million (€161 million). BRL 515 million of these issues will mature in 2025 and BRL 231 million in 2028;
 - on August 27, 2018, ENGIE Brasil Energia took out 11 bank loans to finance wind farm projects totaling BRL 730 million (€153 million) and maturing in 2035;
 - in April 2018 and November 2018, ENGIE Brasil Energia took out four bank loans totaling USD 400 million including €174 million maturing in 2020 and €174 million in 2021;
 - in August 2018 and December 2018, ENGIE Brasil Energia took out bank loans totaling BRL 635 million (€143 million) maturing in January 2036;
 - on June 29, 2018, ENGIE Brasil Energia partially redeemed bonds in an amount of BRL 1,685 million (€375 million).

17.4 Derivative instruments

Accounting standards

Derivative financial instruments are measured at fair value. This fair value is determined on the basis of market data, available from external contributors. In the absence of an external benchmark, a valuation based on internal models recognized by market participants and favoring data directly derived from observable data such as OTC quotations will be used.

The change in fair value of derivative financial instruments is recorded in the income statement except when they are designated as hedging instruments in a cash flow hedge or net investment hedge. In this case, changes in the value of the hedging instruments are recognized directly in equity, excluding the ineffective portion of the hedges.

The Group uses derivative financial instruments to manage and reduce its exposure to market risks arising from fluctuations in interest rates, foreign currency exchange rates and commodity prices, mainly for gas and electricity. The use of derivative instruments is governed by a Group policy for managing interest rate, currency and commodity risks (see *Note 18 – Risks arising from financial instruments*).

Derivative financial instruments are contracts (i) whose value changes in response to the change in one or more observable variables, (ii) that do not require any material initial net investment, and (iii) that are settled at a future date.

Derivative instruments therefore include swaps, options, futures and swaptions, as well as forward commitments to purchase or sell listed and unlisted securities, and firm commitments or options to purchase or sell non-financial assets that involve physical delivery of the underlying.

For purchases and sales of electricity and natural gas, the Group systematically analyzes whether the contract was entered into in the “normal” course of operations and therefore falls outside the scope of IFRS 9. This analysis consists firstly in demonstrating that the contract is entered into and continues to be held for the purpose of physical delivery or receipt of the commodity in accordance with the Group’s expected purchase, sale or usage requirements.

The second step is to demonstrate that the Group has no practice of settling similar contracts on a net basis and that these contracts are not equivalent to written options. In particular, in the case of electricity and gas sales allowing the buyer a certain degree of flexibility concerning the volumes delivered, the Group distinguishes between contracts that are equivalent to capacity sales considered as transactions falling within the scope of ordinary operations and those that are equivalent to written financial options, which are accounted for as derivative financial instruments.

Only contracts that meet all of the above conditions are considered as falling outside the scope of IFRS 9. Adequate specific documentation is compiled to support this analysis.

Embedded derivatives

The main Group contracts that may contain embedded derivatives are contracts with clauses or options potentially affecting the contract price, volume or maturity. This is the case primarily with contracts for the purchase or sale of non-financial assets, whose price is revised based on an index, the exchange rate of a foreign currency or the price of an asset other than the contract’s underlying.

An embedded derivative is a component of a hybrid (combined) instrument that also includes a non-derivative host contract – with the effect that some of the cash flows of the combined instrument vary in a way similar to a stand-alone derivative.

If a hybrid contract contains a host that is an asset within the scope of IFRS 9, the Group applies the presentation and measurements requirements described in paragraph 17.1. to the entire hybrid contract.

Conversely, when a hybrid contract contains a host that is not an asset within the scope of IFRS 9, an embedded derivative shall be separated from the host and accounted for as a derivative if, and only if:

- the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host;
- a separate instrument within the same terms as the embedded derivative would meet the definition of a derivative; and
- the hybrid contract is not measured at fair value with changes in fair value recognized in profit or loss (i.e. a derivative that is embedded in a financial liability at fair value through profit or loss is not separated).

If an embedded derivative is separate from the host contract, it shall be measured at fair value and fair value changes are recognized in profit or loss (except if the embedded derivative is documented in a hedge relationship).

Hedging instruments: recognition and presentation

Derivative instruments qualifying as hedging instruments are recognized in the consolidated statement of financial position and measured at fair value. However, their accounting treatment varies according to whether they are classified as (i) a fair value hedge of an asset or liability; (ii) a cash flow hedge or (iii) a hedge of a net investment in a foreign operation.

Fair value hedges

A fair value hedge is defined as a hedge of the exposure to changes in fair value of a recognized asset or liability such as a fixed-rate loan or borrowing, or of assets, liabilities or an unrecognized firm commitment denominated in a foreign currency. The gain or loss from remeasuring the hedging instrument at fair value is recognized in income. The gain or loss on the hedged item attributable to the hedged risk adjusts the carrying amount of the hedged item and is also recognized in income even if the hedged item is in a category in respect of which changes in fair value are recognized through other comprehensive income. These two adjustments are presented net in the consolidated income statement, with the net effect corresponding to the ineffective portion of the hedge.

Cash flow hedges

A cash flow hedge is a hedge of the exposure to variability in cash flows that could affect the Group's income. The hedged cash flows may be attributable to a particular risk associated with a recognized financial or non-financial asset or a highly probable forecast transaction.

The portion of the gain or loss on the hedging instrument that is determined to be an effective hedge is recognized directly in other comprehensive income, net of tax, while the ineffective portion is recognized in income. The gains or losses accumulated in equity are reclassified to the consolidated income statement under the same caption as the loss or gain on the hedged item – i.e. current operating income for operating cash flows and financial income or expenses for other cash flows – in the same periods in which the hedged cash flows affect income.

If the hedging relationship is discontinued, in particular because the hedge is no longer considered effective, the cumulative gain or loss on the hedging instrument remains recognized in equity until the forecast transaction occurs. However, if a forecast transaction is no longer expected to occur, the cumulative gain or loss on the hedging instrument is immediately recognized in income.

Hedge of a net investment in a foreign operation

In the same way as for a cash flow hedge, the portion of the gain or loss on the hedging instrument that is determined to be an effective hedge of the currency risk is recognized directly in other comprehensive income, net of tax, while the ineffective portion is recognized in income. The gains or losses accumulated in other comprehensive income are transferred to the consolidated income statement when the investment is liquidated or sold.

Hedging instruments: identification and documentation of hedging relationships

The hedging instruments and hedged items are designated at the inception of the hedging relationship. The hedging relationship is formally documented in each case, specifying the hedging strategy, the hedged risk and the method used to assess hedge effectiveness. Only derivative contracts entered into with external counterparties are considered as being eligible for hedge accounting.

Hedge effectiveness is assessed and documented at the inception of the hedging relationship and on an ongoing basis throughout the periods for which the hedge was designated.

Hedge effectiveness is demonstrated both prospectively and retrospectively using various methods, based mainly on a comparison between changes in fair value or cash flows between the hedging instrument and the hedged item. Methods based on an analysis of statistical correlations between historical price data are also used.

Derivative instruments not qualifying for hedge accounting: recognition and presentation

These items mainly concern derivative financial instruments used in economic hedges that have not been – or are no longer – documented as hedging relationships for accounting purposes.

When a derivative financial instrument does not qualify or no longer qualifies for hedge accounting, changes in fair value are recognized directly in income, under “Mark-to-market” or “Mark-to-market on commodity contracts other than trading instruments” below current operating income for derivative instruments with non-financial assets as the underlying, and in financial income or expenses for currency, interest rate and equity derivatives.

Derivative instruments not qualifying for hedge accounting used by the Group in connection with proprietary commodity trading activities and other derivatives expiring in less than 12 months are recognized in the consolidated statement of financial position in current assets and liabilities, while derivatives expiring after this period are classified as non-current items.

Fair value measurement

The fair value of instruments listed on an active market is determined by reference to the market price. In this case, these instruments are presented in level 1 of the fair value hierarchy.

The fair value of unlisted financial instruments for which there is no active market and for which observable market data exist is determined based on valuation techniques such as option pricing models or the discounted cash flow method.

Models used to evaluate these instruments take into account assumptions based on market inputs:

- the fair value of interest rate swaps is calculated based on the present value of future cash flows;
- the fair value of forward foreign exchange contracts and currency swaps is calculated by reference to current prices for contracts with similar maturities by discounting the future cash flow spread (difference between the forward exchange rate under the contract and the forward exchange rate recalculated in line with the new market conditions applicable to the nominal amount);
- the fair value of currency and interest rate options is calculated using option pricing models;
- commodity derivatives contracts are valued by reference to listed market prices based on the present value of future cash flows (commodity swaps or commodity forwards) and option pricing models (options), for which market price volatility may be a factor. Contracts with maturities exceeding the depth of transactions for which prices are observable, or which are particularly complex, may be valued based on internal assumptions;
- exceptionally, for complex contracts negotiated with independent financial institutions, the Group uses the values established by its counterparties.

These instruments are presented in level 2 of the fair value hierarchy except when the evaluation is based mainly on data that are not observable; in which case they are presented in level 3 of the fair value hierarchy. Most often, this is the case for derivatives with a maturity that falls outside the observability period for market data relating to the underlying or when some parameters such as the volatility of the underlying are not observable.

Except in case of enforceable master netting arrangements or similar agreements, counterparty risk is included in the fair value of financial derivative instrument assets and liabilities. It is calculated according to the “expected loss” method and takes into account the exposure at default, the probability of default and the loss given default. The probability of default is determined on the basis of credit ratings assigned to each counterparty (“historical probability of default” approach).

Derivative instruments recognized in assets and liabilities are measured at fair value and broken down as follows:

In millions of euros	Dec. 31, 2018						Dec. 31, 2017 ⁽¹⁾					
	Assets			Liabilities			Assets			Liabilities		
	Non-current	Current	Total	Non-current	Current	Total	Non-current	Current	Total	Non-current	Current	Total
Derivatives hedging borrowings	678	42	720	259	66	325	610	63	673	293	59	352
Derivatives hedging commodities	1,409	10,608	12,018	1,311	11,405	12,716	1,532	7,231	8,763	1,475	8,544	10,018
Derivatives hedging other items ⁽²⁾	606	28	634	1,215	38	1,254	806	83	889	1,212	118	1,329
TOTAL	2,693	10,679	13,372	2,785	11,510	14,295	2,949	7,378	10,326	2,980	8,720	11,700

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 “Restatement of 2017 comparative data”).

(2) Derivatives hedging other items mainly include the interest rate component of interest rate derivatives (not qualifying as hedges or qualifying as cash flow hedges) that are excluded from net debt, as well as net investment hedge derivatives.

17.4.1 Offsetting of derivative instrument assets and liabilities

The net amount of derivative instruments after taking into account enforceable master netting arrangements or similar agreements, whether or not they are set off in accordance with Section 42 of IAS 32, are presented in the table below:

In millions of euros	Dec. 31, 2018					Dec. 31, 2017				
	Gross amount	NET AMOUNT RECOGNIZED IN THE STATEMENT OF FINANCIAL POSITION ⁽²⁾		Other offsetting agreements ⁽³⁾	TOTAL NET AMOUNT	Gross amount	NET AMOUNT RECOGNIZED IN THE STATEMENT OF FINANCIAL POSITION ^(1,2)		Other offsetting agreements ⁽³⁾	TOTAL NET AMOUNT
Assets										
Derivatives hedging commodities	12,588		12,018	(8,409)	3,608	9,177		8,763	(5,061)	3,703
Derivatives hedging borrowings and other items	1,354		1,354	(384)	970	1,563		1,563	(315)	1,248
Liabilities										
Derivatives hedging commodities	(13,286)		(12,716)	10,448	(2,268)	(10,432)		(10,018)	7,221	(2,798)
Derivatives hedging borrowings and other items	(1,579)		(1,579)	601	(978)	(1,682)		(1,682)	393	(1,289)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 “Restatement of 2017 comparative data”).

(2) Net amount recognized in the statement of financial position after taking into account offsetting agreements that meet the criteria set out in Section 42 of IAS 32.

(3) Other offsetting agreements include collateral and other guarantee instruments, as well as offsetting agreements that do not meet the criteria set out in Section 42 of IAS 32.

17.5 Fair value of financial instruments by level in the fair value hierarchy

17.5.1 Financial assets

The table below shows the allocation of financial instruments carried in assets to the different levels in the fair value hierarchy:

In millions of euros	Dec. 31, 2018				Dec. 31, 2017 ⁽¹⁾			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
Other financial assets (excluding loans and receivables at amortized cost)	3,887	1,554	-	2,332	3,493	976	277	1,937
Equity instruments at fair value through other comprehensive income	742	62	-	680	733	55	-	678
Equity instruments at fair value through income	365	-	-	365	393	37	-	356
Debt instruments at fair value through other comprehensive income	1,947	1,025	-	922	1,786	884	-	902
Debt instruments at fair value through income	832	467	-	365	580	-	277	-
Derivative instruments	13,372	38	12,912	422	10,326	21	9,993	313
Derivatives hedging borrowings	720	-	720	-	673	-	673	-
Derivatives hedging commodities - relating to portfolio management activities ⁽²⁾	2,075	-	2,036	39	2,001	-	1,969	32
Derivatives hedging commodities - relating to trading activities ⁽²⁾	9,943	38	9,522	383	6,763	21	6,461	281
Derivatives hedging other items	634	-	634	-	889	-	889	-
TOTAL	17,259	1,593	12,912	2,754	13,820	997	10,270	2,249

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

(2) Derivative financial instruments relating to commodities classified in level 3 mainly include long-term gas supply contracts and a power contract that are measured at fair value and relating to trading activities.

A definition of these three levels is presented in Note 17.4 "Derivative instruments".

Other financial assets (excluding loans and receivables at amortized cost)

At December 31, 2018, changes in level 3 equity and debt instruments at fair value can be analyzed as follows:

In millions of euros	Equity instruments at fair value through other comprehensive income	Equity instruments at fair value through income	Debt instruments at fair value through other comprehensive income	Debt instruments at fair value through income	Other financial assets (excluding loans and receivables at amortized cost)
At December 31, 2017⁽¹⁾	678	356	902	277	2,213
Acquisitions	44	170	170	85	469
Disposals	(61)	(81)	(145)	(2)	(290)
Changes in fair value	34	(46)	-	-	(11)
Changes in scope of consolidation, foreign currency translation and other changes	(15)	(34)	(5)	6	(49)
At December 31, 2018	680	365	922	365	2,332
Gains/(losses) recorded in income relating to instruments held at the end of the period					-

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

Derivative instruments

At December 31, 2018, changes in level 3 derivative instruments commodities can be analyzed as follows:

<i>In millions of euros</i>	Net Asset/(Liability)
At December 31, 2017	(188)
Changes in fair value recorded in income	29
Settlements	87
Transfer out of level 3 to levels 1 and 2	(6)
Net fair value recorded in income	(79)
Deferred Day-One gains/(losses)	(4)
At December 31, 2018	(83)

17.5.2 Financial liabilities

The table below shows the allocation of financial instruments carried in liabilities to the different levels in the fair value hierarchy:

<i>In millions of euros</i>	Dec. 31, 2018				Dec. 31, 2017⁽¹⁾			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
Borrowings used in designated fair value hedges	5,358	-	5,358	-	5,217	-	5,217	-
Borrowings not used in designated fair value hedges	28,293	19,028	9,265	-	30,352	19,478	10,874	-
Derivative instruments	14,295	26	13,764	505	11,700	26	11,173	501
Derivatives hedging borrowings	325	-	325	-	352	-	352	-
Derivatives hedging commodities - relating to portfolio management activities ⁽²⁾	2,124	-	2,075	49	2,210	-	2,140	70
Derivatives hedging commodities - relating to trading activities ⁽²⁾	10,592	26	10,110	456	7,808	26	7,351	431
Derivatives hedging other items	1,254	-	1,254	-	1,329	-	1,329	-
TOTAL	47,946	19,054	28,387	505	47,269	19,504	27,264	501

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

(2) Derivative financial instruments relating to commodities classified in level 3 mainly include long-term gas supply contracts and a power contract that are measured at fair value and relating to trading activities.

A definition of these three levels is presented in Note 17.4 "Derivative instruments".

Borrowings used in designated fair value hedges

This caption includes bonds in a designated fair value hedging relationship which are presented in level 2 in the above table. Only the interest rate component of the bonds is remeasured, with fair value determined by reference to observable inputs.

Borrowings not used in designated fair value hedges

Listed bond issues are included in level 1.

Other borrowings not used in a designated hedging relationship, which are presented in level 2 in the above table. The fair value of these borrowings is determined on the basis of future discounted cash flows and relies on directly or indirectly observable data.

NOTE 18 RISKS ARISING FROM FINANCIAL INSTRUMENTS

The Group mainly uses derivative instruments to manage its exposure to market risks. Financial risk management procedures are set out in Chapter 2 “Risk factors” of the Registration Document.

18.1 Market risks

18.1.1 Commodity risk

Commodity risk arises primarily from the following activities:

- portfolio management; and
- trading.

The Group has identified primarily two types of commodity risks: price risk resulting from fluctuations in market prices, and volume risk inherent to the business.

In the ordinary course of its operations, the Group is exposed to commodity risks on natural gas, electricity, coal, oil and oil products, other fuels, CO₂ and other “green” products. The Group is active on these energy markets either for supply purposes or to optimize and secure its energy production chain and its energy sales. The Group also uses derivatives to offer hedging instruments to its clients and to hedge its own positions.

18.1.1.1 Portfolio management activities

Portfolio management seeks to optimize the market value of assets (power plants, gas and coal supply contracts, energy sales and gas storage and transportation) over various time frames (short-, medium- and long-term). Market value is optimized by:

- guaranteeing supply and ensuring the balance between physical needs and resources;
- managing market risks (price, volume) to unlock optimum value from portfolios within a specific risk framework.

The risk framework aims to safeguard the Group’s financial resources over the budget period and smooth out medium-term earnings (over three or five years, depending on the maturity of each market). It encourages portfolio managers to take out economic hedges on their portfolio.

Sensitivities of the commodity-related derivatives portfolio used as part of the portfolio management activities as at December 31, 2018 are detailed in the table below. They are not representative of future changes in consolidated earnings and equity, insofar as they do not include the sensitivities relating to the purchase and sale contracts for the underlying commodities.

Sensitivity analysis⁽¹⁾

In millions of euros	Changes in price	Dec. 31, 2018		Dec. 31, 2017	
		Pre-tax impact on income	Pre-tax impact on equity	Pre-tax impact on income	Pre-tax impact on equity
Oil-based products	+USD 10/bbl	60	-	307	197
Natural gas	+€3/MWh	961	1	(17)	(48)
Electricity	+€5/MWh	65	(26)	145	(30)
Coal	+USD 10/ton	9	2	33	2
Greenhouse gas emission rights	+€2/ton	37	1	53	-
EUR/USD	+10%	67	(2)	102	(233)
EUR/GBP	+10%	87	-	69	2

(1) The sensitivities shown above apply solely to financial commodity derivatives used for hedging purposes as part of the portfolio management activities.

The change in sensitivity on natural gas compared to December 31, 2017 is mainly related to the sale of the upstream LNG activities, whose long exposure offset the short exposure of the gas supply activities.

18.1.1.2 Trading activities

The Group's trading activities are primarily conducted within:

- ENGIE Global Markets and ENGIE Energy Management. The purpose of these wholly-owned companies is to (i) assist Group entities in optimizing their asset portfolios; (ii) create and implement energy price risk management solutions for internal and external customers;
- ENGIE SA for the optimization of part of its long-term gas supply contracts, of a power exchange contract and of part of its gas sales contracts with retail entities in France and Benelux and with power generation facilities in France and Belgium.

Revenues from trading activities totaled €526 million at December 31, 2018 (€349 million at December 31, 2017).

The use of Value at Risk (VaR) to quantify market risk arising from trading activities provides a transversal measure of risk taking all markets and products into account. VaR represents the maximum potential loss on a portfolio over a specified holding period based on a given confidence interval. It is not an indication of expected results but is back-tested on a regular basis.

The Group uses a one-day holding period and a 99% confidence interval to calculate VaR, as well as stress tests, in accordance with banking regulatory requirements.

The VaR shown below corresponds to the global VaR of the Group's trading entities.

Value at Risk

In millions of euros	Dec. 31, 2018	2018 average ⁽¹⁾	2018 maximum ⁽²⁾	2018 minimum ⁽²⁾	2017 average ⁽¹⁾
Trading activities	13	10	21	4	9

(1) Average daily VaR.

(2) Maximum and minimum daily VaR observed in 2018.

18.1.2 Hedges of commodity risks

The Group enters into cash flow hedges, using derivative instruments (firm or option contracts) contracted over the counter or on organized markets, to reduce its commodity risks that relate mainly to future cash flows from contracted or expected sales and purchases of commodities. These instruments may be settled net or involve physical delivery of the underlying.

The Group applies cash flow hedge accounting as defined by IFRS 9 only for a minor part of the aforementioned hedge transactions. The disposal of the Group's upstream liquefied natural gas activities and of the exploration-production business (70% interest in EPI) in 2018 further reduced the materiality of hedge accounting for commodity risks.

The fair values of commodity derivatives at December 31, 2018 and December 31, 2017 are indicated in the table below:

In millions of euros	Dec. 31, 2018				Dec. 31, 2017 ⁽¹⁾			
	Assets		Liabilities		Assets		Liabilities	
	Non-current	Current	Non-current	Current	Non-current	Current	Non-current	Current
Derivative instruments relating to portfolio management activities	1,409	666	(1,311)	(813)	1,532	468	(1,475)	(736)
Cash flow hedges	46	56	(61)	(129)	186	62	(208)	(110)
Other derivative instruments	1,364	610	(1,249)	(684)	1,346	406	(1,267)	(625)
Derivative instruments relating to trading activities	-	9,943	-	(10,592)	-	6,763	-	(7,808)
TOTAL	1,409	10,608	(1,311)	(11,405)	1,532	7,231	(1,475)	(8,544)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

See also Note 17.4 “Derivative instruments”.

The fair values shown in the table above reflect the amounts for which assets could be exchanged, or liabilities settled, at the end of the reporting period. They are not representative of expected future cash flows insofar as positions (i) are sensitive to changes in prices; (ii) can be modified by subsequent transactions; and (iii) can be offset by future cash flows arising on the underlying transactions.

18.1.2.1 Cash flow hedges

The fair values of cash flow hedges by type of commodity are as follows:

In millions of euros	Dec. 31, 2018				Dec. 31, 2017 ⁽¹⁾			
	Assets		Liabilities		Assets		Liabilities	
	Non-current	Current	Non-current	Current	Non-current	Current	Non-current	Current
Natural gas	20	15	(1)	(3)	14	12	-	(10)
Electricity	1	3	(44)	(120)	3	7	(44)	(52)
Coal	7	3	-	-	8	4	-	-
Oil	-	-	-	-	145	1	-	(1)
Other ⁽²⁾	18	35	(16)	(6)	16	38	(164)	(47)
TOTAL	46	56	(61)	(129)	186	62	(208)	(110)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 “Restatement of 2017 comparative data”).

(2) Includes mainly foreign currency hedges on commodities.

Notional amounts (net)⁽¹⁾

Notional amounts and maturities of cash flow hedges are as follows:

	Unit	Total at Dec. 31, 2018	2019	2020	2021	2022	2023	Beyond 5 years
Natural gas	GWh	5,619	3,258	2,361	-	-	-	-
Electricity	GWh	(8,028)	(4,601)	(2,241)	(1,186)	-	-	-
Coal	Thousands of tons	220	128	92	-	-	-	-
Oil-based products	Thousands of barrels	-	-	-	-	-	-	-
Forex	Millions of euros	65	25	21	18	-	-	-
Greenhouse gas emission rights	Thousands of tons	1,050	900	150	-	-	-	-

(1) Long/(short) position.

At December 31, 2018, a loss of €35 million was recognized in equity in respect of cash flow hedges, versus a loss of €24 million at December 31, 2017. A loss of €20 million was reclassified from equity to income in 2018, compared to a loss of €185 million in 2017.

Gains and losses arising from the ineffective portion of hedges are taken through profit or loss. This represented a gain of €8 million in 2018, compared to a loss of €6 million in 2017.

18.1.2.2 Other commodity derivatives

Other commodity derivatives include:

- commodity purchase and sale contracts that were not entered into or are no longer held for the purpose of the receipt or delivery of commodities in accordance with the Group’s expected purchase, sale or usage requirements;
- embedded derivatives; and
- derivative financial instruments that are not eligible for hedge accounting in accordance with IFRS 9 or for which the Group has elected not to apply hedge accounting.

18.1.3 Currency risk

The Group is exposed to currency risk, defined as the impact on its statement of financial position and income statement of fluctuations in exchange rates affecting its operating and financing activities. Currency risk comprises (i) transaction risk arising in the ordinary course of business, (ii) specific transaction risk related to investments, mergers and acquisitions or disposal projects, and (iii) translation risk arising from the conversion in euros of income statement and statement of financial position items from subsidiaries with a functional currency other than the euro. The main translation risk exposures correspond, in order, to assets in American dollars, Brazilian real and pounds sterling.

18.1.3.1 Financial instruments by currency

The following tables present a breakdown by currency of outstanding gross debt and net debt, before and after hedging:

Outstanding gross debt

	Dec. 31, 2018		Dec. 31, 2017	
	Before hedging	After hedging	Before hedging	After hedging
EUR	68%	76%	69%	79%
USD	12%	14%	12%	11%
GBP	8%	1%	7%	0%
Other currencies	12%	9%	12%	10%
TOTAL	100%	100%	100%	100%

Net debt

	Dec. 31, 2018		Dec. 31, 2017	
	Before hedging	After hedging	Before hedging	After hedging
EUR	63%	75%	65%	80%
USD	15%	18%	16%	14%
GBP	12%	1%	9%	(1)%
Other currencies	10%	6%	10%	7%
TOTAL	100%	100%	100%	100%

18.1.3.2 Currency risk sensitivity analysis

Sensitivity analysis to currency risk on financial income/(loss) – excluding the income statement translation impact of foreign subsidiaries – was performed based on all financial instruments managed by the treasury department and representing a currency risk (including derivative financial instruments).

Sensitivity analysis to currency risk on equity was performed based on all financial instruments qualified as net investment hedges at the reporting date.

For currency risk, sensitivity corresponds to a 10% rise or fall in exchange rates of foreign currencies against the euro compared to closing rates.

	Dec. 31, 2018		
	Impact on income	Impact on equity	
<i>In millions of euros</i>	+10% ⁽¹⁾	-10% ⁽¹⁾	+10% ⁽¹⁾
Exposures denominated in a currency other than the functional currency of companies carrying the liabilities on their statements of financial position ⁽²⁾	(18)	18	NA
Financial instruments (debt and derivatives) qualified as net investment hedges ⁽³⁾	NA	NA	137

(1) +(-)10%: depreciation (appreciation) of 10% on all foreign currencies against the euro.

(2) Excluding derivatives qualified as net investment hedges.

(3) This impact is countered by the offsetting change in the net investment hedged.

18.1.4 Interest rate risk

The Group seeks to manage its borrowing costs by limiting the impact of interest rate fluctuations on its income statement. The Group's policy is therefore to arbitrate between fixed rates, floating rates and capped floating rates for its net debt. The interest rate mix may shift within a range defined by the Group Management in line with market trends.

In order to manage the interest rate structure for its net debt, the Group uses hedging instruments, particularly interest rate swaps and options. At December 31, 2018, the Group had a portfolio of interest rate options (caps) protecting it from a rise in short-term interest rates for the euro.

The Group has a portfolio of 2019 and 2020 forward interest rate pre-hedges with respective 18- and 10-year maturities to protect the refinancing interest rate on a portion of its debt.

18.1.4.1 Analysis of financial instruments by type of interest rate

The following tables present a breakdown by type of interest rate of outstanding gross debt and net debt before and after hedging.

Outstanding gross debt

	Dec. 31, 2018		Dec. 31, 2017	
	Before hedging	After hedging	Before hedging	After hedging
Floating rate	23%	43%	29%	39%
Fixed rate	77%	57%	71%	61%
TOTAL	100%	100%	100%	100%

Net debt

	Dec. 31, 2018		Dec. 31, 2017	
	Before hedging	After hedging	Before hedging	After hedging
Floating rate	(11)%	19%	(1)%	14%
Fixed rate	111%	81%	101%	86%
TOTAL	100%	100%	100%	100%

18.1.4.2 Interest rate risk sensitivity analysis

Sensitivity was analyzed based on the Group's net debt position (including the impact of interest rate and foreign currency derivatives relating to net debt) at the reporting date.

For interest rate risk, sensitivity corresponds to a 100-basis-point rise or fall in the yield curve compared to year-end interest rates.

In millions of euros	Dec. 31, 2018			
	Impact on income		Impact on equity	
	+100 basis points	-100 basis points	+100 basis points	-100 basis points
Net interest expense on floating-rate net debt (nominal amount) and on floating-rate leg of derivatives	(40)	39	NA	NA
Change in fair value of derivatives not qualifying as hedges	51	(65)	NA	NA
Change in fair value of derivatives qualifying as cash flow hedges	NA	NA	321	(412)

18.1.5 Currency and interest rate hedges

18.1.5.1 Currency risk management

Foreign currency exchange risk (or “FX” risk) is reported and managed based on a Group-wide approach, reflected in a dedicated Group policy that is validated by Group Management. The policy distinguishes between the three following main sources of currency risk:

- **Regular transaction risk**

Regular transaction risk corresponds to the potential negative financial impact of currency fluctuations on business and financial operations denominated in a currency other than the functional currency.

The management of regular transaction risk is fully delegated to the subsidiaries for their scope of activities, while the risks related to central activities are managed at corporate level.

FX risks related to operational activities are systematically hedged when the related cash flows are certain, with a hedging horizon that corresponds at least to the medium-term plan horizon. For cash flows that are not certain, in their entirety, the hedge is initially based on a “no regret” volume. Exposures are monitored and managed based on the sum of nominal cash flows in FX, including highly probable amounts and related hedges.

For FX risks related to financial activities, all significant exposures related to cash, financial debts, etc. are systematically hedged. Exposures are monitored based on the net sum of balance sheet items in FX.

- **Project transaction risk**

Specific project transaction risk corresponds to the potential negative financial impact of FX fluctuations on specific major operations such as investment projects, acquisitions, disposals and restructuring projects, involving multiple currencies.

The management of these FX risks includes the definition and implementation of hedging transactions, taking into account the likelihood of the risk (including probability of project completion) and its evolution, the availability of hedging instruments and their associated cost. Management’s aim is to ensure the viability and the profitability of the transactions.

- **Translation risk**

Translation risk corresponds to the potential negative financial impact of FX fluctuations concerning consolidated entities with a functional currency other than the euro. It relates to the translation of their income and expenses and their net assets.

Translation risk is managed centrally, with a focus on securing the net asset value.

The pertinence of hedging this translation risk is assessed regularly for each currency (as a minimum) or set of assets in the same currency, taking into account notably the value of the assets and the hedging costs.

Hedging instruments and sources of hedge ineffectiveness

The Group principally uses the following risk management levers for mitigating currency risk:

- derivative instruments: these mostly correspond to over-the-counter contracts and include FX forward transactions, FX swaps, currency swaps, cross currency swaps, plain vanilla FX options or combinations (calls, puts or collars);
- monetary items such as debt, cash and loans.

Sources of hedge ineffectiveness are mainly related to uncertainty regarding the timing and in some cases the amount of the future cash flows in foreign currency that are being hedged.

18.1.5.2 Interest rate risk management

The Group is exposed to interest rate risk through its financing and investing activities. Interest rate risk is defined as a financial risk resulting from fluctuations in base interest rates that may increase the cost of debt and affect the viability of investments. Base interest rates are market interest rates, such as EURIBOR, LIBOR, etc., that do not include the borrower's credit spread.

A Group-wide approach on interest rate risk management is reflected in a dedicated Group policy that is validated by Group Management. This policy distinguishes between the two following main sources of interest rate risk:

- **Interest rate risk relating to Group net debt**

Interest rate risk relating to Group net debt designates the financial impact of base rate movements on the debt and cash portfolio from recurring financing activities. This risk is mainly managed centrally.

Risk management objectives are, in order of importance:

- to protect the long term viability of assets;
- to optimize financing costs and ensure competitiveness; and
- to minimize uncertainty on the cost of debt.

The evolution of the interest rate risk is managed actively by monitoring the market rates and their effect on the Group's gross and net debt.

- **Project interest rate risk**

Specific project interest rate risk corresponds to the potential negative financial impact of base rate movements on specific major operations such as investment projects, acquisitions, disposals and restructuring projects. Interest rate risk after the closing of an operation is considered as regular (see paragraph "Interest rate risk" above).

Managing interest rate risk for specific project transactions aims to protect the economic viability of projects, acquisitions, disposals and restructuring initiatives against adverse changes in interest rates. It may include the implementation of hedging transactions, depending on a number of factors including the likeliness of completion, the availability of hedging instruments and their associated cost.

Hedging instruments and sources of hedge ineffectiveness

The Group uses principally the following risk management levers for mitigating interest rate risk:

- derivative instruments: these mostly correspond to over-the-counter contracts allowing to manage base interest rates. Such instruments include:
 - swaps, to change the nature of interest payments on debts, typically from fixed to floating rates or vice versa, and
 - plain vanilla interest rate options;
- caps, floors and collars that allow the impact of interest rate fluctuations to be limited by setting minimum and/or maximum limits on floating interest rates.

Sources of hedge ineffectiveness are mainly related to changes in the credit quality of the counterparties and related charges, as well as potential gaps in settlement dates and in indices between the derivative instruments and the related underlying exposures.

18.1.5.3 Currency and interest rate hedges

The Group has elected to apply hedge accounting whenever possible and suitable for currency risk and interest rate risk management and also manages a portfolio of undesignated derivative instruments, corresponding to economic hedges relating to net debt and foreign currency exposures.

The Group uses the three hedge accounting methods: cash flow hedging, fair value hedging and net investment hedging.

In general, the Group does not frequently reset hedging relationships, does not designate specific risk components as a hedged item and does not designate credit exposures as measured at fair value through income.

The Group qualifies interest rate or cross currency swaps transforming fixed-rate debt into floating-rate debt as fair value hedges.

Cash flow hedges are mainly used to hedge future cash flows in foreign currency, floating-rate debt as well as future refinancing requirements.

Net investment hedging instruments are mainly FX swaps and forwards.

The fair values of derivatives (excluding commodity instruments) at December 31, 2018 and December 31, 2017 are indicated in the table below:

	Dec. 31, 2018				Dec. 31, 2017 ⁽¹⁾			
	Assets		Liabilities		Assets		Liabilities	
	Non-current	Current	Non-current	Current	Non-current	Current	Non-current	Current
<i>In millions of euros</i>								
Derivatives hedging borrowings	678	42	(259)	(66)	610	63	(293)	(59)
Fair value hedges	521	1	(29)	(1)	449	9	(38)	-
Cash flow hedges	24	-	(191)	-	15	1	(191)	-
Derivative instruments not qualifying for hedge accounting	133	42	(39)	(65)	147	53	(64)	(59)
Derivatives hedging other items	606	28	(1,215)	(38)	806	83	(1,212)	(118)
Fair value hedges	-	-	-	-	-	-	-	-
Cash flow hedges	21	1	(284)	(4)	128	5	(375)	(37)
Net investment hedges	1	-	(5)	-	54	-	(8)	-
Derivative instruments not qualifying for hedge accounting	583	27	(927)	(34)	625	78	(830)	(80)
TOTAL	1,283	71	(1,474)	(105)	1,417	146	(1,505)	(177)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

See also Note 17.4 "Derivative instruments".

The fair values shown in the table above reflect the amounts relating to the price that would be received for the sale of an asset or paid for the transfer of a liability between market participants in the normal course of business. They are not representative of expected future cash flows insofar as positions (i) are sensitive to changes in prices or to changes in credit ratings, (ii) can be modified by subsequent transactions, and (iii) can be offset by future cash flows arising on the underlying transactions.

Amount, timing and uncertainty of future cash flows

The following tables provide a profile of the timing at December 31, 2018 of the nominal amount of the hedging instruments, and, if applicable, the average price or rate of the hedging instrument:

In millions of euros

Buy/Sell	Interest rate type	Derivative instrument type	Currency	Total	2019	2020	2021	2022	2023	Beyond 5 years
Buy	Fixed	CCS	AUD	(527)	(123)	(123)	(123)	(52)	(52)	(52)
			CHF	(954)	(399)	(399)	(155)	-	-	-
			EUR	(615)	(322)	(288)	(6)	-	-	-
			GBP	(13,808)	(2,041)	(2,041)	(1,789)	(1,789)	(1,230)	(4,919)
			HKD	(1,338)	(256)	(256)	(256)	(256)	(156)	(156)
			JPY	(993)	(358)	(358)	(278)	-	-	-
			NOK	(151)	(50)	(50)	(50)	-	-	-
			PEN	(967)	(263)	(263)	(252)	(189)	-	-
			USD	(2,281)	(1,053)	(1,097)	(44)	(44)	(44)	-
			USD	(580)	(262)	(318)	-	-	-	-
Sale	Fixed	CCS	CLP	13	7	6	-	-	-	-
			EUR	17,988	3,095	3,138	2,568	2,277	1,541	5,369
			GBP	550	286	259	5	-	-	-
			INR	58	-	58	-	-	-	-
			USD	1,030	289	286	260	195	-	-
	Floating	CCS	BRL	600	300	300	-	-	-	-
			EUR	2,633	1,180	1,180	273	-	-	-

In millions of euros

Buy/Sell	Interest rate type	Derivative instrument type	Currency	Total	2019	2020	2021	2022	2023	Beyond 5 years
Buy	Fixed	CAP	EUR	2,000	1,000	1,000	-	-	-	-
			HUF	1	-	-	-	-	-	-
			AUD	2	2	-	-	-	-	-
		IRS	CAD	-	-	-	-	-	-	-
			CZK	16	4	4	3	2	1	-
			EUR	38,495	5,671	7,324	8,197	6,157	3,660	7,486
			GBP	13	5	4	3	1	-	-
			USD	2,526	831	705	292	249	201	248
		FRA	EUR	3,600	1,950	1,650	-	-	-	-
	Floating	IRS	BRL	675	250	250	176	-	-	-
			EUR	45,484	13,056	11,751	7,589	5,972	2,482	4,635

The tables presented above exclude currency derivatives (except for cross currency swaps - CCS). These hedges are mainly short term, with maturity dates aligned with those of the hedged items.

Pursuant to the FX and interest rate risk management policy, FX sensitivity is presented in Note 18.1.3.2 "Currency risk sensitivity analysis" and the average cost of debt is 2.68% as presented in Note 11.1 "Cost of net debt".

Effects of hedge accounting on the Group's financial position and performance

The following tables show:

- the carrying amounts of the hedging instruments (financial assets separately from financial liabilities), with reference to the line item in the statement of financial position that includes the hedging instrument; and
- the nominal amounts of the hedging instruments.

Currency derivatives

In millions of euros	Dec. 31, 2018				Dec. 31, 2017	
	Fair value			Nominal	Fair value	Nominal
	Assets	Liabilities	Total	Total	Total	Total
Cash flow hedges	45	(380)	(335)	3,268	(167)	3,285
Net investment hedges	1	(5)	(3)	1,114	47	3,370
Derivative instruments not qualifying for hedge accounting	82	(105)	(23)	10,996	(76)	5,161
TOTAL	128	(489)	(361)	15,379	(197)	11,815

Interest rate derivatives

In millions of euros	Dec. 31, 2018				Dec. 31, 2017	
	Fair value			Nominal	Fair value	Nominal
	Assets	Liabilities	Total	Total	Total	Total
Fair value hedges	521	(30)	491	4,846	420	4,941
Cash flow hedges	1	(99)	(98)	1,434	(287)	1,550
Derivative instruments not qualifying for hedge accounting	703	(960)	(257)	25,216	(55)	21,792
TOTAL	1,226	(1,090)	136	31,496	78	28,283

The fair values shown in the table above are positive for an asset and negative for a liability.

Hedge inefficiency is calculated based on the change in the fair value of the hedging instrument compared to the change in the fair value of the hedged items since inception of the hedge. The fair value of the hedging instruments at December 31, 2018 reflects the cumulative change in the fair value of the hedging instruments since inception of the hedges. For fair value hedges, the same principle applies to the hedged items.

Fair value hedges

The following tables concerning fair value hedges show:

- the carrying amounts of the hedged items and the accumulated amounts of fair value adjustments included in these carrying amounts, financial assets separately from financial liabilities, and with reference to the line item in the statement of financial position that includes the hedged items;
- the nominal amounts of the hedging instruments;
- the accumulated amount of fair value hedge adjustments remaining in the statement of financial position for any hedged items that have ceased to be adjusted for hedging gains and losses in accordance with paragraph 6.5.10 of IFRS 9; and
- the ineffective portion of the hedge recognized in the statement of profit or loss.

In millions of euros	Nominal amount	Fair value	Line item of the statement of financial position	Change in fair value used for calculating hedge ineffectiveness ⁽¹⁾	Ineffective portion recognized in profit or loss	Line item of the income statement
Hedging instruments	4,941	420	Derivatives hedging borrowings	420	(2)	Cost of net debt

In millions of euros	Outstanding amount	Impact of fair value hedge ^(1,2)	Line item of the statement of financial position	Change in value used for calculating hedge ineffectiveness
Hedged items	4,951	365	Long-term and short-term borrowings	142

(1) The difference between the fair value used to determine the ineffective portion relating to hedging instruments and that relating to the hedged items corresponds to the amortized cost of borrowings and debt that are part of fair value hedge relationship.

(2) Of which €153 million relating to hedging items that have ceased to be adjusted as a result of fair value hedge discontinuance.

Cash flow hedges

The following tables concerning cash flow hedges show:

- the change in fair value of the hedged item used as the basis for recognizing hedge ineffectiveness for the period;
- the balances in the cash flow hedge reserve for continuing hedges;
- the balances remaining in the cash flow hedge reserve for hedging relationships for which hedge accounting is no longer applied;
- the ineffective portion of the hedge recognized in the statement of profit or loss; and
- the gains and losses recognized in and reclassified from equity.

<i>In millions of euros</i>	Nominal amount	Fair value	Line item of the statement of financial position	Change in fair value used for calculating hedge ineffectiveness	Change in the value of the hedging instrument recognized in equity ⁽¹⁾	Ineffective portion recognized in profit or loss ⁽¹⁾	Line item of the income statement	Amount reclassified from the hedge reserve to profit or loss ⁽¹⁾	Line item of the income statement
			Derivatives hedging borrowings/ other items				Other financial income and expenses/ Income/(loss) from operating activities		Other financial income and expenses/ Income/(loss) from operating activities
Hedging instruments	4,835	(454)		(291)	65	(1)		127	
<i>(1) Gains/(losses).</i>									

<i>In millions of euros</i>	Change in fair value used for calculating hedge ineffectiveness	Cash flow hedge reserve - hedge accounting still applied	Cash flow hedge reserve - hedge accounting no longer applied
Hedged items	290	(265)	(459)

Foreign currency and interest rate derivatives designated as cash flow hedges can be analyzed as follows by maturity:

At December 31, 2018

<i>In millions of euros</i>	Total	2019	2020	2021	2022	2023	Beyond 5 years
Fair value of derivatives by maturity date	(433)	4	(25)	(28)	(12)	(13)	(360)

At December 31, 2017

<i>In millions of euros</i>	Total	2018	2019	2020	2021	2022	Beyond 5 years
Fair value of derivatives by maturity date	(454)	(49)	(31)	(62)	(29)	(22)	(261)

Net investment hedges

The following tables concerning net investment hedges show:

- the change in fair value of the hedged item used as the basis for recognizing hedge ineffectiveness for the period;
- the balances in the foreign currency translation reserve for continuing hedges;
- the balances remaining in the foreign currency translation reserve for hedging relationships for which hedge accounting is no longer applied;
- the ineffective portion of the hedge recognized in the statement of profit or loss; and
- the gains and losses recognized in and reclassified from equity.

<i>In millions of euros</i>	Nominal amount	Fair value	Line item of the statement of financial position	Change in fair value used for calculating hedge ineffectiveness	Change in the value of the hedging instrument recognized in equity ⁽¹⁾	Ineffectiveness recognized in profit or loss ⁽¹⁾	Line item of the income statement	Amount reclassified from the hedge reserve to profit or loss ⁽¹⁾	Line item of the income statement
Hedging instruments	3,370	47	Derivatives hedging other items	3	25	-	Other financial income and expenses	(32)	Income/(loss) from operating activities
(1) Gains/(losses).									

<i>In millions of euros</i>	Change in fair value used for calculating hedge ineffectiveness	Cash flow hedge reserve - hedge accounting still applied	Cash flow hedge reserve - hedge accounting no longer applied
Hedged items	(3)	(313)	NA

Amounts presented in the statement of changes in equity and of comprehensive income

The following table provides a reconciliation of each component of equity and an analysis of other comprehensive income:

<i>In millions of euros</i>	Cash flow hedge			Net investment hedge
	Derivatives hedging borrowings - currency risk hedging ⁽¹⁾	Derivatives hedging other items - interest rate risk hedging ⁽¹⁾	Derivatives hedging other items - currency risk hedging ⁽²⁾	Derivatives hedging other items - currency risk hedging ⁽²⁾
At December 31, 2017	46	(562)	(18)	(320)
Effective portion recognized in equity	(72)		7	(25)
Amount reclassified from the hedge reserve to profit or loss	(156)		29	32
Translation differences	-	-	-	-
Changes in scope of consolidation and other	1	5	(3)	-
AT DECEMBER 31, 2018	46	(741)	(28)	(313)

(1) Time period related to cash flow hedges.

(2) Transaction related to cash flow hedges.

18.2 Counterparty risk

Due to its financial and operational activities, the Group is exposed to the risk of default of its counterparties (customers, suppliers, EPC contractors, partners, intermediaries, and banks). Default could affect payments, goods delivery and/or asset performance.

The principles of counterparty risk management are set out in the Group counterparty risk policy, which:

- assigns roles and responsibilities for managing and controlling counterparty risk at different levels (Corporate, BU or entity), and ensures operational procedures are in place and consistent across the Group;
- characterizes counterparty risk and the mechanisms by which it impacts the economic performance and financial statements of the Group;
- defines indicators, reporting and control mechanisms to ensure a visibility and to provide tools for financial performance management; and

- provides guidelines on the use of mitigating mechanisms such as collaterals and guarantees, which are widely used by some businesses.

Depending on the nature of the business, the Group is exposed to different types of counterparty risk. As a result some businesses use collateral instruments – particularly the Energy Management business, where the use of margin calls and other types of financial collateral (standardized legal framework) is a market standard. In addition, other businesses may request guarantees from their counterparties in certain cases (parent company guarantees, bank guarantees, etc.).

Under the new standard IFRS 9, the Group has defined and applied a Group-wide methodology which includes the two different approaches:

- a portfolio approach, for which the Group determines that:
 - coherent customer portfolios and sub-portfolios have to be considered (i.e., portfolios that have comparable credit risk and/or comparable payment behavior), taking into account different aspects:
 - public or private counterparties,
 - residential or BtoB counterparties,
 - geography,
 - type of activity,
 - size of the counterparty,
 - any other aspects the Group may consider relevant, and
 - impairment rates must be determined based on historical ageing balances and, when correlation is proven and documentation possible, the historical data must be adjusted by forward-looking elements;
- an individualized approach for significant counterparties, for which the Group has set rules for defining the stage of the concerned asset for Expected Credit Loss (ECL) calculations:
 - stage 1 covers financial assets that have not deteriorated significantly since initial recognition. The ECL for stage 1 is calculated on a 12-month basis,
 - stage 2 covers financial assets for which the credit risk has significantly increased. The ECL for stage 2 is calculated on a lifetime basis. The decision to move an asset from stage 1 to stage 2 is based on certain criteria such as:
 - a significant downgrade of the counterparty's creditworthiness and/or its parent company and/or its guarantor (if any),
 - significant adverse change in the regulatory environment,
 - changes in political or country-related risk, and
 - any other aspect the Group may consider relevant.

Regarding financial assets that are more than 30 days past due, the move to stage 2 is not systematically applied as long as the Group has reasonable and supportable information that demonstrates that, even if payments become more than 30 days past due, this does not represent a significant increase in the credit risk since initial recognition.

- stage 3 covers assets for which default has already been observed, such as:
 - when there is evidence of significant and ongoing financial difficulty of the counterparty,
 - when there is evidence of failure in credit support from a parent company to its subsidiary (in this case the subsidiary is the Group's counterparty at risk),
 - when a Group entity has initiated legal proceedings against the counterparty for non-payment.

Regarding financial assets that are more than 90 days past due, the presumption can be rebutted if the Group has reasonable and supportable information that demonstrates that even if payments become more than 90 days past due, this does not indicate counterparty default.

The ECL formula applicable in stages 1 and 2 is $ECL = EAD \times PD \times LGD$, where:

- for 12-month ECL, Exposure At Default (EAD) equals the carrying amount of the financial asset, to which the relevant Probability of Default (PD) and the Loss Given Default (LGD) are applied;

- for lifetime ECL, the calculation method consists in identifying the evolution of exposure for each year, especially the expected timing and amount of the contractual repayments, and then applying to each repayment the relevant PD and the LGD, and discounting the figures obtained. ECL is then the sum of the discounted figures; and
- probability of default: is the likelihood of default over a particular time horizon (in stage 1, this time horizon is 12 months after the reporting period; in stage 2 this time horizon is the entire lifetime of the financial asset). This information is based on external data from a well-known rating agency. The PD depends on the time horizon and of the rating of the counterparty. The Group uses external ratings if they are available; ENGIE's credit risk experts determine an internal rating for major counterparties with no external rating.

LGD levels are notably based on Basel standards:

- 75% for subordinated assets; and
- 45% for standard assets.

For assets considered as of strategic importance for the counterparty, such as essential public services or goods, the LGD parameter is set at 30%.

The Group has decided that write-off applies in the following situations:

- for assets for which a legal recovery procedure is pending: no write-off to be applied as long as the procedure is ongoing;
- for assets for which no legal recovery procedure is pending: write-off should be booked once the trade receivable is 3 years overdue (5 years overdue for public counterparties).

18.2.1 Operating activities

Counterparty risk arising on operating activities is managed via standard mechanisms such as third-party guarantees, netting agreements and margin calls, using dedicated hedging instruments or special prepayment and debt recovery procedures, particularly for retail customers.

Under the Group's policy, each business unit is responsible for managing counterparty risk, although the Group continues to manage the biggest counterparty exposures centrally.

The credit rating of large- and mid-sized counterparties with which the Group has exposures above a certain threshold is measured based on a specific rating process, while a simplified credit scoring process is used for commercial customers with which the Group has fairly low exposures. These processes are based on formally documented, consistent methods across the Group. Consolidated exposures are monitored by counterparty and by segment (credit rating, sector, etc.) using standard indicators (payment risk, mark-to-market exposure).

The Group's Energy Market Risk Committee (CRME) consolidates and monitors the Group's exposure to its main energy counterparties on a quarterly basis and ensures that the exposure limits set for these counterparties are respected.

18.2.1.1 Trade and other receivables, contract assets

The following tables concerning exposure to counterparty risk of "Trade and other receivables" and "Contract assets" show:

- the allocation of the outstanding amount according to the approach chosen (individual or collective) for monitoring expected credit losses;
- the breakdown of the outstanding amount relating to "Trade and other receivables" and "Contract assets" monitored according to the individual approach:
 - by risk level (levels 1, 2 and 3),
 - by counterparty type (investment grade versus other);

- the breakdown of the outstanding amount relating to “Trade and other receivables” and “Contract assets” monitored according to the collective approach between past due assets and assets neither impaired nor past due.

Total outstanding exposures presented in the tables hereafter do not include impacts relating to VAT or to any other item not subject to credit risk, which amounted to €2,547 million and €13 million respectively for “Trade and other receivables” and “Contract assets” at December 31, 2018 (compared to €2,114 million and €12 million at December 31, 2017).

Outstanding exposure breaks down as follows by type of monitoring approach:

		Dec. 31, 2018			Dec. 31, 2017		
		Individual approach	Collective approach	Total	Individual approach	Collective approach	Total
<i>In millions of euros</i>							
Trade and other receivables, net	Gross	10,339	3,804	14,142	8,548	3,546	12,094
	Expected credit losses	(323)	(754)	(1,076)	(352)	(729)	(1,081)
TOTAL		10,016	3,050	13,066	8,196	2,817	11,013
Assets from contracts with customers	Gross	3,052	4,381	7,432	2,757	4,073	6,831
	Expected credit losses	(7)	(1)	(8)	(7)	(5)	(12)
TOTAL		3,045	4,379	7,424	2,750	4,068	6,818

Individual approach

Outstanding “Trade and other receivables” and “Contract assets” exposures monitored according to the individual approach break down as follows by risk level:

		Dec. 31, 2018				Dec. 31, 2017			
		Level 1: low credit risk	Level 2: increased credit risk	Level 3: impaired assets	Total	Level 1: low credit risk	Level 2: increased credit risk	Level 3: impaired assets	Total
<i>In millions of euros</i>									
Trade and other receivables, net	Gross	9,694	422	222	10,339	7,821	455	272	8,548
	Expected credit losses	(107)	(71)	(145)	(323)	(103)	(76)	(173)	(352)
TOTAL		9,587	352	77	10,016	7,718	379	99	8,196
Assets from contracts with customers	Gross	2,730	261	61	3,052	2,047	507	203	2,757
	Expected credit losses	(6)	-	(1)	(7)	(5)	-	(1)	(7)
TOTAL		2,725	261	59	3,045	2,042	507	202	2,750

Outstanding “Trade and other receivables” and “Contract assets” exposures monitored according to the individual approach break down as follows by counterparty type:

		Dec. 31, 2018			Dec. 31, 2017		
		Investment Grade ⁽¹⁾	Other	Total	Investment Grade ⁽¹⁾	Other	Total
<i>In millions of euros</i>							
Trade and other receivables, net	Gross	9,161	1,178	10,339	7,258	1,290	8,548
	Expected credit losses	(205)	(118)	(323)	(164)	(189)	(352)
TOTAL		8,956	1,060	10,016	7,094	1,101	8,196
Assets from contracts with customers	Gross	2,358	694	3,052	1,780	977	2,757
	Expected credit losses	(4)	(3)	(7)	(6)	(1)	(7)
TOTAL		2,354	691	3,045	1,774	976	2,750

(1) Investment Grade corresponds to counterparties that are rated at least BBB- by Standard & Poor's.

Collective approach

Outstanding past due "Trade and other receivables" and "Contract assets" exposures monitored according to the collective approach break down as follows:

In millions of euros		0 to 6 months	6 to 12 months	beyond	Total past due assets at Dec. 31, 2018
Trade and other receivables, net	Gross	730	146	368	1,243
	Expected credit losses	(18)	(19)	(243)	(281)
TOTAL		711	126	125	962
Assets from contracts with customers	Gross	34	3	4	42
	Expected credit losses	-	-	-	-
TOTAL		34	3	4	42

In millions of euros		0 to 6 months	6 to 12 months	beyond	Total past due assets at Dec. 31, 2017
Trade and other receivables, net	Gross	730	135	517	1,381
	Expected credit losses	(19)	(26)	(230)	(274)
TOTAL		711	109	287	1,107
Assets from contracts with customers	Gross	75	-	-	75
	Expected credit losses	-	-	-	-
TOTAL		75	-	-	75

18.2.1.2 Commodity derivatives

In the case of commodity derivatives, counterparty risk arises from positive fair value. Counterparty risk is taken into account when calculating the fair value of these derivative instruments.

In millions of euros	Dec. 31, 2018		Dec. 31, 2017	
	Investment Grade ⁽³⁾	Total	Investment Grade ⁽³⁾	Total
Gross exposure ⁽¹⁾	9,325	12,027	7,309	8,764
Net exposure ⁽²⁾	2,701	3,683	2,913	3,705
% of credit exposure to "Investment Grade" counterparties	73.4%		78.6%	

- (1) Corresponds to the maximum exposure, i.e. the value of the derivatives shown under assets (positive fair value).
 (2) After taking into account the liability positions with the same counterparties (negative fair value), collateral, netting agreements and other credit enhancement techniques.
 (3) Investment Grade corresponds to transactions with counterparties that are rated at least BBB- by Standard & Poor's, Baa3 by Moody's, or equivalent by Dun & Bradstreet. "Investment Grade" is also determined based on an internal rating tool that has been rolled out within the Group, and covers its main counterparties.

18.2.2 Financing activities

For its financing activities, the Group has put in place procedures for managing and monitoring risk based on (i) the accreditation of counterparties according to external credit ratings, objective market data (credit default swaps, market capitalization) and financial structure, and (ii) counterparty risk exposure limits.

To reduce its counterparty risk exposure, the Group drew increasingly on a structured legal framework based on master agreements (including netting clauses) and collateralization contracts (margin calls).

The oversight procedure for managing counterparty risk arising from financing activities is managed by a Middle Office that operates independently of the Group's Treasury department and reports to the Finance division.

18.2.2.1 Loans and receivables at amortized cost

The following tables concerning exposure to counterparty risk of “Loans and receivables at amortized cost” show the breakdown of the outstanding exposure:

- by risk level (levels 1, 2 and 3);
- by counterparty type (investment grade versus other).

Total outstanding exposures presented in tables hereafter do not include impacts relating to VAT or to any other item not subject to credit risk, which amount at December 31, 2018 to €809 million (compared to €533 million at December 31, 2017).

Outstanding exposure breaks down as follows by risk level:

In millions of euros	Dec. 31, 2018				Dec. 31, 2017			
	Level 1: low credit risk	Level 2: increased credit risk	Level 3: impaired assets	Total	Level 1: low credit risk	Level 2: increased credit risk	Level 3: impaired assets	Total
Gross	3,402	466	233	4,100	2,799	517	245	3,561
Expected credit losses	(91)	-	(227)	(319)	(36)	-	(232)	(269)
TOTAL	3,311	466	5	3,781	2,763	517	13	3,293

Outstanding exposure breaks down as follows by counterparty type:

In millions of euros	Dec. 31, 2018			Dec. 31, 2017		
	Investment Grade ⁽¹⁾	Other	Total	Investment Grade ⁽¹⁾	Other	Total
Gross	2,003	2,098	4,100	2,079	1,482	3,561
Expected credit losses	(86)	(233)	(319)	(21)	(247)	(269)
TOTAL	1,917	1,865	3,781	2,058	1,235	3,293

(1) Investment Grade corresponds to counterparties that are rated at least BBB- by Standard & Poor's.

18.2.2.2 Counterparty risk arising from investing activities and the use of derivative financial instruments

The Group is exposed to counterparty risk arising from investments of surplus cash and from the use of derivative financial instruments. In the case of financial instruments at fair value through income, counterparty risk arises on instruments with a positive fair value. Counterparty risk is taken into account when calculating the fair value of these derivative instruments.

At December 31, 2018, total outstanding exposure to credit risk amounted to €9,634 million.

In millions of euros	Dec. 31, 2018				Dec. 31, 2017			
	Total	Investment Grade ⁽¹⁾	Unrated ⁽²⁾	Non Investment Grade ⁽²⁾	Total	Investment Grade ⁽¹⁾	Unrated ⁽²⁾	Non Investment Grade ⁽²⁾
Exposure	9,634	85.0%	6.0%	8.0%	10,009	84.0%	9.0%	7.0%

(1) Investment Grade corresponds to counterparties that are rated at least BBB- by Standard & Poor's or Baa3 by Moody's.

(2) Most of these two exposures is carried by consolidated companies that include non-controlling interests, or by Group companies that operate in emerging countries, where cash cannot be pooled and is therefore invested locally.

Furthermore, at December 31, 2018, Crédit Agricole Corporate and Investment Bank (CACIB) is the main Group counterparty and represents 29% of cash surpluses. This relates mainly to a depositary risk.

18.3 Liquidity risk

In the context of its operating activities, the Group is exposed to a risk of having insufficient liquidity to meet its contractual obligations. As well as the risks inherent in managing working capital requirements (WCR), margin calls are required in certain market activities.

The Group has set up a quarterly committee tasked with managing and monitoring liquidity risk throughout the Group, by maintaining a broad range of investments and sources of financing, preparing forecasts of cash investments and divestments, and performing stress tests on the margin calls put in place when commodity, interest rate and currency derivatives are negotiated.

The Group centralizes virtually all financing needs and cash flow surpluses of the companies it controls, as well as most of their medium- and long-term external financing requirements. Centralization is provided by financing vehicles (long-term and short-term) and by dedicated Group cash pooling vehicles based in France, Belgium and Luxembourg.

Surpluses held by these structures are managed in accordance with a uniform policy. Unpooled cash surpluses are invested in instruments selected on a case-by-case basis in light of local financial market imperatives and the financial strength of the counterparties concerned.

The onslaught of successive financial crises since 2008 and the ensuing rise in counterparty risk prompted the Group to tighten its investment policy with the aim of keeping an extremely high level of liquidity and protecting invested capital and a daily monitoring of performance and counterparty risks for both investment types, allowing the Group to take immediate action where required in response to market developments. Consequently, 78% of cash pooled at December 31, 2018 was invested in overnight bank deposits and standard money market funds with daily liquidity.

The Group's financing policy is based on:

- centralizing external financing;
- diversifying sources of financing between credit institutions and capital markets;
- achieving a balanced debt repayment profile.

The Group seeks to diversify its sources of financing by carrying out public or private bond issues within the scope of its Euro Medium Term Notes program. It also issues negotiable commercial paper in France and in the United States.

At December 31, 2018, bank loans accounted for 17% of gross debt (excluding overdrafts and the impact of derivatives and amortized cost), while the remaining debt was raised on capital markets (including €22,645 million in bonds, or 74% of gross debt).

Outstanding negotiable commercial paper issues represented 9% of gross debt, or €2,894 million at December 31, 2018. As negotiable commercial paper is relatively inexpensive and highly liquid, it is used by the Group in a cyclical or structural fashion to finance its short-term cash requirements. However, the refinancing of all outstanding negotiable commercial paper remains secured by confirmed bank lines of credit allowing the Group to continue to finance its activities if access to this financing source were to dry up.

Available cash, comprising cash and cash equivalents and liquid debt instruments dedicated to cash investments, totaled €9,935 million at December 31, 2018, of which 70% was invested in the Eurozone.

The Group also has access to confirmed credit lines. These facilities are appropriate for the scale of its operations and for the timing of contractual debt repayments. Confirmed credit facilities had been granted for a total of €13,297 million at December 31, 2018, of which €13,232 million was available. 95% of available credit facilities are centralized. None of these centralized facilities contain a default clause linked to covenants or minimum credit ratings.

At December 31, 2018, all the entities of the Group whose debt is consolidated comply with the covenants and declarations included in their financial documentation, except for some non-significant entities for which compliance actions are being implemented.

18.3.1 Undiscounted contractual payments relating to financial activities

At December 31, 2018, undiscounted contractual payments on net debt excluding the impact of derivatives, margin calls and amortized cost break down as follows by maturity:

At December 31, 2018

<i>In millions of euros</i>	Total	2019	2020	2021	2022	2023	Beyond 5 years
Bond issues	22,645	1,202	2,496	1,778	2,613	2,675	11,882
Bank borrowings	4,620	349	952	411	401	345	2,163
Negotiable commercial paper	2,894	2,894	-	-	-	-	-
Drawdowns on credit facilities	66	33	17	2	2	2	11
Liabilities under finance leases	380	118	92	82	10	9	70
Other borrowings	125	51	20	19	4	5	26
Bank overdrafts and current accounts	464	464	-	-	-	-	-
OUTSTANDING BORROWINGS AND DEBT	31,195	5,111	3,577	2,291	3,030	3,035	14,152
Assets related to financing	(53)	(1)	(5)	(2)	-	-	(46)
Liquid debt instruments dedicated to cash investments	(1,230)	(1,230)	-	-	-	-	-
Cash and cash equivalents	(8,706)	(8,706)	-	-	-	-	-
NET DEBT EXCLUDING THE IMPACT OF AMORTIZED COST, DERIVATIVE INSTRUMENTS AND MARGIN CALLS	21,206	(4,825)	3,572	2,290	3,029	3,034	14,106

At December 31, 2017

<i>In millions of euros</i>	Total	2018	2019	2020	2021	2022	Beyond 5 years
OUTSTANDING BORROWINGS AND DEBT	32,427	7,714	1,408	3,380	2,239	3,070	14,617
Assets related to financing, liquid debt instruments dedicated to cash investments and cash and cash equivalents	(10,128)	(10,069)	-	(3)	(2)	-	(54)
NET DEBT EXCLUDING THE IMPACT OF AMORTIZED COST, DERIVATIVE INSTRUMENTS AND MARGIN CALLS	22,300	(2,355)	1,408	3,377	2,237	3,070	14,563

At December 31, 2018, undiscounted contractual interest payments on outstanding borrowings and debt break down as follows by maturity:

At December 31, 2018

<i>In millions of euros</i>	Total	2019	2020	2021	2022	2023	Beyond 5 years
Undiscounted contractual interest flows on outstanding borrowings and debt	9,335	894	825	734	619	534	5,730

At December 31, 2017

<i>In millions of euros</i>	Total	2018	2019	2020	2021	2022	Beyond 5 years
Undiscounted contractual interest flows on outstanding borrowings and debt	9,500	930	808	741	651	531	5,839

At December 31, 2018, undiscounted contractual payments on outstanding derivatives (excluding commodity instruments) recognized in assets and liabilities break down as follows by maturity (net amounts):

At December 31, 2018

<i>In millions of euros</i>	Total	2019	2020	2021	2022	2023	Beyond 5 years
Derivatives (excluding commodity instruments)	(138)	(16)	37	93	59	(29)	(282)

At December 31, 2017

<i>In millions of euros</i>	Total	2018	2019	2020	2021	2022	Beyond 5 years
Derivatives (excluding commodity instruments)	(105)	(156)	(106)	(62)	(55)	(12)	286

To better reflect the economic substance of these transactions, the cash flows linked to the derivatives recognized in assets and liabilities shown in the table above relate to net positions.

The maturities of the Group's undrawn credit facility programs are analyzed in the table below:

At December 31, 2018

<i>In millions of euros</i>	Total	2019	2020	2021	2022	2023	Beyond 5 years
Confirmed undrawn credit facility programs	13,232	760	1,263	429	5,514	5,012	255

Of these undrawn programs, an amount of €2,894 million is allocated to covering commercial paper issues.

At December 31, 2018, no single counterparty represented more than 5% of the Group's confirmed undrawn credit lines.

At December 31, 2017

<i>In millions of euros</i>	Total	2018	2019	2020	2021	2022	Beyond 5 years
Confirmed undrawn credit facility programs	13,389	704	540	1,421	5,018	5,515	191

18.3.2 Undiscounted contractual payments relating to operating activities

The table below provides an analysis of undiscounted fair values due and receivable in respect of commodity derivatives recorded in assets and liabilities at the statement of financial position date.

The Group provides an analysis of residual contractual maturities for commodity derivative instruments included in its portfolio management activities. Derivative instruments relating to trading activities are considered to be liquid in less than one year, and are presented under current items in the statement of financial position.

At December 31, 2018

<i>In millions of euros</i>	Total	2019	2020	2021	2022	2023	Beyond 5 years
Derivative instruments carried in liabilities							
<i>Relating to portfolio management activities</i>	(2,114)	(811)	(780)	(342)	(108)	(37)	(36)
<i>Relating to trading activities</i>	(10,579)	(10,579)	-	-	-	-	-
Derivative instruments carried in assets							
<i>Relating to portfolio management activities</i>	2,080	672	937	306	126	32	6
<i>Relating to trading activities</i>	9,952	9,952	-	-	-	-	-
TOTAL AT DECEMBER 31, 2018	(661)	(766)	157	(36)	18	(5)	(30)

At December 31, 2017

<i>In millions of euros</i>	Total	2018	2019	2020	2021	2022	Beyond 5 years
Derivative instruments carried in liabilities							
<i>Relating to portfolio management activities</i>	(2,179)	(713)	(858)	(374)	(172)	(49)	(12)
<i>Relating to trading activities</i>	(7,801)	(7,801)	-	-	-	-	-
Derivative instruments carried in assets							
<i>Relating to portfolio management activities</i>	2,018	463	794	433	220	56	52
<i>Relating to trading activities</i>	6,770	6,770	-	-	-	-	-
TOTAL AT DECEMBER 31, 2017	(1,192)	(1,281)	(64)	59	48	7	40

18.3.3 Commitments relating to commodity purchase and sale contracts entered into within the ordinary course of business

Some Group operating companies have entered into long-term contracts, some of which include “take-or-pay” clauses. These consist of firm commitments to purchase (sell) specified quantities of gas, electricity or steam as well as related services, in exchange for a firm commitment from the other party to deliver (purchase) said quantities and services. These contracts were documented as falling outside the scope of IFRS 9. The table below shows the main future commitments arising from contracts entered into by the GEM, Latin America and North America reportable segments (expressed in TWh):

<i>In TWh</i>	Total at Dec. 31, 2018	2019	2020-2023	Beyond 5 years	Total at Dec. 31, 2017
Firm purchases	(3,070)	(500)	(994)	(1,576)	(5,680)
Firm sales	1,329	337	503	489	2,046

NOTE 19 EQUITY

19.1 Share capital

	Number of shares			Value (in millions of euros)		
	Total	Treasury stock	Outstanding	Share capital	Additional	Treasury stock
AT DECEMBER 31, 2016	2,435,285,011	(37,522,838)	2,397,762,173	2,435	32,506	(761)
Purchase/disposal of treasury stock	-	(9,335,181)	(9,335,181)	-	-	(122)
AT DECEMBER 31, 2017	2,435,285,011	(46,858,019)	2,388,426,992	2,435	32,506	(883)
Link 2018 worldwide employee share plan	6,036,166	26,655,602	32,691,768	6	60	459
Cancellation of treasury stock shares	(6,036,166)	6,036,166	-	(6)	-	81
Purchase of shares from the French State	-	(11,111,111)	(11,111,111)	-	-	(152)
Delivery of treasury stock (bonus)	-	1,386,192	1,386,192	-	-	35
AT DECEMBER 31, 2018	2,435,285,011	(23,891,170)	2,411,393,841	2,435	32,565	(460)

Changes in the number of shares during 2018 resulted from:

- employee share issuances as part of the “Link 2018” worldwide employee share plan. All in all, 30.9 million shares were subscribed and 1.8 million bonus shares were awarded under employee contribution schemes, representing a total of 32.7 million shares. At August 2, 2018 the transaction resulted in the sale to employees of 26.7 million shares partly repurchased from the French State in September 2017 (€153 million) and in July 2018 (€152 million) for a total amount of 22.2 million shares, on the one hand, and in a capital increase for €66 million, on the other. This last amount is broken down into a capital increase for €6 million and additional paid-in capital for €60 million;
- an equity decrease of €81 million broken down into a €6 million capital decrease and a €75 million decrease in consolidated reserves;
- the delivery of treasury stock for 1.4 million shares as part of bonus share plans.

Changes in the number of shares during 2017 result from net treasury stock acquisitions for 9 million shares, mainly repurchased from the French State in accordance with its share transfer program (0.46% of ENGIE’s share capital). These shares have been allocated to the employee savings transactions planned by the Group.

19.1.1 Potential share capital and instruments providing a right to subscribe for new ENGIE SA shares

At December 31, 2017, the last stock subscription option plan came to an end.

Shares to be allocated under bonus share plans, performance share award plans as well as the stock purchase option plans, described in Note 24 “Share-based payments”, are covered by existing ENGIE SA shares.

19.1.2 Treasury stock

Accounting standards

Treasury shares are recognized at acquisition cost and deducted from equity. Gains and losses on disposals of treasury shares are recorded directly in equity and do not therefore impact income for the period.

The Group has a stock repurchase program as a result of the authorization granted to the Board of Directors by the Ordinary and Extraordinary Shareholders’ Meeting of May 18, 2018. This program provides for the repurchase of up to 10% of the shares comprising the share capital of ENGIE SA at the date of the said Shareholders’ Meeting. The aggregate amount of acquisitions net of expenses under the program may not exceed €7.3 billion, and the purchase price must be less than €30 per share excluding acquisition costs.

At December 31, 2018, the Group held 23.9 million treasury shares, allocated in full to cover the Group's share commitments to employees and corporate officers.

The liquidity agreement signed with an investment service provider assigns to the latter the role of operating on the market on a daily basis, to buy or sell ENGIE SA shares, in order to ensure liquidity and an active market for the shares on the Paris and Brussels stock exchanges. To date, the resources allocated to the implementation of this agreement amount to €150 million.

19.2 Other disclosures concerning additional paid-in capital, consolidated reserves and issuance of deeply-subordinated perpetual notes (Group share)

Total additional paid-in capital, consolidated reserves and issuance of deeply-subordinated perpetual notes (including net income for the fiscal year), amounted to €36,547 million at December 31, 2018, including €32,565 million in additional paid-in capital.

Consolidated reserves include the cumulative income of the Group, the legal and statutory reserves of ENGIE SA, the cumulative actuarial gains and losses, net of tax and change in fair value of equity instruments at fair value through OCI.

Under French law, 5% of the net income of French companies must be allocated to the legal reserve until the latter reaches 10% of share capital. This reserve can only be distributed to shareholders in the event of liquidation. The ENGIE SA legal reserve amounts to €244 million.

The cumulative actuarial gains and losses Group share represent losses of €3,275 million at December 31, 2018 (losses of €3,095 million at December 31, 2017). Deferred taxes relating to these actuarial gains and losses amount to €790 million at December 31, 2018 (€744 million at December 31, 2017).

19.2.1 Issuance of deeply-subordinated perpetual notes

On January 16, 2018, ENGIE SA carried out an issue of green deeply-subordinated perpetual notes for an amount of €1 billion offering a coupon of 1.375% with an annual reimbursement option from April 2023.

In accordance with the provisions of IAS 32 – *Financial Instruments – Presentation*, and given their characteristics, these instruments were accounted for in equity in the Group's consolidated financial statements for a total amount of €989 million.

On June 6, 2018, ENGIE gave notice of the annual prepayment option of the €600 million tranche (a total amount of €621 million accrued interest included), previously recognized in equity for a net amount of €584 million. ENGIE SA made the reimbursement on July 10, 2018.

On December 5, 2018, ENGIE gave notice of the annual prepayment option of the GBP 300 million tranche (a total amount of €352 million accrued interest included), previously recognized in equity for a net amount of €340 million.

At December 31, 2018 the level of deeply-subordinated notes amounted to €3,750 million.

The coupons ascribed to the owners of these notes, of which €145 million was paid in 2018, are accounted for as a deduction from equity in the Group's consolidated financial statements; the relating tax saving is accounted for in the income statement.

19.2.2 Distributable capacity of ENGIE SA

ENGIE SA's distributable capacity totaled €33,320 million at December 31, 2018 (compared with €33,969 million at December 31, 2017), after deducting the interim dividend paid on 12 October 2018 for a total amount of €892 million, including €32,565 million of additional paid-in capital.

19.2.3 Dividends

The table below shows the dividends and interim dividends paid by ENGIE SA in respect of 2017 and 2018.

	Amount distributed (in millions of euros)	Net dividend per share (in euros)
In respect of 2017		
Interim dividend (paid on October 13, 2017)	836	0.35
Remaining dividend for 2017 (paid on May 24, 2018)	836	0.35
Remaining additional dividend for 2017 (paid on May 24, 2018)	11	0.07
In respect of 2018		
Interim dividend (paid on October 12, 2018)	892	0.37

The Shareholders' Meeting of May 18, 2018 approved the distribution of a total dividend of €0.70 per share in respect of 2017. In accordance with Article 26.2 of the bylaws, a dividend increase of 10% (€0.07 per share) has been allocated to shares registered in the name of the holder for at least two years at December 31, 2017, provided they are held in this form by the same shareholder until the payment date. This 10% increase may only apply, for any one shareholder, for a number of shares not representing more than 0.5% of the capital.

As an interim dividend of €0.35 per share was paid on October 13, 2017, for an amount of €836 million, ENGIE SA settled the remaining dividend balance of €0.35 per share in cash on May 24, 2018, for an amount of €836 million, for shares benefiting from an ordinary dividend, as well as the remaining €0.42 per share for shares benefiting from the bonus dividend. In addition, the Board of Directors' Meeting of July 26, 2018 approved the payment of an interim dividend of €0.37 per share payable on October 12, 2018 for a total amount of €892 million.

Proposed dividend in respect of 2018

Shareholders at the Shareholders' Meeting convened to approve the ENGIE Group financial statements for the year ended December 31, 2018, will be asked to approve a dividend of €1.12 per share, representing a total payout of €2,701 million based on the number of shares outstanding at December 31, 2018. This proposed dividend per share includes an ordinary dividend of €0.75 per share and an exceptional dividend of €0.37 per share. It will be increased by 10% for all shares held for at least two years on December 31, 2018 and up to the 2018 dividend payment date. Based on the number of outstanding shares on December 31, 2018, this increase is valued at €24 million.

Subject to approval by the Shareholders' Meeting of May 17 2019, this dividend, net of the interim dividend paid (€892 million), will be detached on May 21, 2019 and paid on May 23, 2019 for an estimated amount of €1,809 million, outstanding shares excluded. It is not recognized as a liability in the financial statements at December 31, 2018, since the financial statements at the end of 2018 are presented before the appropriation of earnings.

19.3 Total gains and losses recognized in equity (Group share)

All the items shown in the table below correspond to cumulative gains and losses (Group share) at December 31, 2018 and December 31, 2017, which are recyclable to income in subsequent periods.

In millions of euros	Dec. 31, 2018	Dec. 31, 2017 ⁽¹⁾
Debt instruments	28	(1)
Net investment hedges	(313)	(320)
Cash flow hedges (excl. commodity instruments)	(725)	(542)
Commodity cash flow hedges	(30)	(37)
Deferred taxes on the items above	244	201
Share of entities accounted for using the equity method in recyclable items, net of tax	(223)	(473)
Translation adjustments	(1,130)	(1,063)
Recyclable items relating to discontinued operations, net of tax	-	(6)
TOTAL RECYCLABLE ITEMS	(2,149)	(2,240)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

19.4 Capital management

ENGIE SA seeks to optimize its financial structure at all times by pursuing an optimal balance between its net debt and its EBITDA. The Group's key objective in managing its financial structure is to maximize value for shareholders and reduce the cost of capital, while ensuring that the Group has the financial flexibility required to continue its expansion. The Group manages its financial structure and makes any necessary adjustments in light of prevailing economic conditions. In this context, it may choose to adjust the amount of dividends paid to shareholders, reimburse a portion of capital, carry out share buybacks (see Note 19.1.2 "*Treasury stock*"), issue new shares, launch share-based payment plans, recalibrate its investment budget, or sell assets in order to scale back its net debt.

The Group's policy is to maintain an "A" rating by the rating agencies. To achieve this, it manages its financial structure in line with the indicators usually monitored by these agencies, namely the Group's operating profile, financial policy and a series of financial ratios. One of the most commonly used ratios is the ratio where the numerator includes operating cash flows less net financial expense and taxes paid, and the denominator includes adjusted net financial debt. Net debt is mainly adjusted for nuclear provisions, provisions for unfunded pension plans and operating lease commitments.

The Group's objectives, policies and processes for managing capital have remained unchanged over the past few years.

ENGIE SA is not obliged to comply with any minimum capital requirements except those provided for by law.

NOTE 20 PROVISIONS

Accounting standards

General principles related to the recognition of a provision

The Group recognizes a provision where it has a present obligation (legal or constructive) towards a third party arising from past events and where it is probable that an outflow of resources will be necessary to settle the obligation with no expected consideration in return.

A provision for restructuring costs is recognized when the general criteria for setting up a provision are met, i.e. when the Group has a detailed formal plan relating to the restructuring and has raised a valid expectation in those affected that it will carry out the restructuring by starting to implement that plan or announcing its main features to those affected by it.

Provisions with a maturity of over 12 months are discounted when the effect of discounting is material. The Group's main long-term provisions are provisions for the back-end of the nuclear fuel cycle, provisions for dismantling facilities and provisions for site restoration costs. The discount rates used reflect current market assessments of the time value of money and the risks specific to the liability concerned. Expenses with respect to unwinding the discount on the provision are recognized as other financial income and expenses.

Estimates of provisions

Parameters having a significant influence on the amount of provisions, and particularly, but not solely, those relating to the back-end of the nuclear fuel cycle and to the dismantling of nuclear facilities, as well as those relating to the dismantling of gas infrastructures in France, include:

- cost estimates (notably the retained scenario for managing radioactive nuclear fuel consumed) (*see Note 20.2*);
- the timing of expenditure (notably, for nuclear power generation activities, the timetable for reprocessing radioactive nuclear fuel consumed and for dismantling facilities as well as the timetable for the end of gas operations regarding the main gas infrastructure businesses in France) (*see Notes 20.2 and 20.3*);
- and the discount rate applied to cash flows.

These parameters are based on information and estimates deemed by the Group to be the most appropriate as of today.

Modifications to certain parameters could lead to a significant adjustment in these provisions.

<i>In millions of euros</i>	Dec. 31, 2017 ⁽¹⁾	Additions	Reversals (utilizations)	Reversals (surplus provisions)	Changes in scope of consolidation	Impact of unwinding discount adjustments	Translation adjustments	Other	Dec. 31, 2018	Non- current	Current
Post-employment and other long-term benefits	6,142	294	(399)	(8)	-	113	(9)	238	6,371	6,264	107
Back-end of the nuclear fuel cycle	5,914	102	(52)	-	-	207	-	-	6,170	6,114	57
Dismantling of plant and equipment ⁽²⁾	5,728	52	(73)	-	(58)	209	(4)	227	6,081	6,081	-
Site rehabilitation	313	6	(14)	-	(81)	3	(6)	1	222	222	1
Litigation, claims, and tax risks	703	97	(107)	(86)	12	2	(8)	17	629	16	613
Other contingencies	2,915	331	(673)	(79)	(199)	20	1	23	2,340	497	1,842
TOTAL PROVISIONS	21,715	882	(1,317)	(173)	(327)	554	(26)	505	21,813	19,194	2,620

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

(2) Of which €5,337 million in provisions for dismantling nuclear facilities, compared to €5,159 million at December 31, 2017.

The impact of unwinding discount adjustments in respect of post-employment and other long-term benefits relates to the interest expense on the benefit obligation, net of the interest income on plan assets.

The "Other" column mainly comprises actuarial gains and losses arising on post-employment benefit obligations in 2018 which are recorded in "Other comprehensive income" as well as provisions recorded against a dismantling or site rehabilitation asset.

Additions, reversals and the impact of unwinding discounting adjustments are presented as follows in the consolidated income statement:

<i>In millions of euros</i>	Dec. 31, 2018
Income/(loss) from operating activities	555
Other financial income and expenses	(541)
Income taxes	59
Income/(loss) from discontinued operations	(18)
TOTAL	55

The different types of provisions and the calculation principles applied are described below.

20.1 Post-employment benefits and other long-term benefits

See Note 21 "Post-employment benefits and other long-term benefits" for a description of the main pension plans and other post-employment and long-term benefits.

20.2 Nuclear power generation activities

In the context of its nuclear power generation activities, the Group assumes obligations relating to the back-end of the nuclear fuel cycle and the dismantling of nuclear facilities.

20.2.1 Legal framework

The Belgian law of April 11, 2003 granted Group subsidiary Synatom responsibility for managing provisions set aside to cover the costs of dismantling nuclear power plants and managing radioactive fissile material from such plants. The tasks of the Commission for Nuclear Provisions set up pursuant to the above-mentioned law is to oversee the process of computing and managing these provisions. The Commission also issues opinions on the maximum percentage of funds that Synatom can lend to operators of nuclear plants and on the types of assets in which Synatom may invest its outstanding funds (see Note 17.1.4 "Financial assets set aside to cover the future costs of dismantling nuclear facilities and managing radioactive fissile material").

To enable the Commission for Nuclear Provisions to carry out its work in accordance with the law, Synatom is required to submit a report every three years describing the core inputs used to measure these provisions.

Synatom submitted its triennial report to the Commission for Nuclear Provisions on September 12, 2016. The Commission issued its opinion on December 12, 2016 based on the prior opinion given by ONDRAF, the Belgian agency for radioactive waste and enriched fissile material.

If any changes are observed from one triennial report to another that could materially impact the financial inputs used, the industrial scenario, estimated costs or their timing, the Commission for Nuclear Provisions may decide to revise its opinion.

The provisions related to nuclear power generation activities are measured taking into account the prevailing contractual and legal framework, which sets the operating life of the Tihange 1 reactor and the Doel 1 and 2 reactors at 50 years, and the other reactors at 40 years.

The provisions take into account all existing or planned environmental regulatory requirements on a European, national and regional level. If new legislation were to be introduced in the future, the cost estimates used as a basis for the calculations could vary. However, the Group is not aware of any planned legislation on this matter which could materially impact the amount of the provisions, other than the matters described in Note 20.2.2 below.

The estimated provision amounts also include margins for contingencies and other risks in order to take into account the degree of control of techniques related to dismantling and radioactive spent fuel management, being understood that contingency margins for the disposal of waste are determined by ONDRAF and included in its fees. Thus, the Group considers that the provisions approved by the Commission for Nuclear Provisions take into account all currently available information to manage the contingencies and other risks associated with processes such as dismantling nuclear facilities and managing radioactive spent fuel.

Based on the information disclosed in Notes 20.2.2 and 20.2.3 below, core inputs for measuring provisions including management scenarios, implementation program and timetable, detailed technical analyses (physical and radiological inventories), estimation methods and timing of expenditures, as well as discount rates, are those approved by the Commission for Nuclear Provisions in 2016.

Consequently, changes in provisions in the Group's financial statements in 2018 therefore mainly relate to recurring items linked to the passage of time (the unwinding of discounting adjustments) and provisions for fuel spent during the year.

20.2.2 Provisions for the back-end of the nuclear fuel cycle

Accounting standards

Allocations to the provisions for the back-end of the nuclear fuel cycle are computed based on the average unit cost of the quantities expected to be used up to the end of the operating life of the plants, applied to quantities used at the closing date. An annual allocation is also recognized with respect to unwinding the discount on the provisions.

When spent nuclear fuel is removed from a reactor and temporarily stored on-site, it remains radioactive and requires processing. There are two scenarios for managing radioactive spent fuel:

- either based essentially on reprocessing;
- or based essentially on conditioning without reprocessing.

ENGIE considers that the "mixed" scenario adopted by the Commission for Nuclear Provisions in 2016 continues to apply, whereby around one-quarter of total fuel is reprocessed, and the rest disposed of directly without reprocessing.

Furthermore, ONDRAF proposed on February 9, 2018 that geological storage be adopted as the national policy for managing high-level and/or long-lived radioactive waste. The proposal is subject to the approval of the Belgian government after obtaining the opinion of the Federal Agency for Nuclear Control (*Agence Fédérale de Contrôle Nucléaire – AFCN*).

The provisions booked by the Group for nuclear fuel processing and storage cover all of the costs linked to the “mixed” scenario, including on-site storage, transportation, reprocessing, conditioning, storage and geological removal. They are calculated based on the following inputs:

- storage costs primarily comprise the costs of building and operating additional dry storage facilities and operating existing facilities, along with the costs of purchasing containers;
- part of the radioactive spent fuel is transferred for reprocessing. The resulting plutonium and uranium is sold to a third party;
- radioactive spent fuel that has not been reprocessed is to be conditioned, which requires conditioning facilities to be built according to ONDRAF's approved criteria;
- the reprocessing residues and conditioned radioactive spent fuel are transferred to ONDRAF;
- the cost of burying fuel in deep geological repositories is estimated by ONDRAF;
- the long-term obligation is calculated using estimated internal costs and external costs assessed based on offers received from third parties;
- the discount rate used is 3.5% and was calculated based on an inflation rate of 2.0% (actual rate of 1.5%). It is based on an analysis of trends in and average, past and prospective benchmark long-term rates.

The costs effectively incurred in the future may, however, differ from the estimates in terms of their nature and timing of payment. The provisions may be subsequently adjusted in line with changes in the above-mentioned inputs and related cost estimates. In particular:

- As regards the partial reprocessing scenario, Belgium's current legal framework does not prescribe methods for managing nuclear waste. The reprocessing of radioactive spent fuel was suspended following a resolution adopted by the House of Representatives in 1993. The scenario adopted is based on the assumption that the Belgian government will allow Synatom to reprocess spent fuel and that an agreement will be reached between Belgium and France designating Orano (formerly Areva) as responsible for these reprocessing operations. The Commission's 2016 opinion recommends that the necessary steps be officially initiated to ensure that this partial reprocessing scenario is implemented.

A scenario assuming the direct disposal of waste without reprocessing would lead to a decrease in the provision compared to the provision resulting from the “mixed” scenario currently used and approved by the Commission for Nuclear Provisions.

- The Belgian government has not yet taken a decision as to whether the medium- and high-level radioactive waste should be buried in a deep geological repository or stored over the long term. In accordance with the European Directive, in 2015 the government submitted its proposed national program for the management of spent fuel and radioactive waste to the European Commission. This program was approved by ministerial order in 2016, based on the assumption that the waste would be buried in a deep clay layer at Boom. This assumption was accepted by the Commission for Nuclear Provisions in 2016 although to date, there is no accredited site in Belgium where the waste may be buried. However, the Commission for Nuclear Provisions asked for a scenario to be developed that includes the creation of a storage facility concept that the authorities would be likely to authorize.

In these conditions, in 2018 ONDRAF's Board of Directors adopted a new reference scenario for the geological storage of this waste, based on a new architecture and a potentially greater burial depth, on condition that a suitable site could be identified in Belgium. On that basis and in accordance with the procedures set out in the Royal Decree of March 30, 1981 “determining the tasks and setting the operational procedures of the public agency for the management of radioactive waste and fissile material”, ONDRAF set the new fees to be charged for the management and storage of high-level and/or long-lived waste. These fees were approved by ONDRAF's Board of Directors on September 28, 2018 and notified to the Commission for Nuclear Provisions and Synatom. However, they have yet to be integrated in the agreements to be entered into by ONDRAF and the nuclear waste producers, including Electrabel and Synatom.

The new technical arrangements will result in the following:

- Estimated costs of €8.0 billion based on 2017 economic conditions, meaning a twofold increase in the cost of geological storage of waste compared with the cost assumptions used in the 2016 proposal submitted to the Commission for Nuclear Provisions. This amount includes technical optimizations for €2.7 billion, based on 2017 economic conditions, to be confirmed by a special working group by 2020.
- Significant delays in the payment schedule for the various expenses related to the conditioning and storage of nuclear waste. These delays could be as long as 35 years for some expense categories, such as facilities for conditioning radioactive spent fuel and for the removal of conditioned fuel, thus reducing the net present value of the expenses and, therefore, the impact of the increase in burial costs on the measurement of nuclear provisions.

ONDRAF has asked the Commission for Nuclear Provisions to ensure that provisions are sufficient to cover the expenses for the back end of the nuclear fuel cycle, should the optimizations subject to expert appraisal fail to materialize.

Given the expected trend in assumptions for geological waste storage costs, reprocessed volumes, unit reprocessing costs and the timetable for operations, the Group believes, based on information available to date, that the impact of the new technical scenario on the provisions for the back-end cycle should not significantly alter the net present value of its commitments as estimated today.

The amount of provisions for radioactive spent fuel at December 31, 2018 therefore remained based on the industrial scenarios and cash flow projections approved by the Commission for Nuclear Provisions in December 2016 at the time of the last triennial report.

The new estimate, taking into account the new fees and timetable, will be included in Synatom's proposal to be submitted to the Commission for Nuclear Provisions no later than at the time of the next triennial report in 2019.

Sensitivity

Provisions for the back-end of the nuclear fuel cycle remain sensitive to assumptions regarding costs, the timing of operations and expenditure, as well as to discount rates. Based on the new scenario notified by ONDRAF:

- a 10% increase in ONDRAF fees for the removal of high-level and/or long lived waste would lead to an increase in provisions of approximately €140 million at unchanged contingency margins;
- a five-year advance in ONDRAF's program for high-level and/or long-lived radioactive waste conditioning and removal would lead to an increase in provisions of approximately €90 million. A five-year delay in the payment schedule for these various expenses would lead to a decrease of a similar amount;
- a change of ten basis points in the discount rate used could lead to an adjustment of approximately €190 million in provisions for the back-end of the nuclear fuel cycle. A fall in discount rates would lead to an increase in outstanding provisions, while a rise in discount rates would reduce the provision amount.

These sensitivities are calculated on a purely financial basis and should therefore be interpreted with appropriate caution in view of the variety of other inputs – some of which may be interdependent – included in the evaluation.

20.2.3 Provisions for dismantling nuclear facilities

Accounting standards

A provision is recognized when the Group has a present legal or constructive obligation to dismantle facilities or to restore a site. The present value of the engagement at the time of commissioning represents the initial amount of the provision for dismantling with, as counterpart, an asset for the same amount which is included in the carrying amount of the facilities concerned. This asset is depreciated over the operating life of the facilities. Adjustments to the provision due to subsequent changes in (i) the expected outflow of resources, (ii) the timing of dismantling expenses or (iii) the discount rate, are deducted from or, subject to specific conditions, added to the cost of the corresponding asset. The impacts of unwinding the discount are recognized in expenses for the period.

Nuclear power plants have to be dismantled at the end of their operating life. Provisions are set aside in the Group's accounts to cover all costs relating to (i) the shutdown phase, which involves removing radioactive spent fuel from the site and (ii) the dismantling phase, which consists of decommissioning and cleaning up the site.

The dismantling strategy is based on the facilities being dismantled (i) immediately after the reactor is shut down, (ii) on a "serial" rather than on a site-by-site basis, and (iii) completely, the land being subsequently returned to greenfield status.

Provisions for dismantling nuclear facilities are calculated based on the following inputs:

- costs payable over the long term are calculated by reference to the estimated costs for each nuclear facility, based on a study conducted by independent experts under the assumption that the facilities will be dismantled "in series";
- an inflation rate of 2.0% is applied until the dismantling obligations expire in order to determine the value of the future obligation;
- a discount rate of 3.5% (including inflation of 2.0%) is applied to determine the net present value (NPV) of the obligation. This rate is the same as that used for the back-end of the nuclear fuel cycle;
- the operating life is 50 years for Tihange 1 and Doel 1 and 2, and 40 years for the other facilities;
- the start of the technical shutdown procedures depends on the facility concerned and on the timing of operations for the nuclear reactor as a whole. The shutdown procedures are immediately followed by dismantling operations.

The costs effectively incurred in the future may differ from the estimates in terms of their nature and timing of payment. The provisions may be subsequently adjusted in line with changes in the above-mentioned inputs. The assumptions used have a significant impact on the related implementation costs. However, these inputs and assumptions are based on information and estimates which the Group deems reasonable to date and which have been approved by the Commission for Nuclear Provisions.

The scenario adopted is based on a dismantling program and on timetables that have to be approved by the nuclear safety authorities.

Provisions are also recognized for the Group's share of the expected dismantling costs for the nuclear facilities in which it has drawing rights.

Sensitivity

Based on currently applied inputs for estimating costs and the timing of payments, a change of ten basis points in the discount rate used could lead to an adjustment of approximately €60 million in dismantling provisions. A fall in discount rates would lead to an increase in outstanding provisions, while a rise in discount rates would reduce the provision amount.

This sensitivity is calculated on a purely financial basis and should therefore be interpreted with appropriate caution in view of the variety of other inputs – some of which may be interdependent – included in the evaluation.

20.3 Dismantling of non-nuclear plant and equipment and site rehabilitation

20.3.1 Dismantling obligations arising on other non-nuclear plant and equipment

Certain plant and equipment, including conventional power stations, transmission and distribution pipelines, storage facilities and LNG terminals, have to be dismantled at the end of their operational lives. This obligation is the result of prevailing environmental regulations in the countries concerned, contractual agreements, or an implicit Group commitment.

Based on estimates of proven and probable gas reserves through 2260 using current production levels, dismantling provisions for gas infrastructures in France have a present value near zero.

20.3.2 Hazelwood Power Station & Mine (Australia)

Following the Group and its partner Mitsui's announcement in November 2016 of their decision to close the coal-fired Hazelwood Power Station, the adjoining mine was shut down in late March 2017. The Group holds a 72% interest in the 1,600 MW power station, which was previously fully consolidated and has been consolidated on joint operation since September 2018.

At end-2018, the Group's share (72%) of the provision covering the obligation to dismantle and rehabilitate the mine amounted to €310 million.

Dismantling and site rehabilitation work was initiated in 2017 and includes site rehabilitation, with the purpose of ensuring long-term land and wall stability, the demolition and dismantling of all of the site's industrial facilities, the monitoring of environmental incidents and any related remediation plans, as well as long-term site monitoring.

Several laws that have a direct or indirect impact on mine rehabilitation and on the agencies that administer the laws are currently being reformed. Consequently, the ultimate regulatory obligations could be revised during the life of the project and could therefore have an impact on provisions.

The average discount rate used to determine the amount of the provisions is 4.22%.

The amount of the provision recognized is based on the Group's best current estimate of the dismantling and rehabilitation costs that Hazelwood is expected to incur. However, the amount of this provision may be adjusted in the future to take into account any changes in the key inputs.

20.4 Litigation and tax risks

This caption includes essentially provisions for commercial litigation, and tax claims and disputes.

20.5 Other contingencies

This caption includes notably provisions for onerous contracts relating to storage and transport capacity reservation contracts recognized in 2017 (see Note 10.5).

NOTE 21 POST-EMPLOYMENT BENEFITS AND OTHER LONG-TERM BENEFITS

Accounting principles

Depending on the laws and practices in force in the countries where the Group operates, Group companies have obligations in terms of pensions, early retirement payments, retirement bonuses and other benefit plans. Such obligations generally apply to all employees within the companies concerned.

The Group's obligations in relation to pensions and other employee benefits are recognized and measured in compliance with IAS 19. Accordingly:

- the cost of defined contribution plans is expensed based on the amount of contributions payable in the period;
- the Group's obligations concerning pensions and other employee benefits payable under defined benefit plans are assessed on an actuarial basis using the projected unit credit method. These calculations are based on assumptions relating to mortality, staff turnover and estimated future salary increases, as well as the economic conditions specific to each country or entity of the Group. Discount rates are determined by reference to the yield, at the measurement date, on investment grade corporate bonds in the related geographical area (or on government bonds in countries where no representative market for such corporate bonds exists).

Pension commitments are measured on the basis of actuarial assumptions. The Group considers that the assumptions used to measure its obligations are relevant and documented. However, any change in these assumptions could have a significant impact on the resulting calculations.

Provisions are recorded when commitments under these plans exceed the fair value of plan assets. Where the value of plan assets (capped where appropriate) is greater than the related commitments, the surplus is recorded as an asset under "Other assets" (current or non-current).

As regards post-employment benefit obligations, actuarial gains and losses are recognized in other comprehensive income. Where appropriate, adjustments resulting from applying the asset ceiling to net assets relating to overfunded plans are treated in a similar way. However, actuarial gains and losses on other long-term benefits such as long-service awards, are recognized immediately in income.

Net interest on the net defined benefit liability (asset) is presented in net financial income/(loss).

21.1 Description of the main pension plans

21.1.1 Companies belonging to the Electricity and Gas Industries sector in France

Since January 1, 2005, the CNIEG (*Caisse Nationale des Industries Électriques et Gazières*) has operated the pension, disability, death, occupational accident and occupational illness benefit plans for electricity and gas industry (hereinafter "EGI") companies in France. The CNIEG is a social security legal entity under private law placed under the joint responsibility of the ministries in charge of social security and the budget.

Employees and retirees of EGI sector companies have been fully affiliated to the CNIEG since January 1, 2005. The main affiliated Group entities are ENGIE SA, GRDF, GRTgaz, ELENGY, STORENGY, ENGIE Thermique France, CPCU, CNR and SHEM.

Following the funding reform of the special EGI pension plan introduced by Law No. 2004-803 of August 9, 2004 and its implementing decrees, specific benefits (pension benefits on top of the standard benefits payable under ordinary law) already vested at December 31, 2004 ("past specific benefits") were allocated between the various EGI entities. Past specific benefits (benefits vested at December 31, 2004) relating to regulated transmission and distribution businesses

("regulated past specific benefits") are funded by the levy on gas and electricity transmission and distribution services (*Contribution Tarifaire d'Acheminement*) and therefore no longer represent an obligation for the ENGIE Group. Unregulated past specific benefits (benefits vested at December 31, 2004) are funded by EGI sector companies to the extent defined by Decree No. 2005-322 of April 5, 2005.

The special EGI pension plan is a legal pension plan available to new entrants.

The specific benefits vested under the plan since January 1, 2005 are wholly financed by EGI sector companies in proportion to their respective weight in terms of payroll costs within the EGI sector.

As this plan represents a defined benefit plan, the Group has set aside a pension provision in respect of specific benefits payable to employees of unregulated activities and specific benefits vested by employees of regulated activities since January 1, 2005. This provision also covers the Group's early retirement obligations. The provision amount may be subject to fluctuations based on the weight of the Group's companies within the EGI sector.

Pension benefit obligations and other "mutualized" obligations are assessed by the CNIEG.

At December 31, 2018, the projected benefit obligation in respect of the special pension plan for EGI sector companies amounted to €3.2 billion.

The duration of the pension benefit obligation of the EGI pension plan is 20 years.

21.1.2 Companies belonging to the electricity and gas sector in Belgium

In Belgium, the rights of employees in electricity and gas sector companies, principally Electrabel, Laborelec, ENGIE CC and some ENGIE Energy Management Trading employee categories, are governed by collective bargaining agreements.

These agreements, applicable to "wage-rated" employees recruited prior to June 1, 2002 and managerial staff recruited prior to May 1, 1999, specify the benefits entitling employees to a supplementary pension equivalent to 75% of their most recent annual income, for a full career and in addition to the statutory pension. These top-up pension payments provided under defined benefit plans are partly reversionary. In practice, the benefits are paid in the form of a lump sum for the majority of plan participants. Most of the obligations resulting from these pension plans are financed through pension funds set up for the electricity and gas sector and by certain insurance companies. Pre-funded pension plans are financed by employer and employee contributions. Employer contributions are calculated annually based on actuarial assessments.

The projected benefit obligation relating to these plans represented around 15% of total pension obligations and related liabilities at December 31, 2018. The average duration is 10 years.

"Wage-rated" employees recruited after June 1, 2002 and managerial staff (i) recruited after May 1, 1999 or (ii) having opted for the transfer through defined contribution plans, are covered under defined contribution plans. Prior to January 1, 2017, the law specified a minimum average annual return (3.75% on wage contributions and 3.25% on employer contributions) when savings are liquidated.

The law on supplementary pensions, approved on December 18, 2016 and enforced on January 1, 2017 henceforth specifies a minimum rate of return, depending on the actual rate of return of Belgian government bonds, within a range of 1.75%-3.25% (the rates are now identical for employee and employer contributions). In 2018, the minimum rate of return stood at 1.75%.

An expense of €24 million was recognized in 2018 in respect of these defined contribution plans (€31 million in 2017).

21.1.3 Multi-employer plans

Employees of some Group companies are affiliated to multi-employer pension plans.

Under multi-employer plans, risks are pooled to the extent that the plan is funded by a single contribution rate determined for all affiliated companies and applicable to all employees.

Multi-employer plans are particularly common in the Netherlands, where employees are normally required to participate in a compulsory industry-wide plan. These plans cover a significant number of employers, thereby limiting the impact of potential default by an affiliated company. In the event of default, the vested rights are maintained in a special compartment and are not transferred to the other members. Refinancing plans may be set up to ensure the funds are balanced.

The ENGIE Group accounts for multi-employer plans as defined contribution plans.

The expense recognized in 2018 in respect of multi-employer pension plans was stable as compared to 2017 at €70 million.

21.1.4 Other pension plans

Most other Group companies also grant their employees retirement benefits. In terms of financing, pension plans within the Group are almost equally split between defined benefit and defined contribution plans.

The Group's main pension plans outside France, Belgium and the Netherlands concern:

- the United Kingdom: the large majority of defined benefit pension plans is now closed to new entrants and future benefits no longer vest under these plans. All entities run a defined contribution scheme. The pension obligations of International Power's subsidiaries in the United Kingdom are covered by the special Electricity Supply Pension Scheme (ESPS). The assets of this defined benefit scheme are invested in separate funds. Since June 1, 2008, the scheme has been closed and a defined contribution plan was set up for new entrants;
- Germany: the Group's German subsidiaries have closed their defined benefit plans to new entrants and now offer defined contribution plans;
- Brazil: ENGIE Brasil Energia operates its own pension scheme. This scheme has been split into two parts, one for the (closed) defined benefit plan, and the other for the defined contribution plan that has been available to new entrants since the beginning of 2005.

21.2 Description of other post-employment benefit obligations and other long-term benefits

21.2.1 Other benefits granted to current and former EGI sector employees

Other benefits granted to EGI sector employees are:

Post-employment benefits:

- reduced energy prices;
- end-of-career indemnities;
- bonus leave;
- death capital benefits.

Long-term benefits:

- allowances for occupational accidents and illnesses;
- temporary and permanent disability allowances;
- long-service awards.

The Group's main obligations are described below.

21.2.1.1 Reduced energy prices

Under Article 28 of the national statute for electricity and gas industry personnel, all employees (current and former employees, provided they meet certain length-of-service conditions) are entitled to benefits in kind which take the form of reduced energy prices known as "employee rates".

This benefit entitles employees to electricity and gas supplies at a reduced price. For retired employees, this provision represents a post-employment defined benefit. Retired employees are only entitled to the reduced rate if they have completed at least 15 years' service within EGI sector companies.

In accordance with the agreements signed with EDF in 1951, ENGIE provides gas to all current and former employees of ENGIE and EDF, while EDF supplies electricity to these same beneficiaries. ENGIE pays (or benefits from) the balancing contribution payable in respect of its employees as a result of energy exchanges between the two utilities.

The obligation to provide energy at a reduced price to current and former employees is measured as the difference between the energy sale price and the preferential rate granted.

The provision set aside in respect of reduced energy prices stood at €3.0 billion at December 31, 2018. The duration of the obligation is 21 years.

21.2.1.2 End-of-career indemnities

Retiring employees (or their dependents in the event of death during active service) are entitled to end-of-career indemnities, which increase in line with the length of service within the EGI sector.

21.2.1.3 Compensation for occupational accidents and illnesses

EGI sector employees are entitled to compensation for accidents at work and occupational illnesses. These benefits cover all employees or the dependents of employees who die as a result of occupational accidents or illnesses, or injuries suffered on the way to work.

The amount of the obligation corresponds to the likely present value of the benefits to be paid to current beneficiaries, taking into account any reversionary annuities.

21.2.2 Other benefits granted to employees of the gas and electricity sector in Belgium

Electricity and gas sector companies also grant other employee benefits such as the reimbursement of medical expenses, electricity and gas price reductions, as well as length-of-service awards and early retirement schemes. These benefits are not prefunded, with the exception of the special "*allocation transitoire*" termination indemnity, considered as an end-of-career indemnity.

21.2.3 Other collective agreements

Most other Group companies also grant their staff post-employment benefits (early retirement plans, medical coverage, benefits in kind, etc.) and other long-term benefits such as jubilee and length-of-service awards.

21.3 Defined benefit plans

21.3.1 Amounts presented in the statement of financial position and statement of comprehensive income

In accordance with IAS 19, the information presented in the statement of financial position relating to post-employment benefit obligations and other long-term benefits results from the difference between the gross projected benefit obligation and the fair value of plan assets. A provision is recognized if this difference is positive (net obligation), while a prepaid benefit cost is recorded in the statement of financial position when the difference is negative, provided that the conditions for recognizing the prepaid benefit cost are met.

Changes in provisions for post-employment benefits and other long-term benefits, plan assets and reimbursement rights recognized in the statement of financial position are as follows:

<i>In millions of euros</i>	Provisions	Plan assets	Reimbursement rights
At December 31, 2016	(6,422)	69	130
Exchange rate differences	31	17	-
Transfer to "Liabilities directly associated with assets classified as held for sale"	233	-	-
Changes in scope of consolidation and other	(86)	8	-
Actuarial gains and losses	92	5	13
Periodic pension cost of continued operations	(427)	(50)	3
Periodic pension cost of discontinued operations	(28)	-	-
Asset ceiling	2	-	-
Contributions/benefits paid	464	53	12
At December 31, 2017	(6,142)	101	159
Exchange rate differences	(22)	-	-
Changes in scope of consolidation and other	95	(26)	(12)
Actuarial gains and losses	(237)	7	8
Periodic pension cost of continued operations	(457)	(68)	3
Asset ceiling	-	-	-
Contributions/benefits paid	392	93	11
AT DECEMBER 31, 2018	(6,371)	108	168

Plan assets and reimbursement rights are presented in the statement of financial position under "Other non-current assets" or "Other current assets".

The cost recognized for the period amounted to €525 million in 2018 (€477 million in 2017). The components of this defined benefit cost in the period are set out in Note 21.3.4 "Components of the net periodic pension cost".

The Eurozone represented 97% of the Group's net obligation at December 31, 2018 (compared to 96% at December 31, 2017).

Cumulative actuarial gains and losses recognized in equity amounted to €3,472 million at December 31, 2018, compared to €3,327 million at December 31, 2017.

Net actuarial differences arising in the period and presented on a separate line in the statement of comprehensive income represented a net actuarial loss of €231 million in 2018 and a net actuarial gain of €99 million in 2017.

21.3.2 Change in benefit obligations and plan assets

The table below shows the amount of the Group's projected benefit obligations and plan assets, changes in these items during the periods presented, and their reconciliation with the amounts reported in the statement of financial position:

In millions of euros	Dec. 31, 2018				Dec. 31, 2017			
	Pension benefit obligations ⁽¹⁾	Other post-employment benefit obligations ⁽²⁾	Long-term benefit obligations ⁽³⁾	Total	Pension benefit obligations ⁽¹⁾	Other post-employment benefit obligations ⁽²⁾	Long-term benefit obligations ⁽³⁾	Total
A - CHANGE IN PROJECTED BENEFIT OBLIGATION								
Projected benefit obligation at January 1	(7,653)	(3,739)	(539)	(11,931)	(7,945)	(3,731)	(556)	(12,232)
Service cost	(308)	(62)	(42)	(412)	(278)	(57)	(46)	(381)
Interest expense	(165)	(73)	(8)	(245)	(189)	(73)	(9)	(271)
Contributions paid	(16)	-	-	(16)	(13)	-	-	(13)
Amendments	(3)	(5)	10	2	(7)	-	-	(7)
Changes in scope of consolidation	(37)	31	49	43	3	1	5	9
Curtailments/settlements	1	-	-	1	6	-	-	6
Non-recurring items	-	2	-	2	-	(2)	-	(2)
Financial actuarial gains and losses	(44)	(35)	(1)	(80)	23	(53)	23	(8)
Demographic actuarial gains and losses	101	1	1	103	(195)	1	(8)	(201)
Benefits paid	397	97	40	533	498	129	46	673
Transfer to "liabilities directly associated with assets classified as held for sale"	-	-	-	-	404	44	6	454
Other (of which translation adjustments)	16	(11)	(10)	(5)	39	1	-	40
Projected benefit obligation at December 31	A (7,712)	(3,794)	(499)	(12,006)	(7,653)	(3,739)	(539)	(11,931)
B - CHANGE IN FAIR VALUE OF PLAN ASSETS								
Fair value of plan assets at January 1	5,904	-	-	5,904	5,919	1	-	5,920
Interest income on plan assets	128	-	-	128	144	-	-	144
Financial actuarial gains and losses	(253)	-	-	(253)	321	-	-	321
Contributions received	309	15	-	324	298	21	-	318
Changes in scope of consolidation	32	-	-	32	-	-	-	-
Settlements	-	-	-	-	(9)	(1)	-	(10)
Benefits paid	(341)	(15)	-	(357)	(441)	(21)	-	(462)
Transfer to "liabilities directly associated with assets classified as held for sale"	-	-	-	-	(222)	-	-	(222)
Other (of which translation adjustments)	(11)	-	-	(11)	(105)	-	-	(105)
Fair value of plan assets at December 31	B 5,767	-	-	5,767	5,904	-	-	5,904
C - FUNDED STATUS	A+B (1,945)	(3,794)	(499)	(6,239)	(1,749)	(3,739)	(539)	(6,027)
Asset ceiling	(25)	-	-	(25)	(14)	-	-	(14)
NET BENEFIT OBLIGATION	(1,970)	(3,794)	(499)	(6,263)	(1,763)	(3,739)	(539)	(6,041)
ACCRUED BENEFIT LIABILITY	(2,078)	(3,794)	(499)	(6,371)	(1,865)	(3,739)	(538)	(6,142)
PREPAID BENEFIT COST	108	-	-	108	101	-	-	101

(1) Pensions and retirement bonuses.

(2) Reduced energy prices, healthcare, gratuities and other post-employment benefits.

(3) Length-of-service awards and other long-term benefits.

21.3.3 Change in reimbursement rights

Changes in the fair value of reimbursement rights relating to plan assets managed by Contassur are as follows:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017
Fair value at January 1	159	130
Interest income on plan assets	3	3
Financial actuarial gains and losses	8	13
Actual return	11	16
Curtailments/settlements	(12)	-
Employer contributions	18	16
Employee contributions	-	-
Benefits paid	(7)	(3)
Other	-	-
FAIR VALUE AT DECEMBER 31	168	159

21.3.4 Components of the net periodic pension cost

The net periodic cost recognized in respect of defined benefit obligations for the years ended December 31, 2018 and 2017 breaks down as follows:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017
Current service cost	412	360
Actuarial gains and losses ⁽¹⁾	(1)	(14)
Plan amendments	(2)	6
Gains or losses on pension plan curtailments, terminations and settlements	(1)	2
Non-recurring items	(2)	1
Total recognized under current operating income after share in net income of entities accounted for using the equity method	407	355
Net interest expense	117	122
Total accounted for under net financial income/(loss)	117	122
TOTAL	525	477

(1) On the long-term benefit obligation.

21.3.5 Funding policy and strategy

When defined benefit plans are funded, the related plan assets are invested in pension funds and/or with insurance companies, depending on the investment practices specific to the country concerned. The investment strategies underlying these defined benefit plans are aimed at striking the right balance between return on investment and acceptable levels of risk.

The objectives of these strategies are twofold: to maintain sufficient liquidity to cover pension and other benefit payments; and as part of risk management, to achieve a long-term rate of return higher than the discount rate or, where appropriate, at least equal to future required returns.

When plan assets are invested in pension funds, investment decisions are the responsibility of the fund management concerned. For French companies, where plan assets are invested with an insurance company, the latter manages the investment portfolio for unit-linked policies or euro-denominated policies, in a manner adapted to the risk and long-term profile of the liabilities.

The funding of these obligations at December 31 for each of the periods presented can be analyzed as follows:

<i>In millions of euros</i>	Projected benefit obligation	Fair value of plan assets	Asset ceiling	Total net obligation
Underfunded plans	(5,648)	4,294	(23)	(1,377)
Overfunded plans	(1,375)	1,473	(2)	96
Unfunded plans	(4,977)	-	-	(4,977)
AT DECEMBER 31, 2018	(12,000)	5,767	(25)	(6,258)
Underfunded plans	(5,876)	4,505	(9)	(1,380)
Overfunded plans	(1,286)	1,399	(5)	108
Unfunded plans	(4,768)	-	-	(4,768)
AT DECEMBER 31, 2017	(11,930)	5,904	(14)	(6,041)

The allocation of plan assets by principal asset category can be analyzed as follows:

<i>In %</i>	Dec. 31, 2018	Dec. 31, 2017
Equity investments	27	27
Sovereign bond investments	25	24
Corporate bond investments	27	28
Money market securities	4	3
Real estate	2	2
Other assets	15	17
TOTAL	100	100

All plan assets were quoted on an active market at December 31, 2018.

The actual return on assets of EGI sector companies stood at a negative 5% in 2018.

The actual return on plan assets of Belgian entities amounted to approximately 3% in Group insurance and a negative 5% in pension funds.

The allocation of plan asset categories by geographic area of investment can be analyzed as follows:

<i>In %</i>	Europe	North America	Latin America	Asia - Oceania	Rest of the World	Total
Equity investments	57	26	3	11	4	100
Sovereign bond investments	77	2	21	-	-	100
Corporate bond investments	76	18	1	3	1	100
Money market securities	67	-	4	-	29	100
Real estate	90	-	7	-	3	100
Other assets	12	8	3	3	73	100

21.3.6 Actuarial assumptions

Actuarial assumptions are determined individually by country and company in conjunction with independent actuaries. Weighted discount rates for the main actuarial assumptions are presented below:

		Pension benefit obligations		Other post-employment benefit obligations		Long-term benefit obligations		Total benefit obligations	
		2018	2017	2018	2017	2018	2017	2018	2017
Discount rate	Eurozone	2.0%	1.9%	2.1%	2.0%	1.6%	1.8%	1.9%	1.9%
	UK Zone	2.5%	2.6%	-	-	-	-	-	-
Inflation rate	Eurozone	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%
	UK Zone	3.3%	3.2%	-	-	-	-	-	-

21.3.6.1 Discount and inflation rate

The discount rate applied is determined based on the yield, at the date of the calculation, investment grade corporate bonds with maturities mirroring the term of the plan.

The rates were determined for each monetary area based on data for AA corporate bond yields. For the Eurozone, data (from Bloomberg) are extrapolated on the basis of government bond yields for long maturities.

According to the Group's estimates, a 100-basis-point increase or decrease in the discount rate would result in a change of approximately 16% in the projected benefit obligation.

The inflation rates were determined for each monetary area. A 100-basis-point increase or decrease in the inflation rate (with an unchanged discount rate) would result in a change of approximately 13% in the projected benefit obligation.

21.3.6.2 Other assumptions

The increase in the rate of medical costs (including inflation) was estimated at 2.8%.

A 100-basis-point change in the assumed increase in medical costs would have the following impacts:

<i>In millions of euros</i>	100 basis point increase	100 basis point decrease
Impact on expenses	-	-
Impact on pension obligations	6	(5)

21.3.7 Estimated employer contributions payable in 2019 under defined benefit plans

The Group expects to pay around €265 million in contributions into its defined benefit plans in 2019, including €126 million for EGI sector companies. Annual contributions in respect of EGI sector companies will be made by reference to rights vested in the year, taking into account the funding level for each entity in order to even out contributions over the medium term.

21.4 Defined contribution plans

In 2018, the Group recorded a €133 million expense in respect of amounts paid into Group defined contribution plans (€142 million in 2017). These contributions are recorded under "Personnel costs" in the consolidated income statement.

NOTE 22 FINANCE LEASES

Accounting principles

Leases are analyzed based on the situations and indicators set out in IAS 17 in order to determine whether they constitute operating leases or finance leases.

A finance lease is defined as a lease which transfers substantially all the risks and rewards incidental to the ownership of the related asset to the lessee.

The following main factors are considered by the Group to assess whether or not a lease transfers substantially all the risks and rewards incidental to ownership: whether (i) the lessor transfers ownership of the asset to the lessee by the end of the lease term; (ii) the lessee has an option to purchase the asset and if so, the conditions applicable to exercising that option; (iii) lease term is for the major part of the economic life of the asset; (iv) the asset is of a highly specialized nature; and (v) the present value of minimum lease payments amounts to at least substantially all of the fair value of the leased asset.

Accounting for finance leases

On initial recognition, assets held under finance leases are recorded as property, plant and equipment and the related liability is recognized under borrowings. At inception of the lease, finance leases are recorded at amounts equal to the fair value of the leased asset or, if lower, the present value of the minimum lease payments.

Accounting for arrangements that contain a lease

IFRIC 4 deals with the identification of services and take-or-pay sales or purchasing contracts that do not take the legal form of a lease but convey rights to customers/suppliers to use an asset or a group of assets in return for a payment or a series of fixed payments. Contracts meeting these criteria should be identified as either operating leases or finance leases. In the latter case, a finance receivable should be recognized to reflect the financing deemed to be granted by the Group where it is considered as acting as lessor and its customers as lessees.

The Group is concerned by this interpretation mainly with respect to:

- some energy purchase and sale contracts, particularly where the contract conveys to the purchaser of the energy an exclusive right to use a production asset;
- certain contracts with industrial customers relating to assets held by the Group.

22.1 Finance leases for which ENGIE acts as lessee

The carrying amounts of property, plant and equipment held under finance leases are broken down into different categories depending on the type of asset concerned.

The main finance lease agreements concluded by the Group primarily concern power plants in the Latin America segment (mostly ENGIE Energía Perú – Peru) and ENGIE Cofely's cogeneration plants.

The undiscounted and present values of future minimum lease payments break down as follows:

In millions of euros	Dec. 31, 2018		Dec. 31, 2017	
	Undiscounted value	Present value	Undiscounted value	Present value
Year 1	125	121	155	151
Years 2 to 5 inclusive	209	193	334	306
Beyond year 5	69	61	27	20
TOTAL	403	376	516	477

The following table provides a reconciliation of liabilities under finance leases as reported in the statement of financial position (see Note 17.2.3 “Borrowings and debt”) with undiscounted future minimum lease payments by maturity:

<i>In millions of euros</i>	Total	Year 1	Years 2 to 5 inclusive	Beyond year 5
Liabilities under finance leases	380	118	193	69
Impact of discounting future repayments of principal and interest	23	7	16	-
UNDISCOUNTED FUTURE MINIMUM LEASE PAYMENTS	403	125	209	69

22.2 Finance leases for which ENGIE acts as lessor

These leases mainly fall within the scope of IFRIC 4 guidance on the interpretation of IAS 17. They concern (i) energy purchase and sale contracts where the contract conveys an exclusive right to use a production asset; and (ii) certain contracts with industrial customers relating to assets held by the Group.

The Group has recognized finance lease receivables, notably for cogeneration plants for Wapda and NTDC (Uch – Pakistan) and Lanxess (Electrabel – Belgium).

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017
Undiscounted future minimum lease payments	919	1,013
Unguaranteed residual value accruing to the lessor	27	27
TOTAL GROSS INVESTMENT IN THE LEASE	946	1,041
Unearned financial income	170	197
NET INVESTMENT IN THE LEASE (STATEMENT OF FINANCIAL POSITION)	777	844
<i>Of which present value of future minimum lease payments</i>	758	828
<i>Of which present value of unguaranteed residual value</i>	19	16

Undiscounted future minimum lease payments receivable under finance leases can be analyzed as follows:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017
Year 1	182	130
Years 2 to 5 inclusive	420	456
Beyond year 5	317	427
TOTAL	919	1,013

NOTE 23 OPERATING LEASES

Accounting standards

All leases that do not meet the definition of a finance lease are classified as operating leases.

Payments made under operating leases are recognized as an expense on a straight-line basis over the lease term.

23.1 Operating leases for which ENGIE acts as lessee

The Group has entered into operating leases mainly in connection with miscellaneous buildings and fittings.

Operating lease income and expenses for 2018 and 2017 can be analyzed as follows:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Minimum lease payments	(686)	(642)
Contingent lease payments	(13)	(17)
Sub-letting income	-	(1)
Sub-letting expenses	(29)	(35)
Other operating lease expenses	(99)	(94)
TOTAL	(828)	(789)

(1) Comparative data at December 31, 2017 have been restated due to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities (see Note 2 "Restatement of 2017 comparative data").

The present values of future minimum lease payments under non-cancelable operating leases can be analyzed as follows:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Year 1	353	459
Years 2 to 5 inclusive	839	1,159
Beyond year 5	895	696
TOTAL	2,087	2,314

(1) Comparative data at December 31, 2017 have been restated due to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities (see Note 2 "Restatement of 2017 comparative data").

23.2 Operating leases for which ENGIE acts as lessor

These leases fall mainly within the scope of IFRIC 4 guidance on the interpretation of IAS 17. They primarily concern power plants operated in the Africa/Asia segment.

Operating lease income for 2018 and 2017 can be analyzed as follows:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Minimum lease payments	126	271
Contingent lease payments	-	6
TOTAL	126	277

(1) Comparative data at December 31, 2017 have been restated due to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities (see Note 2 "Restatement of 2017 comparative data").

NOTE 23 OPERATING LEASES

The present values of future minimum lease payments receivable under non-cancelable operating leases can be analyzed as follows:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Year 1	31	286
Years 2 to 5 inclusive	72	58
Beyond year 5	67	3
TOTAL	170	347

(1) Comparative data at December 31, 2017 have been restated due to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities (see Note 2 "Restatement of 2017 comparative data").

NOTE 24 SHARE-BASED PAYMENTS

Accounting standards

Under IFRS 2, share-based payments made in consideration for services provided are recognized as personnel costs. These services are measured at the fair value of the instruments awarded.

The fair value of bonus share plans is estimated by reference to the share price at the grant date, taking into account the fact that no dividend is payable over the vesting period, and based on the estimated turnover rate for the employees concerned and the probability that the Group will meet its performance targets. The fair value measurement also takes into account the non-transferability period associated with these instruments. The cost of shares granted to employees is expensed over the vesting period of the rights and offset against equity.

A Monte Carlo pricing model is used for performance shares granted on a discretionary basis and subject to external performance criteria.

Expenses recognized in respect of share-based payments break down as follows:

In millions of euros	Note	Expense for the year	
		Dec. 31, 2018	Dec. 31, 2017
Employee share issues ⁽¹⁾	24.2	31	1
Bonus/performance share plans	24.3	46	36
Other Group companies' plans		3	1
TOTAL		80	38

(1) Including Share Appreciation Rights set up within the scope of employee share issues in certain countries.

24.1 Stock option plans

No new ENGIE stock option grants were approved by the Group's Board of Directors in either 2018 or 2017.

At December 31, 2017, the last stock purchase plan expired.

24.2 Link 2018

24.2.1 Description of available ENGIE share plans

In 2018, Group employees and former Group employees were entitled to purchase ENGIE shares as part of the "LINK 2018" worldwide employee share ownership plan. The offering mainly involved the sale of treasury shares, including 22.2 million shares bought back from the French State following the private placements carried out in (see Note 19.1). Employees could subscribe to either:

- the Link Classique Plan: this plan allows employees to subscribe to shares at a discount, either directly or via an employee mutual fund and with an employer top-up contribution;
- the Link Multiple Plan: under this plan, employees may subscribe to shares at a discount, either directly or via an employee mutual fund, and also benefit from any increase in the share price (leverage effect) in addition to the amounts invested. Through a Swap Agreement with a bank, employees are guaranteed to recover 100% of the invested amount as well as a minimum capitalized return;
- the Link+ Plan: under this plan, employees may subscribe to shares at a discount, either directly or via an employee mutual fund, and also benefit from any increase in the share price (higher leverage effect than the Link Multiple Plan) in addition to the amounts invested. This plan is subject to a lock-up period of ten years. Through a Swap Agreement with a bank, employees are guaranteed to recover 100% of the invested amount as well as a guaranteed minimum capitalized return;

- Share Appreciation Rights (SARs): this leveraged plan entitles beneficiaries who purchase shares to receive a cash bonus equal to the increase in the share price after a period of five years. The resulting employee liability is covered by warrants.

The Link Classique Plan and the Link+ Plan featured an employer contribution under the terms and conditions described below:

- participating French employees were entitled to bonus ENGIE shares depending on the amount of their own contribution to the plans:
 - the Link Classique Plan: for an employee contribution of €150, the employer contribution corresponded to 200% of this amount ; for an additional employee contribution of €150, the employer contribution represented 100% of the amount. The employer contribution was capped at €450;
 - the Link+ Plan: for an employee contribution of €100, the employer contribution corresponded to 300% of this amount.
- for employees in other countries, ENGIE shares were granted through a bonus share award plan, subject to the still being employed with the Group and depending on their own contribution to the plan:
 - for an employee contribution of €150, two bonus shares were granted for every one share subscribed;
 - for employee contributions from €150 to €300, one bonus share was granted for every share subscribed.

The bonus shares will be awarded to employees on August 2, 2023, provided that they are still employed by the ENGIE Group.

24.2.2 Accounting impacts

Subscription price for the 2018 plan represents the average closing price of the ENGIE share on the NYSE Euronext Paris Eurolist market over the 20 trading days between May 24, 2018 and June 20, 2018 inclusive. The reference price is set at €13.65 less 20% for the Link Classique and the Link Multiple plans, i.e. €10.92 and less 30% for the Link+ plan, i.e. €9.56.

The expense recognized in the consolidated financial statements in respect of the Link Classique, Link Multiple and Link+ plans corresponds to the difference between the fair value of the shares subscribed and the subscription price. The fair value takes into account the lock-up period of five or ten years, as provided for by French legislation. It also considers the opportunity cost implicitly borne by ENGIE under the leveraged share ownership plan in allowing its employees to benefit from more attractive financial conditions than those that would have been available to them as individual investors.

The following assumptions were applied:

	5 years	10 years
Risk-free interest rate	0.26%	0.88%
Spread applicable to the retail banking network	3.64%	3.60%
Employee financing cost	3.90%	4.48%
Share lending cost	1.00%	1.50%
Share price at grant date	13.65	13.65
Volatility spread	1.90%	7.50%

The accounting impacts are break down as follows:

	Link Classique	Link Multiple	Link+	Link+ France - additional employer's contribution	Link Classique France - additional employer's contribution	Total
Amount subscribed (in millions of euros)	24	187	111	-	-	321
Number of shares subscribed (in millions of shares)	2.2	17.1	11.6	0.9	0.9	32.7
Discount (€/share)	2.7	2.7	4.1	13.7	13.7	-
Non-transferability restriction (€/share)	(3.3)	(3.3)	(7.6)	(7.6)	(3.3)	-
Opportunity cost (€/share)	-	0.3	1.0	-	-	-
Cost for the Group (in millions of euros)	-	4	12	6	9	31

Subscriptions to the Link 2018 worldwide employee share ownership plan totaled €321 million and break down as follows:

- the sale of treasury shares to employees amounted to €255 million;
- a capital increase and additional paid-in capital of €66 million (excluding issuance costs). This amount is broken down into €4 million for Link Classique and €62 million for Link Multiple.

The Group recognized a total expense of €31 million for 2018 in respect of the 30.9 million shares subscribed and 1.8 million bonus shares awarded under employer contributions.

The accounting impact of cash-settled Share Appreciation Rights consists in recognizing a payable to the employee over the vesting period, with a corresponding adjustment recorded in income. At December 31, 2018, the fair value of the liability relating to the 2014 and 2018 awards amounted to €0.8 million.

24.3 Bonus shares and performance shares

24.3.1 New awards in 2018

ENGIE Performance Share plan of December 11, 2018

On December 11, 2018, the Board of Directors approved the award of 5 million performance shares to members of the Group's executive and senior management, breaking down into three tranches:

- performance shares vesting on March 14, 2022, subject to a further one-year lock-up period;
- performance shares vesting on March 14, 2022, without a lock-up period; and
- performance shares vesting on March 14, 2023, without a lock-up period.

In addition to a condition requiring employees to be employed with the Group at the vesting date, each tranche is made up of instruments subject to three different conditions, excluding the first 150 performance shares granted to beneficiaries (excluding top management) which are exempt from performance conditions. The performance conditions, each of which accounts for one-third of the total grant, are as follows:

- a market performance condition relating to ENGIE's Total Shareholder Return compared to that of a reference panel of ten companies, as assessed between November 2018 and January 2022;
- two internal performance conditions relating to net recurring income Group share and to Return On Capital Employed (ROCE) in 2020 and 2021.

As part of this plan, performance shares without conditions were also awarded to the winners of the Innovation and Incubation programs (21,150 shares awarded).

ENGIE Bonus Share plan of August 2, 2018

As part of the Link 2018 employee share plan, bonus shares were awarded to subscribers of the Link Classique plan (outside France), with two bonus shares awarded for €150 of shares purchased, and one bonus share awarded for shares purchased beyond €150 and up to €300. A total of 301,816 shares were awarded under this plan, subject to the employees still being employed with the ENGIE Group on August 2, 2023.

24.3.2 Fair value of bonus share plans with or without performance conditions

The following assumptions were used to calculate the fair value of the new plans awarded by ENGIE in 2018:

Award date	Vesting date	End of the lock-up period	Price at the award date	Expected dividend	Financing cost for the employee	Non-transferability cost	Market-related performance condition	Fair value per unit
August 2, 2018	August 2, 2023	August 2, 2023	14.0	0.75	NA	NA	no	10.28
Weighted average fair value of the August 2, 2018 plan								10.28
December 11, 2018	March 14, 2022	March 14, 2023	12.3	0.75	4.4%	0.32	yes	8.95
December 11, 2018	March 14, 2022	March 14, 2022	12.3	0.75	4.4%	0.32	yes	9.32
December 11, 2018	March 14, 2022	March 14, 2022	12.3	0.75	4.4%	0.40	no	10.00
December 11, 2018	March 14, 2023	March 14, 2023	12.3	0.75	4.4%	0.32	yes	8.62
Weighted average fair value of the December 11, 2018 plan								8.90

24.3.3 Review of internal performance conditions applicable to the plans

In addition to the condition of continuing employment within the Group, eligibility for certain bonus share and performance share plans is subject to an internal performance condition. When this condition is not fully met, the number of bonus shares granted to employees is reduced in accordance with the plans' regulations, leading to a decrease in the total expense recognized in relation to the plans in accordance with IFRS 2. Performance conditions are reviewed at each reporting date.

24.3.4 Free share plans with or without performance conditions in force at December 31, 2018, and impact on income

The expense recorded during the year on plans in effect was as follows:

	Expense for the year (In millions of euros)	
	Dec. 31, 2018	Dec. 31, 2017
Bonus share plans	-	-
Performance share plans	46	36
of which expense for the year	46	37
of which reversal for performance conditions not achieved	-	(1)
TOTAL	46	36

NOTE 25 RELATED PARTY TRANSACTIONS

This note describes material transactions between the Group and its related parties.

Compensation payable to key management personnel is disclosed in Note 26 “Executive compensation”.

Transactions with joint ventures and associates are described in Note 4 “Investments in entities accounted for using the equity method”.

Only material transactions are described below.

25.1 Relations with the French State and with entities owned or partly owned by the French State

25.1.1 Relations with the French State

On July 30, 2018, the French State sold to ENGIE a 0.46% in the Group's share capital (11.1 million shares for €151.7 million). Consequently, the share of ENGIE owned by the French State decreased from 24.10% to 23.64%, allowing it to appoint four representatives to the Group's 19-member Board of Directors (instead of five previously).

Since August 2018, the French State has held 34.51% of the Group's theoretical voting rights (or 34.79% of the exercisable voting rights) compared to 34.87% at the end of July 2018, and 28.07% at the end of December 2017.

The French State holds a golden share aimed at protecting France's critical interests and ensuring the continuity and safeguarding of supplies in the energy sector. The golden share is granted to the French State indefinitely and entitles it to veto decisions taken by ENGIE if it considers they could harm France's interests.

Public service engagements in the energy sector are defined by the law of January 3, 2003.

On November 6, 2015, the French State and ENGIE renewed the public service contract which sets out how such engagements are implemented, the Group's public service obligations and the conditions for rate regulation in France:

- as part of its public service obligations, the Group reaffirmed its commitments in terms of security of supply, quality of customer relations, solidarity and assistance to low-income customers, sustainable development and protection of the environment, as well as in terms of research;
- regarding the conditions for rate regulation in France, the contract confirms the overall regulatory framework for setting and changing natural gas tariffs in France, according to the Decree of December 18, 2009, which notably forecasts rate changes based on costs incurred, while also defining the transitional framework following the elimination of regulated natural gas tariffs for business customers.

Transmission rates on the GRTgaz transportation network and the gas distribution network in France, rates for accessing the French LNG terminals, as well as revenues related to storage capacity are all regulated.

25.1.2 Relations with EDF

Following the creation on July 1, 2004 of the French gas and electricity distribution network operator (EDF Gaz de France Distribution), Gaz de France SA and EDF entered into an agreement on April 18, 2005 setting out their relationship as regards the distribution business. The December 7, 2006 law on the energy sector reorganized the natural gas and electricity distribution networks. Enedis SA (previously ERDF SA), a subsidiary of EDF SA, and GRDF SA, a subsidiary of ENGIE SA, were created on January 1, 2007 and January 1, 2008, respectively, and act in accordance with the agreement previously signed by the two incumbent operators.

25.2 Relations with the CNIEG (*Caisse Nationale des Industries Électriques et Gazières*)

The Group's relations with the CNIEG, which manages all old-age, death and disability benefits for active and retired employees of the Group who belong to the special EGI pension plan, employees of EDF and Non-Nationalized Companies (*Entreprises Non Nationalisées – ENN*), are described in Note 21 "Post-employment benefits and other long-term benefits".

NOTE 26 EXECUTIVE COMPENSATION

The executive compensation presented below includes the compensation of the members of the Group's Executive Committee and Board of Directors.

The Executive Committee had 11 members at December 31, 2018 (12 members at December 31, 2017).

Their compensation breaks down as follows:

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017
Short-term benefits	21	17
Post-employment benefits	6	8
Shared-based payments	5	6
Termination benefits	0	-
TOTAL	32	31

The amount of pension benefit obligations in respect of members of the Group's Executive Committee stood at €29 million at December 31, 2018, being specified that this is an estimated amount as these commitments are, as a rule, not individualized. The Group has a policy of financing pension obligations through hedging assets, without these being specifically dedicated to the retirement obligations of a dedicated population.

NOTE 27 WORKING CAPITAL REQUIREMENTS, INVENTORIES, OTHER ASSETS AND OTHER LIABILITIES

Accounting standards

In accordance with IAS 1, the Group's current and non-current assets and liabilities are shown separately in the consolidated statement of financial position. For most of the Group's activities, the breakdown into current and non-current items is based on when assets are expected to be realized, or liabilities extinguished. Assets expected to be realized or liabilities extinguished within 12 months of the reporting date are classified as current, while all other items are classified as non-current.

27.1 Composition of change in working capital requirements

<i>In millions of euros</i>	Change in working capital requirements at Dec. 31, 2018	Change in working capital requirements at Dec. 31, 2017 ⁽¹⁾
Inventories	(268)	(487)
Trade and other receivables, net	(2,311)	732
Trade and other payables, net	2,177	7
Tax and employee-related receivables/payables	237	102
Margin calls and derivative instruments hedging commodities relating to trading activities	197	993
Other	117	267
TOTAL	149	1,613

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 and to the classification as "Discontinued operations" of ENGIE's upstream liquefied natural gas (LNG) activities sold in July 2018 (see Note 2 "Restatement of 2017 comparative data").

27.2 Inventories

Accounting standards

Inventories are measured at the lower of cost and net realizable value. Net realizable value corresponds to the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale.

The cost of inventories is determined based on the first-in, first-out method or the weighted average cost formula.

Nuclear fuel purchased is consumed in the process of producing electricity over a number of years. The consumption of this nuclear fuel inventory is recorded based on estimates of the quantity of electricity produced per unit of fuel.

Gas inventories

Gas injected into underground storage facilities includes working gas, which can be withdrawn without adversely affecting the subsequent operation of the reservoirs, and cushion gas, which is inseparable from the reservoirs and essential for their operation (see Note 16).

Working gas is classified in inventories and measured at weighted average purchase cost upon entering the transportation network regardless of its source, including any regasification costs.

Group inventory outflows are valued using the weighted average unit cost method.

An impairment loss is recognized when the net realizable value of inventories is lower than their weighted average cost.

Certain inventories are used for trading purposes and are recognized at fair value less the estimated costs necessary to make the sale in accordance with IAS 2. Any changes in this fair value are recognized in the consolidated income statement for the year to which they occur.

Greenhouse gas emissions rights

European Directive 2003/87/EC establishes a greenhouse gas (GHG) emissions allowance trading scheme within the European Union. Under the Directive, each year the sites concerned have to surrender a number of allowances equal to the total GHG emissions of their installations during the previous calendar year. As there are no specific rules under IFRS dealing with the accounting treatment of GHG emissions allowances, the Group decided to apply the following principles:

- emission rights are classified as inventories, as they are consumed in the production process;
- emission rights purchased on the market are recognized at acquisition cost;
- emission rights granted free of charge are recorded in the statement of financial position for a value of nil.

The Group records a liability at the year-end in the event that it does not have enough emission rights to cover its GHG emissions during the year. This liability is measured at the market value of the allowances required to meet its obligations at the year-end or based on the price of future contracts concluded to hedge this lack of emission rights.

Energy savings certificates (ESC)

In the absence of current IFRS Standards or IFRIC Interpretations on accounting for energy savings certificates (ESC), the following principles are applied:

- in the event that the number of ESCs held exceeds the obligation at the reporting date, they are accounted in inventories; otherwise, a liability is recorded;
- ESC inventories are valued at weighted average cost (acquisition cost for ESCs acquired or cost incurred for ESCs generated internally).

<i>In millions of euros</i>	Dec. 31, 2018	Dec. 31, 2017⁽¹⁾
Inventories of natural gas, net	1,274	1,423
Inventories of uranium	595	575
CO ₂ emission rights, green certificates and energy saving certificates, net	654	650
Inventories of commodities other than gas and other inventories, net	1,635	1,513
TOTAL	4,158	4,161

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

27.3 Other assets and other liabilities

<i>In millions of euros</i>	Dec. 31, 2018				Dec. 31, 2017⁽¹⁾			
	Assets		Liabilities		Assets		Liabilities	
	Non-current	Current	Non-current	Current	Non-current	Current	Non-current	Current
Other assets and liabilities	474	9,337	(960)	(12,529)	566	8,508	(1,007)	(11,531)
Tax receivables/payables	-	6,999	-	(7,449)	-	6,529	-	(6,685)
Employee receivables/payables	275	72	(5)	(2,461)	259	27	(3)	(2,376)
Dividend receivables/payables	-	12	-	(170)	-	6	-	(119)
Other	198	2,255	(954)	(2,449)	306	1,946	(1,004)	(2,351)

(1) Comparative data at December 31, 2017 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data").

At December 31, 2018, other non-current assets also include a receivable towards EDF Belgium in respect of nuclear provisions amounting to €74 million (€75 million at December 31, 2017).

NOTE 28 LEGAL AND ANTI-TRUST PROCEEDINGS

The Group is party to a number of legal and anti-trust proceedings with third parties or with legal and/or administrative authorities (including tax authorities) in the normal course of its business.

Provisions recorded in respect of these proceedings totaled €629 million at December 31, 2018 (€703 million at December 31, 2017).

The main disputes and investigations presented hereafter are recognized as liabilities or give rise to contingent assets or liabilities.

In the normal course of its business, the Group is also involved in a number of disputes and investigations before state courts, arbitral tribunals or regulatory authorities. The disputes and investigations that could have a material impact on the Group are presented below.

28.1 Latin America

28.1.1 Concessions in Buenos Aires and Santa Fe

In 2003, ENGIE and its joint shareholders, water distribution concession operators in Buenos Aires and Santa Fe, initiated two arbitration proceedings against the Argentinean State before the International Center for Settlement of Investment Disputes (ICSID). The purpose of these proceedings was to obtain compensation for the loss in value of investments made since the start of the concession, in accordance with bilateral investment protection treaties.

As a reminder, prior to the stock market listing of SUEZ Environnement Company, ENGIE and SUEZ (formerly SUEZ Environnement) entered into an agreement providing for the economic transfer to SUEZ of the rights and obligations relating to the ownership interests held by ENGIE in Aguas Argentinas and Aguas Provinciales de Santa Fe, including the rights and obligations resulting from the arbitration proceedings.

On April 9, 2015, the ICSID ordered the Argentinean State to pay USD 405 million in respect of termination of the Buenos Aires water distribution and treatment concession contracts (including USD 367 million to ENGIE and its subsidiaries), and on December 4, 2015, to pay USD 225 million in respect of termination of the Santa Fe concession contracts. The Argentinean State sought the annulment of these awards. By decision dated May 5, 2017, the claim for the annulment of the Buenos Aires award was rejected. The claim to annul the award in the Santa Fe case was rejected by a decision dated December 14, 2018. Consequently, the two ICSID awards, which are a step in the settlement of the dispute, are now final.

28.1.2 Planned construction of an LNG terminal in Uruguay

GNLS SA, a joint subsidiary of Marubeni and ENGIE, was selected in 2013 to build an offshore LNG terminal in Uruguay. On November 20, 2013, GNLS contracted out the design and construction of the terminal to Construtora OAS SA. Following a number of problems and defects, GNLS terminated the contract in March 2015 and made use of its guarantees. OAS challenged the termination of the contract but did not take action against GNLS. OAS went bankrupt in Uruguay on April 8, 2015. In September 2015, GNLS and the authorities agreed to cancel the planned construction.

On May 24, 2017, OAS and GNLS appeared before the Uruguayan courts in a conciliation process at the request of OAS. The conciliation process was unsuccessful. OAS then threatened to call GNLS before the Uruguayan courts to claim damages. Since GNLS had incurred significant losses as a result of the termination of the contract, it filed a request for arbitration on August 22, 2017 in accordance with the terms of the contract providing for dispute resolution in Madrid by the ICC International Court of Arbitration, claiming a principal amount of USD 373 million. OAS responded by summoning GNLS before the Montevideo Commercial Court, claiming USD 311 million in damages. ENGIE was officially named as a party to the proceedings on December 5, 2018. Both proceedings are still pending.

28.2 Benelux

28.2.1 Resumption and extension of operations at the nuclear reactors

Various associations have brought actions before the Constitutional Court, the *Conseil d'État* and the ordinary courts against the laws and administrative decisions authorizing the extension of operations at the Doel 1 and 2 and Tihange 1 reactors. On June 22, 2017, the Constitutional Court referred the case to the Court of Justice of the European Union for a preliminary ruling. The Brussels Court of Appeal dismissed Greenpeace's claims in a decision dated June 12, 2018. The other actions are still pending.

In addition, some local authorities and various organizations have challenged the authorization to restart operations at the Tihange 2 reactor. On November 9, 2018, the *Conseil d'État* rejected the action brought by some German local authorities seeking the annulment of this decision. Civil proceedings are still ongoing before the Brussels Court of First Instance.

28.2.2 Claim by the Dutch tax authorities related to interest deductibility

Based on a disputable interpretation of a statutory modification that came into force in 2007, the Dutch tax authorities refuse the deductibility of a portion (€1.1 billion) of the interest paid on financing contracted for the acquisition of investments made in the Netherlands since 2000. Following the Dutch tax authorities' rejection of the administrative claim against the 2007 tax assessment, action was brought before the Arnhem Court of First Instance in June 2016. On October 4, 2018, the court ruled in favor of the tax authorities. However, given that ENGIE Energie Nederland Holding BV considers the court's reasoning to be contradictory and disputable, both in light of Dutch and European law, it has appealed the decision.

28.2.3 Claim by the Dutch tax authorities related to power plant impairment losses

The Dutch tax authorities plan to disallow the tax deduction of asset impairment losses reported by ENGIE Energie Nederland NV on its 2010-2013 tax returns. The authorities challenged both the period of coverage of the impairment losses and the amount. Accordingly, they added back the full amount of the accumulated asset impairment losses over the abovementioned period, i.e., an amount of €1.9 billion. ENGIE has contested the tax authorities' position as regards both the period and the amount and filed an appeal in November 2018.

28.3 France

28.3.1 Withholding tax

In their tax deficiency notice dated December 22, 2008, the French tax authorities questioned the tax treatment of the non-recourse sale by SUEZ (now ENGIE) of a withholding tax (*précompte*) receivable in 2005 for an amount of €995 million (receivable relating to withholding tax paid in respect of the 1999-2003 fiscal years). In May 2016, the French tax authorities issued an assessment notice for part of the resulting corporate income tax, in an amount of €89.6 million. ENGIE paid this sum and filed an application to institute proceedings before the Montreuil Administrative Court in July 2017.

Regarding the dispute over the *précompte* itself, on February 1, 2016, the *Conseil d'État* dismissed the appeal before the Court of Cassation seeking the repayment of the *précompte* in respect of the 1999, 2000 and 2001 fiscal years, and cases seeking the repayment of the *précompte* in respect of the 2002, 2003 and 2004 fiscal years are still pending before the appellate courts.

Furthermore, after ENGIE and several French groups lodged a complaint, on April 28, 2016, the European Commission issued a reasoned opinion to the French State as part of infringement proceedings, setting out its view that the *Conseil d'État* did not comply with European Union law when handing down decisions in disputes regarding the *précompte*, such as those involving ENGIE. On July 10, 2017, the European Commission referred the matter to the Court of Justice of the European Union on the grounds of France's failure to comply. On October 4, 2018, the Court of Justice of the European

Union ruled partially in favor of the European Commission. Following this decision, France must revisit its methodology in order to determine the *précompte* repayment amounts used in closed and pending court cases.

28.4 Europe excluding France & Benelux

28.4.1 Spain – Punica

In the Punica case (investigation into the awarding of contracts), 12 Cofely España employees as well as the company itself were placed under investigation by the examining judge in charge of the case. The criminal investigation is in progress and is scheduled to be closed by March 30, 2022.

28.4.2 Italy – Vado Ligure

On March 11, 2014, the Court of Savona seized and closed down the VL3 and VL4 coal-fired production units at the Vado Ligure thermal power plant belonging to Tirreno Power S.p.A. (TP), a company which is 50%-owned by the ENGIE Group. This decision was taken as part of a criminal investigation against the present and former executive managers of TP into environmental infringements and public health risks. The investigation was closed on July 20, 2016. The case was referred to the Savone Court to be tried on the merits. The proceedings began on December 11, 2018 and will continue through 2019.

28.4.3 Italy – Tax dispute relating to excise duties and ENGIE Italia VAT (formerly GDF SUEZ Energie)

In 2017, the Italian tax authorities challenged the excise duty waiver for gas transfers carried out by ENGIE Italia for industrial customers in Italy on the grounds that it did not have a certificate for these customers. The authorities plan to issue a tax reassessment for a total amount of €126 million (excise duties, VAT, late payment penalties and interest). ENGIE Italia has challenged the legality of this procedure both in light of Italian and European law and in any event deems the sanction to be disproportionate compared to a formal requirement.

In 2018, ENGIE Italia launched an appeal with the Perugia Court of First Instance requesting the cancellation of the tax reassessment notice.

In October 2018, the Court of First Instance dismissed the cancellation request, simply applying an outdated ministerial decree and ignoring ENGIE Italia's legal arguments.

ENGIE Italia appealed the ruling in November 2018.

28.5 Infrastructures Europe

28.5.1 Commissioning

In the dispute between GRDF and various gas suppliers, in a decision dated June 2, 2016, the Paris Court of Appeal (i) recalled that the risk of unpaid compensation for the "transmission" part of the agreement with the end customer should be borne by the grid manager and not the gas supplier; (ii) held that the compensation for customer management services provided by the supplier on behalf of the grid manager should be fair and commensurate with the grid manager's cost savings; and (iii) ordered GRDF to bring its transmission agreements into compliance with these principles. GRDF appealed the decision handed down by the Court of Appeal before the Court of Cassation. On January 18, 2018, the Energy Regulatory Commission (*Commission de Régulation de l'Énergie* – CRE) published a decision setting the rate for access to the grids for management services provided to single contract customers from January 1, 2018. This compensation is included in the costs covered by the transmission rate and is therefore ultimately borne by the grids' users. On June 18, 2018, the CRE's Standing Committee for Disputes and Sanctions (*Comité de règlement des différends et des sanctions* – CoRDs), which has been tasked by the Court of Appeal to evaluate the amount of the customer management

services, instructed GRDF to propose to Direct Energie (retroactively since 2005 and going forward) and to ENI (retroactively since June 2, 2016 and going forward) a new addendum providing for compensation of €91 per year for T3, T4 and TP customers, and €8.10 per year for T1 and T2 customers. Both GRDF on the one hand and Direct Energie and ENI on the other have appealed the decision dated June 18, 2018 before the Paris Court of Appeal. The CRE has been asked to submit its observations by December 2018. A decision may be handed down during the second quarter of 2019.

Regarding the customer management services carried out on behalf of the grid manager in the electricity sector (in this case ERDF, now ENEDIS), following proceedings brought by ENGIE, in a decision of July 13, 2016, the *Conseil d'État* also ruled that the same principle whereby the grid manager pays compensation to the supplier should apply. In the same decision, the *Conseil d'État* denied the CRE the right to set a customer threshold beyond which the compensation would not be payable, which until then prevented ENGIE from receiving any compensation. In light of this decision, ENGIE brought an action against ENEDIS with the purpose of obtaining payment for these customer management services. ENGIE also brought an action before the *Conseil d'État* against the CRE's decision of October 26, 2017 in respect of the compensation for customer management services in the electricity sector, seeking the annulment of the decision for the period prior to January 1, 2018 only.

28.6 Other

28.6.1 Luxembourg – State aid investigation

On September 19, 2016, the European Commission announced its decision to open an investigation into whether or not two private rulings granted by the Luxembourg State in 2008 and 2010 covering two similar transactions between several of the Group's Luxembourg subsidiaries constituted State aid. On June 20, 2018, the European Commission adopted a final, unfavorable decision deeming that Luxembourg had provided ENGIE with State aid. On September 4, 2018, ENGIE requested the annulment of the decision before the European Courts, thereby challenging the existence of a selective advantage. As these proceedings do not have a suspensive effect, ENGIE paid a sum of €123 million into an escrow account on October 22, 2018 for one of the proceedings in question, no aid actually having been paid in the other transaction. Following the proceedings before the European Courts, this sum will be returned to ENGIE or paid to the Luxembourg State depending on whether or not the Commission's decision is annulled.

28.6.2 United Kingdom – State aid investigation regarding Gibraltar

On October 7, 2016, the European Commission announced its decision to open a state aid investigation against the United Kingdom with regard to Gibraltar's tax system. The decision covers Gibraltar's tax ruling practices and cited 165 tax rulings, which could constitute State aid. One of the rulings was obtained by a subsidiary of International Power Ltd in 2011 as part of the dismantling of a facility in Gibraltar. ENGIE contested this decision on November 25, 2016, pending the Commission's final decision.

28.6.3 Claim against sales tax adjustments in Brazil

On December 14, 2018, the Brazilian tax authorities issued tax deficiency notices to Engie Brasil Energia for fiscal years 2014, 2015 and 2016, considering that it was liable for the PIS and COFINS federal sales taxes on the amounts reimbursed to it in respect of certain fuels used by thermo-power generation plants. The adjustments were for an aggregate amount of BRL 480 million, comprising BRL 229 million of tax plus interest and penalties.

Engie Brasil Energia is contesting these tax deficiency notices and filed a tax claim in January 2019.

NOTE 29 SUBSEQUENT EVENTS

No significant subsequent events have occurred since the closing of the accounts at December 31, 2018.

NOTE 30 FEES PAID TO THE STATUTORY AUDITORS AND TO MEMBERS OF THEIR NETWORKS

Pursuant to Article 222-8 of the General Regulations of the French Financial Markets Authority (AMF), the following table presents information on the fees paid by ENGIE SA, its fully consolidated subsidiaries and joint operations to each of the auditors in charge of auditing the annual and consolidated financial statements of the ENGIE Group.

The Shareholders' Meeting of ENGIE SA of April 28, 2014 decided to renew the terms of office of Deloitte and EY as Statutory Auditors for a six-year period from 2014 to 2019.

In million of euros	Deloitte			EY			Total
	Deloitte & Associés	Network	Total	EY & others	Network	Total	
Statutory audit and review of consolidated and parent company financial statements	5.2	7.9	13.0	6.4	4.7	11.1	24.1
ENGIE SA	2.3	-	2.3	3.2	-	3.2	5.5
Controlled entities	2.9	7.9	10.8	3.2	4.7	7.9	18.7
Non-audit services	0.9	1.9	2.8	0.8	1.7	2.5	5.3
ENGIE SA	0.6	-	0.6	0.6	-	0.6	1.2
Of which services related to legal and regulatory requirements	0.4	-	0.4	0.3	-	0.3	0.7
Of which other audit services	0.2	-	0.2	0.3	-	0.3	0.5
Of which reviews of internal control	-	-	-	-	-	-	-
Of which due diligence services	-	-	-	-	-	-	-
Of which tax services	-	-	-	-	-	-	-
Controlled entities	0.3	1.9	2.3	0.2	1.6	1.9	4.2
Of which services related to legal and regulatory requirements	-	0.4	0.4	0.2	0.2	0.4	0.8
Of which other audit services	0.2	0.3	0.5	0.1	0.4	0.5	1.0
Of which reviews of internal control	0.1	0.2	0.3	-	0.1	0.1	0.4
Of which due diligence services	-	0.7	0.7	-	0.1	0.1	0.8
Of which tax services	-	0.4	0.4	-	0.8	0.8	1.2
Total	6.0	9.8	15.9	7.3	6.4	13.6	29.5

NOTE 31 INFORMATION REGARDING LUXEMBOURG AND DUTCH COMPANIES EXEMPTED FROM THE REQUIREMENTS TO PUBLISH ANNUAL FINANCIAL STATEMENTS

Some companies in the Benelux, GEM & LNG and Other segments do not publish annual financial statements pursuant to domestic provisions in Luxembourg law (Article 70 of the Law of December 19, 2002) and Dutch law (Article 403 of the Civil Code) relating to the exemption from the requirement to publish audited annual financial statements.

The companies exempted are: ENGIE Energie Nederland NV, ENGIE Energie Nederland Holding BV, ENGIE Nederland Retail BV, ENGIE United Consumers Energie BV, Epon Eemscentrale III BV, Epon Eemscentrale IV BV, Epon Eemscentrale V BV, Epon Eemscentrale VI BV, Epon Eemscentrale VII BV, Epon Eemscentrale VIII BV, Epon International BV, Epon Power Engineering BV, ENGIE Portfolio Management BV, IPM Energy Services BV, Electrabel Invest Luxembourg, ENGIE Corp Luxembourg SARL, ENGIE Treasury Management SARL and ENGIE Invest International SA.



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2019 MANAGEMENT REPORT AND ANNUAL CONSOLIDATED FINANCIAL STATEMENTS



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04 STATUTORY AUDITORS' REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

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01 MANAGEMENT REPORT

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1 ENGIE 2019 RESULTS

The previously published financial data presented hereafter have been restated to take into account impacts resulting from the transition method used for the application of IFRS 16 – Leases. A reconciliation of the reported data with the restated comparative data is presented in section 6 of the management report for key financial indicators and Note 1 “Accounting framework and basis for preparing the consolidated financial statements”.

ENGIE financial information at December 31, 2019

2019 net recurring income Group share guidance achieved
EUR 0.80 dividend per share to be proposed at the AGM (+7% vs. 2018)

- Net recurring income Group share (NRIGs) of €2.7 billion, up 9%, and 11% on an organic ⁽¹⁾ basis.
- Current operating income (COI) of €5.7 billion, up 11%, and 14% on an organic basis, mainly driven by Nuclear, Others (notably Energy Management), Thermal and Renewables, partially offset by Supply and Networks. EBITDA of €10.4 billion, up 7%, and 8% on an organic basis.
- Financial net debt increased by €2.7 billion mainly due to growth investments, notably the TAG acquisition, which closed in H1. Financial net debt / EBITDA ratio of 2.5x.
- For fiscal year 2019, it will be proposed to the AGM to increase the dividend to €0.80 per share, up 7% versus 2018 ordinary dividend.
- 2020 net recurring income Group share (NRIGs) expected to be between €2.7 billion – €2.9 billion ⁽²⁾. For 2022, ENGIE anticipates a NRIGs CAGR in the range of 6-8% (to reach €3.2 billion and €3.4 billion).

Key Financial data at December 31, 2019

In billions of euros	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	% change (reported basis)	% change (organic basis)
Revenues	60.1	57.0	+5.4%	+4.1%
Adjusted revenues ⁽¹⁾	64.1	60.6	+5.8%	+4.7%
EBITDA	10.4	9.7	+6.8%	+8.1%
CURRENT OPERATING INCOME (COI)	5.7	5.2	+11.1%	+14.4%
Net recurring income relating to continued operations, Group share ⁽¹⁾	2.7	2.5	+9.3%	+11.1%
Net income, Group share	1.0	1.0		
Cash Flow From Operations (CFFO) ⁽²⁾	7.6	7.7	(0.2)	
Financial net debt	25.9	23.3	2.7 vs Dec. 31, 2018	

(1) In Q4 2019, the Group has implemented a new IFRS pronouncement related to commodity derivatives and requiring a change in presentation of Revenues with no impact on other performance indicators. For comparability with previous communications, adjusted revenues are also provided based on the former definition. For more information please refer to Note 1 to the 2019 consolidated financial statements.

(2) Cash flow from operations = Free cash flow before maintenance Capex.

In 2019, the drivers of the gross COI evolution were as follows:

- **Nuclear** was driven by higher availability of Belgian production units and slightly more favorable achieved prices;
- In business line **Others**, increasing Energy Management results were mainly driven by the partial sale of a gas supply contract, performance of market activities and gas contract renegotiations;

(1) Organic variation: gross variation without scope and foreign exchange effect.

(2) These targets and this indication assume average weather conditions in France, full pass through of supply costs in French regulated gas tariffs, no significant accounting changes, no major regulatory or macroeconomic changes, commodity price assumptions based on market conditions as of December 31, 2019 for the non-hedged part of the production, no change in the nuclear provision legal and regulatory framework, average foreign exchange rates as follows for 2020: €/USD: 1.13; €/BRL: 4.57 and dilution from the €4 billion disposal plan for 2020-22.

- **Client Solutions** results benefited from the contribution of acquisitions and the performance of decentralized energy activities, partly offset by investments in business development capability and some operational restructuring actions;
- **Networks** was impacted by several negative effects outside France (mainly one-offs and temperature) as well as several adverse factors in France that were expected and are mostly temporary (mainly tariff smoothing in transmission). Networks also benefited from the first year contribution of the TAG gas transmission pipeline in Brazil, acquired in mid-2019;
- **Renewables** benefited from higher Brazilian hydro prices and increasing commissioning of renewable capacity (3.0 GW in 2019). The target of 9 GW to be commissioned from 2019 to 2021 is now fully secured;
- Supply activities continued to be impacted by a difficult market context, mainly from margin contractions in French retail, by positive 2018 one-offs in Benelux and adverse temperature effects in Australia and France;
- **Thermal** was impacted by the disposal of Glow partly offset by Power Purchase Agreement (PPA) performance and positive market price conditions in Chile as well as the reinstatement of the capacity remuneration mechanism in the United Kingdom.

ENGIE continued to pursue its strategic focus on the energy transition in 2019.

In **Client Solutions**, ENGIE and its partners won commercial contracts for the University of Iowa (United States), government buildings in Ottawa (Canada), a “smart region” around Angers (France) and industrial buildings in Singapore. In addition, ENGIE made several acquisitions including Conti in North America, Otto Industries in Germany and Powerlines in Austria. ENGIE Impact was created to bring large customers with solutions to build their sustainability roadmap and accelerate their energy transition.

In **Networks**, ENGIE announced on June 13, 2019 that the consortium in which it holds a majority stake completed the acquisition of a 90% shareholding in TAG, the largest gas transmission network owner in Brazil. TAG has a portfolio of long-term contracts providing an attractive earnings stream and improves diversification of ENGIE’s geographic footprint in Networks activities. In January 2020, ENGIE also further strengthened its position in Brazil by announcing the acquisition of a project of a 1,800 km power transmission line. Finally, ENGIE gained visibility on the financial outlook of its French gas networks activities with the conclusion of the regulatory reviews between the end of 2019 and the beginning of 2020.

In **Renewables**, 3.0 GW of renewable capacity was commissioned and the 9 GW commissioning target, over 2019-21, is now fully secured. The new joint-venture in Mexico with Tokyo Gas and the strategic partnership signed with Edelweiss Infrastructures Yield in India at the beginning of 2020 demonstrate ENGIE’s ability to deploy the DBSO ⁽¹⁾ model and attract partners for the development of its portfolio. In addition, ENGIE, along with financial partners, won a bid to acquire a 1.7 GW hydroelectric portfolio from EDP in Portugal. Finally, in January 2020, ENGIE reached an agreement with EDPR for the 50/50 joint-venture in offshore wind to create a global offshore wind player.

In **Thermal**, ENGIE continued to execute its carbon footprint reduction strategy, with coal now approximately 4% of global power generation capacity, following the disposal of its 69.1% stake in Glow in Thailand and Laos (3.2 GW of generation capacity, of which 1.0 GW is coal), ending its participation in coal in the Asia-Pacific region, and the disposal of its German and Dutch coal assets (capacity of 2.3 GW).

In **Nuclear**, an arrangement on Belgian nuclear provisions was reached reducing uncertainty for all parties regarding the level of provisions and their funding.

1.1 Analysis of financial results at December 31, 2019

1.1.1. Revenues of €60,1 billion

Revenues were €60.1 billion, up 5.4% on a gross basis and 4.1% on an organic basis.

(1) Develop, Build, Share & Operate.

Reported revenue growth was driven by scope effects, including various acquisitions in Client Solutions (primarily in the United States with Conti, France and Latin America with CAM) and in BtoB Supply in the US, partially offset by the disposals of ENGIE's stake in Glow in Thailand in March 2019 and of BtoB Supply activities in Germany at the end of 2018. This growth also includes a slightly positive foreign exchange effect, mainly due to the appreciation of the US dollar, partly offset by the depreciation of the Argentinian peso and the Brazilian real against the euro.

Organic revenue growth was primarily driven by Supply revenues in North America, France and Europe, growth in Client Solutions in Europe, energy management services and favorable market conditions for Global Energy Management (GEM) activities and strong momentum in Latin America (PPA portfolio growth in Chile as well as commissioning of new wind and solar farms in Brazil). This growth was partially offset by lower revenues from Supply activities in the UK and Australia and from Thermal activities in Europe.

Clients Solutions revenues were up 11% on a gross basis and 3% on an organic basis, benefiting from a positive effect of acquisitions and favorable market context for industrial clients in Europe.

1.1.2. EBITDA of €10.4 billion

EBITDA was €0.4 billion, up 6.8% on a gross basis and 8.1% on an organic basis.

These gross and organic variations are overall in line with the current operating income growth, except for the increase in depreciation mainly due to the commissioning of assets in Latin America and in France, especially in Networks which are not taken into account at EBITDA level.

In addition, Lean 2021, which contributes to the organic increase at EBITDA and COI levels, exceeded the 2019 targets and is on track to meet the target set for 2021.

1.1.3. Current operating income (COI) of €5.7 billion

Current operating income amounted to €5.7 billion, up 11.1% on a reported basis and 14.4% on an organic basis.

The reported COI growth includes a positive foreign exchange effect, mainly due to the appreciation of the US dollar, partly offset by the depreciation of the Argentinian peso and the Brazilian real against the euro. This positive effect is partly offset by an aggregate negative scope effect, including the disposal of the 69.1% stake in Glow in Thailand and Laos, partly offset by various acquisitions predominantly in Networks (TAG) and in Client Solutions.

Organic COI performance varied across the Group's business lines:

In millions of euros	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	% change (reported basis)	% change (organic basis)
Client Solutions	1,090	1,010	+7.9% ⁽¹⁾	-0.9%
Networks	2,327	2,401	-3.1%	-5.6%
Renewables	1,190	1,129	+5.4%	+7.5%
Thermal	1,260	1,423	-11.5%	+7.2%
Nuclear	(314)	(1,051)	+70.1%	+70.1%
Supply	345	539	-36.0%	-33.5%
Others	(172)	(297)	+42.1%	+41.6%
TOTAL	5,726	5,154	+11.1%	+14.4%

(1) Excluding the impact from the 2019 SUEZ one-offs, this gross evolution would have been c. +7% (c. € +10 million net positive impact: positive outcome on Argentina court case, restructuring costs and asset write-downs).

- **Client Solutions** reported a 1% organic COI decrease, impacted by headwinds in specific segments and an increase in development costs notably on newer growth businesses. These effects were partly offset by an increased contribution from SUEZ and decentralized energy activities.
- **Networks** reported a 6% organic COI decrease, mainly due to gas distribution activities with 2018-19 negative one-off effects recorded outside of France and negative temperature effects in France and in Europe, only partially offset by a commissioning costs provision reversal and tariff increases in France. Gas transmission activities in France also suffered from a negative volume effect due to the merger of the North and South gas market zones and from a negative price effect resulting from tariff smoothing.

- **Renewables** reported an 8% organic COI increase, primarily driven by higher prices for hydroelectric power generation in Brazil and in France and the 3.0 GW commissioning of new capacities since January 1, 2019, notably in Brazil (0.5 GW), the United States (0.5 GW), Spain (0.4 GW), Mexico (0.3 GW), India (0.3 GW), France (0.3 GW) and Egypt (0.3 GW). These positive effects were partly offset by lower DBSO margins compared to the high level of DBSO transactions in 2018 and lower hydroelectric power generation in France.
- **Thermal** showed a 7% organic COI increase, mainly attributable to the PPA portfolio growth and positive market price conditions in Chile. In addition, the reinstatement of the capacity remuneration mechanism in the United Kingdom, as well as and the favorable impact of the gas spreads in Europe were positive. These effects were partially offset by the expiry of a PPA in Turkey in April 2019. The amount of liquidated damages received was roughly stable in 2019 versus 2018.
- **Nuclear** delivered a 70% organic COI growth, benefiting from higher availability rates in Belgium following 2018 unplanned outages (+2,720bps and +62% volumes produced) and better achieved prices (+2€/MWh).
- **Supply** COI reduced by 34% on an organic basis, primarily driven by margin pressures on French gas and electricity retail contracts, a commissioning costs accrual reversal (related to the coverage of the cost to serve customers handled by energy suppliers during the French market opening, from 2007 to 2016, fully offset by a symmetrical provision reversal for Gas distribution in France), 2018 positive one-offs in Benelux and negative temperature effects in Australia and in France. These effects were partly offset by higher business margins in France.
- **Others** business line delivered 42% organic COI growth, mainly reflecting GEM's good performance coming from the partial sale of a gas supply contract to Shell and a positive impact from gas contract renegotiations and overall favorable market conditions, as well as lower Corporate costs.

Organic COI performance varied across segments:

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	% change (reported basis)	% change (organic basis)
France	2,861	3,057	-6.4%	-7.0%
France excluding Infrastructures	903	1,039	-13.1%	-15.2%
France Infrastructures	1,957	2,018	-3.0%	-2.8%
Rest of Europe	684	46	+1,400.5%	+1,121.9%
Latin America	1,694	1,359	+24.6%	+20.2%
USA & Canada	159	153	+3.9%	-5.5%
Middle East, Asia & Africa	559	896	-37.6%	-9.1%
Others	(231)	(357)		
TOTAL	5,726	5,154	+11.1%	+14.4%

Based on the reportable segments, the organic COI growth was led by the **Rest of Europe** (mainly driven by the recovery of Nuclear activities with better availability and higher prices, the reinstatement of the capacity remuneration mechanism in the United Kingdom, the favorable impact of gas spreads in Europe; partly offset by 2018 positive one-offs including Liquidated Damages received, difficulties in Benelux and the UK in Supply activities and in Client Solutions with some loss-making contracts), by the **Others** segment (mainly due to GEM's good performance in market activities and an increased contribution from SUEZ) and by **Latin America** (notably due to the favorable impact of LDs received in Thermal activities in 2019, higher prices for hydroelectric power generation and commissioning of new wind and solar assets in Brazil and in Mexico as well as PPA portfolio growth in Chile).

These positive impacts were partly offset by an organic COI decrease in **Middle East, Africa & Asia** (mainly driven by headwinds in Supply in Australia and Africa, in Networks in Turkey, partly offset by positive contribution of Thermal generation and Renewables activities), in France (for France excluding Infrastructures, mainly due to lower DBSO margins compared to the 2018 high level, margin pressure in Supply activities and lower hydroelectric power generation partly offset by higher hydro prices, increased wind and solar contributions and improved profitability in Client Solutions activities; for France Infrastructures, mainly due to the lower contribution of transmission and distribution activities) and in **USA & Canada** (mainly driven by Client Solutions, notably due to negative one-offs booked in 2019, lower contribution from Thermal activities due to lower capacity prices; partly offset by higher DBSO margins and commissioned asset contributions in Renewable activities).

1.1.4. Net recurring income relating to continued operations, Group share of €2.7 billion and Net income Group share of €1.0 billion

Net recurring income relating to continued operations, Group share amounted to €2.7 billion compared with €2.5 billion in 2018. This increase was mainly driven by the continued improvement in the current operating income partly offset by higher taxes, mainly due to the 2018 positive effect from the recognition of deferred tax assets and slightly higher recurring financial costs, reflecting the modification in the business mix (higher debt in Brazil).

Net income Group share amounted to €1.0 billion in 2019, stable year-on-year, as a result of the increase in Net recurring income and gains on disposals, mainly resulting from the Glow transaction, which offset the impact of the triennial review of nuclear provisions in Belgium and minor negative mark-to-market variation.

1.1.5. Financial net debt of €25.9 billion

Financial net debt stood at €25.9 billion, up €2.7 billion compared to December 31, 2018. This variation is attributed to (i) capital expenditures over the period (EUR 10.0 billion ⁽¹⁾, including the €1.5 billion expenditures for the TAG transaction in Brazil), (ii) dividends paid to ENGIE SA shareholders (€1.8 billion) and to non-controlling interests (€0.7 billion) and (iii) other elements (€0.6 billion) mainly related to foreign exchange rates, new right-of-use assets and mark-to-market variations. These items were partly offset by (i) cash flow from operations (€7.6 billion) and (ii) the impacts of the portfolio rotation program (€2.8 billion, mainly related to the Glow disposal).

Cash flow from operations ⁽²⁾ amounted to €7.6 billion, down €0.2 billion. The decrease stemmed predominantly from working capital requirement variations (€1.3 billion negative impact), mainly caused by margin calls on derivatives and mark-to-market variation of financial derivatives, partly offset by the increase of operating cash flow (€0.9 billion) and lower tax and interests payments (€0.2 billion).

At the end of December 2019, the **financial net debt to EBITDA** ratio amounted to 2.5x. Excluding the TAG acquisition which was not included in the 2019 guidance and which contributed only partially to the 2019 EBITDA, this ratio amounted to 2.4x, stable compared to the end of 2018 and on the target of less than or equal to 2.5x. The average cost of gross debt was 2.70%, slightly up compared to the end of 2018, notably due to new borrowings in Brazil.

At the end of December 2019, the **economic net debt** ⁽³⁾ to EBITDA ratio stood at 4.0x. Excluding the TAG acquisition, this ratio stood at 3.8x, slightly increasing compared to December 2018.

1.2 Financial targets

The targets for the financial years ended 31 December 2020 and 2022 set forth below are based on data, assumptions and estimates considered to be reasonable by the Group at the date of issuance of this document.

These data and assumptions may evolve or be amended due to uncertainties related to the economic, financial, accounting, competitive, regulatory and tax environment or other factors that the Group may not be aware of at the date of registration of the management report. In addition, the fulfilment of forecasts requires the success of the Group's strategy. The Group therefore makes no commitment or warranty regarding the fulfilment of the forecasts set out in this section.

The targets presented below and the underlying assumptions, also been prepared in accordance with the provisions of Delegated Regulation (EU) No 2019/980 supplementing Regulation (EU) No 2017/1129 and the ESMA recommendations on forecasts.

(1) Net of DBSO partial sell-downs.

(2) Cash flow from operations = Free cash flow before maintenance CAPEX.

(3) Economic net debt amounted to €41.1 billion at the end of December 2019 (compared with €35.7 billion at the end of December 2018); it includes, in particular, nuclear provisions and post-employment benefits.

The targets presented below result from the budget and medium-term plan process as described in Note 13 to the consolidated financial statements; they have been prepared on a comparable basis with historical financial information and in accordance with the accounting methods applied to the Group's consolidated financial statements for the year ended December 31, 2019 (including IFRS 16 and IFRIC 23, which the Group has applied as from January 1, 2019) described in the consolidated financial statements.

Assumptions

- strategy: confirmation and deepening of the Group ambition to establish ENGIE as a leading force in the energy and climate transition;
- acquisitions and disposals: no significant change in the Group scope of consolidation beyond acquisitions or disposals already announced or impacts specifically mentioned in the targets below;
- foreign exchange rates:
 - 2020: average annual €/US Dollar and €/Brazilian real foreign exchange rates at 1.13 and 4.57 respectively,
 - 2021 and 2022: average annual €/US Dollar and €/Brazilian real foreign exchange rates at 1.16 and 4.57, respectively;
- Belgium nuclear assets availability: 74%, 93% and 94% for 2020, 2021 and 2022, respectively (rates computed on the basis of the installed capacity, assuming Doel 3 closure in October 2022);
- regulated tariffs in France Infrastructures:
 - distribution, transport and storage : tariffs as published by the CRE in January 2020,
 - regasification: estimated updated tariffs as from 2021; the CRE tariff review will take place in 2020;
- regulated gas & power tariffs in France: full pass through of supply costs;
- commodity prices: based on market conditions as of December 31, 2019 (notably for European outright power, forwards at 44, 47, 48 €/MWh in 2020, 2021 and 2022 respectively) for the non-hedged part of the production (20%, 46% and 77% in 2020, 2021 and 2022 respectively);
- climate: normalized conditions in France (gas distribution and energy supply + normalized hydro production), hydrology in Brazil to improve by 2022;
- recurring effective tax rate: 31% in 2020, reducing by ~300bps through 2022;
- employee benefit provisions discount rates: based on market conditions as of December 31, 2019, as disclosed in Note 20 to the consolidated financial statements;
- no significant accounting changes compared to 2019;
- no major regulatory and macro-economic changes compared to 2019.

2020 and 2022 financial targets

ENGIE anticipates 2020 **net recurring income, Group share to be between €2.7 and €2.9 billion.**

This guidance is based on an indicative EBITDA range of €10.5 to €10.9 billion and COI range of €5.8 to €6.2 billion.

COI Indicative expectations by Business Line for 2020:

In millions of euros	Dec. 31, 2019	COI 2019-2020 ⁽¹⁾	Key drivers
Client Solutions	1,090	+	Organic revenues and margin growth, new acquisitions
Networks	2,327	-	Increase from TAG offset by decreases in new remuneration rates
Renewables	1,190	++	Hydro volume and prices in France and decision in Brazil on compensation for past losses due to low hydro dispatch. Wind & Solar increase due to DBSO and COD of assets
Thermal	1,260	--	Scope impact and decreasing spreads
Nuclear	(314)	+	Higher achieved prices, lower volumes
Supply	345	++	Positive effect from negative 2019 one-offs and normalized temperatures in 2020

(1) A single + or – sign accounts for single digit growth or decrease; double ++ or -- signs account for a double-digit growth or decrease.

For 2020 and over the long term, ENGIE anticipates an economic net debt/EBITDA ratio below or equal to 4.0x and remains committed to a strong investment grade rating.

For 2022, ENGIE anticipates **net recurring income, Group share to grow at a CAGR ⁽¹⁾ range of 6-8%** (i.e. between €3.2 and 3.4 billion). This guidance is based on an indicative CAGR range for EBITDA between 2-4% and for COI between 4-6%.

For the 2020-2022 period, ENGIE expects to invest €10 billion ⁽²⁾ in growth, €8 billion in maintenance and €4 billion in the Synatom financial Capex for the full funding of the nuclear waste provision by 2025. Disposals are expected to amount to €4 billion, primarily aiming at further reducing CO₂ emissions and simplifying geographical footprint and structure.

1.3 Dividend policy

For **fiscal year 2019**, ENGIE confirms the payment of a **€0.80 per share dividend** representing a payout ratio of 72%, **payable in cash**.

The annual dividend will be paid at one time, after the Ordinary General Meeting (OGM) approving the annual accounts.

For the future, ENGIE confirms the **medium-term dividend policy, in the range of 65 to 75% NRIs payout ratio**.

(1) CAGR: Compound Annual Growth Rate.

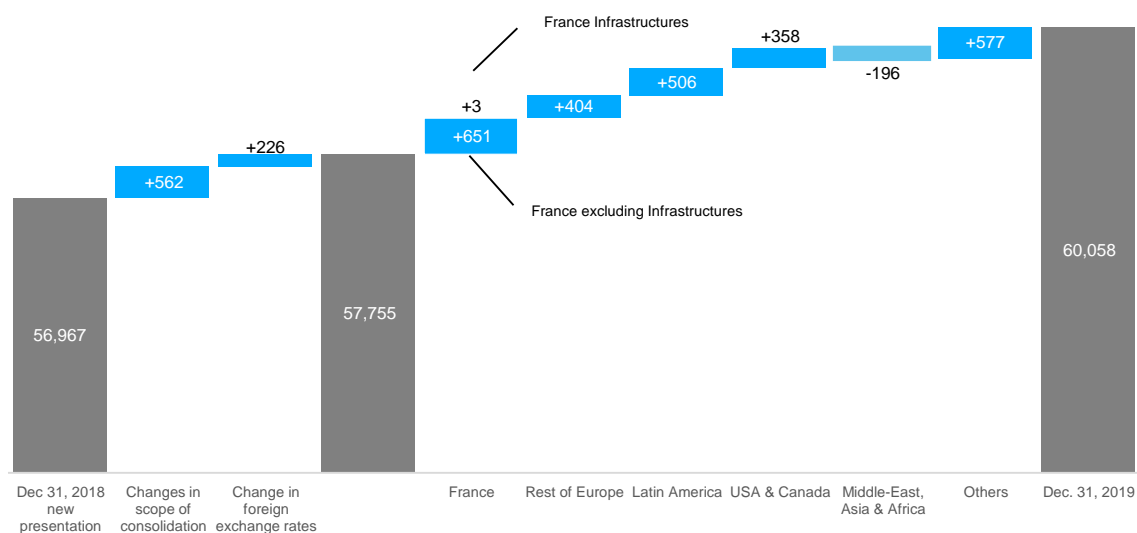
(2) Net of DBSO partial sell-downs.

2 BUSINESS TRENDS

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	% change (reported basis)	% change (organic basis)
Revenues	60,058	56,967	+5.4%	+4.1%
EBITDA	10,366	9,702	+6.8%	+8.1%
Net depreciation and amortization/Other	(4,640)	(4,548)		
CURRENT OPERATING INCOME (COI)	5,726	5,154	+11.1%	+14.4%

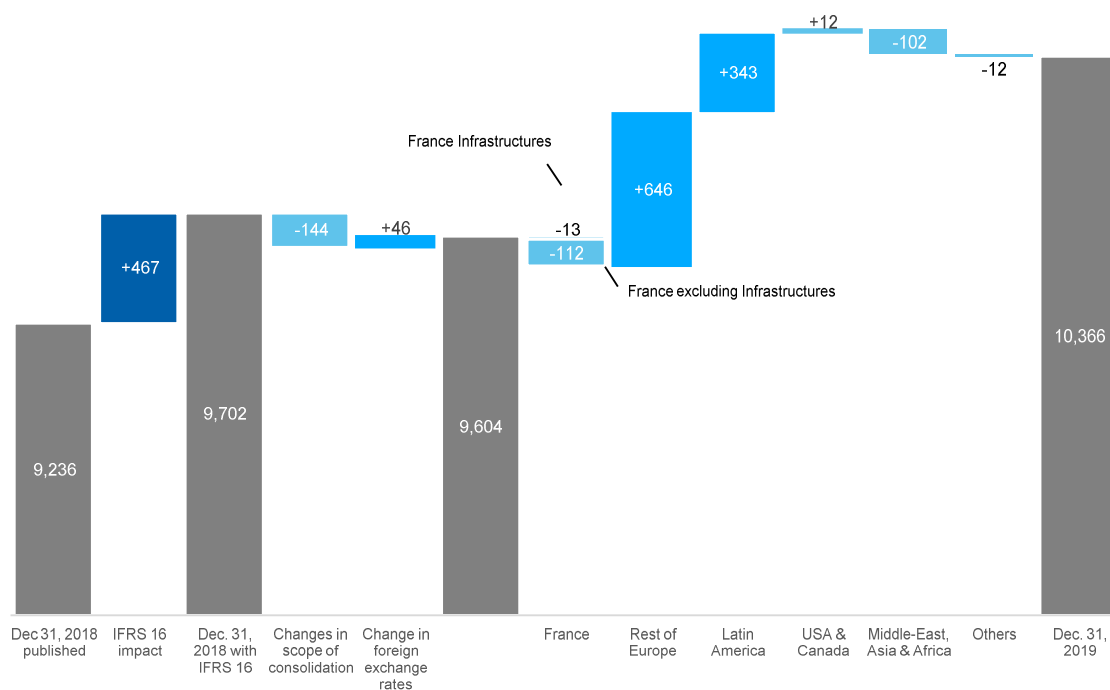
REVENUE TRENDS

In millions of euros



EBITDA TRENDS

In millions of euros



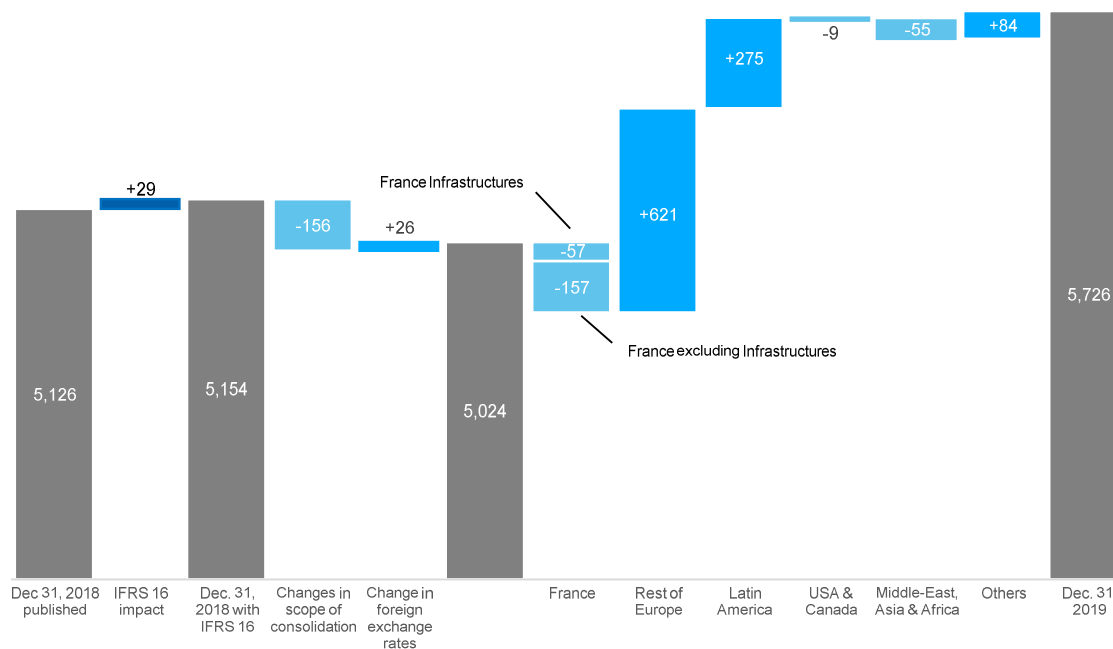
Geography/Business Line matrix

In millions of euros	Client							TOTAL at Dec 31, 2019
	Solutions	Networks	Renewables	Thermal	Nuclear	Supply	Others	
France	959	3,537	421	-	-	294	-	5,211
Rest of Europe	577	137	145	442	192	256	-	1,750
Latin America	35	339	1,035	750	-	62	-	2,221
USA & Canada	64	1	70	32	-	63	61	291
Middle East, Asia & Africa	44	17	97	563	-	6	-	727
Others	156	(8)	(43)	(23)	-	(42)	125	166
TOTAL EBITDA	1,835	4,024	1,725	1,765	192	639	186	10,366

In millions of euros	Client							TOTAL at Dec. 31, 2018 with IFRS 16
	Solutions	Networks	Renewables	Thermal	Nuclear	Supply	Others	
France	920	3,554	503	-	-	352	-	5,329
Rest of Europe	552	151	125	515	(555)	294	-	1,081
Latin America	11	280	901	554	-	43	-	1,789
USA & Canada	70	1	5	64	-	37	74	252
Middle East, Asia & Africa	40	57	82	898	-	57	-	1,133
Others	137	(7)	(27)	9	-	-	6	119
TOTAL EBITDA	1,730	4,035	1,589	2,040	(555)	783	81	9,702

CURRENT OPERATING INCOME (COI) TRENDS

In millions of euros



Geography/Business Line matrix

In millions of euros								TOTAL at
	Client Solutions	Networks	Renewables	Thermal	Nuclear	Supply	Others	Dec 31, 2019
France	574	1,957	181	-	-	149	-	2,861
Rest of Europe	345	82	88	293	(314)	190	-	684
Latin America	-	280	849	504	-	61	-	1,694
USA & Canada	13	1	45	26	-	25	49	159
Middle East, Asia & Africa	25	15	72	460	-	(13)	-	559
Others	132	(8)	(45)	(23)	-	(65)	(222)	(231)
TOTAL COI	1,090	2,327	1,190	1,260	(314)	345	(172)	5,726

In millions of euros								TOTAL at
	Client Solutions	Networks	Renewables	Thermal	Nuclear	Supply	Others	Dec. 31, 2018 with IFRS 16
France	552	2,018	259	-	-	227	-	3,057
Rest of Europe	341	108	70	342	(1,051)	235	-	46
Latin America	(1)	227	749	342	-	42	-	1,359
USA & Canada	24	1	(5)	59	-	13	60	153
Middle East, Asia & Africa	32	54	63	708	-	40	-	896
Others	44	(7)	(28)	9	-	(19)	(356)	(357)
TOTAL COI	993	2,402	1,109	1,460	(1,051)	538	(296)	5,154

2.1 France

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	% change (reported basis)	% change (organic basis)
Revenues	21,423	20,448	+4.8%	+3.2%
Total revenues (incl. intra-group transactions)	22,736	21,760	+4.5%	
EBITDA	5,211	5,329	-2.2%	-2.4%
Net depreciation and amortization/Other	(2,351)	(2,272)		
CURRENT OPERATING INCOME (COI)	2,861	3,057	-6.4%	-7.0%

2.1.1. France excluding Infrastructures

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	% change (reported basis)	% change (organic basis)
Revenues	15,854	14,998	+5.7%	+4.4%
EBITDA	1,672	1,775	-5.8%	-6.5%
Net depreciation and amortization/Other	(769)	(736)		
CURRENT OPERATING INCOME (COI)	903	1,039	-13.1%	-15.2%

Volumes sold

<i>In TWh</i>	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	% change (reported basis)
Gas sales	83.2	88.3	-5.8%
Electricity sales	38.8	39.0	-0.5%

France climatic adjustment

<i>In TWh</i>	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	Total change in TWh
Climate adjustment volumes (negative figure = warm climate, positive figure = cold climate)	(3.6)	(2.9)	(0.7)

Revenues in the France excluding Infrastructures segment amounted to €15,854 million, up 5.7% on a reported basis and 4.4% on an organic basis. Organic growth can be explained by higher revenues in the BtoC power segment and BtoB services businesses. Acquisitions in BtoB services also contributed significantly to growth on a reported basis (in particular Powerlines, Pierre Guerin, Endel SRA and Sodelem).

Gas sales volumes in the BtoC segment decreased by 5.1 TWh compared to 2018, of which 0.7 TWh related to a negative temperature effect, mainly as a result of the end of regulated gas tariffs. The BtoC power portfolio recorded a significant increase of 1.6 TWh, whereas volumes produced by power generation and France Networks dropped by 1.8 TWh.

Current operating income was €903 million, down 13.1% on a reported basis and 15.2% on an organic basis. This drop was mainly due to lower DBSO (Develop, Build, Share & Operate) margins in 2019, and higher operating expenses (OPEX) in the BtoC segment to support the development of gas and power market offers. 2019 results were also affected by the impact of lower hydroelectric power generation. These underperformances were partly offset by higher prices for hydro power, higher wind and solar production, and a good organic performance in BtoB activities thanks to new contracts and increased profitability.

2.1.2. France Infrastructures

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	% change (reported basis)	% change (organic basis)
Revenues	5,569	5,450	+2.2%	+0.1%
Total revenues (incl. intra-group transactions)	6,548	6,575	-0.4%	
EBITDA	3,539	3,554	-0.4%	-0.4%
Net depreciation and amortization/Other	(1,582)	(1,536)		
CURRENT OPERATING INCOME (COI)	1,957	2,018	-3.0%	-2.8%

Revenues in the France Infrastructures segment amounted to €5,569 million, €119 million above 2018. The increase was driven by terminalling activities, which benefited from the outsourcing of LNG activities as well as tariff increases in distribution activities, and by transmission activities, although growth was limited by tariff smoothing and lower subscribed capacity. These favorable impacts were partly offset by a decrease in storage activities with a reduction in buy/sale operations in France following the introduction of new regulations in 2018, offset by international activities.

Current operating income for the period was €1,957 million, down 2.8% on an organic basis. In transmission activities, this decrease was due to negative price effects in France – mainly tariff smoothing – and Germany. To a lesser extent, storage activities were impacted by customer penalties in France due to a temporarily deteriorated operating performance as well as to negative price effects in Germany, while terminalling activities were impacted by tariff changes. Growth in distribution activities partly offset these effects, with tariff hikes more than offsetting mild climate and other changes in OPEX.

2.2 Rest of Europe

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	% change (reported basis)	% change (organic basis)
Revenues	17,270	16,946	+1.9%	+2.4%
EBITDA	1,750	1,081	+61.9%	+59.4%
Net depreciation and amortization/Other	(1,066)	(1,036)		
CURRENT OPERATING INCOME (COI)	684	46		

Revenues in the Rest of Europe segment amounted to €17,270 million, up 2.4% on an organic basis. This growth was driven by Supply and Client Solutions activities, whereas Thermal revenues decreased.

Supply activities benefited from positive price effects in Belgium, the Netherlands and Romania, partly offset by Supply activities in the United Kingdom and Germany due to the divestments in the German Retail BtoB portfolio in 2018.

The increase in Client Solutions mainly arose from Belgium's installation and energy efficiency segments, Central Europe which benefited from positive scope effects in Germany as a result notably of the acquisition of OTTO (January 2019), and organic growth in Spain mainly in installation activities.

Current operating income amounted to €684 million. The reported growth of €639 million was mainly driven by Nuclear activities and a slight increase in Renewables. Client Solutions remained stable compared to last year, while Supply, Networks and Thermal activities were down.

Nuclear activities benefited from higher availability rates in Belgium (2018 had been impacted by a high number of days of unplanned outages) and better achieved prices. Renewable activities benefited from good performances in wind onshore activities in Benelux.

Client Solutions reported a lower contribution from asset-light activities as a result of a significant drop notably in the United Kingdom and Benelux due to contract renegotiations and legacy loss-making contracts, but achieved a better performance in asset-based activities mainly in the Generation Europe BU through its cogeneration units as well as in the North, South and Eastern Europe BU in Italy and Germany.

The decrease in Thermal activities mainly arose from higher positive one-offs in 2018, lower coal spreads partially offset by better gas spreads, and capacity market reinstatement in the United Kingdom. Supply activities decreased in Benelux and the United Kingdom, and Networks activities decreased in Germany.

2.3 Latin America

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	% change (reported basis)	% change (organic basis)
Revenues	5,341	4,639	+15.1%	+10.9%
EBITDA	2,221	1,789	+24.2%	+19.1%
Net depreciation and amortization/Other	(527)	(430)		
CURRENT OPERATING INCOME (COI)	1,694	1,359	+24.6%	+20.2%

Revenues in the Latin America segment totaled €5,341 million, up 15.1% on a reported basis and 10.9% organically. Reported growth comprises the positive effect of a Client Solutions entity acquired at the end of last year (CAM), partially offset by a negative net foreign exchange effect, with the depreciation of the Brazilian real (-2.4%) and Argentinian peso (-36.0%) being partially offset by the appreciation of the US dollar (+5.5%), Mexican peso (+5.3%) and Peruvian sol (+3.9%). In Chile, business was positively impacted by the ramp-up of new Power Purchase Agreements with distribution companies. In Brazil, organic growth was mainly driven by the commissioning of wind and solar farms and a new thermal unit, and the effect of inflation on PPA contracts.

Current operating income totaled €1,694 million, up 24.6% on a reported basis and 20.2% on an organic basis. Reported growth benefited from the positive impact of the acquisition in June 2019 of a gas transportation entity in Brazil (TAG). The organic growth was due to the favorable impact of liquidated damages received in Chile and Brazil in 2019, and the positive organic effects mentioned above for revenues. These impacts were partially offset by a positive one-off recorded in 2018 in Mexico.

2.4 USA & Canada

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	% change (reported basis)	% change (organic basis)
Revenues	4,545	3,355	+35.5%	+10.1%
EBITDA	291	252	+15.6%	+4.5%
Net depreciation and amortization/Other	(132)	(99)		
CURRENT OPERATING INCOME (COI)	159	153	+3.9%	-5.5%

Revenues in the USA & Canada segment came in at €4,545 million, up 35.5% on a reported basis. In addition to positive foreign exchange effects, revenues benefited from scope-in effects relating to recent acquisitions in Client Solutions and Retail BtoB (Plymouth Rock) in the United States. The 10.1% organic growth was mainly the result of positive price effects on BtoB power sales in the United States with no effect at current operating income level.

Current operating income totaled €159 million, down 5.5% on an organic basis compared to 2018. The main reasons for the decrease were a lower operational performance in Client Solutions due to loss-making contracts, set-up costs for ENGIE Impact and lower capacity prices in Thermal activities. These effects were partly offset by the progressive ramp-up of Renewables activities in the United States, including the DBSO sell down of a wind project (Live Oak) and contributions from two wind projects commissioned in 2019.

2.5 Middle East, Asia & Africa

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	% change (reported basis)	% change (organic basis)
Revenues	2,914	4,014	-27.4%	-6.7%
EBITDA	727	1,133	-35.9%	-12.5%
Net depreciation and amortization/Other	(168)	(237)		
CURRENT OPERATING INCOME (COI)	559	896	-37.6%	-9.1%

Revenues for the Middle East, Africa & Asia segment totaled €2,914 million, down 27.4% on a reported basis and 6.7% organically. The reported decrease was mainly due to the disposal of Glow (Thailand) in March 2019, a weakened performance in Supply (mainly Simply Energy in Australia), as well as lower revenues in Client Solutions in Africa and Australia. The decrease was partly offset by acquisitions in the Middle East (Cofely Besix) and Asia (RCS Engineering), and positive foreign exchange effects.

Electricity sales decreased by 27 TWh to 16.8 TWh, with reduced volumes mostly due to the sale of Glow and Loy Yang B.

Current operating income totaled €559 million, down 37.6% on a reported basis and 9.1% organically. The gross reported decrease was due to the negative impact of the disposal of Glow and Loy Yang B, partly offset by positive foreign exchange effects. The organic decrease notably reflects difficulties (i) in Supply in Australia and Africa, (ii) in Networks partly related to a positive provision reversal in Turkey in 2018, and to a lesser extent (iii) in Services activities. The decrease was partly offset by the positive contribution of Thermal Generation and the positive impact of Renewables activities, including liquidated damages for the Willogoleche wind farm in Australia.

2.6 Others

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	% change (reported basis)	% change (organic basis)
Revenues	8,565	7,565	+13.2%	+7.5%
EBITDA	166	119	+39.7%	-9.9%
Net depreciation and amortization/Other	(397)	(476)		
CURRENT OPERATING INCOME/(LOSS) (COI)	(231)	(357)	+35.4%	+23.5%

The Others reportable segment includes (i) GEM, (ii) Tractebel, (iii) GTT, (iv) Hydrogen, as well as (v) the Group's holding and corporate activities which include the entities centralizing the Group's financing requirements, *Entreprises & Collectivités (E&C)* and the contribution of SUEZ (associate).

Revenues for the Others reportable segment amounted to €8,565 million. The 13.2% reported growth compared to 2018 represented €1,000 million, mainly driven by GEM due to a favorable market context and E&C mainly due to an increase in power volumes and average prices (up €910 million gross for both GEM & E&C).

Current operating loss amounted to €231 million euros, representing a €126 million improvement compared to 2018. This improvement was mainly due to a strong performance by GEM in market activities, the partial transfer of a gas supply contract, gas contract renegotiations and the Certinergy acquisition in February 2019, partially offset by a sluggish performance by storage activities in bearish markets. Current operating income/(loss) also benefited from positive one-offs at SUEZ and in connection with the Link 2018 employee shareholding plan. These favorable impacts were partly offset by a decline in margins for Tractebel Engineering.

3 OTHER INCOME STATEMENT ITEMS

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 with IFRS 16	% change (reported basis)
CURRENT OPERATING INCOME (COI)	5,726	5,154	+11.1%
(+) Mark-to-Market on commodity contracts other than trading instruments	(426)	(223)	
Current operating income including operating MtM and share in net income of equity method entities	5,300	4,932	+7.5%
Impairment losses	(1,770)	(1,798)	
Restructuring costs	(218)	(162)	
Changes in scope of consolidation	1,604	(150)	
Other non-recurring items	(1,240)	(147)	
Income/(loss) from operating activities	3,676	2,674	+37.5%
Net financial income/(loss)	(1,387)	(1,414)	
Income tax benefit/(expense)	(640)	(702)	
NET INCOME/(LOSS) RELATING TO CONTINUED OPERATIONS	1,649	558	
NET INCOME/(LOSS) RELATING TO DISCONTINUED OPERATIONS	-	1,067	
NET INCOME/(LOSS)	1,649	1,624	+1.5%
Net income/(loss) Group share	984	1,029	
Of which Net income/(loss) relating to continued operations, Group share	984	(14)	
Of which Net income/(loss) relating to discontinued operations, Group share	-	1,043	
Non-controlling interests	664	595	
Of which Non-controlling interests relating to continued operations	664	572	
Of which Non-controlling interests relating to discontinued operations	-	24	

Income from operating activities amounted to €3,676 million in 2019, representing an increase compared with 2018, mainly due to (i) gains on asset disposals (principally relating to the disposal of ENGIE's interest in Glow), (ii) the improvement in current operating income, (iii) partly offset by the recognition of additional costs related to the triennial review of nuclear provisions in Belgium.

Income from operating activities was also affected by:

- net impairment losses of €1,770 million in 2019 compared with €1,798 million in 2018, mainly relating to Belgian nuclear power assets (including €638 million on dismantling assets for nuclear facilities whose operating life may not be extended, recognized against the provision, as part of the triennial review of nuclear provisions) and thermal power generation assets in Latin America and the Middle East (see Note 9.1);
- restructuring costs of €218 million (compared with €162 million in 2018) (see Note 9.2);
- positive scope effects of €1,604 million, mainly relating to the disposal of ENGIE's interest in Glow;
- other non-recurring items for a negative €1,240 million, mainly including the €1,166 million net expense related to additions to provisions for the back-end of the nuclear fuel cycle as part of the triennial review of nuclear provisions in Belgium.

The **net financial loss** amounted to €1,387 million in 2019, compared with €1,414 million the previous year (see Note 10).

The **income tax expense** for 2019 amounted to €640 million (versus €702 million in 2018). It includes an income tax benefit of €471 million arising on non-recurring taxable items (versus €147 million in 2018), mainly comprising mark-to-market losses recognized by ENGIE SA. The effective tax rate decreased significantly in 2019 (35.8% versus 78.1% in 2018), mainly due to the non-taxation of proceeds from the Glow disposal. Adjusted for these non-recurring items, the effective recurring tax rate was 28.2%, up on the 2018 rate of 23.7% mainly due to the impact of more positive one-off effects in 2018 than in 2019.

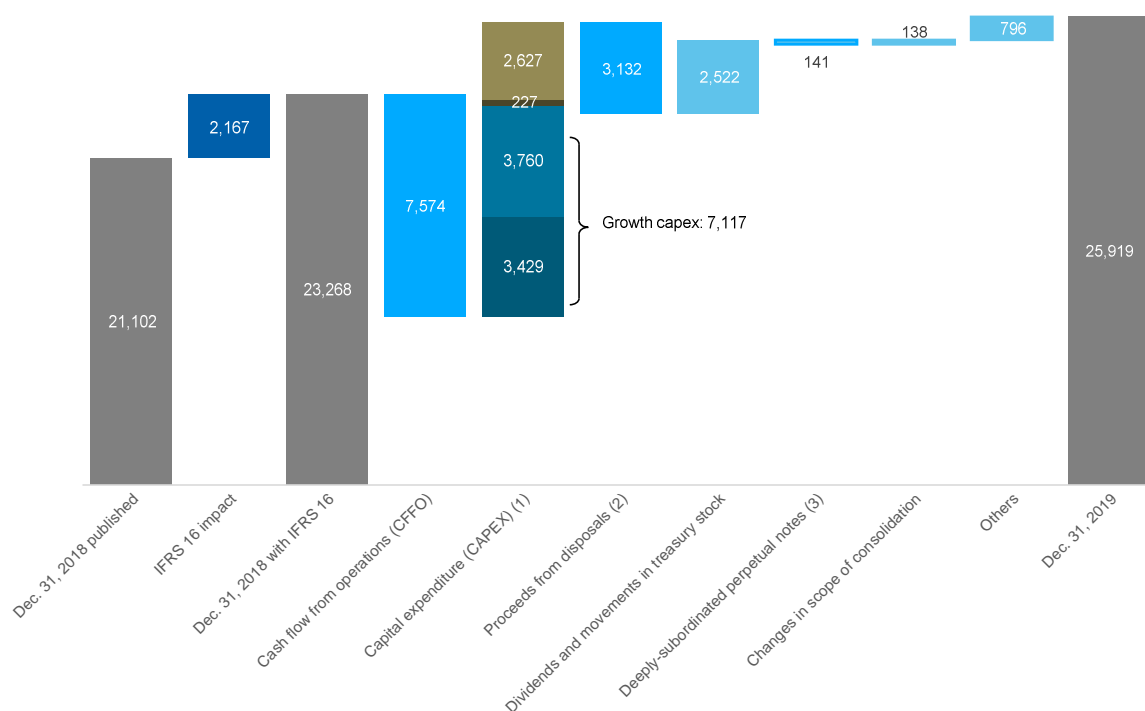
Net income relating to continued operations attributable to non-controlling interests amounted to €664 million, compared with €595 million in 2018. The increase was mainly due to lower impairment losses compared to the previous year on coal assets in Germany, partly offset by the deconsolidation of ENGIE's interest in Glow as from March 14, 2019 following its disposal.

4 CHANGES IN NET FINANCIAL DEBT

Net financial debt stood at €25.9 billion, up 2.7 billion compared to December 31, 2018. This increase is mainly attributable to (i) capital expenditure over the period (€10.0 billion⁽¹⁾), including €1.5 billion in expenditure for the TAG transaction in Brazil), (ii) dividends paid to ENGIE SA shareholders (€1.8 billion) and to non-controlling interests (€0.7 billion) and (iii) other items (€0.6 billion) mainly related to foreign exchange rates, new leased right-of-use assets and mark-to-market variations. These items were partly offset by (i) cash flow from operations (€7.6 billion) and (ii) the impacts of the portfolio rotation program (€3.0 billion, mainly related to the completion of the disposal of the stake in Glow).

Changes in net financial debt break down as follows:

In millions of euros



- (1) Capital expenditure net of DBSO proceeds.
- (2) Excluding DBSO proceeds.
- (3) See Note 18.2.1 "Issuance of deeply-subordinated perpetual notes".

	Development CAPEX (net of DBSO)
	Financial CAPEX
	Change in Synatom investments
	Maintenance CAPEX

(1) Net of DBSO proceeds.

4 CHANGES IN NET FINANCIAL DEBT

The net financial debt to EBITDA ratio came out at 2.50 at December 31, 2019.

<i>In millions of euros</i>	Dec. 31, 2019	Jan. 1, 2019 with IFRS 16
Net financial debt	25,919	23,268
EBITDA	10,366	9,702
NET DEBT/EBITDA RATIO	2.50	2.40

The economic net debt to EBITDA ratio stood at 3.96 at December 31, 2019.

<i>In millions of euros</i>	Dec. 31, 2019	Jan. 1, 2019 with IFRS 16
Economic net debt	41,078	35,669
EBITDA	10,366	9,702
ECONOMIC NET DEBT/EBITDA RATIO	3.96	3.68

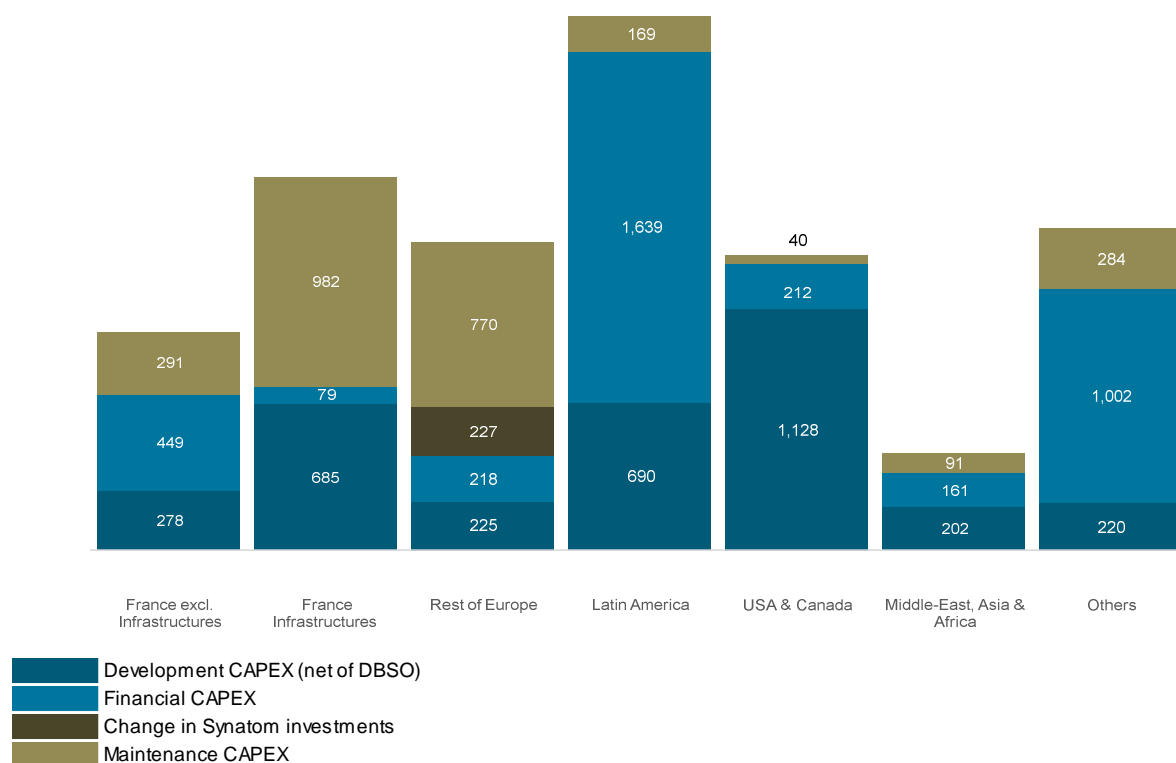
4.1 Cash flow from operations (CFFO)

Cash flow from operations (CFFO) amounted to €7.6 billion, down €0.2 billion. The decrease stemmed predominantly from working capital requirement variations (€1.2 billion negative impact) caused by margin calls on derivatives and mark-to-market variation of financial derivatives, partly offset by the increase of operating cash flow (€0.9 billion) and lower tax and interests paid (€0.2 billion).

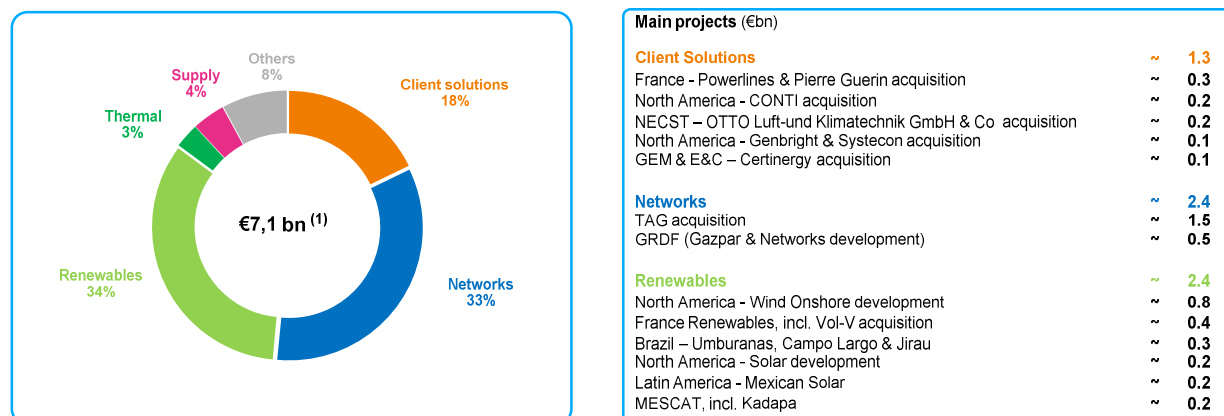
4.2 Net investments

Capital expenditure (CAPEX) amounted to €10,042 million, breaking down as follows by segment:

In millions of euros



Growth capital expenditure amounted to €7,117 million, breaking down as follows by Business Line:



(1) Net of disposals under DBSO operations, excluding Corporate, and Synatom reallocated to maintenance expenditure.

The **geography/Business Line matrix** for capital expenditures is presented hereunder:

In millions of euros	Client Solutions	Networks	Renewables	Thermal	Nuclear	Supply	Others	TOTAL at Dec. 31, 2019
France	423	1,709	481	-	-	151	-	2,764
Rest of Europe	416	77	42	174	636	95	-	1,440
Latin America	47	1,651	541	254	-	6	-	2,499
USA & Canada	330	1	968	8	-	73	-	1,380
Middle East, Asia & Africa	80	9	271	-	-	93	-	453
Others	325	-	186	81	-	38	876	1,506
TOTAL CAPEX	1,621	3,446	2,488	517	636	457	876	10,042

In millions of euros	Client Solutions	Networks	Renewables	Thermal	Nuclear	Supply	Others	TOTAL at Dec. 31, 2018
France	469	1,617	237	-	-	148	-	2,471
Rest of Europe	357	58	18	143	750	104	-	1,430
Latin America	145	129	1,024	456	-	4	-	1,758
USA & Canada	350	-	461	1	-	100	5	918
Middle East, Asia & Africa	84	10	239	214	-	69	-	616
Others	131	-	6	-	-	28	284	449
TOTAL CAPEX	1,537	1,814	1,986	813	750	454	289	7,643

Net investments amounted to €7,586 million and include:

- growth capital expenditure for €7,117 million. This mainly stemmed from (i) the acquisition in Infrastructures, in consortium with the Caisse de Dépôt et Placement du Québec (CDPQ), of a 90% stake in Transportadora Associada de Gás S.A. (TAG) in Brazil (€1,557 million, including acquisition costs), of the energy services company Conti in North America (€178 million), and in Client Solutions of the OTTO Luft-und Klimatechnik GmbH & Co facilities and services company in Germany (€149 million), (ii) the development in Infrastructures of blending and development projects in the natural gas distribution and transportation network in France (€685 million), (iii) investments in Renewables relating to the development of wind and photovoltaic farms in the United States (approximately €1 billion), Mexico (€345 million), Brazil (€307 million) and India (€139 million), and (iv) the financing of the Nord Stream 2 pipeline project (€433 million);
- gross maintenance capital expenditure amounting to €2,627 million;
- the €227 million increase in Synatom investments;
- new leased right-of-use assets recognized over the period (€539 million);

- changes in the scope of consolidation for the period relating to acquisitions and disposals of subsidiaries for €138 million; and
- proceeds from disposals representing an inflow of €3,132 million, mainly relating to the disposal of ENGIE's interest in Glow in Thailand.

4.3 Dividends and movements in treasury stock

Dividends and movements in treasury stock during the period amounted to €2,522 million and included:

- €1,833 million in dividends paid by ENGIE SA to its shareholders, which corresponds to the balance of the 2018 dividend (€0.75 per share for shares with rights to an ordinary and exceptional dividend and €0.86 per share for shares with rights to a dividend mark-up) paid in May 2019;
- dividends paid by various subsidiaries to their non-controlling interests in an amount of €538 million, the payment of interest on hybrid debt for €150 million and movements in treasury stock.

4.4 Net financial debt at December 31, 2019

Excluding amortized cost but including the impact of foreign currency derivatives, at December 31, 2019 a total of 74% of net financial debt was denominated in euros, 15% in US dollars and 10% in Brazilian real.

Including the impact of financial instruments, 79% of net financial debt is at fixed rates.

The average maturity of the Group's net financial debt is 11.2 years.

At December 31, 2019, the Group had total undrawn confirmed credit lines of €13.0 billion.

5 OTHER ITEMS IN THE STATEMENT OF FINANCIAL POSITION

<i>In millions of euros</i>	Dec. 31, 2019	Jan. 1, 2019 with IFRS 16 & IFRIC 23	Net change
Non-current assets	99,297	93,818	5,479
Of which goodwill	18,665	17,809	856
Of which property, plant and equipment and intangible assets, net	58,996	57,776	1,220
Of which investments in equity method entities	9,216	7,846	1,370
Current assets	60,496	61,994	(1,498)
Of which assets classified as held for sale	468	3,809	(3,340)
Total equity	38,037	40,930	(2,893)
Provisions	25,115	21,512	3,603
Borrowings	38,544	34,345	4,199
Other liabilities	58,097	59,024	(928)
Of which liabilities directly associated with assets classified as held for sale	92	2,141	(2,049)

The carrying amount of **property, plant and equipment and intangible assets** was €59.0 billion, up €1.2 billion compared with December 31, 2018. The increase was primarily the result of acquisitions and development capital expenditure during the period (€7.4 billion positive impact), translation adjustments (€0.1 billion positive impact), partly offset by depreciation and amortization charges (€4.3 billion negative impact), impairment losses (€1.7 billion negative impact), changes in the scope of consolidation (€0.8 billion negative impact), the classification of renewable energy assets in Mexico and green gas production assets in operation in France as “Assets classified as held for sale” (€0.4 billion negative impact), and disposals (€0.2 billion negative impact).

Goodwill increased by €0.9 billion to €18.7 billion, mainly due to acquisitions made by the following BUs: France BtoB, France Renewables, Northern, Southern and Eastern Europe, and Latin America, partly offset by the recognition of impairment losses on the disposal of the coal-fired power plants in Germany and the Netherlands (see Note 4.1.2).

Total equity amounted to €38.0 billion, a decrease of €2.9 billion compared with December 31, 2018. The decrease stemmed mainly from the payment of the cash dividend (€2.3 billion negative impact, including €1.8 billion of dividends paid by ENGIE SA to its shareholders and €0.5 billion paid to non-controlling interests), other items of comprehensive income (€1.8 billion negative impact), and the effect of the deconsolidation of Glow following its disposal (€0.5 billion negative impact), partly offset by net income for the period (€1.6 billion positive impact).

Provisions increased by €3.6 billion to €25.1 billion compared with December 31, 2018. This increase stemmed mainly from the impacts of the triennial review of nuclear provisions in Belgium (which added €2.1 billion to the total amount) (see Note 19), actuarial losses on provisions for post-employment benefits and other long-term benefits (which added €1.1 billion to the total amount) owing to the fall in discount rates over the period (see Note 20).

At December 31, 2019, assets and liabilities classified under “**Assets classified as held for sale**” and “**Liabilities directly associated with assets classified as held for sale**” comprised renewable energy assets in Mexico and green gas production assets in operation in France.

6 ADJUSTMENT OF COMPARATIVE INFORMATION

The aforementioned 2018 figures have been adjusted in respect of:

- the application of the IFRIC position on commodity derivative accounting, leading the Group to review the presentation of some items of the income statement (with no impact on net income, equity or the current operating income indicator used in the management dialogue and financial communication) (see *restatements presented in Note 1 to the consolidated financial statements*);
- the transition method used for the application of IFRS 16 – Leases (see hereunder);

in order to make them comparable to the 2019 figures.

The adjustments relating to the application of IFRS 16 on the income statement and certain Group key indicators are as follows:

In millions of euros	Dec. 31, 2018 new presentation ⁽¹⁾	IFRS 16	Dec. 31, 2018 new presentation with IFRS 16
Income statement			
REVENUES	56,967	-	56,967
Purchases and operating derivatives	(38,660)	466	(38,194)
Personnel costs	(10,624)	-	(10,624)
Depreciation, amortization and provisions	(3,586)	(438)	(4,024)
Taxes	(1,069)	1	(1,068)
Other operating income	1,514	-	1,514
Current operating income including operating MtM	4,542	29	4,571
Share in net income of equity method entities	361	-	360
Current operating income including operating MtM and share in net income of equity method entities	4,903	29	4,932
Impairment losses	(1,798)	-	(1,798)
Restructuring costs	(162)	-	(162)
Changes in scope of consolidation	(150)	-	(150)
Other non-recurring items	(147)	-	(147)
INCOME/(LOSS) FROM OPERATING ACTIVITIES	2,645	29	2,674
NET FINANCIAL INCOME/(LOSS)	(1,381)	(33)	(1,414)
Income tax expense	(704)	2	(702)
NET INCOME/(LOSS) RELATING TO CONTINUED OPERATIONS	560	(2)	558
NET INCOME/(LOSS) RELATING TO DISCONTINUED OPERATIONS	1,069	(2)	1,067
NET INCOME/(LOSS)	1,629	(4)	1,624
Net income/(loss) Group share	1,033	(4)	1,029
of which Net income/(loss) relating to continued operations, Group share	(12)	(2)	(14)
of which Net income/(loss) relating to discontinued operations, Group share	1,045	(2)	1,043
Non-controlling interests	595	-	595
of which Non-controlling interests relating to continued operations	572	-	572
of which Non-controlling interests relating to discontinued operations	24	-	24
BASIC EARNINGS/(LOSS) PER SHARE (EUROS)	0.37	(0.00)	0.37
of which Basic earnings/(loss) relating to continued operations per share	(0.07)	(0.00)	(0.07)
of which Basic earnings/(loss) relating to discontinued operations per share	0.44	(0.00)	0.44
DILUTED EARNINGS/(LOSS) PER SHARE (EUROS)	0.37	(0.00)	0.37
of which Diluted earnings/(loss) relating to continued operations per share	(0.07)	(0.00)	(0.07)
of which Diluted earnings/(loss) relating to discontinued operations per share	0.43	(0.00)	0.43
EBITDA	9,236	467	9,702
CURRENT OPERATING INCOME (COI)	5,126	29	5,154
NET RECURRING INCOME	3,238	(4)	3,234
NET RECURRING INCOME GROUP SHARE	2,425	(4)	2,421
NET RECURRING INCOME RELATING TO CONTINUED OPERATIONS, GROUP SHARE	2,458	(2)	2,455

(1) Comparative data at December 31, 2018 have been reclassified in accordance with the new income statement presentation adopted by the Group consequent to the application of the IFRIC position on commodity derivatives.

6 ADJUSTMENT OF COMPARATIVE INFORMATION

<i>In millions of euros</i>	Dec. 31, 2018 published	IFRS 16	Dec. 31, 2018 with IFRS 16
Cash flows			
CASH FLOW FROM OPERATIONS (CFFO)	7,300	437	7,736

<i>In millions of euros</i>	Dec. 31, 2018 published	IFRS 16 & IFRIC 23	Jan. 1, 2019 with IFRS 16 & IFRIC 23
Statement of financial position			
NET DEBT	21,102	2,167	23,268
ECONOMIC NET DEBT	35,590	79	35,669
INDUSTRIAL CAPITAL EMPLOYED	51,412	2,156	53,568

The application of IFRS 16 and its impact on the statement of financial position at January 1, 2019 is presented in Note 1 “Accounting framework and basis for preparing the consolidated financial statements”.

7 PARENT COMPANY FINANCIAL STATEMENTS

The figures provided below relate to the financial statements of ENGIE SA, prepared in accordance with French GAAP and applicable regulations.

Revenues for ENGIE SA in 2019 totaled €17,282 million, a decrease compared to 2018 (€27,833 million), mainly due to lower gas sales to other gas operators.

The net operating loss was €931 million at December 31, 2019, an improvement of €127 million compared with a loss of €1,058 million in 2018. Energy margin increased by €143 million, thanks to lower supply costs and continued growth in the electricity business.

Net financial income amounted to €1,192 million, €2,525 million less than in 2018 when dividend payments and income from receivables were €2,449 million higher.

Non-recurring items represented a loss of €835 million, mainly comprising impairment of equity investments.

The income tax benefit amounted to €377 million compared to a benefit of €549 million in 2018, including a tax consolidation benefit of €294 million.

The net loss for the year came out at €196 million.

Shareholders' equity amounted to €34,594 million at end-2019 compared with €36,616 million at end-2018. The €2,022 million decrease was mainly due to the 2019 net loss of €196 million and to the dividend payment of €1,833 million.

At December 31, 2019, borrowings and debt stood at €39,234 million, and cash and cash equivalents totaled €9,891 million (of which €7,753 relating to subsidiaries' current accounts).

Information relating to payment terms

Pursuant to the application of Article D.441-4 of the French Commercial Code, companies whose annual financial statements are subject to a statutory audit must publish information regarding supplier and customer payment terms. The purpose is to demonstrate that there is no significant failure to comply with such terms.

Information relating to supplier and customer payment terms mentioned in Article D.441-4 of the French Commercial Code

	Article D. 441 I.- 1°: Invoices received, unpaid and overdue at the reporting date						Article D. 441 I.- 2°: Invoices issued, unpaid and overdue at the reporting date					
	0 days (indicative)	1 to 30 days	31 to 60 days	61 to 90 days	91 days or more	Total (1 day or more)	0 days (indicative)	1 to 30 days	31 to 60 days	61 to 90 days	91 days or more	Total (1 day or more)
<i>In millions of euros</i>												
(A) By aging category												
Number of invoices	-					34,346	-					5,532,869
Aggregate invoice amount (incl. VAT)	-	132.8	11.4	0.6	86.8	231.5	-	109.9	80.7	42.3	533.8	766.8
Percentage of total amount of purchases (incl. VAT) for the period	-	0.67%	0.06%	0.00%	0.43%	1.16%						
Percentage of total revenues (incl. VAT) for the period							-	0.54%	0.40%	0.21%	2.62%	3.76%
(B) Invoices excluded from (A) relating to disputed or unrecognized receivables and payables												
Number of excluded invoices			325						1,203			
Aggregate amount of excluded invoices			6.7						57.1			
(C) Standard payment terms used (contractual or legal terms - Article L. 441-6 or Article L. 443-1 of the French Commercial Code)												
Payment terms used to calculate late payments	Legal payment terms: 30 days						Contractual payment terms: 14 days Legal payment terms: 30 days					

02 CONSOLIDATED FINANCIAL STATEMENTS

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INCOME STATEMENT

<i>In millions of euros</i>	Notes	Dec. 31, 2019 ⁽¹⁾	Dec. 31, 2018 ^(1, 2)
REVENUES	6.2 & 7	60,058	56,967
Purchases and operating derivatives	8.1	(39,950)	(38,660)
Personnel costs	8.2	(11,478)	(10,624)
Depreciation, amortization and provisions	8.3	(4,393)	(3,586)
Taxes		(1,108)	(1,069)
Other operating income		1,670	1,514
Current operating income including operating MtM		4,800	4,542
Share in net income of equity method entities	6.2	500	361
Current operating income including operating MtM and share in net income of equity method entities	6.2	5,300	4,903
Impairment losses	9.1	(1,770)	(1,798)
Restructuring costs	9.2	(218)	(162)
Changes in scope of consolidation	9.3	1,604	(150)
Other non-recurring items	9.4	(1,240)	(147)
INCOME/(LOSS) FROM OPERATING ACTIVITIES	9	3,676	2,645
Financial expenses		(2,300)	(1,981)
Financial income		913	600
NET FINANCIAL INCOME/(LOSS)	10	(1,387)	(1,381)
Income tax benefit/(expense)	11	(640)	(704)
NET INCOME/(LOSS) RELATING TO CONTINUED OPERATIONS		1,649	560
NET INCOME/(LOSS) RELATING TO DISCONTINUED OPERATIONS		-	1,069
NET INCOME/(LOSS)		1,649	1,629
Net income/(loss) Group share		984	1,033
<i>Of which Net income/(loss) relating to continued operations, Group share</i>		984	(12)
<i>Of which Net income/(loss) relating to discontinued operations, Group share</i>		-	1,045
Non-controlling interests		664	595
<i>Of which Non-controlling interests relating to continued operations</i>		664	572
<i>Of which Non-controlling interests relating to discontinued operations</i>		-	24
BASIC EARNINGS/(LOSS) PER SHARE (EUROS)	12	0.34	0.37
<i>Of which Basic earnings/(loss) relating to continued operations per share</i>		0.34	(0.07)
<i>Of which Basic earnings/(loss) relating to discontinued operations per share</i>		-	0.44
DILUTED EARNINGS/(LOSS) PER SHARE (EUROS)	12	0.34	0.37
<i>Of which Diluted earnings/(loss) relating to continued operations per share</i>		0.34	(0.07)
<i>Of which Diluted earnings/(loss) relating to discontinued operations per share</i>		-	0.43

(1) Data presented at December 31, 2019 have been prepared in accordance with the new income statement presentation adopted by the Group. Comparative data at December 31, 2018 have been reclassified in accordance with this new presentation (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

(2) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

STATEMENT OF COMPREHENSIVE INCOME

<i>In millions of euros</i>	Notes	Dec. 31, 2019	Dec 31, 2019 Owners of the parent	Dec 31, 2019 Non- controlling interests	Dec 31, 2018 ⁽¹⁾	Dec 31, 2018 Owners of the parent ⁽¹⁾	Dec 31, 2018 Non- controlling interests ⁽¹⁾
NET INCOME/(LOSS)		1,649	984	664	1,629	1,033	595
Debt instruments	16.1	48	48	-	29	29	-
Net investment hedges	17	29	29	-	7	7	-
Cash flow hedges (excl. commodity instruments)	17	(229)	(232)	3	(175)	(184)	9
Commodity cash flow hedges	17	(744)	(808)	64	(18)	7	(26)
Deferred tax on items above	11	240	261	(21)	48	43	5
Share of equity method entities in recyclable items, net of tax		(250)	(239)	(11)	201	201	-
Translation adjustments		(45)	32	(78)	22	(54)	77
Recyclable items relating to discontinued operations, net of tax		-	-	-	36	39	(3)
TOTAL RECYCLABLE ITEMS		(953)	(910)	(43)	150	88	62
Equity instruments	16.1	103	103	-	42	42	-
Actuarial gains and losses	20	(1,128)	(1,040)	(88)	(245)	(247)	1
Deferred tax on items above	11	255	232	22	58	58	-
Share of equity method entities in actuarial gains and losses, net of tax		(31)	(31)	-	(43)	(45)	2
Non-recyclable items relating to discontinued operations, net of tax		-	-	-	(3)	(1)	(2)
TOTAL NON-RECYCLABLE ITEMS		(801)	(735)	(66)	(192)	(193)	2
TOTAL COMPREHENSIVE INCOME/(LOSS)		(105)	(660)	555	1,586	928	659

(1) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

STATEMENT OF FINANCIAL POSITION

ASSETS

<i>In millions of euros</i>	Notes	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
Non-current assets			
Goodwill	13	18,665	17,809
Intangible assets, net	14	7,038	6,718
Property, plant and equipment, net	15	51,958	48,917
Other financial assets	16	7,022	6,193
Derivative instruments	16	4,137	2,693
Assets from contracts with customers	7	15	-
Investments in equity method entities	3	9,216	7,846
Other non-current assets	24	384	474
Deferred tax assets	11	860	1,066
TOTAL NON-CURRENT ASSETS		99,297	91,716
Current assets			
Other financial assets	16	2,546	2,290
Derivative instruments	16	10,134	10,679
Trade and other receivables, net	7	15,180	15,613
Assets from contracts with customers	7	7,816	7,411
Inventories	24	3,617	4,158
Other current assets	24	10,216	9,337
Cash and cash equivalents	16	10,519	8,700
Assets classified as held for sale	4.2	468	3,798
TOTAL CURRENT ASSETS		60,496	61,986
TOTAL ASSETS		159,793	153,702

(1) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 and IFRIC 23 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

STATEMENT OF FINANCIAL POSITION

LIABILITIES

<i>In millions of euros</i>	Notes	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
Shareholders' equity		33,087	35,551
Non-controlling interests	2	4,950	5,391
TOTAL EQUITY	18	38,037	40,941
Non-current liabilities			
Provisions	19	22,817	19,194
Long-term borrowings	16	30,002	26,434
Derivative instruments	16	5,129	2,785
Other financial liabilities	16	38	46
Liabilities from contracts with customers	7	45	36
Other non-current liabilities	24	1,222	960
Deferred tax liabilities	11	4,631	5,415
TOTAL NON-CURRENT LIABILITIES		63,882	54,869
Current liabilities			
Provisions	19	2,298	2,620
Short-term borrowings	16	8,543	5,745
Derivative instruments	16	10,446	11,510
Trade and other payables	16	19,109	19,759
Liabilities from contracts with customers	7	4,286	3,598
Other current liabilities	24	13,101	12,529
Liabilities directly associated with assets classified as held for sale	4.2	92	2,130
TOTAL CURRENT LIABILITIES		57,874	57,891
TOTAL EQUITY AND LIABILITIES		159,793	153,702

(1) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 and IFRIC 23 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

STATEMENT OF CHANGES IN EQUITY

<i>In millions of euros</i>	Number of shares	Share capital	Additional paid-in capital	Consolidated reserves	Deeply-subordinated perpetual notes	Changes in fair value and other	Translation adjustments	Treasury stock	Shareholders' equity	Non-controlling interests	Total
EQUITY AT DECEMBER 31, 2017	2,435,285,011	2,435	32,506	1,455	3,129	(915)	(1,088)	(883)	36,639	5,938	42,577
IFRS 9 & 15 impact ⁽¹⁾	-	-	-	(122)	-	(270)	36	-	(357)	(99)	(455)
Reclassification of premiums and coupons ⁽²⁾				(570)	570	-	-	-	-	-	-
EQUITY AT JANUARY 1, 2018 ^{(1) (2)}	2,435,285,011	2,435	32,506	763	3,699	(1,184)	(1,053)	(883)	36,282	5,840	42,122
Net income/(loss)				1,033					1,033	595	1,629
Other comprehensive income/(loss)				(193)		165	(78)		(106)	63	(42)
TOTAL COMPREHENSIVE INCOME/(LOSS)				840		165	(78)		928	659	1,586
Employee share issues and share-based payment		6	60	80					146	1	146
Cancellation of treasury stock		(6)	-	(75)	-	-	-	81	-	-	-
Dividends paid in cash				(1,739)					(1,739)	(882)	(2,621)
Purchase/disposal of treasury stock				(236)				342	105	-	105
Deeply-subordinated perpetual notes ⁽²⁾				(11)	1,000				989	-	989
Reclassification under debt and redemption of deeply-subordinated perpetual notes ⁽²⁾				(24)	(949)				(973)	-	(973)
Interests on deeply-subordinated perpetual notes				(123)					(123)	-	(123)
Transactions between owners				(34)					(34)	10	(24)
Transactions with impact on non-controlling interests ⁽³⁾				-					-	(229)	(229)
Share capital increases and decreases subscribed by non-controlling interests									-	(6)	(6)
Other changes				(29)		-			(30)	(2)	(31)
EQUITY AT DECEMBER 31, 2018 ⁽⁴⁾	2,435,285,011	2,435	32,565	(590)	3,750	(1,019)	(1,130)	(460)	35,551	5,391	40,941

(1) Comparative data at January 1, 2018 have been restated due to the application of IFRS 9 and IFRS 15 (see Note 2 "Restatement of 2017 comparative data" to the 2018 consolidated financial statements).

(2) For clarity's sake, it has been decided to present deeply-subordinated perpetual notes at their nominal value instead of their net value (premiums and coupons deducted). This reclassification has no impact on equity. Transactions for the period are presented in Note 19.2.1 "Issuance of deeply-subordinated perpetual notes" to the 2018 consolidated financial statements.

(3) Mainly relating to the deconsolidation of the ENGIE E&P International following its disposal (see Note 5.1.2 "Disposal of the exploration-production business" to the 2018 consolidated financial statements) and the change of consolidation method for Hazelwood (see Note 3.1 "List of main subsidiaries at December 31, 2018" to the 2018 consolidated financial statements).

(4) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements")

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

CONSOLIDATED FINANCIAL STATEMENTS

STATEMENT OF CHANGES IN EQUITY

<i>In millions of euros</i>	Number of shares	Share capital	Additional paid-in capital	Consolidated reserves	Deeply-subordinated perpetual notes	Changes in fair value and other	Translation adjustments	Treasury stock	Shareholders' equity	Non-controlling interests	Total
EQUITY AT DECEMBER 31, 2018 ⁽¹⁾	2,435,285,011	2,435	32,565	(590)	3,750	(1,019)	(1,130)	(460)	35,551	5,391	40,941
IFRS 16 impact (see Note 1)	-	-	-	(7)	-	-	-	-	(7)	(4)	(11)
EQUITY AT JANUARY 1, 2019 with IFRS 16	2,435,285,011	2,435	32,565	(597)	3,750	(1,019)	(1,130)	(460)	35,544	5,386	40,930
Net income/(loss)				984					984	664	1,649
Other comprehensive income/(loss)				(735)		(942)	32		(1,645)	(109)	(1,754)
TOTAL COMPREHENSIVE INCOME/(LOSS)				250	-	(942)	32	-	(660)	555	(105)
Employee share issues and share-based payment		-	-	50					50	-	50
Dividends paid in cash ⁽²⁾			(1,096)	(738)					(1,833)	(453)	(2,286)
Purchase/disposal of treasury stock				(157)				157	-	-	-
Deeply-subordinated perpetual notes ⁽²⁾				(172)	163				(9)	-	(9)
Transactions between owners				36					36	4	40
Transactions with impact on non-controlling interests ⁽³⁾				-					-	(515)	(515)
Application of IFRIC 23 rule by Suez				(35)					(35)	-	(35)
Share capital increases and decreases subscribed by non-controlling interests									-	(28)	(28)
Other changes				(6)	-	-			(6)	1	(5)
EQUITY AT DECEMBER 31, 2019	2,435,285,011	2,435	31,470	(1,369)	3,913	(1,961)	(1,098)	(303)	33,087	4,950	38,037

(1) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

(2) Transactions of the period are listed in Note 18 "Equity".

(3) Mainly relates to the deconsolidation of Glow following its disposal (see Note 4.1 "Disposals carried out in 2019").

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

STATEMENT OF CASH FLOWS

In millions of euros	Notes	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
NET INCOME/(LOSS)		1,649	1,629
- Net income/(loss) relating to discontinued operations		-	1,069
NET INCOME/(LOSS) RELATING TO CONTINUED OPERATIONS		1,649	560
- Share in net income of equity method entities	3	(500)	(361)
+ Dividends received from equity method entities		773	572
- Net depreciation, amortization, impairment and provisions		7,083	5,085
- Impact of changes in scope of consolidation and other non-recurring items		(1,579)	195
- Mark-to-market on commodity contracts other than trading instruments		426	223
- Other items with no cash impact		(18)	105
- Income tax expense	11	640	704
- Net financial income/(loss)	10	1,387	1,381
Cash generated from operations before income tax and working capital requirements		9,863	8,464
+ Tax paid		(575)	(757)
Change in working capital requirements	24.1	(1,110)	149
CASH FLOW FROM OPERATING ACTIVITIES RELATING TO CONTINUED OPERATIONS		8,178	7,857
CASH FLOW FROM OPERATING ACTIVITIES RELATING TO DISCONTINUED OPERATIONS		-	17
CASH FLOW FROM OPERATING ACTIVITIES		8,178	7,873
Acquisitions of property, plant and equipment and intangible assets	5.6	(6,524)	(6,202)
Acquisitions of controlling interests in entities, net of cash and cash equivalents acquired	5.6	(864)	(983)
Acquisitions of investments in equity method entities and joint operations	5.6	(1,746)	(338)
Acquisitions of equity and debt instruments	5.6	(595)	(283)
Disposals of property, plant and equipment, and intangible assets		134	114
Loss of controlling interests in entities, net of cash and cash equivalents sold		2,676	2,865
Disposals of investments in equity method entities and joint operations		14	2
Disposals of equity and debt instruments		148	186
Interest received on financial assets		28	26
Dividends received on equity instruments		67	52
Change in loans and receivables originated by the Group and other	5.6	(532)	(251)
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES RELATING TO CONTINUED OPERATIONS		(7,193)	(4,813)
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES RELATING TO DISCONTINUED OPERATIONS		-	(1,282)
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES		(7,193)	(6,095)
Dividends paid ⁽²⁾		(2,522)	(2,659)
Repayment of borrowings and debt		(3,035)	(5,328)
Change in financial assets held for investment and financing purposes		(135)	(289)
Interest paid		(780)	(727)
Interest received on cash and cash equivalents		82	79
Cash flow on derivatives qualifying as net investment hedges and compensation payments on derivatives and on early buyback of borrowings		(114)	(152)
Increase in borrowings		6,622	4,724
Increase/decrease in capital		(1,372)	70
Issue of deeply-subordinated perpetual notes		1,478	989
Purchase and/or sale of treasury stock		-	104
Changes in ownership interests in controlled entities	5.6	(12)	(18)
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES RELATING TO CONTINUED OPERATIONS		212	(3,207)
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES RELATING TO DISCONTINUED OPERATIONS		-	1,279
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES		212	(1,928)
Effects of changes in exchange rates and other relating to continued operations ⁽³⁾		623	(78)
Effects of changes in exchange rates and other relating to discontinued operations		-	(1)
TOTAL CASH FLOW FOR THE PERIOD		1,819	(229)
Reclassification of cash and cash equivalents relating to discontinued operations		-	-
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD		8,700	8,929
CASH AND CASH EQUIVALENTS AT END OF PERIOD		10,519	8,700

(1) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

(2) The line "Dividends paid" includes the coupons paid to owners of the deeply subordinated perpetual notes for an amount of €150 million at December 31, 2019 (€123 million at December 31, 2018).

(3) Of which €619 million of other financial assets deducted from net financial debt reclassified from "Other financial assets" to "Cash and cash equivalents" (see Note 16.1 "Financial assets"), with no impact on net financial debt

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

03 NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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ENGIE SA, the parent company of the Group, is a French *société anonyme* with a Board of Directors that is subject to the provisions of Book II of the French Commercial Code (*Code de Commerce*), as well as to all other provisions of French law applicable to French commercial companies. It was incorporated on November 20, 2004 for a period of 99 years.

It is governed by current and future laws and by regulations applicable to *sociétés anonymes* and its bylaws.

The Group is headquartered at 1 place Samuel de Champlain, 92400 Courbevoie (France).

ENGIE shares are listed on the Paris, Brussels and Luxembourg stock exchanges.

On February 26, 2020, the Group's Board of Directors approved and authorized for issue the consolidated financial statements of the Group for the year ended December 31, 2019.

NOTE 1 ACCOUNTING FRAMEWORK AND BASIS FOR PREPARING THE CONSOLIDATED FINANCIAL STATEMENTS

1.1 Accounting standards

Pursuant to European Regulation (EU) 2019/980 dated March 14, 2019, financial information concerning the assets, liabilities, financial position, and profit and loss of ENGIE has been provided for the last two reporting periods (ended December 31, 2018 and 2019). This information was prepared in accordance with European Regulation (EC) 1606/2002 "on the application of international accounting standards" dated July 19, 2002. The Group's consolidated financial statements for the year ended December 31, 2019 have been prepared in accordance with IFRS Standards as published by the International Accounting Standards Board and endorsed by the European Union ⁽¹⁾.

The accounting standards applied in the consolidated financial statements for the year ended December 31, 2019 are consistent with the policies used to prepare the consolidated financial statements for the year ended December 31, 2018, except for those described in § 1.1.1 below.

1.1.1 IFRS Standards, amendments or IFRIC Interpretations applicable in 2019

1.1.1.1 IFRS 16 – Leases and IFRIC 23 – Uncertainty over Income Tax Treatments

- **IFRS 16 – Leases**

In January 2016, the IASB issued a new standard on leases. IFRS 16 – *Leases* replaces IAS 17 – *Leases* along with its interpretations (IFRIC 4 – *Determining whether an Arrangement contains a Lease*, SIC 15 – *Operating Leases-Incentives* and SIC 27 – *Evaluating the Substance of Transactions Involving the Legal Form of a Lease*).

Under the new standard, on the lessee side, all lease commitments, for which no exemption applies due to the contract's short term and/or the low value of the assets leased, will be recognized on the balance sheet, without distinguishing operating leases from finance leases. Previously, only the latter were recognized in the balance sheet of the lessee. As a result, an amount representing the right-of-use asset during the lease period is recognized as an asset and a debt corresponding to the present value of fixed lease payments as a liability, in the balance sheet. In the income statement, rental expenses previously recognized for operating leases are partially replaced by depreciation of the right-of-use asset and by financial expenses related to the interest on the lease liability. The

(1) Available on the European Commission's website: http://ec.europa.eu/internal_market/accounting/ias/index_en.htm.

presentation of the cash flow statement is also impacted with an improvement in cash flows from operating activities against an increase in cash flows from financing activities.

On the lessor's side, the accounting principles are substantially unchanged compared to IAS 17. Lessors will continue to classify leases either as operating or finance leases using similar principles as under IAS 17. IFRS 16 does not as such have an impact for leases where the Group is the lessor.

The Group adopted IFRS 16 – *Leases* from January 1, 2019, using the modified retrospective approach. Under this method, comparative information is not restated and the cumulative effect of initial application is recognized in equity as an adjustment to opening balance of retained earnings for the current period.

On applying IFRS 16 for the first time, on January 1, 2019, the Group chose to use the following practical expedients permitted by the standard:

- not to reassess whether a contract previously assessed under IAS 17 and IFRIC 4 contains a lease (“the grand-fathering clause”);
- adjust the right-of-use assets by the amount of the provisions for onerous leases recognized in the statement of financial position as at December 31, 2018 (rather than performing an impairment test);
- exclude initial direct costs from the measurement of the right-of-use assets;
- use a single discount rate for a portfolio of leases with reasonably similar characteristics; and
- use hindsight, for example when determining the lease term, if the contract contains options to extend or terminate the lease.

On the other hand, the Group decided not to exclude leases for which the residual lease term ends within 12 months of the transition date.

Assessment of the lease term, including whether a renewal option is reasonably certain to be exercised or a termination option is reasonably certain not to be exercised, was made on a case-by-case basis.

The Group uses the recognition exemptions allowed by the standard, and therefore does not recognize any right-of-use assets and liabilities for leases with a lease term of 12 months or less (“short-term leases”), or for leases for which the underlying asset is of a low value (“low-value asset”).

The Group does not apply the practical expedient allowed by the standard, which permits the application of a portfolio approach for leases with similar characteristics, nor the one which makes it possible not to separate lease and services components.

Lease liabilities were measured at the present value of the remaining lease payments, discounted using the lessee's incremental borrowing rate at January 1, 2019. The weighted average incremental borrowing rate applied to the lease liabilities on January 1, 2019 was 1.43% (see *Note 15 “Property, plant and equipment” for more information on the methodology used to determine the weighted average incremental borrowing rate*).

The impacts on transition of newly recognized assets and liabilities on the consolidated statement of financial position, for leases where the Group acts as lessee, are summarized below:

<i>In millions of euros</i>	Jan. 1, 2019
Right-of-use assets presented in Property, plant and equipment	3,045
Finance leases reclassified under Right-of-use assets	(905)
Other current and non-current assets	(31)
TOTAL ASSETS	2,110
TOTAL EQUITY	(11)
Lease liabilities presented in Short and long term borrowings	2,167
Other current and non-current liabilities	(46)
TOTAL EQUITY AND LIABILITIES	2,110

Newly recognized right-of-use assets mainly concern the following types of assets:

<i>In millions of euros</i>	Jan. 1, 2019
Real estate	1,782
Vehicles	206
Others	153
TOTAL	2,141

For leases previously classified as finance leases, and as required by the standard, the Group did not change the carrying amounts of existing assets and liabilities at the date of initial application (i.e., the right-of-use assets and lease liabilities equal the lease assets and liabilities recognized under IAS 17). These commitments were reclassified as right-of-use assets for a net amount of €905 million, mainly relating to power plants in Latin America.

In the consolidated income statement, the reversal of the rental expenses under leases previously considered as operating leases results in an increase in EBITDA, in depreciation and in financial expenses.

The difference between (i) the commitments relating to operating leases under IAS 17 for which ENGIE acts as lessee, disclosed in the Group's consolidated financial statements at December 31, 2018 (see Note 23.1 "Operating leases – for which ENGIE acts as lessee") with an amount of €2,087 million and (ii) the liability accounted for as a lease liability in accordance with IFRS 16 at January 1, 2019 which amounts to €2,546 million corresponds to (i) leases previously classified as finance leases for €380 million and (ii) the discounting effect for €79 million.

- **IFRIC 23 – Uncertainty over Income Tax Treatments**

IFRIC 23 clarifies the requirements of IAS 12 – *Income Taxes*. What is clarified is how income taxes are recognized and measured where there is an uncertainty regarding the treatment of an item, regarding the determination of taxable profit or loss, the tax bases of assets and liabilities, unused tax losses, unused tax credits and tax rates.

The Group has applied IFRIC 23 – *Uncertainty over Income Tax Treatments* since January 1, 2019, without restating comparative information. This interpretation has no material impact on the Group's consolidated financial statements.

- **Impact of the application of IFRS 16 and IFRIC 23 on the consolidated statement of financial position at January 1, 2019**

Impacts relating to the first-time application of IFRS 16 and IFRIC 23 on the statement of financial position at January 1, 2019 are presented hereunder:

<i>In millions of euros</i>	Dec. 31, 2018 published	IFRS 16 & IFRIC 23	Jan. 1, 2019 with IFRS 16 & IFRIC 23
Non-current assets			
Goodwill	17,809	-	17,809
Intangible assets, net	6,718	(7)	6,711
Property, plant and equipment, net	48,917	2,148	51,065
Other financial assets	6,193	-	6,193
Derivative instruments	2,693	-	2,693
Investments in equity method entities	7,846	-	7,846
Other non-current assets	474	(39)	435
Deferred tax assets	1,066	-	1,066
TOTAL NON-CURRENT ASSETS	91,716	2,102	93,818
Current assets			
Other financial assets	2,290	-	2,290
Derivative instruments	10,679	-	10,679
Trade and other receivables, net	15,613	-	15,613
Assets from contracts with customers	7,411	-	7,411
Inventories	4,158	-	4,158
Other current assets	9,337	(3)	9,334
Cash and cash equivalents	8,700	-	8,700
Assets classified as held for sale	3,798	11	3,809
TOTAL CURRENT ASSETS	61,986	8	61,994
TOTAL ASSETS	153,702	2,110	155,812
Shareholders' equity	35,551	(7)	35,544
Non-controlling interests	5,391	(4)	5,386
TOTAL EQUITY	40,941	(11)	40,930
Non-current liabilities			
Provisions	19,194	-	19,194
Long-term borrowings	26,434	1,777	28,211
Derivative instruments	2,785	-	2,785
Other financial liabilities	46	-	46
Liabilities from contracts with customers	36	-	36
Other non-current liabilities	960	-	960
Deferred tax liabilities	5,415	(4)	5,410
TOTAL NON-CURRENT LIABILITIES	54,869	1,773	56,642
Current liabilities			
Provisions	2,620	(301)	2,318
Short-term borrowings	5,745	389	6,134
Derivative instruments	11,510	-	11,510
Trade and other payables	19,759	-	19,759
Liabilities from contracts with customers	3,598	-	3,598
Other current liabilities	12,529	249	12,778
Liabilities directly associated with assets classified as held for sale	2,130	11	2,141
TOTAL CURRENT LIABILITIES	57,891	348	58,239
TOTAL EQUITY AND LIABILITIES	153,702	2,110	155,812

1.1.1.2 Other IFRS Standards, amendments or IFRIC Interpretations

The other amendments and interpretations applicable as from 2019 have no significant impact on the Group's consolidated financial statements.

- Amendments to IFRS 9 – *Financial Instruments: Prepayment Features with Negative Compensation*.
- Amendments to IAS 28 – *Investments in Associates and Joint Ventures: Long-term Interests in Associates and Joint Ventures*.
- Amendments to IAS 19 – *Employee Benefits: Plan Amendment, Curtailment or Settlement*.

- Annual improvements to IFRSs - 2015-2017 cycle.

1.1.1.3 Other pronouncements

In its agenda decision of March 2019, the IFRS Interpretations Committee (IFRIC) concluded that, due to the characteristics of particular contracts entered into to buy or sell non-financial items, accounted for as derivatives under IFRS 9, and settled by either delivering or taking delivery of the non-financial items, said contracts have to be accounted for on a single line of the consolidated income statement, including their changes in fair value as well as the effects of their physical settlement.

This agenda decision applies to the Group's derivative financial instruments relating to commodities, including gas and electricity, used in economic hedging relationships but which are not qualified as such under IFRS.

The Group's practice was up to now, to present the changes in the fair value (mark-to-market or MtM) of commodity derivatives, not qualified as either trading or hedging instruments under IFRS, below "Current operating income after share in net income of equity method entities". At physical settlement, gains and losses were reclassified in operating income together with the economically hedged item, so that the operating performance of the transactions concerned is recognized at the hedged rate.

Following the IFRIC decision, the Group changed its accounting policy as from the year ended December 31, 2019, with no impact on net income, equity or the current operating income indicator used in the management dialogue and financial communication. The Group therefore now presents unrealized income/(loss) relating to the concerned derivatives, whether it represents a seller or buyer position, on the same line as realized income/(loss) arising from their physical settlement, i.e. under "Purchases and operating derivatives" within the indicator now named "Current operating income including operating MtM and share in net income of equity method entities". Thus:

- MtM on commodity contracts other than trading instruments, previously presented under "Income/(loss) from operating activities", is now included in "Purchases and operating derivatives";
- commodity sale transactions giving rise to physical delivery and used for economic hedging purposes which fall within the scope of IFRS 9, previously presented under "Revenues from other contracts" are now presented as a deduction from the "Purchases" line.

The performance management indicator (COI), which is defined as excluding operating MtM, is now calculated and reconciled to "Current operating income including operation MtM and share in net income of equity method entities" in Note 5 "Financial indicators used in financial communication".

The Group has also decided to improve the presentation by nature of the other items of "Current operating income including operating MtM and share in net income of equity method entities", without impacting the total for this indicator.

The reconciliation between the old and new presentation of the income statement at December 31, 2018 is summarized below:

In millions of euros	Dec. 31, 2018 old presentation	Operating MtM ⁽¹⁾	Commodity sales transactions ⁽²⁾	Taxes ⁽³⁾	Other expenses ⁽⁴⁾	Dec. 31, 2018 new presentation	
Revenues from contracts with customers	56,388	-	(221)	-	-	56,167	Revenues from contracts with customers
Revenues from other contracts	4,208	-	(3,408)	-	-	801	Revenues from other
REVENUES	60,596	-	(3,629)	-	-	56,967	REVENUES
Purchases	(32,190)	(223)	3,629	314	(10,190)	(38,660)	Purchases and operating derivatives
Personnel costs	(10,624)	-	-	-	-	(10,624)	Personnel costs
Depreciation, amortization and provisions	(3,586)	-	-	-	-	(3,586)	Depreciation, amortization and provisions
Taxes	-	-	-	(1,069)	-	(1,069)	Taxes
Other operating expenses	(10,981)	-	-	755	10,226	-	Other operating expenses
Other operating income	1,550	-	-	-	(36)	1,514	Other operating income
CURRENT OPERATING INCOME	4,765	(223)	-	-	-	4,542	Current operating income including operating MtM
Share in net income of entities accounted for using the equity method	361	-	-	-	-	361	Share in net income of equity method entities
CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF ENTITIES ACCOUNTED FOR USING THE EQUITY METHOD	5,126	(223)	-	-	-	4,903	Current operating income including operating MtM and share in net income of equity method entities
Mark-to-market on commodity contracts other than trading instruments	(223)	223	-	-	-	-	
Impairment losses	(1,798)	-	-	-	-	(1,798)	Impairment losses
Restructuring costs	(162)	-	-	-	-	(162)	Restructuring costs
Changes in scope of consolidation	(150)	-	-	-	-	(150)	Changes in scope of consolidation
Other non-recurring items	(147)	-	-	-	-	(147)	Other non-recurring items
INCOME/(LOSS) FROM OPERATING ACTIVITIES	2,645	-	-	-	-	2,645	INCOME/(LOSS) FROM OPERATING ACTIVITIES

- (1) Reclassification under "Purchases" of the unrealized income/(loss) (MtM) on derivatives not qualified as trading.
(2) Reclassification under "Purchases" of the realized income/(loss) on physical commodity contracts not qualified as IFRS 15 contracts.
(3) Accounted for under a single dedicated line for operating tax effects and taxes (excluding social security contributions presented within personnel costs and excluding income tax presented on a dedicated mine).
(4) Reclassification of other operating expenses according to their nature.

Revenues without a change in accounting policy consequent to the IFRIC decision would have stood at €64,137 million at December 31, 2019.

1.1.2 IFRS Standards, amendments or IFRIC Interpretations effective in 2020 and that the Group has elected to early adopt

- Amendments to IFRS 9 – Financial Instruments ; IAS 39 – Financial Instruments: recognition and measurement ; IFRS 7 – Financial Instruments: Disclosures – Interest rate benchmark reform (See Note 17.1.5.2) ⁽¹⁾.

(1) These standards, amendments and interpretations have not yet been adopted by the European Union.

1.1.3 IFRS Standards, amendments or IFRIC Interpretations effective in 2020 and that the Group has elected not to early adopt

- Amendments to IFRS 3 – *Business Combinations: Definition of a Business* ⁽¹⁾.
- Amendments to IAS 1 – *Presentation of Financial Statements* and IAS 8 – *Accounting Policies, Changes in Accounting Estimates and Errors: Definition of Material*.
- IFRS 17 – *Insurance Contracts* ⁽¹⁾.

The impact of these standards and amendments is currently being assessed.

1.2 Measurement and presentation basis

1.2.1 Historical cost convention

The Group's consolidated financial statements are presented in euros and have been prepared using the historical cost convention, except for financial instruments that are accounted for under the financial instrument categories defined by IFRS 9.

1.2.2 Chosen options

1.2.2.1 Reminder of IFRS 1 transition options

The Group used some of the options available under IFRS 1 for its transition to IFRS in 2005. The options that continue to have an impact on the consolidated financial statements are:

- translation adjustments: the Group elected to reclassify cumulative translation adjustments within consolidated equity at January 1, 2004;
- business combinations: the Group elected not to restate business combinations that took place prior to January 1, 2004 in accordance with IFRS 3.

1.2.2.2 Business combinations

Business combinations carried out prior to January 1, 2010 were accounted for in accordance with IFRS 3 prior to the revision. In accordance with IFRS 3 revised, these business combinations have not been restated.

Since January 1, 2010, the Group applies the purchase method as defined in IFRS 3 revised, which consists in recognizing the identifiable assets acquired and liabilities assumed at their fair values at the acquisition date, as well as any non-controlling interests in the acquiree. Non-controlling interests are measured either at fair value or at the entity's proportionate interest in the net identifiable assets of the acquiree. The Group determines on a case-by-case basis which measurement option to be used to recognize non-controlling interests.

1.2.2.3 Consolidated statement of cash flows

The consolidated statement of cash flows is prepared using the indirect method starting from net income.

"Interest received on non-current financial assets" is classified within investing activities because it represents a return on investments. "Interest received on cash and cash equivalents" is shown as a component of financing activities because

(1) These standards, amendments and interpretations have not yet been adopted by the European Union.

the interest can be used to reduce borrowing costs. This classification is consistent with the Group's internal organization, where debt and cash are managed centrally by the Group treasury department.

As impairment losses on current assets are considered to be definitive losses, changes in current assets are presented net of impairment.

Cash flows relating to the payment of income tax are presented on a separate line.

1.2.3 Foreign currency transactions

1.2.3.1 Translation of foreign currency transactions

Foreign currency transactions are recorded in the functional currency at the exchange rate prevailing on the date of the transaction.

Functional currency is the currency of the primary economic environment in which an entity operates, which in most cases corresponds to local currency. However, certain entities may have a functional currency different from the local currency when that other currency is used for an entity's main transactions and better reflects its economic environment.

At each reporting date:

- monetary assets and liabilities denominated in foreign currencies are translated at year-end exchange rates. The resulting translation gains and losses are recorded in the consolidated income statement for the year to which they relate;
- non-monetary assets and liabilities denominated in foreign currencies are recognized at the historical cost applicable at the date of the transaction.

1.2.3.2 Translation of the financial statements of subsidiaries with a functional currency other than the euro (the presentation currency)

The statements of financial position of these subsidiaries are translated into euros at the official year-end exchange rates. Income statement and cash flow statement items are translated using the average exchange rate for the year. Any differences arising from the translation of the financial statements of these subsidiaries are recorded under "Translation adjustments" as other comprehensive income.

Goodwill and fair value adjustments arising on the acquisition of foreign entities are classified as assets and liabilities of those foreign entities and are therefore denominated in the functional currencies of the entities and translated at the year-end exchange rate.

1.2.4 Use of estimates and judgments

1.2.4.1 Estimates

The preparation of consolidated financial statements requires the use of estimates and assumptions to determine the value of assets and liabilities and contingent assets and liabilities at the reporting date, as well as income and expenses reported during the period.

Developments in the economic and financial environment prompted the Group to step up its risk oversight procedures and include an assessment of these risks in measuring financial instruments and performing impairment tests. The Group's estimates used in business plans and determination of discount rates used in impairment tests and for calculating provisions, take into account the environment and the important market volatility.

Accounting estimates are made in a context that remains sensitive to energy market developments, therefore making it difficult to apprehend medium-term economic prospects.

Due to uncertainties inherent in the estimation process, the Group regularly revises its estimates in light of currently available information. Final outcomes could differ from those estimates.

The key estimates used in preparing the Group's consolidated financial statements relate mainly to:

- measurement of the fair value of assets acquired and liabilities assumed in a business combination (see Note 4);
- measurement of revenue not yet metered, so called un-metered revenue (see Note 7);
- measurement of recognized tax loss carry-forwards (see Note 11);
- measurement of the recoverable amount of goodwill (see Note 13), other intangible assets (see Note 14) and property, plant and equipment (see Note 15);
- financial instruments (see Notes 16 and 17);
- measurement of provisions, particularly for back-end of nuclear fuel cycle, dismantling obligations, disputes, pensions and other employee benefits (see Notes 19 and 20).

1.2.4.2 Judgment

As well as relying on estimates, Group management also makes judgments to define the appropriate accounting policies to apply to certain activities and transactions, particularly when the effective IFRS Standards and IFRIC Interpretations do not specifically deal with the related accounting issues.

In particular, the Group exercised its judgment in assessing:

- the type of control (see Note 2);
- the performance obligations of sales contracts (see Note 7);
- how revenue is recognized for distribution or transmission services invoiced to clients (see Note 7);
- the identification of "own use contracts" as defined by IFRS 9 within non-financial purchase and sales contracts (electricity, gas, etc.) (see Note 16);
- the determination of whether arrangements are / or contain a lease (see Notes 15 and 16);
- the regrouping of operating segments for the presentation of reportable segments; and in the context of defining the various Business Lines (see Note 6).

Entities for which judgment on the nature of control has been exercised are listed in Note 2 "Main subsidiaries at December 31, 2019" and Note 3 "Investments in equity method entities".

Accounting standards

Accounting standards are presented in the Notes to which they relate in the form of an insert.

NOTE 2 MAIN SUBSIDIARIES AT DECEMBER 31, 2019

Accounting standards

Controlled entities (subsidiaries) are fully consolidated in accordance with IFRS 10 – *Consolidated Financial Statements*. An investor (the Group) controls an entity and therefore must consolidate it if all of the following three criteria are met:

- it has the ability to direct the relevant activities of the entity;
- it has the rights and is exposed to variable returns from its involvement with the entity;
- it has the ability to use its power over the entity to affect the investor's return.

2.1 List of main subsidiaries at December 31, 2019

The following lists are made available by the Group to third parties, pursuant to Regulation No. 2016-09 of the French accounting standards authority (ANC) issued on December 2, 2016:

- list of companies included in consolidation;
- list of companies excluded from consolidation because their individual and cumulative incidence on the Group's consolidated accounts is not material. They correspond to entities deemed not significant as regards the Group's main key figures (revenues, total equity, etc), shell companies or entities that have ceased all activities and are undergoing liquidation/closure proceedings;
- list of main non-consolidated interests.

This information is available on the Group's website (www.engie.com, Investors/Regulated information section). Non-consolidated companies are classified under non-current financial assets (see Note 16.1.1.1) under "Equity instruments at fair value".

The list of the main subsidiaries consolidated under the full consolidation method presented below was determined, as regards operating entities, based on their contribution to Group revenues, EBITDA, net income and net debt. The main equity-accounted investments (associates and joint ventures) are presented in Note 3 "Investments in equity method entities".

Some entities such as ENGIE SA, ENGIE Energie Services SA or Electrabel SA comprise both operating activities and headquarters functions which report to management teams of different reportable segments. In the following tables, these operating activities and headquarters functions are shown within their respective reportable segments under their initial company name followed by a (*) sign.

France excluding Infrastructures

Company name	Activity	Country	% interest	
			Dec. 31, 2019	Dec. 31, 2018
ENGIE SA *	Energy sales	France	100.0	100.0
ENGIE Energie Services SA *	Energy services/Networks	France	100.0	100.0
Axima Concept	Systems, facilities and maintenance	France	100.0	100.0
Endel Group	Systems, facilities and maintenance	France	100.0	100.0
INEO Group	Systems, facilities and maintenance	France	100.0	100.0
Compagnie Nationale du Rhône	Electricity distribution and generation	France	49.9	49.9
ENGIE Green	Electricity distribution and generation	France	100.0	100.0
CPCU	Urban heating networks	France	66.5	66.5

France Infrastructures

Company name	Activity	Country	% interest	
			Dec. 31, 2019	Dec. 31, 2018
GRDF	Natural gas distribution	France	100.0	100.0
GRTgaz Group (excluding Elengy)	Natural gas transportation	France, Germany	74.6	74.6
Elengy	LNG terminals	France	74.6	74.6
Fosmax LNG	LNG terminals	France	54.1	54.1
Storengy France	Underground natural gas storage	France	100.0	100.0
Storengy Deutschland GmbH	Underground natural gas storage	Germany	100.0	100.0

Rest of Europe

Company name	Activity	Country	% interest	
			Dec. 31, 2019	Dec. 31, 2018
ENGIE Thermique France	Electricity generation	France	100.0	100.0
Electrabel SA *	Electricity generation, Energy sales	Belgium	100.0	100.0
Synatom	Managing provisions relating to power plants and nuclear fuel	Belgium	100.0	100.0
Cofely Fabricom SA	Systems, facilities and maintenance	Belgium	100.0	100.0
ENGIE Energie Nederland N.V. *	Electricity generation, Energy sales	Netherlands	100.0	100.0
ENGIE Services Nederland N.V.	Energy services	Netherlands	100.0	100.0
ENGIE Energielösungen GmbH	Energy services	Germany	-	100.0
ENGIE Deutschland GmbH	Energy services	Germany	100.0	100.0
ENGIE Deutschland AG *	Electricity generation	Germany	100.0	100.0
ENGIE Kraftwerk Wilhelmshaven GmbH & Co.	Electricity generation	Germany	-	57.0
ENGIE Supply Holding UK Limited	Energy sales	United Kingdom	100.0	100.0
ENGIE Retail Investment UK Limited	Holding	United Kingdom	100.0	100.0
First Hydro Holdings Company	Electricity generation	United Kingdom	75.0	75.0
Keepmoat Regeneration	Energy services	United Kingdom	100.0	100.0
ENGIE Services Holding UK Ltd	Energy services	United Kingdom	100.0	100.0
ENGIE Services Limited	Energy services	United Kingdom	100.0	100.0
ENGIE Cartagena	Electricity generation	Spain	100.0	100.0
ENGIE Italia S.p.A *	Energy sales	Italy	100.0	100.0
Engie Servizi S.p.A	Energy services	Italy	100.0	100.0
ENGIE Romania	Natural gas distribution, Energy sales	Romania	51.0	51.0

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 2 MAIN SUBSIDIARIES AT DECEMBER 31, 2019

Latin America

Company name	Activity	Country	% interest	
			Dec. 31, 2019	Dec. 31, 2018
ENGIE Energía Chile Group	Electricity distribution and generation	Chile	52.8	52.8
ENGIE Energía Perú	Electricity distribution and generation	Peru	61.8	61.8
ENGIE Brasil Energia Group	Electricity distribution and generation	Brazil	68.7	68.7

USA & Canada

Company name	Activity	Country	% interest	
			Dec. 31, 2019	Dec. 31, 2018
ENGIE North America	Electricity distribution and generation, Natural gas, LNG, Energy services	United States	100.0	100.0
ENGIE Holding Inc.	Holding - parent company	United States	100.0	100.0
ENGIE Infinity Renewables	Electricity distribution and generation	United States	100.0	100.0
SoCore Energy LLC	Development and installation of photovoltaic panels	United States	100.0	100.0
ENGIE Resources Inc.	Energy sales	United States	100.0	100.0
Engie Insight Service	Energy services	United States	100.0	100.0

Middle East, Asia & Africa

Company name	Activity	Country	% interest	
			Dec. 31, 2019	Dec. 31, 2018
Glow Group ⁽¹⁾	Electricity distribution and generation	Thailand	-	69.1
UCH Power Limited	Electricity generation	Pakistan	100.0	100.0
Simply Energy	Energy sales	Australia	72.0	72.0
Baymina Enerji A.S.	Electricity generation	Turkey	95.0	95.0

(1) The disposal of Glow Group was finalized on March 14, 2019 (see Note 4 "Main changes in Group structure").

Others

Company name	Activity	Country	% interest	
			Dec. 31, 2019	Dec. 31, 2018
ENGIE SA *	Holding - parent company, Energy management trading, Energy sales, LNG	France	100.0	100.0
ENGIE Energie Services SA *	Holding	France	100.0	100.0
ENGIE FINANCE SA	Financial subsidiaries	France	100.0	100.0
ENGIE Solar	Solar EPC	France	100.0	100.0
Gaztransport & Technigaz (GTT)	Engineering	France	40.4	40.4
Electrabel SA *	Holding, Electricity generation, Energy management trading	France/Belgium	100.0	100.0
ENGIE Global Markets	Energy management trading	France, Belgium, Singapore	100.0	100.0
ENGIE Energy Management *	Energy management trading	France, Belgium, Italy, United Kingdom	100.0	100.0
ENGIE CC	Financial subsidiaries, Central functions	Belgium	100.0	100.0
Tractebel Engineering	Engineering	Belgium	100.0	100.0
International Power Limited	Holding	United Kingdom	100.0	100.0
ENGIE Energy Management Holding Switzerland AG	Holding	Switzerland	100.0	100.0

2.2 Significant judgments exercised when assessing control

The Group primarily considers the following information and criteria when determining whether it has control over an entity:

- governance arrangements: voting rights and whether the Group is represented in the governing bodies, majority rules and veto rights;
- the nature of substantive or protective rights granted to shareholders, relating to the entity's relevant activities;
- deadlock resolution mechanisms;
- whether the Group is exposed, or has rights, to variable returns from its involvement with the entity.

The Group exercised its judgment regarding the entities and sub-groups described below.

Entities in which the Group has the majority of the voting rights

GRTgaz (France Infrastructures): 74.6%

In addition to the analysis of the shareholder agreement with Société d'Infrastructures Gazières, a subsidiary of *Caisse des Dépôts et Consignations* (CDC), which owns 24.8% of the share capital of GRTgaz, the Group also assessed the rights granted to the French Energy Regulatory Commission (*Commission de régulation de l'énergie* – CRE). As a regulated activity, GRTgaz has a dominant position on the gas transportation market in France. Accordingly, since the transposition of the Third European Directive of July 13, 2009 into French law (Code de l'énergie -Energy Code) of May 9, 2011, GRTgaz has been subject to independence rules as concerns its directors and senior management team. The French Energy Code confers certain powers on the CRE in the context of its duties to control the proper functioning of the gas markets in France, including verifying the independence of the members of the Board of Directors and senior management and assessing the choice of investments. The Group considers that it exercises control over GRTgaz and its subsidiaries (including Elengy) in view of its current ability to appoint the majority of the members of the Board of Directors and take decisions about the relevant activities, especially in terms of the level of investment and planned financing.

Entities in which the Group does not have the majority of the voting rights

In the entities in which the Group does not have a majority of the voting rights, judgment is exercised with regard to the following items, in order to assess whether there is a situation of *de facto* control:

- dispersion of the shareholding structure: number of voting rights held by the Group relative to the number of rights held respectively by the other vote holders and their dispersion;
- voting patterns at shareholders' meetings: the percentages of voting rights exercised by the Group at shareholders' meetings in recent years;
- governance arrangements: representation in the governing body with strategic and operational decision-making power over the relevant activities;
- rules for appointing key management personnel;
- contractual relationships and material transactions.

The main fully consolidated entities in which the Group does not have the majority of the voting rights are Compagnie Nationale du Rhône (49.98%) and Gaztransport & Technigaz (40.4%).

Compagnie Nationale du Rhône ("CNR" – France excluding Infrastructures): 49.98%

The Group holds 49.98% of the share capital of CNR, with CDC holding 33.2%, and the balance (16.82%) being dispersed among around 200 local authorities. In view of the current provisions of the French "Murcef" law, under which a majority of CNR's share capital must remain under public ownership, the Group is unable to hold more than 50% of the share capital. However, the Group considers that it exercises *de facto* control as it holds the majority of the voting rights exercised at shareholders' meetings due to the widely dispersed shareholding structure and the absence of evidence of the minority shareholders acting in concert.

Gaztransport & Technigaz (“GTT” – Others): 40.4%

Since GTT's initial public offering in February 2014, ENGIE has been the largest shareholder in the company with a 40.4% stake, the free float representing around 49% of the share capital. The Group holds the majority of the voting rights exercised at shareholders' meetings in view of the widely dispersed shareholding structure and the absence of evidence of minority shareholders acting in concert. ENGIE also holds the majority of the seats on the Board of Directors. The Group considers that it exercises *de facto* control over GTT, based on an IFRS 10 criteria.

2.3 Subsidiaries with material non-controlling interests

The following table shows the non-controlling interests in Group entities that are deemed to be material, the respective contributions to equity and net income at December 31, 2019 and December 31, 2018, as well as the dividends paid to non-controlling interests of these significant subsidiaries:

Corporate name	Activity	Percentage interest of non-controlling interests		Net income/(loss) of non-controlling interests		Equity of non-controlling interests		Dividends paid to non-controlling interests	
		Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾	Dec. 31, 2019	Dec. 31, 2018
In millions of euros									
GRTgaz Group (France Infrastructures, France)	Regulated gas transportation activities and management of LNG terminals	25.4	25.4	89	99	1,076	1,133	120	158
ENGIE Energía Chile Group (Latin America, Chile) ⁽²⁾	Electricity distribution and generation - thermal power plants	47.2	47.2	54	49	926	913	52	25
Glow Group (Middle East, Asia & Africa, Thailand) ⁽²⁾	Electricity distribution and generation - hydroelectric, wind and thermal power plants	-	30.9	32	96	-	512	-	75
ENGIE România Group (Rest of Europe, Romania)	Distribution of natural gas, Energy sales	49.0	49.0	47	43	533	512	14	18
ENGIE Brasil Energia Group (Latin America, Brazil) ⁽²⁾	Electricity distribution and generation	31.3	31.3	177	170	520	473	94	206
ENGIE Energía Perú (Latin America, Peru) ⁽²⁾	Electricity distribution and generation - thermal and hydroelectric power plants	38.2	38.2	36	34	393	376	22	11
Gaztransport & Technigaz (Other, France) ⁽²⁾	Naval engineering, cryogenic membrane containment systems for LNG transportation	59.6	59.6	75	63	343	339	73	59
Other subsidiaries with non-controlling interests				154	41	1,159	1,131	78	331
TOTAL				664	595	4,950	5,391	453	882

(1) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 (see Note 1 “Accounting framework and basis for preparing the consolidated financial statements”).

(2) Engie Energía Chile, Engie Brasil Energia, Gaztransport & Technigaz and Engie Energía Perú are listed in their respective countries.

(3) The disposal of Glow Group was finalized on March 14, 2019 (see Note 4 “Main changes in Group structure”).

2.3.1 Condensed financial information on subsidiaries with material non-controlling interests

The condensed financial information concerning these subsidiaries presented in the table below is based on a 100% interest and is shown before intragroup eliminations.

	GRTgaz Group		ENGIE Energía Chile Group		Glow Group ⁽¹⁾		ENGIE Romania Group	
<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018
Income statement								
Revenues	2,275	2,298	1,180	1,028	255	1,354	1,436	1,231
Net income/(loss)	325	389	103	94	93	262	95	87
Net income/(loss) Group share	236	283	49	45	61	165	49	44
Other comprehensive income/(loss) – Owners of the parent	(77)	(13)	9	49	(162)	41	(13)	(3)
TOTAL COMPREHENSIVE INCOME/(LOSS) – OWNERS OF THE PARENT	159	270	59	94	(101)	206	36	41
Statement of financial position								
Current assets	689	918	546	364	-	3,278	613	626
Non-current assets	10,403	10,404	2,707	2,700	-	(257)	809	787
Current liabilities	(1,016)	(921)	(322)	(271)	-	(950)	(277)	(312)
Non-current liabilities	(6,097)	(6,198)	(1,025)	(910)	-	(835)	(65)	(64)
TOTAL EQUITY	3,979	4,204	1,907	1,882	-	1,237	1,080	1,037
TOTAL NON-CONTROLLING INTERESTS	1,076	1,133	926	913	-	512	533	512
Statement of cash flows								
Cash flow from operating activities	967	1,213	467	249	93	421	71	109
Cash flow from (used in) investing activities	(495)	(493)	(144)	(248)	(93)	(132)	(77)	(58)
Cash flow from (used in) financing activities	(480)	(740)	(171)	(15)	(14)	(534)	(34)	(54)
TOTAL CASH FLOW FOR THE PERIOD ⁽²⁾	(8)	(20)	152	(14)	(14)	(245)	(40)	(3)

(1) The disposal of Glow Group was finalized on March 14, 2019 (see Note 4 “Main changes in Group structure”).

(2) Excluding effects of changes in exchange rates and other.

	ENGIE Brasil Energia Group		ENGIE Energía Perú		Gaztransport & Technigaz	
<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018
Income statement						
Revenues	2,207	2,017	479	427	289	246
Net income/(loss)	623	544	94	88	126	106
Net income/(loss) Group share	446	374	58	55	51	43
Other comprehensive income/(loss) – Owners of the parent	(93)	(119)	12	27	(1)	-
TOTAL COMPREHENSIVE INCOME/(LOSS) – OWNERS OF THE PARENT	353	255	70	81	51	43
Statement of financial position						
Current assets	1,533	1,045	295	255	343	319
Non-current assets	5,792	4,232	1,714	1,728	452	491
Current liabilities	(1,345)	(907)	(177)	(174)	(174)	(166)
Non-current liabilities	(3,757)	(2,983)	(802)	(824)	(46)	(74)
TOTAL EQUITY	2,224	1,388	1,029	985	575	570
TOTAL NON-CONTROLLING INTERESTS	520	473	393	376	343	339
Statement of cash flows						
Cash flow from operating activities	1,045	875	237	195	139	168
Cash flow from (used in) investing activities	(1,136)	(851)	(22)	(19)	(10)	(9)
Cash flow from (used in) financing activities	436	89	(199)	(144)	(122)	(94)
TOTAL CASH FLOW FOR THE PERIOD ⁽²⁾	345	113	16	33	7	66

(1) Excluding effects of changes in exchange rates and other.

NOTE 3 INVESTMENTS IN EQUITY METHOD ENTITIES

Accounting standards

The Group accounts for its investments in associates (entities over which the Group has significant influence) and joint ventures using the equity method. Under IFRS 11 – *Joint Arrangements*, a joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement.

The respective contributions of associates and joint ventures in the statement of financial position, the income statement and the statement of comprehensive income at December 31, 2019 and December 31, 2018 are as follows:

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018
Statement of financial position		
Investments in associates	4,646	4,590
Investments in joint ventures	4,570	3,256
INVESTMENTS IN EQUITY METHOD ENTITIES	9,216	7,846
Income statement		
Share in net income/(loss) of associates	255	88
Share in net income/(loss) of joint ventures	245	273
SHARE IN NET INCOME/(LOSS) OF EQUITY METHOD ENTITIES	500	361
Statement of comprehensive income		
Share of associates in "Other comprehensive income/(loss)"	(123)	132
Share of joint ventures in "Other comprehensive income/(loss)"	(158)	26
SHARE OF EQUITY METHOD ENTITIES IN "OTHER COMPREHENSIVE INCOME/(LOSS)"	(281)	158

Significant judgments

The Group primarily considers the following information and criteria in determining whether it has joint control or significant influence over an entity:

- governance arrangements: whether the Group is represented in the governing bodies, majority rules and veto rights;
- the nature of substantive or protective rights granted to shareholders, relating to the entity's relevant activities. This can be difficult to determine in the case of "project management" or "one-asset" entities, as certain decisions concerning the relevant activities are made upon the creation of the joint arrangement and remain valid throughout the project. Accordingly, the rights' analysis relates to the relevant residual activities of the entity (those that significantly affect the variable returns of the entity);
- deadlock resolution mechanisms;
- whether the Group is exposed, or has rights, to variable returns from its involvement with the entity. This can also involve analyzing the Group's contractual relations with the entity, in particular the conditions in which these contracts are entered into, their duration as well as the management of conflicts of interest that may arise when the entity's governing body casts votes.

The Group exercised its judgment regarding the following entities and sub-groups:

Project management entities in the Middle East

The significant judgments made in determining the consolidation method to be applied to these project management entities related to the risks and rewards relating to contracts between ENGIE and the entity concerned, as well as an analysis of the residual relevant activities over which the entity retains control after its creation. The Group considers that it has significant influence or joint control over these entities, since the decisions taken throughout the term of the project about the relevant activities such as refinancing, or the renewal or amendment of significant contracts (sales, purchases, operating and maintenance services) require, depending on the case, the unanimous consent of two or more parties sharing control.

SUEZ Group (32.06%)

Since the SUEZ shareholders' agreement expired on July 22, 2013, ENGIE no longer controls SUEZ but exercises significant influence over the SUEZ group. In particular, this is because: (i) the Group does not have a majority of members on SUEZ's Board of Directors, (ii) at Shareholders' Meetings, although SUEZ's shareholder base is fragmented and ENGIE holds a large interest, past voting shows that ENGIE alone did not have the majority at Ordinary and Extraordinary Shareholders' Meetings between 2010 and 2019.

Transportadora Asociada de Gas S.A. ("TAG" - Latin America): 58.5% holding interest (directly and indirectly) representing a net interest in of 49.3%

The Group exercises joint control over TAG (*see Note 4.3.1*).

Joint ventures in which the Group holds an interest of more than 50%

Tihama (60%)

ENGIE holds a 60% stake in the Tihama cogeneration plant in Saudi Arabia and its partner Saudi Oger holds 40%. The Group considers that it has joint control over Tihama since the decisions about its relevant activities, including for example the preparation of the budget and amendments to major contracts, etc., require the unanimous consent of the parties sharing control.

Joint control – difference between joint ventures and joint operations

Classifying a joint arrangement requires the Group to use its judgment to determine whether the entity in question is a joint venture or a joint operation. IFRS 11 requires an analysis of "other facts and circumstances" when determining the classification of jointly controlled entities.

The IFRS Interpretations Committee (IFRS IC) (November 2014) decided that for an entity to be classified as a joint operation, other facts and circumstances must give rise to direct enforceable rights to the assets, and obligations for the liabilities, of the joint arrangement.

In view of this position and its application to our analyses, the Group has no material joint operations at December 31, 2019.

3.1 Investments in associates

3.1.1 Contribution of material associates and of associates that are not material to the Group taken individually

The table hereafter shows the contribution of each material associate along with the aggregate contribution of associates deemed not material taken individually, in the consolidated statement of financial position, income statement, statement of comprehensive income, and the "Dividends received from equity method entities" line of the statement of cash flows.

NOTE 3 INVESTMENTS IN EQUITY METHOD ENTITIES

The Group used qualitative and quantitative criteria to determine material associates. These criteria include the contribution to the consolidated line items “Share in net income/(loss) of associates” and “Investments in associates”, the total assets of associates in Group share, and associates carrying major projects in the study or construction phase for which the related investment commitments are material.

Corporate name	Activity	Capacity	Percentage interest of investments in associates		Carrying amount of investments in associates		Share in net income/(loss) of associates		Other comprehensive income/(loss) of associates		Dividends received from associates	
			Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018
In millions of euros												
SUEZ Group (Other)	Water and waste processing		32.06	32.06	1,953	1,968	113	55	(37)	21	129	130
Project management entities in the Middle East (Middle-East, Asia & Africa, Saudi Arabia, Bahrain, Qatar, United Arab Emirates, Oman, Kuwait) ⁽¹⁾	Gas-fired power plants and seawater desalination facilities				950	1,004	79	97	(96)	96	77	97
Energia Sustentável Do Brasil (Latin America, Brazil)	Hydro power plant	3 750 MW	40.00	40.00	659	646	(49)	(57)	-	-	-	-
GASAG (Rest of Europe, Germany)	Gas and heat networks		31.57	31.57	233	261	16	18	(17)	1	9	4
Other investments in associates that are not material taken individually					852	710	96	(25)	27	14	61	104
INVESTMENTS IN ASSOCIATES					4,646	4,590	255	88	(123)	132	277	334

(1) Investments in associates operating gas-fired power plants and seawater desalination facilities in the Arabian Peninsula have been grouped together under “Project management entities in the Middle East”. This includes around 40 associates operating thermal power plants with a total installed capacity of 27,632 MW (at 100%) and a further 1,507 MW (at 100%) in capacity under construction. These associates have fairly similar business models and joint arrangements: the project management entities selected as a result of a competitive bidding process develop, build and operate power generation plants and seawater desalination facilities. The entire output of these facilities is sold to government-owned companies under power and water purchase agreements, over periods generally spanning 20 to 30 years.

In accordance with their contractual arrangements, the corresponding plants are recognized as property, plant and equipment or as financial receivables whenever substantially all of the risks and rewards associated with the assets are transferred to the buyer of the output. This treatment complies with IFRIC 4 and IFRS 16. The shareholding structure of these entities systematically includes a government-owned company based in the same country as the project management entity. The Group's percentage interest and percentage voting rights in each of these entities varies between 20% and 50%.

The share in net income/(loss) of associates includes a net non-recurring loss for a total amount of €79 million in 2019 (compared to a net non-recurring loss of €155 million in 2018), mainly including changes in the fair value of derivative instruments and disposal gains and losses, net of tax (see Note 5.3 “Net recurring income Group share”).

3.1.2 Financial information regarding material associates

The tables below provide condensed financial information for the Group's main associates. The amounts shown have been determined in accordance with IFRS, before the elimination of intragroup items and after (i) adjustments made in line with Group accounting policies and (ii) fair value measurements of the assets and liabilities of the associate performed at the date of acquisition at the level of ENGIE, as required by IAS 28. All amounts are presented based on a 100% interest with the exception of "Total equity attributable to ENGIE".

In millions of euros	Revenues	Net income/(loss)	Other comprehensive income/(loss)	Total comprehensive income/(loss)	Current assets	Non-current assets	Current liabilities	Non-current liabilities	Total equity	% interest of Group	Total equity attributable to ENGIE
AT DECEMBER 31, 2019											
SUEZ Group ⁽¹⁾	18,015	352	(58)	294	11,481	24,153	12,098	14,248	9,288	32.06	1,953
Project management entities in the Middle East	3,778	390	(409)	(19)	2,851	21,053	3,543	16,644	3,717	-	950
Energia Sustentável Do Brasil	578	(123)	-	(123)	204	4,137	304	2,388	1,648	40.00	659
GASAG	1,251	51	(54)	(2)	850	1,847	1,757	203	736	31.57	233
AT DECEMBER 31, 2018											
SUEZ Group ⁽¹⁾	17,331	335	(103)	232	10,872	22,681	11,664	12,896	8,993	32.06	1,968
Project management entities in the Middle East	4,254	467	406	873	2,572	21,401	3,775	16,263	3,934	-	1,004
Energia Sustentável Do Brasil	564	(142)	-	(142)	199	4,388	544	2,428	1,615	40.00	646
GASAG	1,196	56	3	59	798	1,733	1,508	196	827	31.57	261

(1) The data indicated in the table for SUEZ correspond to financial information published by SUEZ. Total SUEZ equity attributable to the Group amounts to €6,463 million based on the published financial statements of SUEZ and €6,092 million based on the financial statements of ENGIE. The difference in these amounts mainly reflects the non-inclusion of the share in deeply-subordinated perpetual notes issued by SUEZ in total equity attributable to ENGIE, partly offset by the fair value measurement of the assets and liabilities of SUEZ at the date the Group changed its consolidation method (July 22, 2013).

SUEZ is the only material listed associate. Based on the closing share price at December 31, 2019, the market value of this interest was €2,686 million.

3.1.3 Transactions between the Group and its associates

The data below set out the impact of transactions with associates on the Group's 2019 consolidated financial statements.

In millions of euros	Purchases of goods and services	Sales of goods and services	Net financial income (excluding dividends)	Trade and other receivables	Loans and receivables at amortized cost	Trade and other payables	Borrowings and debt
Project management entities in the Middle East	-	254	-	36	130	2	-
Contassur ⁽¹⁾	-	-	-	160	2	-	-
Energia Sustentável Do Brasil	140	-	-	-	29	10	-
Other	65	35	28	14	264	10	760
AT DECEMBER 31, 2018	205	289	28	211	426	21	760

(1) Contassur is a life insurance company accounted for using the equity method. Contassur offers insurance contracts, chiefly with pension funds that cover post-employment benefit obligations for Group employees and also employees of other companies mainly engaged in regulated activities in the electricity and gas sector in Belgium. Insurance contracts entered into by Contassur represent reimbursement rights recorded within "Other assets" in the statement of financial position. These reimbursement rights totaled €161 million at December 31, 2019 (€168 million at December 31, 2018).

3.2 Investments in joint ventures

3.2.1 Contribution of material joint ventures and of joint ventures that are not material to the Group taken individually

The table below shows the contribution of each material joint venture along with the aggregate contribution of joint ventures deemed not material taken individually to the consolidated statement of financial position, income statement, statement of comprehensive income, and the "Dividends received from entities accounted for using the equity method" line of the statement of cash flows.

The Group used qualitative and quantitative criteria to determine material joint ventures. These criteria include the contribution to the line items "Share in net income/(loss) of joint ventures" and "Investments in joint ventures", the Group's share in total assets of joint ventures, and joint ventures conducting major projects in the study or construction phase for which the related investment commitments are material.

Corporate name	Activity	Capacity	Percentage interest of investments in joint ventures		Carrying amount of investments in joint ventures		Share in net income/(loss) of joint ventures		Other comprehensive income/(loss) of joint ventures		Dividends received from joint ventures	
			Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018
In millions of euros												
Transportadora Associada de Gás S.A. (TAG) (Latin America, Brazil)	Gas transmission network		58.50	-	1,364	-	44	-	(71)	-	159	-
National Central Cooling Company "Tabreed" (Middle-East, Asia & Africa, Abu Dhabi)	District cooling networks		40.00	40.00	740	710	42	40	-	-	24	39
EcoEléctrica (USA & Canada, Puerto Rico)	Combined-cycle gas-fired power plant and LNG terminal	507 MW	50.00	50.00	395	416	25	34	-	-	59	104
Portfolio of power generation assets in Portugal (Rest of Europe, Portugal)	Electricity generation	2 909 MW	50.00	50.00	312	325	39	44	(2)	1	50	49
WSW Energie und Wasser AG (Rest of Europe, Germany)	Electricity distribution and generation	142 MW	33.10	33.10	207	204	(4)	11	-	-	4	3
Tihama Power Generation Co (Middle-East, Asia & Africa, Saudi Arabia)	Electricity generation	1 599 MW	60.00	60.00	108	163	32	34	(5)	1	86	-
Ohio State Energy Partners (USA & Canada, Unites States)	Services		50.00	50.00	114	129	2	5	(10)	5	9	4
Megal GmbH (France Infrastructures, Germany)	Gas transmission network		49.00	49.00	79	91	2	6	-	-	14	13
Transmisora Eléctrica del Norte (Latin America, Chile)	Electricity transmission line		50.00	50.00	80	85	7	7	(10)	8	-	-
Other investments in joint ventures that are not material taken individually					1,171	1,134	55	92	(61)	11	35	31
INVESTMENTS IN JOINT VENTURES					4,570	3,256	245	273	(158)	26	439	244

The share in net income/(loss) of joint ventures includes non-recurring loss of €14 million in 2019 (non-recurring income of €6 million in 2018), resulting chiefly from changes in the fair value of derivatives, impairment losses and disposal gains and losses, net of tax (see Note 5.3 "Net recurring income Group share").

3.2.2 Financial information regarding material joint ventures

The amounts shown have been determined in accordance with IFRS before the elimination of intragroup items and after (i) adjustments made in line with Group accounting policies and (ii) fair value measurements of the assets and liabilities of the joint venture performed at the date of acquisition at the level of ENGIE, as required by IAS 28. All amounts are presented based on a 100% interest with the exception of "Total equity attributable to ENGIE" in the statement of financial position.

Information on the income statement and statement of comprehensive income

<i>In millions of euros</i>	Revenues	Depreciation and amortization on intangible assets and property, plant and equipment	Net financial income/(loss)	Income tax expense	Net income/(loss)	Other comprehensive income/(loss)	Total comprehensive income/(loss)
AT DECEMBER 31, 2019							
Transportadora Asociada de Gás S.A.	655	(191)	(191)	(52)	88	(121)	(34)
National Central Cooling Company "Tabreed"	370	(41)	(44)	-	105	-	105
EcoElectrica	308	(69)	-	(2)	50	-	50
Portfolio of power generation assets in Portugal	426	(67)	(29)	(36)	93	(7)	86
WSW Energie und Wasser AG	729	(12)	(2)	6	(11)	-	(11)
Tihama Power Generation Co	42	(5)	(23)	(8)	54	(8)	46
Ohio State Energy Partners	121	-	(44)	-	4	(20)	(15)
Megal GmbH	123	(69)	(4)	3	4	-	4
Transmisora Eléctrica del Norte	76	-	(30)	(5)	15	(21)	(6)
AT DECEMBER 31, 2018							
Transportadora Asociada de Gás S.A.	-	-	-	-	-	-	-
National Central Cooling Company "Tabreed"	335	(34)	(37)	-	100	-	100
EcoElectrica	280	(63)	2	(3)	68	-	68
Portfolio of power generation assets in Portugal	749	(65)	(31)	(37)	106	3	109
WSW Energie und Wasser AG	856	(11)	(3)	(19)	35	-	35
Tihama Power Generation Co	111	(5)	(24)	(8)	56	1	57
Ohio State Energy Partners	52	-	(33)	-	10	11	21
Megal GmbH	124	(63)	(4)	2	12	-	12
Transmisora Eléctrica del Norte	75	-	(33)	(5)	14	16	30

Information on the statement of financial position

<i>In millions of euros</i>	Cash and cash equivalents	Other current assets	Non-current assets	Short-term borrowings	Other current liabilities	Long-term borrowings	Other non-current liabilities	Total equity	% interest of Group	Total equity attributable to ENGIE
AT DECEMBER 31, 2019										
Transportadora Asociada de Gás S.A.	88	329	7,844	595	88	4,618	829	2,331	58.50	1,364
National Central Cooling Company "Tabreed"	-	143	2,871	13	184	785	-	1,851	40.00	740
EcoEléctrica	34	97	701	(7)	29	-	21	789	50.00	395
Portfolio of power generation assets in Portugal	232	635	1,039	178	139	770	92	728	50.00	312
WSW Energie und Wasser AG	19	59	805	37	54	94	92	806	33.10	207
Tihama Power Generation Co	58	124	432	89	26	325	13	179	80.00	108
Ohio State Energy Partners	19	1,055	89	343	25	522	43	229	50.00	114
Megal GmbH	8	2	729	210	41	262	82	182	49.00	79
Transmisora Eléctrica del Norte	43	34	774	42	4	845	-	180	50.00	80
AT DECEMBER 31, 2018										
National Central Cooling Company "Tabreed"	85	124	2,574	-	173	818	-	1,775	40.00	710
EcoEléctrica	24	107	755	3	27	-	23	833	50.00	418
Portfolio of power generation assets in Portugal	231	588	1,305	287	178	763	115	781	50.00	325
WSW Energie und Wasser AG	12	148	778	55	84	101	103	596	33.10	204
WSW Energie und Wasser AG	129	140	488	81	40	370	15	271	80.00	183
Tihama Power Generation Co	16	8	1,039	(8)	7	804	-	257	50.00	129
Megal GmbH	-	13	752	10	55	448	70	185	49.00	91
Transmisora Eléctrica del Norte	88	30	773	75	3	821	-	170	50.00	85

3.2.3 Transactions between the Group and its joint ventures

The data below set out the impact of transactions with joint ventures on the Group's 2019 consolidated financial statements.

<i>In millions of euros</i>	Purchases of goods and services	Sales of goods and services	Net financial income (excluding dividends)	Trade and other receivables	Loans and receivables at amortized cost	Trade and other payables	Borrowings and debt
EcoEléctrica	-	147	-	18	-	-	-
Portfolio of power generation assets in Portugal	-	-	-	1	128	-	-
WSW Energie und Wasser AG	-	23	-	1	-	1	-
Megal GmbH	65	-	-	-	51	-	-
Futures Energies Investissements Holding	3	19	3	2	207	-	-
Other	(40)	89	8	27	200	6	5
AT DECEMBER 31, 2019	28	278	11	49	585	7	5

3.3 Other information on investments accounted for using the equity method

3.3.1 Unrecognized share of losses of associates and joint ventures

Cumulative unrecognized losses of associates (corresponding to the cumulative amount of losses exceeding the carrying amount of investments in the associates concerned) including other comprehensive income/(loss), amounted to €113 million in 2019 (€171 million in 2018). This decrease resulted from (i) unrecognized income relating to fiscal year 2019 amounting to €89 million and (ii) changes in other comprehensive income.

These unrecognized losses correspond to the negative fair value of derivative instruments designated as interest rate and commodity hedges ("Other comprehensive income/(loss)") contracted by associates in the Middle-East, Africa & Asia reportable segment in connection with the financing of construction projects for power generation plants.

3.3.2 Commitments and guarantees given by the Group in respect of equity method entities

At December 31, 2019, the main commitments and guarantees given by the Group in respect of equity method entities concern:

- Energia Sustentável do Brasil ("Jirau"), for an aggregate amount of BRL 4,210 million (€930 million).
At December 31, 2019, the amount of loans granted by Banco Nacional de Desenvolvimento Econômico e Social, the Brazilian Development Bank, to Energia Sustentável do Brasil amounted to BRL 10,525 million (€2,325 million). Each partner stands as guarantor for this debt to the extent of its ownership interest in the consortium;
- TAG for performance bonds and other guarantees for an amount of €176 million;
- The project management entities in the Middle East and Africa, for an aggregate amount of €917 million.

Commitments and guarantees given by the Group in respect of these project management entities chiefly correspond to:

- an equity contribution commitment (capital/subordinated debt) for €101 million. These commitments only concern entities acting as holding companies for projects in the construction phase,
- letters of credit to guarantee debt service reserve accounts for an aggregate amount of €200 million. The project financing set up in certain entities can require those entities to maintain a certain level of cash within the company (usually enough to service its debt for six months). This is particularly the case when the financing is without recourse. This level of cash may be replaced by letters of credit,
- collateral given to lenders in the form of pledged shares in the project management entities, for an aggregate amount of €266 million,
- performance bonds and other guarantees for an amount of €350 million.

NOTE 4 MAIN CHANGES IN GROUP STRUCTURE

Accounting standards

In accordance with IFRS 5 - *Non-Current Assets Held for Sale and Discontinued Operations*, assets or groups of assets held for sale are presented separately on the face of the statement of financial position and are measured and accounted for at the lower of their carrying amount and fair value less costs to sell.

An asset is classified as “held for sale” when its sale is highly probable within twelve months from the date of classification, when it is available for immediate sale under its present condition and when the management is committed to a plan to sell the asset and an active program to locate a buyer and complete the plan has been initiated. To assess whether a sale is highly probable, the Group takes into consideration among other things indications of interest and offers received from potential buyers as well as specific execution risks attached to certain transactions.

Furthermore, assets or group of assets are presented as discontinued operations in the Group’s consolidated financial statements when they are classified as “held for sale” and represent a separate major line of business under IFRS 5.

4.1 Disposals carried out in 2019

The Group unveiled its 2019-2021 strategy on February 28, 2019 and on the same occasion announced a €6 billion asset disposal program as part of its continued transformation.

The table below shows the impact of the main disposals and sale agreements of 2019 on the Group’s net debt, excluding partial disposals with respect to DBSO ⁽¹⁾ activities:

<i>In millions of euros</i>	Disposal price	Reduction in net debt
Disposal of ENGIE's interest in Glow - Thailand	2,591	2,466
Disposal of German and Dutch coal-fired power plants	213	106
Other disposals that are not material taken individually	606	522
TOTAL	3,410	3,094

Additional disposals in the process of completion at December 31, 2019 are described in Note 4.2 “Assets held for sale”.

4.1.1 Disposal of ENGIE's interest in Glow (Thailand)

On March 14, 2019, the Group completed the sale of its 69.1% interest in Glow to Global Power Synergy Public Company Ltd. (GPSC), having received official approval from Thailand's Energy Regulatory Commission on March 8, 2019. This transaction followed an initial agreement entered into by ENGIE and GPSC in June 2018.

The combined effects of the transaction and of the cash generated by these activities since January 1, 2019 have reduced the Group’s net debt by €2,466 million. The disposal gain before tax amounted to €1,580 million in 2019, of which €143 million corresponds to the recycling to the income statement of items from the statement of comprehensive income (translation adjustments for €351 million and hedges for a negative €208 million).

(1) *Develop, Build, Share and Operate*, a model used in renewable energies based on the continuous rotation of capital employed, for which the impacts of disposals are recorded as deduction from CAPEX within current operating income.

4.1.2 Disposal of ENGIE's interest in coal-fired power plants in Germany and the Netherlands

On November 29, 2019, the Group finalized the disposal to Riverstone Holdings LLC, an international investment fund specializing in energy, of the coal-fired power plants of Farge, Zolling and Wilhelmshaven in Germany and Rotterdam in the Netherlands, with a total installed capacity of 2,345 MW.

This transaction resulted in a €106 million reduction in ENGIE's net debt at December 31, 2019 (and €84 million to be received in 2020). The disposal loss before tax amounted to €26 million at December 31, 2019, following a negative value adjustment of €121 million, mainly corresponding to goodwill.

4.2 Assets held for sale

Total "Assets classified as held for sale" and total "Liabilities directly associated with assets classified as held for sale" amounted to €468 million and €92 million, respectively, at December 31, 2019.

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
Property, plant and equipment, net and intangible assets	378	2,661
Other assets	90	1,137
TOTAL ASSETS CLASSIFIED AS HELD FOR SALE	468	3,798
Borrowings and debt	26	1,019
Other liabilities	65	1,111
TOTAL LIABILITIES DIRECTLY ASSOCIATED WITH ASSETS CLASSIFIED AS HELD FOR SALE	92	2,130

(1) Data published at December 31, 2018 was not restated due to the transition approach used when applying IFRS 16 and IFRIC 23 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

The assets related to Glow (Thailand), solar parks in operation by Langa in France, and renewable energy assets in Mexico, recorded in "Assets classified as held for sale" at December 31, 2018, were sold in 2019 (see Note 4.1 "Disposals carried out in 2019").

Assets classified as held for sale at December 31, 2019 include renewable energy assets in Mexico and green gas production assets in operation in France. These transactions are expected to be completed in first-half 2020. Given the expected capital gains from the disposal, no value adjustment has been recorded.

4.3 Acquisitions carried out in 2019

4.3.1 Acquisition of a 58.5% interest in Transportadora Asociada de Gás S.A. (TAG) in Brazil

In early April 2019, a consortium comprising ENGIE (32.5%), ENGIE Brasil Energia (32.5%) and Caisse de Dépôt et Placement du Québec (CDPQ) (35%), won the bidding process initiated by Petrobras for the acquisition of a 90% interest in Transportadora Asociada de Gás S.A. (TAG).

ENGIE therefore holds a 58.5% interest in TAG directly and indirectly, representing a net interest of 49.3% for the Group. The other TAG shareholders are CDPQ with 31.5% and Petrobras, which has retained a 10% stake.

The acquisition price was USD 8.6 billion, of which USD 5.3 billion was financed by debt external to the consortium and USD 2.4 billion by the shareholders. The impact of the acquisition on the Group's net debt was €1.6 billion (including acquisition costs).

The transaction was completed on June 13, 2019.

TAG owns the largest natural gas transportation network in Brazil, a key country in ENGIE's recently unveiled strategy, and will provide the Group with a steady contractual income stream. TAG's assets include 4,500 kilometers of gas pipelines, representing 47% of the country's gas infrastructure.

The Group has joint control over TAG since the decisions about its relevant activities, including for example preparation of the budget and medium-term plan, investments, operations and maintenance, are taken by majority vote requiring the consent of both ENGIE and CDPQ. Consequently, this interest is accounted for using the equity method.

4.3.2 Other transactions in 2019

Various other acquisitions were made in 2019, including OTTO Luft-und Klimatechnik GmbH & Co, a German ventilation installation and services company; SUEZ's nuclear maintenance business (formerly SRA SAVAC); Vol V Biomasse, which operates across the entire biomethane value chain; TIKO, a developer of smart energy management systems for the residential market; a controlling interest in Cofely Besix Facility Management (CBFM); and Conti, an energy services company in North America.

These various acquisitions increased net debt by €1.6 billion.

In addition, on December 19, 2019, the Group and its consortium partners Crédit Agricole Assurances and Mirova (a subsidiary of Natixis Investment Managers) announced that they had won a competitive process conducted by EDP for the acquisition of Portugal's second largest hydroelectric portfolio. ENGIE owns 40% of the consortium, while Crédit Agricole Assurances and Mirova, through managed funds, own 35% and 25%, respectively. A net debt impact of approximately €650 million is anticipated for ENGIE. This investment will be accounted for using the equity method. Closing of the transaction is expected during the second half of 2020.

Finally, ENGIE has also announced the acquisition of Renvico in Italy, a company that operates in the field of renewable energy, specializing in wind farm management. The closing of the transaction is expected to occur in 2020.

NOTE 5 FINANCIAL INDICATORS USED IN FINANCIAL COMMUNICATION

The purpose of this note is to present the main non-GAAP financial indicators used by the Group as well as their reconciliation with the indicators of the IFRS consolidated financial statements. Published data at December 31, 2018, presented below, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 “Accounting framework and basis for preparing the consolidated financial statements”⁽¹⁾).

5.1 EBITDA

The reconciliation between EBITDA and current operating income including operating MtM and share in net income of equity method entities is as follows:

<i>In millions of euros</i>	Dec. 31, 2019	Dec 31, 2018⁽¹⁾
Current operating income including operating MtM and share in net income of equity method entities	5,300	4,903
Mark-to-market on commodity contracts other than trading instruments	426	223
Net depreciation and amortization/Other	4,497	3,882
Share-based payments (IFRS 2)	51	79
Non-recurring share in net income of equity method entities	93	149
EBITDA	10,366	9,236

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 “Accounting framework and basis for preparing the consolidated financial statements”).

5.2 Current operating income (COI)

The reconciliation between current operating income (COI) and current operating income including operating MtM and share in net income of equity method entities is as follows:

<i>In millions of euros</i>	Dec. 31, 2019	Dec 31, 2018⁽¹⁾
Current operating income including operating MtM and share in net income of equity method entities	5,300	4,903
(-) Mark-to-market on commodity contracts other than trading instruments	426	223
CURRENT OPERATING INCOME (COI)	5,726	5,126

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 “Accounting framework and basis for preparing the consolidated financial statements”).

From 2020, the composition of COI will be homogenized with that of EBITDA to exclude, in line with ENGIE's accounting policies, the non-recurring share in net income of equity method entities (negative €93 million in 2019 and negative €149 million in 2018), resulting in an adjusted COI of €5,819 million and €5,275 million at December 31, 2019 and December 31, 2018 respectively.

5.3 Net recurring income Group share

Net recurring income Group share is a financial indicator used by the Group in its financial reporting to present net income Group share adjusted for unusual or non-recurring items.

This financial indicator therefore excludes:

- all items presented between the lines “Current operating income including operating MtM and share in net income of equity method entities” and “Income/(loss) from operating activities”, i.e. “Impairment losses”, “Restructuring

(1) Comparative data including the impact relating to the application of IFRS 16 are presented in Section 1 of this 2019 Annual Financial Report.

costs”, “Changes in scope of consolidation” and “Other non-recurring items”. These items are defined in Note 9 “Other items of income/(loss) from operating activities”;

- mark-to-market on commodity contracts other than trading instruments;
- the following components of net financial income/(loss): the impact of debt restructuring, compensation payments on the early unwinding of derivative instruments net of the reversal of the fair value of these derivatives that were settled early, changes in the fair value of derivative instruments that do not qualify as hedges under IFRS 9 – *Financial Instruments*, as well as the ineffective portion of derivative instruments that qualify as hedges;
- the income tax impact of the items described above, determined using the statutory income tax rate applicable to the relevant tax entity;
- net non-recurring items included in “Share in net income of equity method entities”. The excluded items correspond to the non-recurring items as defined above.

The reconciliation of net income/(loss) with net recurring income Group share is as follows:

<i>In millions of euros</i>	Notes	Dec. 31, 2019	Dec 31, 2018 ⁽¹⁾
NET INCOME/(LOSS) GROUP SHARE		984	1,033
NET INCOME/(LOSS) RELATING TO DISCONTINUED OPERATIONS, GROUP SHARE		-	1,045
NET INCOME/(LOSS) RELATING TO CONTINUED OPERATIONS, GROUP SHARE		984	(12)
Non-controlling interests relating to continued operations		664	572
NET INCOME/(LOSS) RELATING TO CONTINUED OPERATIONS		1,649	560
Reconciliation items between CURRENT OPERATING INCOME AFTER SHARE IN NET INCOME OF EQUITY METHOD ENTITIES and INCOME/(LOSS) FROM OPERATING ACTIVITIES		1,623	2,258
<i>Impairment losses</i>	9.1	1,770	1,798
<i>Restructuring costs</i>	9.2	218	162
<i>Changes in scope of consolidation</i>	9.3	(1,604)	150
<i>Other non-recurring items</i>	9.4	1,240	147
Other adjusted items		154	430
<i>Mark-to-market on commodity contracts other than trading instruments</i>	8.1	426	223
<i>Ineffective portion of derivatives qualified as fair value hedges</i>	10	3	3
<i>Gains/(losses) on debt restructuring and early unwinding of derivative financial instruments</i>	10	(6)	(7)
<i>Change in fair value of derivatives not qualified as hedges and ineffective portion of derivatives qualified as cash flow hedges</i>	10	223	183
<i>Non-recurring income/(loss) from debt instruments and equity instruments</i>	10	(115)	26
<i>Other adjusted tax impacts</i>		(470)	(147)
<i>Non-recurring income/(loss) included in share in net income of equity method entities</i>		93	149
NET RECURRING INCOME RELATING TO CONTINUED OPERATIONS		3,426	3,248
Net recurring income relating to continued operations attributable to non-controlling interests		743	790
NET RECURRING INCOME RELATING TO CONTINUED OPERATIONS, GROUP SHARE		2,683	2,458
Net recurring income/(loss) relating to discontinued operations, Group share		-	(33)
NET RECURRING INCOME GROUP SHARE		2,683	2,425

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 “Accounting framework and basis for preparing the consolidated financial statements”).

5.4 Industrial capital employed

The reconciliation of industrial capital employed with items in the statement of financial position is as follows:

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
(+) Property, plant and equipment and intangible assets, net	58,996	55,635
(+) Goodwill	18,665	17,809
(-) <i>Goodwill Gaz de France - SUEZ and International Power ⁽²⁾</i>	(7,650)	(7,610)
(+) IFRIC 4, IFRS 16 and IFRIC 12 receivables	1,737	1,550
(+) Investments in equity method entities	9,216	7,846
(-) <i>Goodwill arising on the International Power combination ⁽²⁾</i>	(154)	(151)
(+) Trade and other receivables, net	15,180	15,613
(-) <i>Margin calls ^{(2) (3)}</i>	(2,023)	(1,669)
(+) Inventories	3,617	4,158
(+) Assets from contracts with customers	7,831	7,411
(+) Other current and non-current assets	10,601	9,811
(+) Deferred tax	(3,771)	(4,349)
(+) <i>Cancellation of deferred tax on other recyclable items ⁽²⁾</i>	(571)	(247)
(-) Provisions	(25,115)	(21,813)
(+) <i>Actuarial gains and losses in shareholders' equity (net of deferred tax) ⁽²⁾</i>	3,507	2,637
(-) Trade and other payables	(19,109)	(19,759)
(+) <i>Margin calls ^{(2) (3)}</i>	1,996	1,681
(-) Liabilities from contracts with customers	(4,330)	(3,634)
(-) Other current and non-current liabilities	(14,298)	(13,507)
INDUSTRIAL CAPITAL EMPLOYED	54,325	51,412

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

(2) For the purpose of calculating industrial capital employed, the amounts recorded in respect of these items have been adjusted from those appearing in the statement of financial position.

(3) Margin calls included in "Trade and other receivables, net" and "Trade and other payables" correspond to advances received or paid as part of collateralization agreements set up by the Group to manage counterparty risk on commodity transactions.

5.5 Cash flow from operations (CFFO)

The reconciliation of cash flow from operations (CFFO) with items in the statement of cash flows is as follows:

<i>In millions of euros</i>	Dec. 31, 2019	Dec 31, 2018 ⁽¹⁾
Cash generated from operations before income tax and working capital requirements	9,863	8,464
Tax paid	(575)	(757)
Change in working capital requirements	(1,110)	149
Interest received on non-current financial assets	28	26
Dividends received on non-current financial assets	67	52
Interest paid	(780)	(727)
Interest received on cash and cash equivalents	82	79
Change in financial assets at fair value through income	(135)	(289)
(+) <i>Change in financial assets at fair value through income recorded in the statement of financial position</i>	135	303
CASH FLOW FROM OPERATIONS (CFFO)	7,574	7,300

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

5.6 Capital expenditure (CAPEX)

The reconciliation of capital expenditure (CAPEX) with items in the statement of cash flows is as follows:

<i>In millions of euros</i>	Dec. 31, 2019	Dec 31, 2018 ⁽¹⁾
Acquisitions of property, plant and equipment and intangible assets	6,524	6,202
Acquisitions of controlling interests in entities, net of cash and cash equivalents acquired	864	983
(+) <i>Cash and cash equivalents acquired</i>	229	83
Acquisitions of investments in equity method entities and joint operations	1,746	338
Acquisitions of equity and debt instruments	595	283
Change in loans and receivables originated by the Group and other	532	251
(+) <i>Other</i>	8	11
Change in ownership interests in controlled entities	12	18
(+) <i>Payments received in respect of the disposal of non-controlling interests</i>	-	-
(-) Disposal impacts relating to DBSO ⁽²⁾ activities	(468)	(526)
TOTAL CAPITAL EXPENDITURE (CAPEX)	10,042	7,643

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements"), but now includes the impact of disposals carried out in the context of the Group's DBSO activities.

(2) Develop, Build, Share & Operate.

5.7 Net financial debt

The reconciliation of net financial debt with items in the statement of financial position is as follows:

<i>In millions of euros</i>	Notes	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
(+) Long-term borrowings	16.2 & 16.3	30,002	26,434
(+) Short-term borrowings	16.2 & 16.3	8,543	5,745
(+) Derivative instruments - carried in liabilities	16.4	15,575	14,295
(-) <i>Derivative instruments hedging commodities and other items</i>		(15,350)	(13,970)
(-) Other financial assets	16.1	(9,568)	(8,483)
(+) <i>Loans and receivables at amortized cost not included in net financial debt</i>		4,870	3,844
(+) <i>Equity instruments at fair value</i>		1,297	1,107
(+) <i>Debt instruments at fair value not included in net financial debt</i>		1,899	1,551
(-) Cash and cash equivalents	16.1	(10,519)	(8,700)
(-) Derivative instruments - carried in assets	16.4	(14,272)	(13,372)
(+) <i>Derivative instruments hedging commodities and other items</i>		13,443	12,652
NET FINANCIAL DEBT		25,919	21,102

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

5.8 Economic net debt

Economic net debt is as follows:

<i>In millions of euros</i>	Notes	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
NET DEBT	16	25,919	21,102
Future minimum operating lease payments ⁽²⁾			2,087
Provisions for back-end of the nuclear fuel cycle	19	7,611	6,170
Provisions for dismantling of plant and equipment	19	7,329	6,081
Provisions for site rehabilitation	19	237	222
Post-employment benefit - Pension	20	2,427	1,970
(-) <i>Infrastructures regulated companies</i>		(93)	60
Post-employment benefit - Reimbursement rights	20	(160)	(167)
Post-employment benefit - Other benefits	20	5,001	4,293
(-) <i>Infrastructures regulated companies</i>		(3,080)	(2,572)
Deferred tax assets for pension and related obligations	11	(1,635)	(1,374)
(-) <i>Infrastructures regulated companies</i>		759	601
Plan assets relating to nuclear provisions, inventories of uranium and a receivable of Electrabel towards EDF Belgium	16 & 24	(3,236)	(2,884)
ECONOMIC NET DEBT		41,078	35,590

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

(2) As from January 1, 2019, commitments related to lease liabilities are included in net debt due to the application of IFRS 16.

NOTE 6 SEGMENT INFORMATION

6.1 Strengthening of ENGIE's organizational structure

In the first half of 2019, ENGIE unveiled its ambition to become the world leader in the zero carbon transition for its customers and announced measures to strengthen its organizational structure in order to accelerate the implementation of its strategy.

The Group has kept its current decentralized organizational structure based on 24 Business Units (BUs), which are essentially geographical, in order to remain close to its customers and foster initiative, and has strengthened this structure by creating four new Global Business Lines (GBLs): Client Solutions, Networks, Renewables and Thermal.

The role of these GBLs is to support the local teams and encourage cross-cutting performance by proposing an inter-BU strategy for their business, contributing to decisions on the allocation of resources between BUs, identifying and managing the key cross-cutting digital and excellence programs, identifying and implementing worldwide partnerships, and supporting, measuring and presenting the global performance of their business activities. These GBLs plus the Supply and Nuclear business activities form the Group's six core Business Lines (BLs).

The Group now operates on a matrix structure with the BUs forming the primary axis and the BLs the secondary axis.

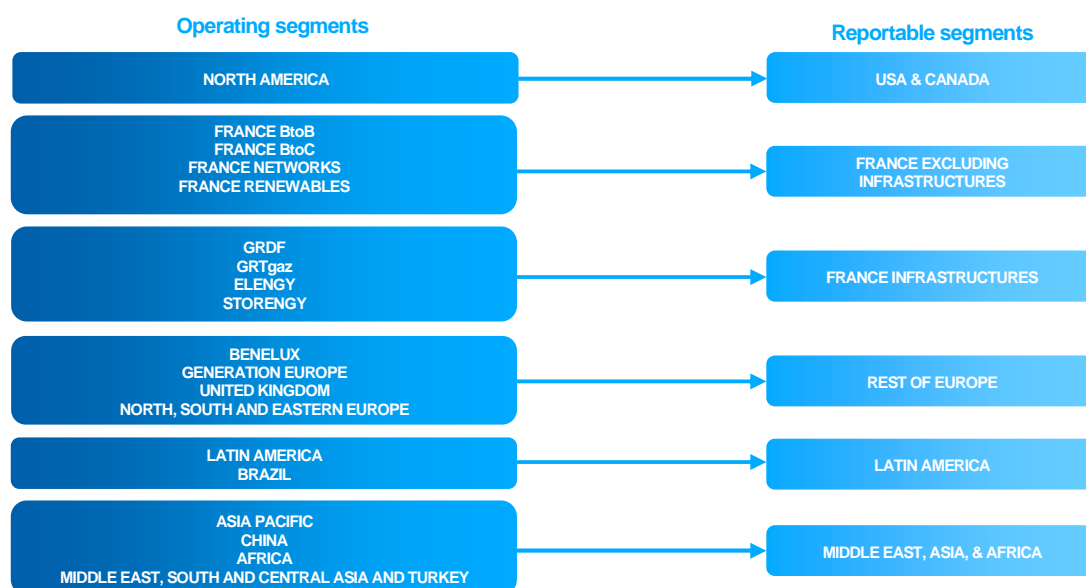
6.2 Operating segments and reportable segments

6.2.1 Definition of reportable segments

In accordance with IFRS 8, the Group has redefined its reportable and operating segments following these organizational developments and the deep changes to the BU business portfolios upon completion of the 2016-2018 transformation plan.

Each BU corresponds to an "operating segment" whose operational and financial performance is regularly reviewed by the Group's Executive Committee, which remains the Group's "chief operating decision maker" within the meaning of IFRS 8. The 24 BUs have now been regrouped into seven reportable segments reflecting the geographic areas where the Group operates:

- one reportable segment corresponding to the USA & Canada operating segment;
- five reportable segments corresponding to groups of operating segments;



- furthermore “Others” comprises operating segments that cannot be grouped together (Global Energy Management, Tractebel, GTT, Hydrogen) as well as the activities of *Entreprises & Collectivités (E&C)* due to the specificity of their businesses and markets or due to their particular risk profile, as well as the Group’s holding and corporate activities.

In order to determine how to group together the operating segments, as set out above, the Group exercised its judgment to decide whether two or more operating segments could be grouped together in the same reportable segment. The following key factors were examined to assess the similarity of the operating segments’ economic characteristics:

- nature of business and services;
- regulatory environment;
- economic environment in which the relevant activities operate (market maturity, growth prospects, political risks, etc.);
- risk profiles of the activities;
- how the activities fit into the Group’s strategy and new business model.

The Group decided to organize the operating segments within the reportable segments for the following reasons:

- the France BtoB, France BtoC, France Networks and France Renewables operating segments have been grouped together within the **France excluding Infrastructures** reportable segment, which encompasses all the French downstream energy businesses (energy services and gas and electricity sales and distribution to BtoB, BtoT and BtoC customers), and the increasingly decentralized renewable energy generation activities. These are complementary unregulated businesses that are supported by a well-developed local network and primarily aim to develop a combined offering for local customers: energy services, decentralized production resources and combined gas and electricity supply contracts. These BUs also operate within an environment driven by the “energy transition for green growth” law (LTECV);
- the GRDF, GRTgaz, Storengy and Elengy operating segments, which comprise the gas infrastructure businesses in Europe (distribution, transport, storage and LNG terminals), have been grouped together within the **France Infrastructures** reportable segment, as they are all regulated businesses with similar risk profiles and margins;
- the Benelux, Generation Europe, United Kingdom and North, South and Eastern Europe operating segments have been grouped together within the **Rest of Europe** reportable segment as these BUs, which comprise all of the Group’s European energy activities excluding France, have a similar business mix (energy production, supply, sale and services), operate in mature energy markets, and are undergoing transformation as part of the energy transition, with rapid development in renewable energy and client solutions;
- the Latin America and Brazil operating segments have been grouped together within the **Latin America** reportable segment, as these segments share similar growth prospects with a substantial proportion of their revenue generated by electricity sales under long-term agreements;
- the Asia-Pacific, China, Africa and Middle East, Southern and Central Asia and Turkey operating segments have been grouped together within the **Middle East, Asia & Africa** reportable segment, as all these regions have high power generation requirements and consequently represent significant growth prospects for the Group in the energy and energy services businesses. They operate in markets driven by the energy transition, with rapid development in renewable energy and client solutions.

6.2.2 Description of reportable segments

- **France excluding Infrastructures:** encompasses the activities of the following BUs: (i) France BtoB: energy sales and services for buildings and industry, cities and regions and major infrastructures, (ii) France BtoC: sales of energy and related services to individual and professional customers, (iii) France Renewables: development, construction, financing, operation and maintenance of all renewable power generation assets in France and (iv) France Networks, which designs, finances, builds and operates decentralized energy production and distribution facilities (heating and cooling networks).
- **France Infrastructures:** encompasses the GRDF, GRTgaz, Elengy and Storengy BUs, which operate natural gas transportation, storage and distribution networks and facilities, and LNG terminals, mainly in France. They also sell access rights to these terminals.

- **Rest of Europe:** encompasses the activities of the following BUs: (i) Benelux (Group's business in Belgium, Netherlands and Luxembourg: nuclear and renewable electricity generation, sales of natural gas and electricity and energy services activities), (ii) Generation Europe, which comprises the Group's thermal electricity generation activities in Europe, (iii) United Kingdom (management of renewable energy generation assets and the portfolio of distribution assets, supply of energy services and solutions, etc.) and (iv) North, South and Eastern Europe (sales of natural gas and electricity and related energy services and solutions, operation of renewable energy generation assets, management of distribution networks).
- **Latin America:** encompasses the activities of (i) the Brazil BU and (ii) the Latin America BU (Argentina, Chile, Mexico and Peru). The subsidiaries concerned are involved in centralized power generation, including renewable energy, gas chain activities (including infrastructure), and energy services.
- **USA & Canada:** encompasses power generation, energy services and natural gas and electricity sales activities in the United States, Canada and Puerto Rico.
- **Middle East, Asia & Africa:** encompasses the activities of the following BUs: (i) Asia-Pacific (Australia, New Zealand, Thailand, Singapore and Indonesia), (ii) China, (iii) Africa (mainly Morocco and South Africa) and (iv) the Middle East, South and Central Asia and Turkey (including India and Pakistan). In all of these regions, the Group is active in electricity generation and sales, gas distribution and sales, energy services and seawater desalination in the Arabian Peninsula.
- **Others:** encompasses the activities of (i) GEM, whose role is to manage and optimize, on behalf of the BUs that hold power generation assets, the Group's physical and contractual asset portfolios (excluding gas infrastructure), particularly in the European market, to sell energy to major pan-European and national industrial companies, and to provide solutions related to its expertise in the financial energy markets to third parties, (ii) Tractebel (engineering companies specialized in energy, hydraulics and infrastructure), (iii) GTT (specialized in the design of cryogenic membrane confinement systems for sea transportation and storage of LNG, both onshore and offshore), (iv) Hydrogen (design of renewable hydrogen-based zero carbon energy solutions), as well as (v) the Group's holding and corporate activities which include the entities centralizing the Group's financing requirements, *Entreprises & Collectivités* (E&C) and the contribution of the associate SUEZ.

The main commercial relationships between the reportable segments are as follows:

- relationships between the "France Infrastructures" reportable segment and the users of those infrastructures, i.e. the "France excluding Infrastructures" and "Others" (GEM and E&C) reportable segments: services relating to the use of the Group's gas infrastructures in France are billed based on regulated rates (or revenues) applicable to all users. Revenue and margins related to GRDF business continue to fall within the scope of "France Infrastructures";
- relationships between the "Others" (GEM) reportable segment and the "France excluding Infrastructures" and "Rest of Europe" reportable segments: GEM manages the Group's natural gas supply contracts and sells gas at market prices to commercial companies within the "France excluding Infrastructures" and "Rest of Europe" reportable segments. As regards electricity, GEM manages and optimizes the power stations and sales portfolios on behalf of entities that hold power generation assets and deducts a percentage of the energy margin in return for providing these services. The revenue and margins related to power generation activities (minus the percentage deducted by GEM) are reported by the segments that hold power generation assets ("France excluding Infrastructures" and "Rest of Europe");
- relationships between the "Generation Europe" operating segment, which is part of the "Rest of Europe" reportable segment, and the commercial entities in the "France excluding Infrastructures" reportable segment: a portion of the power generated by thermal assets within the "Generation Europe" BU is sold to commercial entities from these segments at market prices.

Due to the variety of its businesses and their geographical location, the Group serves a very diverse range of situations and customer types (industry, local authorities and individual customers). Accordingly, no external customer represents individually 10% or more of the Group's consolidated revenues.

6.2.3 Key indicators by reportable segment ⁽¹⁾

In accordance with IFRS 8, comparative segment information at December 31, 2018 has been restated in order to present this information in accordance with the new segment structure introduced by the Group on January 1, 2019.

However, it has not been restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements"), in accordance with the transition options of the standard, applicable as from January 1, 2019.

REVENUES

In millions of euros	Dec. 31, 2019 ⁽¹⁾			Dec. 31, 2018 ⁽¹⁾		
	External revenues	Intra-Group Revenues	Total	External revenues	Intra-Group Revenues	Total
France excluding Infrastructures	15,854	334	16,188	14,998	188	15,186
France Infrastructures	5,569	979	6,548	5,450	1,125	6,575
<i>Total France</i>	<i>21,423</i>	<i>1,313</i>	<i>22,736</i>	<i>20,448</i>	<i>1,312</i>	<i>21,760</i>
Rest of Europe	17,270	1,488	18,758	16,946	1,770	18,716
Latin America	5,341	1	5,342	4,639	-	4,639
USA & Canada	4,545	1	4,547	3,355	62	3,417
Middle East, Asia & Africa	2,914	-	2,914	4,014	4	4,018
Others	8,565	5,995	14,560	7,565	6,332	13,897
Elimination of internal transactions	-	(8,798)	(8,798)	-	(9,481)	(9,481)
TOTAL REVENUES	60,058	-	60,058	56,967	-	56,967

(1) Data presented at December 31, 2019 have been prepared in accordance with the new income statement presentation adopted by the Group. Comparative data at December 31, 2018 have been reclassified in accordance with this new presentation (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

EBITDA

In millions of euros	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
France excluding Infrastructures	1,672	1,670
France Infrastructures	3,539	3,499
<i>Total France</i>	<i>5,211</i>	<i>5,168</i>
Rest of Europe	1,750	973
Latin America	2,221	1,775
USA & Canada	291	224
Middle East, Asia & Africa	727	1,122
Others	166	(27)
TOTAL EBITDA ⁽²⁾	10,366	9,236

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

(2) EBITDA at December 31, 2019 includes the impact of IFRS 16 (cancellation of leases) in an amount of around €0.4 billion.

(1) Comparable data including the impact related to the first-time application of IFRS 16 are presented in Section 1 of this 2019 Annual Financial Report.

DEPRECIATION AND AMORTIZATION

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
France excluding Infrastructures	(761)	(628)
France Infrastructures	(1,581)	(1,479)
<i>Total France</i>	(2,343)	(2,106)
Rest of Europe	(1,041)	(928)
Latin America	(523)	(416)
USA & Canada	(127)	(72)
Middle East, Asia & Africa	(102)	(134)
Others	(360)	(225)
TOTAL DEPRECIATION AND AMORTIZATION	(4,497)	(3,882)

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

SHARE IN NET INCOME OF EQUITY METHOD ENTITIES

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
France excluding Infrastructures	17	1
France Infrastructures	3	12
<i>Total France</i>	20	13
Rest of Europe	55	89
Latin America	8	(25)
USA & Canada	60	75
Middle East, Asia & Africa	246	166
Others	111	42
<i>Of which share in net income of SUEZ</i>	113	55
TOTAL SHARE IN NET INCOME OF EQUITY METHOD ENTITIES	500	361

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

Associates and joint ventures account for €255 million and €245 million respectively of share in net income of equity method entities at December 31, 2019, compared to €88 million and €273 million in 2018.

CURRENT OPERATING INCOME (COI)

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
France excluding Infrastructures	903	1,035
France Infrastructures	1,957	2,016
<i>Total France</i>	2,861	3,051
Rest of Europe	684	37
Latin America	1,694	1,355
USA & Canada	159	151
Middle East, Asia & Africa	559	893
Others	(231)	(362)
TOTAL CURRENT OPERATING INCOME (COI)	5,726	5,126

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

INDUSTRIAL CAPITAL EMPLOYED

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
France excluding Infrastructures	7,143	6,306
France Infrastructures	20,172	19,802
<i>Total France</i>	27,315	26,107
Rest of Europe	1,797	3,563
Latin America	11,462	9,897
USA & Canada	3,717	2,494
Middle East, Asia & Africa	3,633	3,553
Others	6,401	5,796
<i>Of which SUEZ equity value</i>	2,027	2,018
TOTAL INDUSTRIAL CAPITAL EMPLOYED	54,325	51,412

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

CAPITAL EXPENDITURE (CAPEX)

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018
France excluding Infrastructures	1,019	853
France Infrastructures	1,745	1,619
<i>Total France</i>	2,764	2,472
Rest of Europe	1,439	1,430
Latin America	2,499	1,758
USA & Canada	1,380	918
Middle East, Asia & Africa	453	616
Others	1,506	449
TOTAL CAPITAL EXPENDITURE (CAPEX)	10,042	7,643

6.3 Key indicators by Business Line**6.3.1 Definition of Business Lines**

- **Client Solutions** (excluding BtoC clients): encompasses services and service packages such as design, engineering, works, operation, installation, maintenance and facility management, as well as asset management activities such as heating and cooling networks, dedicated energy generation assets (decentralized energy delivered directly to the client). It also includes the Group's interest in the SUEZ group.
- **Networks**: comprises the Group's electricity and gas infrastructure activities and projects. These activities include the management and development of (i) gas and electricity transportation networks in Europe and Latin America and natural gas distribution networks in Europe, Asia and the American continent, (ii) natural gas underground storage in Europe, and (iii) regasification infrastructure in France and Chile. Apart from the historical infrastructure management activities, its asset portfolio also contributes to the challenges of energy decarbonization and network greening (gradual integration of green gas, hydrogen based projects, geothermal projects, energy as a service, etc.).
- **Renewables**: comprises all centralized renewable energy generation activities, including financing, construction and operation of renewable energy facilities, using various energy sources such as hydroelectric, onshore wind, photovoltaic solar, biomass, offshore wind, geothermal and biogas. The energy produced is fed into the grid and sold either on the open or regulated market or through electricity sale agreements.
- **Thermal**: encompasses all the Group's centralized energy generation activities using thermal assets, whether contracted or not. It includes the operation of power plants fueled mainly by gas and coal, as well as pump-operated storage plants. The energy produced is fed into the grid and sold either on the open or regulated market or through electricity sale agreements. It includes the financing, construction and operation of desalination plants, whether or not connected to power plants.
- **Nuclear**: encompasses all of the Group's nuclear power generation activities, with seven reactors in Belgium (four in Doel and three in Tihange) and drawing rights in France.
- **Supply**: encompasses all the Group's activities relating to the sale of gas and electricity to end customers, whether professional or individual. It also includes all the Group's activities in services for residential clients.

Others encompasses (i) energy management and optimization activities, (ii) the GTT BU, and (iii) corporate and holding activities.

6.3.2 Key indicators by Business Line

EBITDA

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
Client Solutions	1,835	1,511
Networks	4,024	3,975
Renewables	1,725	1,575
Thermal	1,765	2,025
Nuclear	192	(555)
Supply	639	764
Others	186	(58)
TOTAL EBITDA	10,366	9,236

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

CURRENT OPERATING INCOME (COI)

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
Client Solutions	1,090	982
Networks	2,327	2,399
Renewables	1,190	1,105
Thermal	1,260	1,455
Nuclear	(314)	(1,051)
Supply	345	537
Others	(172)	(302)
TOTAL CURRENT OPERATING INCOME (COI)	5,726	5,126

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

CAPITAL EXPENDITURE (CAPEX)

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018
Client Solutions	1,621	1,537
Networks	3,446	1,814
Renewables	2,488	1,986
Thermal	517	813
Nuclear	636	750
Supply	457	454
Others	876	289
TOTAL CAPITAL EXPENDITURE (CAPEX)	10,042	7,643

6.4 Key indicators by geographic area

The amounts set out below are analyzed by:

- destination of products and services sold for revenues;
- geographic location of consolidated companies for industrial capital employed.

In millions of euros	Revenues ⁽¹⁾		Industrial capital employed	
	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018 ⁽²⁾
France	24,223	23,661	31,831	30,543
Belgium	5,894	5,098	(6,026)	(3,254)
Other EU countries	14,631	14,196	8,363	7,188
Other European countries	989	815	490	386
North America	5,273	3,838	4,419	2,881
Asia, Middle East & Oceania	3,867	4,776	3,355	3,337
South America	4,759	4,197	10,920	9,515
Africa	422	385	971	816
TOTAL	60,058	56,967	54,325	51,412

(1) Data presented at December 31, 2019 have been prepared in accordance with the new income statement presentation adopted by the Group. Comparative data at December 31, 2018 have been reclassified in accordance with this new presentation (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

(2) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

NOTE 7 REVENUES

7.1 Revenues

Accounting standards

Revenues from contracts with customers concern revenues from contracts that fall within the scope of IFRS 15. Revenues are recognized when the customer obtains control of goods or services promised in the contract, for the amount of consideration to which an entity expects to be entitled in exchange for said promised goods or services.

A contractual analysis of the Group's sale contracts has led to the application of the following revenue recognition principles.

- **Gas, electricity and other energies**
Revenues from sales of gas, electricity and other energies are recognized upon delivery of the power to the retail, business or industrial customer.
Power deliveries are monitored in real time or on a deferred basis for those customers whose energy consumption is metered during the accounting period, in which case the portion of not yet metered revenues "in the meter" is estimated on the closing date.
- **Gas, electrical and other energy infrastructures**
Revenues derived by gas and electricity infrastructure operators upon providing transportation or distribution or storage capacities, are recognized on a straight-line basis over the contract term.
In the countries where the Group acts as an energy provider (supplier) without being in charge of its distribution or transportation, mainly in France and Belgium, an analysis of the energy sales contracts and of the related regulatory framework is carried out to determine whether the distribution or transportation services invoiced to the customers have to be excluded from the revenues recognized under IFRS 15.
Judgment may be exercised by the Group for this analysis in order to determine whether the energy provider acts as an agent or a principal for the gas or electricity distribution or transportation services re-invoiced to the customers. The main criteria used by the Group to exercise its judgment and conclude, in certain countries, that the energy provider acts as an agent of the infrastructure operator are as follows: who is primarily responsible for fulfillment of the distribution or transportation services? Does the energy provider have the ability to commit to capacity reservation contracts towards the infrastructure operator? To what extent does the energy provider have discretion in establishing the price for the distribution or transportation services?
- **Constructions, installations, Operations and Maintenance (O&M), facility management (FM) and other services**
Constructions and installations contracts mainly concern assets built on the premises of customers such as cogeneration units, heaters or other energy-efficiency assets. The related revenues are usually recognized according to the percentage of completion on the basis of the costs incurred.
O&M contracts generally require the Group to perform services ensuring the availability of assets generating energy. These services are performed over time and the related revenues are recognized according to the percentage of completion on the basis of the costs incurred.
FM generally involves managing and integrating a great number of different services, outsourced by customers. The consideration due to FM suppliers can either be fixed or variable depending on the number of hours or on another indicator, irrespective of the nature of the services provided. Hence, the related revenues are recognized according to the percentage of completion on the basis of the costs incurred or of the number of hours performed.

If it is not possible to conclude from the contractual analysis that the contract falls within the scope of IFRS 15, the revenues are then accounted for as non-IFRS 15 revenues.

NOTE 7 REVENUES

Revenues from other contracts, corresponding to revenues from operations that do not fall within the scope of IFRS 15, presented in the "Others" column include lease or concession income, as well as any financial component of operating services.

The table below shows a breakdown of revenues by type of accounting principles:

<i>In millions of euros</i>	Sales of gas	Sales of electricity and other energies	Sales of services linked to infrastructures	Constructions, installations, O&M, FM and other services	Others	Dec. 31, 2019 ⁽¹⁾
France excluding Infrastructures	3,207	4,160	144	8,338	5	15,854
France Infrastructures	64	1	5,265	218	22	5,569
Total France	3,271	4,160	5,409	8,556	27	21,423
Rest of Europe	3,147	6,403	331	7,323	66	17,270
Latin America	559	3,840	351	457	134	5,341
USA & Canada	465	2,734	2	1,342	3	4,545
Middle East, Asia & Africa	446	1,293	21	1,053	101	2,914
Others	3,464	3,303	130	1,050	619	8,565
TOTAL REVENUES	11,351	21,732	6,244	19,781	949	60,058

<i>In millions of euros</i>	Sales of gas	Sales of electricity and other energies	Sales of services linked to infrastructures	Constructions, installations, O&M, FM and other services	Others	Dec. 31, 2018 ⁽¹⁾
France excluding Infrastructures	3,164	4,040	105	7,684	5	14,998
France Infrastructures	155	-	5,092	200	3	5,450
Total France	3,318	4,040	5,197	7,885	9	20,448
Rest of Europe	3,237	6,398	410	6,845	55	16,946
Latin America	461	3,522	322	197	138	4,639
USA & Canada	592	1,858	-	900	5	3,355
Middle East, Asia & Africa	452	2,605	31	806	121	4,014
Others	3,835	2,231	117	908	473	7,565
TOTAL REVENUES	11,895	20,654	6,077	17,540	801	56,967

(1) Data presented at December 31, 2019 have been prepared in accordance with the new income statement presentation adopted by the Group. Comparative data at December 31, 2018 have been reclassified in accordance with this new presentation (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

7.2 Trade and other receivables, assets and liabilities from contracts with customers

Accounting standards

On initial recognition, trade and other receivables are recorded at their transaction price as defined in IFRS 15.

A contract asset is an entity's right to consideration in exchange for goods or services that have been transferred to a customer but for which payment is not yet due or is contingent on the satisfaction of a specific condition stipulated in the contract. When an amount becomes due, it is transferred to receivables.

A receivable is recorded when the entity has an unconditional right to consideration. A right to consideration is unconditional if only the passage of time is required before payment of that consideration.

A contract liability is an entity's obligation to transfer goods or services to a customer for which the entity has already received consideration from the customer. The liability is derecognized upon recognition of the corresponding revenue.

Trade and other receivables and assets from contracts with customers are tested for impairment in accordance with the provisions of IFRS 9 on expected credit losses.

The impairment model for financial assets is based on the expected credit loss model. To calculate expected losses, the Group uses a matrix approach for trade receivables and assets from contracts with customers, for which the change in credit risk is monitored on a portfolio basis. An individual approach is used for large customers and other large counterparties, for which the change in credit risk is monitored on an individual basis.

See Note 17 "Risks arising from financial instruments" for the Group's assessment of counterparty risk.

7.2.1 Trade and other receivables and assets from contracts with customers

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018
Trade and other receivables, net	15,180	15,613
Of which IFRS 15	7,385	7,552
Of which non-IFRS15	7,795	8,060
Assets from contracts with customers	7,831	7,411
Accrued income and unbilled revenues	6,783	6,377
Energy in the meter ^{(1) (2)}	1,048	1,034

(1) i.e. 1.7% of annual revenues.

(2) Net of advance payments.

In 2019, the segments reporting the greatest amounts of assets from contracts were France excluding Infrastructures (€2,884 million, mainly in France BtoB and BtoC), Rest of Europe (€2,708 million, mainly in Benelux, Germany and the United Kingdom) and Others (€1,017 million mainly BU GEM).

<i>In millions of euros</i>	Dec. 31, 2019			Dec. 31, 2018		
	Allowances and expected credit losses			Allowances and expected credit losses		
	Gross	Net		Gross	Net	
Trade and other receivables, net	16,277	(1,097)	15,180	16,689	(1,076)	15,613
Assets from contracts with customers	7,848	(17)	7,831	7,419	(8)	7,411
TOTAL	24,125	(1,114)	23,011	24,108	(1,085)	23,023

Gas and electricity in the meter

For customers whose energy consumption is metered during the accounting period, the gas supplied but not yet metered at the reporting date is estimated based on historical data, consumption statistics and estimated selling prices.

For sales on networks used by a large number of grid operators, the Group is allocated a certain volume of energy transiting through the networks by the grid managers. As the final allocations are sometimes only known several months down the line, revenue figures cannot be determined with absolute certainty. However, the Group has developed measuring and modeling tools allowing it to estimate revenues with a reasonable degree of accuracy and subsequently ensure that risks of error associated with estimating quantities sold and the related revenues can be considered as immaterial.

In France and Belgium, un-metered revenues ("gas in the meter") are calculated using a direct method taking into account customers' estimated consumption based on the last invoice or metering not yet billed. These estimates are in line with the volume of energy allocated by the grid managers over the same period. The average price is used to measure "gas in the meter" and takes account of the category of customer and the age of the delivered unbilled "gas in the meter". The portion of unbilled revenues at the reporting date varies according to the assumptions about volume and average price.

"Electricity in the meter" is also determined using a direct allocation method similar to that used for gas, but taking into account specific factors related to electricity consumption. It is also measured on a customer-by-customer basis or by customer type.

Realized but not yet metered revenues ("un-metered revenues") mainly related to France and Belgium for an amount of €3,275 million at December 31, 2019 (€3,108 at December 31, 2018).

7.2.2 Liabilities from contracts with customers

<i>In millions of euros</i>	Dec. 31, 2019			Dec. 31, 2018		
	Non-current	Current	Total	Non-current	Current	Total
Liabilities from contracts with customers	45	4,286	4,330	36	3,598	3,634
Advances and downpayments received	11	2,190	2,201	-	1,713	1,713
Deferred revenues	34	2,096	2,129	36	1,885	1,921

In 2019, the segments reporting the greatest amounts of revenues recognized over time are France excluding Infrastructures (€2,382 million, mainly in France BtoB and BtoC) and Rest of Europe (€1,295 million, mainly in Benelux, Germany and the United Kingdom).

7.3 Revenues relating to performance obligations not yet satisfied

Revenues relating to performance obligations only partially satisfied at December 31, 2019 amounted to €16,792 million. They mainly concern the United Kingdom (€7,441 million) and France BtoB (€5,052 million) BUs. These BUs handle a large number of construction, installation, maintenance and facility management contracts under which revenues are recognized over time. The Benelux, Tractebel Engineering and North, South and Eastern Europe BUs will also be recognizing revenues over the next three years for performance obligations satisfied over time.

NOTE 8 OPERATING EXPENSES

Accounting standards

Operating expenses include:

- purchases and commodity hedges including:
 - the purchase of commodities and associated costs (infrastructure, transport, storage, etc.),
 - the realized impact, as well as the change in fair value (MtM), of commodity transactions, with or without physical delivery, that fall within the scope of IFRS 9 - *Financial Instruments* and that do not qualify as trading or hedging. These contracts are set up as part of economic hedges of operating transactions in the energy sector;
- purchases of services and other items such as subcontracting and interim expenses, lease expenses (short-term lease contracts or leases with low underlying asset value), concession expenses, etc.;
- personnel costs;
- depreciation, amortization, and provisions; and
- taxes.

8.1 Purchases and operating derivatives

<i>In millions of euros</i>	Dec. 31, 2019 ⁽¹⁾	Dec. 31, 2018 ⁽¹⁾⁽²⁾
Purchases and other income and expenses on operating derivatives other than trading ⁽³⁾	(29,340)	(28,431)
Service and other purchases ⁽⁴⁾	(10,609)	(10,229)
PURCHASES AND OPERATING DERIVATIVES	(39,950)	(38,660)

- (1) Data presented at December 31, 2019 have been prepared in accordance with the new income statement presentation adopted by the Group. Comparative data at December 31, 2018 have been restated in accordance with this new definition (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").
- (2) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").
- (3) Of which a net expense of €426 million at December 31, 2019 relating to MtM on commodity contracts other than trading (compared to a net expense of €223 million at December 31, 2018).
- (4) Of which €258 million in lease expenses, relating to short term lease contracts and leases with a low underlying asset value, accounted for in accordance with IFRS 16 at December 31, 2019 (compared to €828 million lease expenses accounted for in accordance with IAS 17 at December 31, 2018).

8.2 Personnel costs

<i>In millions of euros</i>	Notes	Dec. 31, 2019	Dec. 31, 2018
Short-term benefits		(10,933)	(9,998)
Share-based payments	21	(56)	(86)
Costs related to defined benefit plans	20.3.4	(368)	(407)
Costs related to defined contribution plans	20.4	(121)	(133)
PERSONNEL COSTS		(11,478)	(10,624)

8.3 Depreciation, amortization and provisions

<i>In millions of euros</i>	Notes	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
Depreciation and amortization	14 & 15	(4,497)	(3,882)
Net change in write-downs of inventories, trade receivables and other assets		(104)	-
Net change in provisions	19	208	296
DEPRECIATION, AMORTIZATION AND PROVISIONS		(4,393)	(3,586)

At December 31, 2019, depreciation and amortization mainly break down as €943 million for intangible assets and €3,554 million for property, plant and equipment.

NOTE 9 OTHER ITEMS OF INCOME/(LOSS) FROM OPERATING ACTIVITIES

Accounting standards

Other items of Income/(loss) from operating activities include:

- “Impairment losses” include impairment losses on goodwill, other intangible assets, property, plant and equipment and investments in entities consolidated using the equity method of accounting;
- “Restructuring costs” concern costs corresponding to a restructuring program planned and controlled by management that materially changes either the scope of a business undertaken by the entity, or the manner in which that business is conducted, based on the criteria set out in IAS 37;
- “Changes in the scope of consolidation”. This line includes:
 - direct costs related to acquisitions of controlling interests,
 - in a business combination achieved in stages, remeasurement at fair value at the acquisition date of the previously held interest,
 - subsequent changes in the fair value of contingent consideration,
 - gains or losses from disposals of investments which result in a change of consolidation method, as well as any impact from the remeasurement of retained interests with the exception of gains and losses arising from transactions realized in the framework of “Develop, Build, Share & Operate” (DBSO) or “Develop, Share, Build & Operate” (DSBO) business models. These transactions on renewable activities are recognized in current operating income as they are part of the recurring rotation of the Group’s capital employed;
- “Other non-recurring items” notably include gains and losses on disposals of non-current assets.

9.1 Impairment losses

<i>In millions of euros</i>	Notes	Dec. 31, 2019	Dec. 31, 2018
Impairment losses:			
Goodwill	13.1	(116)	(14)
Property, plant and equipment and other intangible assets	14 & 15	(1,735)	(1,609)
Investments in equity method entities and related provisions		-	(209)
TOTAL IMPAIRMENT LOSSES		(1,851)	(1,831)
Reversal of impairment losses:			
Property, plant and equipment and other intangible assets		61	33
Investments in equity method entities and related provisions		20	-
TOTAL REVERSALS OF IMPAIRMENT LOSSES		81	33
TOTAL		(1,770)	(1,798)

Net impairment losses amounted to €1,770 million in 2019, relating to property, plant and equipment and goodwill. After taking into account the deferred tax effects and the share of impairment losses attributable to non-controlling interests, the impact of these impairment losses on net income Group share for 2019 amounted to €1,579 million.

Impairment tests are performed in accordance with the conditions described in Note 13.3.

9.1.1 Impairment losses recognized in 2019

Net impairment losses amounted to €1,770 million in 2019 and mainly concerned:

- **Belgian nuclear power assets**

As a result of continued investment in extending the operating life of the nuclear power plants to 50 years and the increase in dismantling assets related to the revision of dismantling provisions (see Note 19.2 “Nuclear dismantling liabilities”), the carrying amount of the nuclear power plants increased significantly in 2019 in a context of falling prices. Given the impairment losses recognized in the past (see Note 10.2.1 to the consolidated financial statements for the year ended December 31, 2018), nuclear assets were tested for impairment distinguishing between nuclear power plants where there is no longer any possibility of extending their operating life and those whose operating life may still be extended beyond 2025.

In these conditions, the Group has updated its forecasts in line with the maintenance schedule for nuclear power plants reviewed for the next three years and in line with the adaptation of their management method as they approach the end of their lifetime. The Group recognized impairment losses of €1,023 million in 2019 against plants whose operating life may no longer be extended, including €639 million in respect of dismantling assets corresponding to the increase in nuclear dismantling provisions.

- **Other impairment losses**

Other impairment losses recognized by the Group mainly concerned:

- thermal power generation assets in Latin America for €165 million, following the anticipated shutdown of these plants;
- the decision to mothball a thermal power generation asset in the Middle East for €135 million, in an unfavorable economic environment;
- the intangible asset of €111 million corresponding to the France BtoC client portfolio value. This value was affected by the 2019 law, which enacts the end of regulated gas tariffs from 2023;
- value adjustments of several coal-fired power plants in Germany and the Netherlands in connection with their disposal (see Note 4.1 “Disposals carried out in 2019”) for €148 million mainly recorded against all of the goodwill allocated to the assets sold for €108 million.

9.1.2 Impairment losses recognized in 2018

Net impairment losses amounted to €1,798 million in 2018, and mainly concerned:

- thermal power generation assets in Europe (€646 million), mainly due to the expected impact of a stricter regulatory environment for coal-fired power plants;
- Belgian nuclear power assets (€615 million), in respect of the nuclear plants whose operating life will not be extended;
- other impairment losses related to an investment in the Africa/Asia reportable segment (€209 million), gas infrastructure facilities in Europe (€87 million) and thermal power generation assets in Latin America (€71 million).

After taking into account the deferred tax effects and the share of impairment losses attributable to non-controlling interests, the impact of these impairment losses on net income Group share for 2018 amounted to €1,540 million.

9.2 Restructuring costs

In 2019, restructuring costs totaled €218 million (versus €162 million in 2018). Restructuring costs in both years mainly included costs related to staff reduction plans and measures to adapt to economic situations, as well as the shutdown of production, the closure or restructuring of certain facilities and other miscellaneous restructuring costs.

9.3 Changes in scope of consolidation

The impact of changes in the scope of consolidation in 2019 was a positive €1,604 million and mainly comprised (i) the positive impact of the sale of Glow for €1,580 million, including €143 million in respect of items of other comprehensive income recycled to the income statement (translation adjustments for €351 million and hedges for a negative €208 million).

The impact of changes in the scope of consolidation in 2018 was a negative €150 million and mainly comprised (i) the €87 million negative impact of the sale of the Loy Yang B thermal power plant in Australia, primarily in respect of items of other comprehensive income recycled to the income statement, and (ii) the €27 million negative impact of the sale of LNG operations in the United States.

9.4 Other non-recurring items

Other non-recurring items totaling a negative €1,240 million in 2019, mainly included the non-recurring impact of the nuclear provision review (back-end of the cycle) and other miscellaneous expenses for a negative €1,166 million.

In 2018, other non-recurring items totaling a negative €147 million mainly included asset scrapping, costs related to site closures and other miscellaneous expenses.

NOTE 10 NET FINANCIAL INCOME/(LOSS)

<i>In millions of euros</i>	Expense	Income	Dec. 31, 2019	Expense	Income	Dec. 31, 2018 ⁽¹⁾
<i>Interest expense on gross debt and hedges</i>	(894)	-	(894)	(828)	-	(828)
<i>Foreign exchange gains/losses on borrowings and hedges</i>	-	30	30	-	4	4
<i>Ineffective portion of derivatives qualified as fair value hedges</i>	(3)	-	(3)	(3)	-	(3)
<i>Gains and losses on cash and cash equivalents and liquid debt instruments held for cash investment purposes</i>	-	84	84	-	81	81
<i>Capitalized borrowing costs</i>	106	-	106	134	-	134
Cost of net debt	(790)	114	(676)	(697)	85	(611)
Cost of lease liabilities ⁽²⁾	(48)	-	(48)	(16)	-	(16)
<i>Cash payments made on the unwinding of swaps</i>	(62)	-	(62)	(108)	-	(108)
<i>Reversal of the negative fair value of these early unwound derivative financial instruments</i>	-	62	62	-	102	102
<i>Expenses on debt restructuring transactions</i>	-	6	6	-	13	13
Gains/(losses) on debt restructuring and early unwinding of derivative financial instruments	(62)	68	6	(108)	115	7
<i>Net interest expense on post-employment benefits and other long-term benefits</i>	(121)	-	(121)	(112)	-	(112)
<i>Unwinding of discounting adjustments to other long-term provisions</i>	(566)	-	(566)	(538)	-	(538)
<i>Change in fair value of derivatives not qualified as hedges and ineffective portion of derivatives qualified as cash flow hedges</i>	(223)	-	(223)	(185)	-	(185)
<i>Income/(loss) from debt instruments and equity instruments</i>	(34)	212	179	(84)	73	(11)
<i>Interest income on loans and receivables at amortized cost</i>	-	169	169	-	111	111
<i>Other</i>	(457)	350	(107)	(241)	216	(25)
Other financial income and expenses	(1,400)	731	(669)	(1,161)	400	(761)
NET FINANCIAL INCOME/(LOSS)	(2,300)	913	(1,387)	(1,981)	600	(1,381)

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

(2) At December 31, 2018, the cost of lease liabilities corresponds to interest on finance leases previously classified in "Cost of net debt".

The increase in the cost of net debt was mainly due to the increasing weight of debt in Brazil in relation with the acquisition of TAG (see Note "4.3.1 Acquisition of a 58.5% interest in Transportadora Associada de Gás S.A. (TAG) in Brazil") since December 31, 2018, partly offset by the positive impacts of debt financing transactions carried out by the Group and to active interest-rate management (see Note 16.3.3 "Financial instruments – Main events of the period").

At December 31, 2019, the average cost of debt after hedging came out at 2.70% compared with 2.68% at December 31, 2018.

NOTE 11 INCOME TAX EXPENSE

Accounting standards

The Group calculates taxes in accordance with prevailing tax legislation in the countries where income is taxable.

In accordance with IAS 12, deferred taxes are recognized according to the liability method on temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and their tax bases, using tax rates that have been enacted or substantively enacted by the reporting date. However, under the provisions of IAS 12, no deferred tax is recognized for temporary differences arising from goodwill for which impairment losses are not deductible for tax purposes, or from the initial recognition of an asset or liability in a transaction which (i) is not a business combination and (ii) at the time of the transaction, affects neither accounting income nor taxable income. In addition, deferred tax assets are only recognized to the extent that it is probable that taxable income will be available against which the deductible temporary differences can be utilized.

A deferred tax liability is recognized for all taxable temporary differences associated with investments in subsidiaries, associates, joint ventures and branches, except if the Group is able to control the timing of the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

Net balances of deferred taxes are calculated based on the tax position of each company or on the total income of companies included within the relevant consolidated tax group, and are presented in assets or liabilities for their net amount per tax entity.

Deferred taxes are reviewed at each reporting date to take into account factors including the impact of changes in tax laws and the prospects of recovering deferred tax assets arising from deductible temporary differences.

Deferred tax assets and liabilities are not discounted.

Tax effects relating to coupon payments on deeply-subordinated perpetual notes are recognized in profit or loss.

11.1 Actual income tax expense recognized in the income statement

11.1.1 Breakdown of actual income tax expense recognized in the income statement

The tax expense recognized in the income statement for 2019 amounts to €640 million (€704 million income tax expense in 2018). It breaks down as follows:

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
Current income taxes	(761)	(712)
Deferred taxes	121	9
TOTAL INCOME TAX BENEFIT/(EXPENSE) RECOGNIZED IN INCOME	(640)	(704)

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

11.1.2 Reconciliation of theoretical income tax expense with actual income tax expense

A reconciliation of theoretical income tax expense with the Group's actual income tax expense is presented below:

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
Net income/(loss)	1,649	1,629
Share in net income of equity method entities	500	361
Net income from discontinued operations	-	1,069
Income tax expense	(640)	(704)
Income/(loss) before income tax expense and share in net income of associates (A)	1,790	903
Of which French companies	285	1,434
Of which companies outside France	1,505	(531)
Statutory income tax rate of the parent company (B)	34.4%	34.4%
THEORETICAL INCOME TAX EXPENSE (C) = (A) X (B)	(616)	(311)
Reconciling items between theoretical and actual income tax expense		
Difference between statutory tax rate applicable to the parent and statutory tax rate in force in jurisdictions in France and abroad	215	42
Permanent differences ⁽²⁾	(23)	(72)
Income taxed at a reduced rate or tax-exempt ⁽³⁾	533	123
Additional tax expense ⁽⁴⁾	(123)	(74)
Effect of unrecognized deferred tax assets on tax loss carry-forwards and other tax-deductible temporary differences ⁽⁵⁾	(867)	(968)
Recognition or utilization of tax income on previously unrecognized tax loss carry-forwards and other tax-deductible temporary differences ⁽⁶⁾	212	370
Impact of changes in tax rates ⁽⁷⁾	(55)	54
Tax credits and other tax reductions ⁽⁸⁾	101	185
Other ⁽⁹⁾	(16)	(53)
INCOME TAX BENEFIT/(EXPENSE) RECOGNIZED IN INCOME	(640)	(704)

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

(2) Includes mainly disallowable impairment losses on goodwill, disallowable operating expenses, the deduction of interest expenses arising from hybrid debts and effects relating to the cap on allowable interest on borrowings in France in 2018.

(3) Reflects notably capital gains on disposals of securities exempt from tax or taxed at a reduced rate in some tax jurisdictions, the impact of the specific tax regimes used by some entities, disallowable impairment losses and capital losses on securities, and the impact of untaxed income from remeasuring previously-held (or retained) equity interests in connection with acquisitions and changes in consolidation methods.

(4) Includes mainly tax on dividends resulting from the parent company tax regime, withholding tax on dividends and interest levied in several tax jurisdictions, allocations to provisions for income tax, and regional and flat-rate corporate taxes.

(5) Includes (i) the cancellation of the net deferred tax asset position for some tax entities in the absence of sufficient profit being forecast and (ii) the impact of disallowable impairment losses on fixed assets.

(6) Includes the impact of the recognition of net deferred tax asset positions for some tax entities.

(7) Includes mainly the impact of tax rate changes on deferred tax balances in France.

(8) Includes notably reversals of provisions for tax litigation, tax credits in France and other tax reductions.

(9) Includes mainly the correction of previous tax charges.

11.1.3 Analysis of the deferred tax income/(expense) recognized in the income statement, by type of temporary difference

<i>In millions of euros</i>	Impact in the income statement	
	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
Deferred tax assets:		
Tax loss carry-forwards and tax credits	572	302
Pension and related obligations	28	2
Non-deductible provisions	(137)	(77)
Difference between the carrying amount of PP&E and intangible assets and their tax bases	(93)	(141)
Measurement of financial instruments at fair value (IAS 32 / IFRS 9)	(1,360)	845
Other	(36)	38
TOTAL	(1,028)	969
Deferred tax liabilities:		
Difference between the carrying amount of PP&E and intangible assets and their tax bases	(239)	(249)
Measurement of financial instruments at fair value (IAS 32 / IFRS 9)	1,661	(751)
Other	(273)	116
TOTAL	1,149	(884)
DEFERRED TAX INCOME/(EXPENSE)	121	85
<i>Of which continued activities</i>	121	9

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

11.2 Deferred tax income/(expense) recognized in "Other comprehensive income"

Net deferred tax income/(expense) recognized in "Other comprehensive income" is broken down by component as follows:

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018
Equity and debt instruments	(2)	(1)
Actuarial gains and losses	256	68
Net investment hedges	12	(14)
Cash flow hedges on other items	218	71
Cash flow hedges on net debt	10	(10)
TOTAL EXCLUDING SHARE OF EQUITY METHOD ENTITIES	494	114
Share of equity method entities	81	(20)
Discontinued operations	-	(81)
TOTAL	575	13

11.3 Deferred taxes presented in the statement of financial position

11.3.1 Change in deferred taxes

Changes in deferred taxes recognized in the statement of financial position, after netting deferred tax assets and liabilities by tax entity, break down as follows:

<i>In millions of euros</i>	Assets	Liabilities	Net position
AT DECEMBER 31, 2018 ⁽¹⁾	1,066	(5,415)	(4,349)
IFRS 16 (see Note 1)	-	4	4
AT JANUARY 1, 2019 including IFRS 16	1,066	(5,410)	(4,345)
Impact on net income/(loss) for the year	(1,028)	1,149	121
Impact on other comprehensive income items	482	38	520
Impact of changes in scope of consolidation	(86)	29	(57)
Impact of translation adjustments	10	(27)	(17)
Other	(115)	121	7
Impact of netting by tax entity	531	(531)	-
AT DECEMBER 31, 2019	860	(4,631)	(3,771)

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

11.3.2 Analysis of the net deferred tax position recognized in the statement of financial position (before netting deferred tax assets and liabilities by tax entity), by type of temporary difference

Accounting standards

Measurement of recognized tax loss carry-forwards

Deferred tax assets are recognized on tax loss carry-forwards when it is probable that taxable profit will be available against which the tax loss carry-forwards can be utilized. The probability that taxable profit will be available against which the unused tax losses can be utilized, is based on taxable temporary differences relating to the same taxation authority and the same taxable entity and estimates of future taxable profits. These estimates and utilizations of tax loss carry-forwards were prepared on the basis of profit and loss forecasts over a six-year tax projection period as included in the medium-term business plan validated by Management, subject to exceptions justified by a particular context and, if necessary, on the basis of additional forecasts.

<i>In millions of euros</i>	Statement of financial position at	
	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
Deferred tax assets:		
Tax loss carry-forwards and tax credits	2,118	1,765
Pension obligations	1,635	1,374
Non-deductible provisions	268	371
Difference between the carrying amount of PP&E and intangible assets and their tax bases	763	787
Measurement of financial instruments at fair value (IAS 32 / IFRS 9)	2,199	3,398
Other	518	545
TOTAL	7,502	8,239
Deferred tax liabilities:		
Difference between the carrying amount of PP&E and intangible assets and their tax bases	(8,953)	(8,773)
Measurement of financial instruments at fair value (IAS 32 / IFRS 9)	(1,700)	(3,343)
Other	(620)	(472)
TOTAL	(11,273)	(12,588)
NET DEFERRED TAX ASSETS/(LIABILITIES)	(3,772)	(4,349)

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

11.4 Unrecognized deferred taxes

At December 31, 2019, the tax effect of tax losses and tax credits eligible for carry-forward but not utilized and not recognized in the statement of financial position amounted to €3,836 million (€3,216 million at December 31, 2018). Most of these unrecognized tax losses relate to companies based in countries which allow losses to be carried forward indefinitely (mainly Belgium and Luxembourg) or for up to nine or six years in the Netherlands depending on the year these losses were realized. These tax loss carry-forwards did not give fully or partially rise to the recognition of deferred tax due to the absence of sufficient profit forecasts in the medium term.

The tax effect of other tax-deductible temporary differences not recorded in the statement of financial position was €929 million at end-December 2019 versus €1,364 million at end-December 2018.

NOTE 12 EARNINGS PER SHARE

Accounting standards

Basic earnings per share is calculated by dividing net income Group share for the year by the weighted average number of ordinary shares outstanding during the year. The average number of ordinary shares outstanding during the year is the number of ordinary shares outstanding at the beginning of the year, adjusted by the number of ordinary shares bought back or issued during the year.

For the diluted earnings per share calculation, the weighted average number of shares and basic earnings per share are adjusted to take into account the impact of the conversion or exercise of any dilutive potential ordinary shares (options, warrants and convertible bonds, etc.).

In compliance with IAS 33 – *Earnings per Share*, earnings per share and diluted earnings per share are based on net income/(loss) Group share after deduction of payments to bearers of deeply-subordinated perpetual notes (see Note 18.2.1 “Issuance of deeply-subordinated perpetual notes”).

The Group's dilutive instruments included in the calculation of diluted earnings per share include bonus shares and performance shares granted in the form of ENGIE securities.

	Dec. 31, 2019	Dec. 31, 2018 ⁽¹⁾
Numerator (in millions of euros)		
Net income/(loss) Group share	984	1,033
<i>Of which Net income/(loss) relating to continued operations, Group share</i>	<i>984</i>	<i>(12)</i>
Interest from deeply-subordinated perpetual notes	(165)	(145)
Net income used to calculate earnings per share	820	889
<i>Of which Net income/(loss) relating to continued operations, Group share, used to calculate earnings per share</i>	<i>820</i>	<i>(156)</i>
Impact of dilutive instruments	-	-
Diluted net income/(loss) Group share	820	889
Denominator (in millions of shares)		
Average number of outstanding shares	2,413	2,396
Impact of dilutive instruments:		
Bonus share plans reserved for employees	12	11
Diluted average number of outstanding shares	2,425	2,407
Earnings per share (in euros)		
Basic earnings/(loss) per share	0.34	0.37
<i>Of which Basic earnings/(loss) Group share relating to continued operations per share</i>	<i>0.34</i>	<i>(0.07)</i>
Diluted earnings/(loss) per share	0.34	0.37
<i>Of which Diluted earnings/(loss) Group share relating to continued operations per share</i>	<i>0.34</i>	<i>(0.06)</i>

(1) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 (see Note 1 “Accounting framework and basis for preparing the consolidated financial statements”).

NOTE 13 GOODWILL

Accounting standards

Goodwill is measured as the difference between:

- on the one hand the sum of:
 - the consideration transferred,
 - the amount of non-controlling interests in the acquire, and
 - in a business combination achieved in stages, the acquisition-date fair value of the previously held equity interest in the acquiree;
- on the other hand the net fair value of the identifiable assets acquired and liabilities assumed. The key assumptions and estimates used to determine the fair value of assets acquired and liabilities assumed include the market outlook for the measurement of future cash flows as well as applicable discount rates. These assumptions reflect management's best estimates at acquisition date.

The amount of goodwill recognized at the acquisition date cannot be adjusted after the end of the 12 month measurement period.

Goodwill relating to interests in associates is recorded under "Investments in equity method entities".

Risk of impairment

Goodwill is not amortized but tested for impairment each year in accordance with IAS 36, or more frequently where an indication of impairment is identified. Impairment tests are carried out at the level of cash-generating units (CGUs) or groups of CGUs, which constitute groups of assets which generate cash flows that are largely independent from cash flows generated by other CGUs.

Goodwill is impaired if the net carrying amount of the CGU to which the goodwill is allocated is greater than the recoverable amount of that CGU. The methods used to carry out these impairment tests are described in paragraph 13.3.

Impairment losses in relation to goodwill cannot be reversed and are shown as "Impairment losses" in the income statement.

Indicators of goodwill impairment

The main indicators of impairment used by the Group are:

- using external sources of information
 - a decline in an asset's value over the period that is significantly more than would be expected from the passage of time or normal use,
 - significant adverse changes that have taken place over the period, or will take place in the near future, in the technological market, economic or legal environment in which the entity operates or in the market to which an asset is dedicated,
 - an increase over the period in market interest rates or other market rates of return on investments if such increase is likely to affect the discount rate used in calculating an asset's value in use and decrease its recoverable amount materially,
 - the carrying amount of the net assets of the entity exceeds its market capitalization;
- using internal sources of information
 - evidence of obsolescence or physical damage to an asset,

- significant changes in the extent to which, or manner in which, an asset is used or is expected to be used, that have taken place in the period or soon hereafter and that will have an adverse effect on it. These changes include the asset becoming idle, plans to dispose of an asset sooner than expected, reassessing its useful life as finite rather than indefinite or plans to restructure the operations for which the asset belong,
- internal reports that indicate that the economic performance of an asset is, or will be, worse than expected.

13.1 Movements in the carrying amount of goodwill

<i>In millions of euros</i>	Net amount
AT DECEMBER 31, 2018	17,809
Impairment losses	(116)
Changes in scope of consolidation and Other	876
Translation adjustments	96
AT DECEMBER 31, 2019	18,665

Changes in the period were mainly attributable to (i) the impact of changes in the scope of consolidation primarily relating to the recognition of goodwill arising on the acquisition of Powerlines Group GmbH (€160 million), OTTO Luft-und Klimatechnik GmbH & Co (€137 million), Compañía Americana de Multiservicios (€78 million), CN'Air's Houat group (€77 million) and Pierre Guerin (€69 million), and to (ii) the recognition of an impairment loss amounting to €108 million relating to the disposal of coal-fired power plants in Germany and the Netherlands.

13.2 Goodwill CGUs

The table below shows “material” goodwill CGUs at December 31, 2019:

<i>In millions of euros</i>	Operating segment	Dec. 31, 2019
MATERIAL CGUs		
Benelux	Rest of Europe	4,260
GRDF	France Infrastructures	4,009
France Renewable Energy	France excl. Infrastructures	1,194
United Kingdom	Rest of Europe	1,115
OTHER SIGNIFICANT CGUs		
France BtoB	France excl. Infrastructures	1,052
France BtoC	France excl. Infrastructures	1,046
North America	USA & Canada	986
Northern, Southern and Central Europe	Rest of Europe	818
GRTgaz	France Infrastructures	614
Generation Europe	Rest of Europe	521
OTHER CGUs		3,051
TOTAL		18,665

13.3 Impairment testing of goodwill CGUs

All goodwill CGUs are tested for impairment based on data as of end-June, plus a review of events arisen in the second half of the year. In most cases, the recoverable amount of CGUs is determined by reference to a value in use that is calculated using cash flow projections drawn up on the basis of the 2020 budget and the 2021-2022 medium-term business plan, as approved by the Executive Committee and the Board of Directors, and on extrapolated cash flows beyond that time frame.

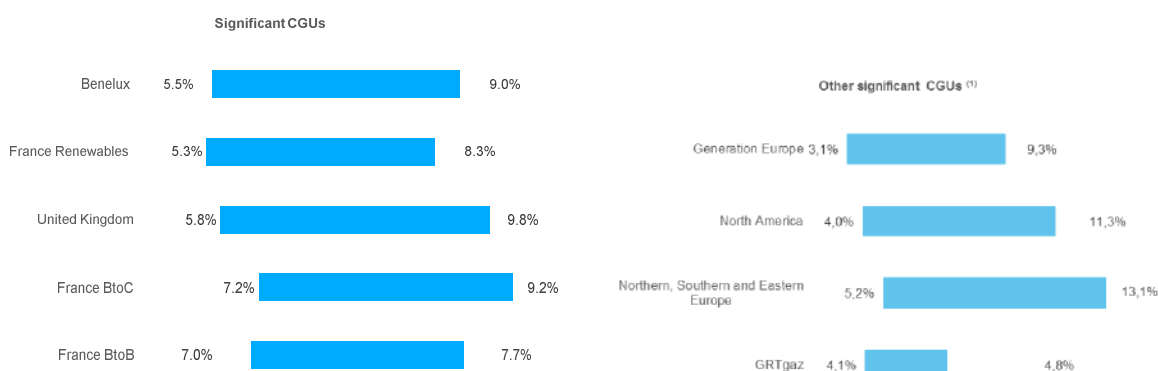
Cash flow projections are determined on the basis of macroeconomic assumptions (inflation, exchange rates and growth rates) and price forecasts resulting from the Group's reference scenario for 2023-2040. The forecasts that feature in the reference scenario were approved by the Executive Committee in December 2019. The forecasts and projections included in the reference scenario were determined on the basis of the following inputs:

- forward market prices over the liquidity period for fuel (coal, oil and gas), CO₂ and electricity on each market;

- beyond this period, medium- and long-term energy prices were determined by the Group based on macroeconomic assumptions and fundamental supply and demand equilibrium models, the results of which are regularly compared against forecasts prepared by external energy sector specialists. Long-term projections for CO₂ are in line with the 2050 targets of climate neutrality set by the European commission as part of the “green deal” published in December 2019. More specifically, medium- and long-term electricity prices were determined by the Group using electricity demand forecasting models, medium- and long-term forecasts of fuel and CO₂ prices, and expected trends in installed capacity and in the technology mix of the production assets within each power generation system.

Discount rate

The discount rates used correspond to the weighted average cost of capital, which is adjusted in order to reflect the business, market, country and currency risk relating to each goodwill CGU reviewed. The discount rates used are consistent with available external information sources. The post-tax rates used in 2019 to measure the value in use of the goodwill CGUs for discounting future cash flows ranged between 3.1% and 13.1%, compared with a range of between 3.7% and 11.3% in 2018. The discount rates used for the main goodwill CGUs are shown below:



(1) The valuation methods used are the discounted cash flows (DCF) method and the discounted dividend model (DDM) method.

13.3.1 Material CGUs

This section presents the method for determining value in use, the key assumptions underlying the valuation, and the sensitivity analyses for the impairment tests on the Group's main goodwill CGUs at December 31, 2019.

13.3.1.1 Benelux CGU

The goodwill allocated to the Benelux CGU amounted to €4,260 million at December 31, 2019. The Benelux CGU includes the Group's activities in Belgium, the Netherlands and Luxembourg: (i) power generation activities using its nuclear power plants and wind farms, (ii) natural gas and electricity sales activities, and (iii) energy services activities, as well as drawing rights on the Chooz B and Tricastin power plants in France.

Key assumptions used for the impairment test

The cash flow projections for the Benelux CGU are based on a large number of key assumptions, such as the long-term prices for fuel and CO₂, expected trends in gas and electricity demand and in electricity prices, the market outlook, and changes in the regulatory environment (especially concerning nuclear capacities in Belgium and the extension of drawing rights agreements for French nuclear plants). The key assumptions also include the discount rate used to calculate the value in use of this goodwill CGU.

Cash flow projections for the period beyond the medium-term business plan were determined as described below:

Activities	Assumptions applied beyond the term of the business plan ⁽¹⁾
Nuclear power generation in Belgium	For Doel 1, Doel 2 and Tihange 1, cash flow projection over the residual useful life of 50 years. For the second generation reactors Doel 3 and Tihange 2, cash flow projection over the residual useful life of 40 years. For the second generation reactors Doel 4 and Tihange 3, extension of the operating life for a period of 20 years.
Drawing rights on Chooz B et Tricastin power plants	Cash flow projection over the remaining term of existing contract plus assumption that drawing rights will be extended for a further 10 years.
Energy retail and service activities	Cash flow projection over the duration of the business plan at mid-term, plus application of a terminal value based on a normative cash flow using a long-term growth rate of 1.9%

(1) Assumptions unchanged from December 31, 2018.

The most important assumptions concerning the Belgian regulatory environment relate to the operating life of existing nuclear reactors and the level of royalties and nuclear contributions paid to the Belgian State.

The impairment test took into account the 10-year extension (through 2025) of the operating life of Tihange 1, Doel 1 and Doel 2, annual royalties totaling €20 million in respect of said extension and the new conditions for determining the nuclear contribution that will apply to second-generation reactors (Doel 3 and 4, Tihange 2 and 3) through their 40th year of operation, as defined in the December 29, 2016 law.

As regards second-generation reactors, the principle of a gradual phase-out of nuclear power and the schedule for this phase-out, with the shutdown of the reactors Doel 3 in 2022, Tihange 2 in 2023 and Tihange 3 and Doel 4 in 2025, after 40 years of operation, were reaffirmed in the law of June 18, 2015 and by the energy pact approved by the government on March 30, 2018. The pact is supplemented by a federal energy strategy based on four objectives: the safeguarding of supplies, the impact on climate, the impact on energy prices, and the safety of power plants. A monitoring committee has been set up to evaluate the achievement of these objectives and, where applicable, make recommendations to policymakers so that corrective action may be taken.

However, in view of (i) the extension of the operating life of Tihange 1, Doel 1 and Doel 2 beyond 40 years, (ii) the importance of nuclear power generation in the Belgian energy mix, (iii) the lack of a sufficiently detailed and attractive industrial plan enticing energy utilities to invest in replacement thermal capacity, and (iv) CO₂ emissions reduction targets, the Group considers that nuclear power will still be needed to guarantee the energy equilibrium in Belgium after 2025. Accordingly, in calculating value in use, the Group assumes a 20-year extension of the operating life of half of its second-generation reactors, while taking into account a mechanism of nuclear contributions to be paid to the Belgian government. Should the circumstances described above change in the future, the Group may adapt its industrial scenarios accordingly.

In France, the Nuclear Safety Authority authorized a fourth 10-yearly inspection for the Tricastin nuclear power plants, allowing a 10-year extension of the operating life of these reactors. The Group therefore included an assumption that its drawing rights on the Tricastin and Chooz B nuclear plants expiring in 2021 and 2037, respectively, would be extended by 10 years. This extension assumption had also been taken into account in 2018 as the Group considered that extending the reactors' operating life was the most credible and likely scenario at this point in time. This was also consistent with the expected French energy mix featured in the Group's reference scenario.

Results of the impairment test

At December 31, 2019, the recoverable amount of the goodwill CGU was higher than its carrying amount. Furthermore, the Group recognized impairment losses of €1,022 million against nuclear reactors (see Note 9.1 "Impairment losses"), including €638 million on dismantling assets for nuclear facilities whose operating life may no longer be extended, the recognition of which follows the triennial review of nuclear provisions (see Note 19.2 "Nuclear power generation activities").

Sensitivity analyses

A decrease of €10/MWh in electricity prices for nuclear power generation would lead to an additional impairment loss of around €0.5 billion. Conversely, an increase of €10/MWh in electricity prices would have a positive impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU.

An increase of 50 basis points in the discount rates used would have a negative 54% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 57% impact on the calculation.

Various transformational scenarios were considered concerning nuclear power generation in Belgium:

- the disappearance of the entire nuclear component from the portfolio in 2025 after 50 years of operation in the case of Tihange 1, Doel 1 and Doel 2, and 40 years of operation for the second-generation reactors would have a strongly adverse impact on the results of the test, with the recoverable amount falling significantly below the carrying amount. In this scenario, the impairment risk would represent around €1.5 billion;
- if the life of half of the second-generation reactors were to be extended by ten years and the entire nuclear component subsequently disappear, the recoverable amount would fall below the carrying amount and the impairment risk would represent €0.6 billion.

13.3.1.2 GRDF CGU

The total amount of goodwill allocated to the GRDF CGU was €4,009 million at December 31, 2019. The GRDF CGU groups together the Group's regulated natural gas distribution activities in France.

The terminal value used to calculate the value in use corresponds to the expected Regulated Asset Base (RAB) with no premium at the end of 2025. The RAB is the value assigned by the French Energy Regulation Commission (CRE) to the assets operated by the distributor. It is the sum of the future pre-tax cash flows, discounted at a rate that equals the pre-tax rate of return guaranteed by the regulator.

The cash flow projections are drawn up based on the tariff for public natural gas distribution networks, known as the "ATRD 6 tariff", which will enter into effect for a period of four years on July 1, 2020, and on the overall level of investments agreed by the CRE as part of its decision on the "ATRD 5 tariff".

Given the regulated nature of the businesses grouped within the GRDF CGU, a reasonable change in any of the valuation inputs would not result in impairment losses.

13.3.1.3 France Renewable Energy CGU

The goodwill allocated to the France Renewable Energy CGU amounted to €1,194 million at December 31, 2019. The France Renewable Energy CGU groups together the development, construction, financing, operation and maintenance of all of the renewable power generation assets in France (hydraulic, wind and photovoltaic).

For the hydraulics business, the terminal value was determined to calculate the value in use by extrapolating the cash flows beyond that period based on the reference scenario adopted by the Group.

The main assumptions and key estimates relate primarily to discount rates, assumptions on the renewal of the hydropower concession agreements and changes in the sales prices of electricity beyond the liquidity period.

Value in use of the Compagnie Nationale du Rhône and SHEM was calculated based on assumptions including the extension or renewal of a tender process for the concession agreements, as well as on the conditions of a potential extension.

The cash flows for the periods covered by the renewal of the concession agreements are based on a number of assumptions relating to the economic and regulatory conditions for operating these assets (royalty rates, required level of investment, etc.) during this period.

A decrease of €10/MWh in electricity prices for hydropower generation would have a negative 73% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. Conversely, an increase of €10/MWh in electricity prices would have a positive 71% impact on the calculation.

An increase of 50 basis points in the discount rates used would have a negative 48% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 65% impact on the calculation.

If the Compagnie Nationale du Rhône hydropower concession agreements are not renewed beyond 2023, this would have a strong adverse impact on the results of the test, with the recoverable amount falling significantly below the carrying amount. In this scenario, the impairment risk would represent around €1.3 billion.

13.3.1.4 United Kingdom CGU

The goodwill allocated to the United Kingdom CGU amounted to €1,115 million at December 31, 2019. The United Kingdom CGU includes activities in (i) renewable power generation (hydraulic, wind and solar), (ii) gas and electricity sales, and (iii) services to individual and professional customers in the United Kingdom.

The terminal value used to calculate the value in use of the services and energy sales businesses was determined by extrapolating the cash flows beyond that period using a long-term growth rate of 2% per year.

The main assumptions and key estimates relate primarily to discount rates and changes in price beyond the liquidity period.

An increase of 50 basis points in the discount rates used would have a negative 52% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 40% impact on the calculation.

A decrease of 10% in the margin captured by power generation assets would have a negative 21% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. An increase of 10% in the margin captured would have a positive 21% impact on this calculation.

13.3.2 Other significant CGUs

13.3.2.1 North America CGU

The goodwill allocated to the North America CGU amounted to €986 million at December 31, 2019. The North America CGU mainly comprises:

- Canada, which includes activities in (i) renewable power generation (wind and biomass), (ii) services to individual and professional customers;
- the United States, which includes activities in (i) gas and electricity sales, (ii) services to individual and professional customers and (iii) thermal power generation;
- Puerto Rico, which includes an investment in EcoElectrica, a key energy industry player in Puerto Rico's economy (see Note 3.2 "Investments in joint ventures"). Despite the difficult financial environment in Puerto Rico, ENGIE does not have any information at December 31, 2019 on the basis of which the Group would modify its valuation assumptions regarding its share in these assets.

The wind and solar energy production activities acquired in the United States in 2018 make up an independent goodwill CGU.

The value in use of these activities was calculated using the cash flow projections drawn up on the basis of the 2020 budget and the 2021-2022 medium-term business plan. A terminal value was calculated for the services and energy sales businesses using EBITDA multiples as a basis.

The main assumptions and key estimates relate primarily to discount rates and changes in captured margins beyond the liquidity period.

An increase of 50 basis points in the discount rates used would have a negative impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive impact on the calculation.

A decrease of 10% in the margin on gas and electricity sales activities would have a negative 18% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. Conversely, an increase of 10% in the margin on gas and electricity sales activities would have a positive 18% impact on the calculation.

A decrease of 10% in service activities would have a negative 8% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. Conversely, an increase of 10% in the margin on gas and electricity sales activities would have a positive 8% impact on the calculation.

13.3.2.2 Generation Europe CGU

The goodwill allocated to the Generation Europe CGU amounted to €521 million at December 31, 2019. The Generation Europe CGU groups together the thermal power generation activities in Europe.

The value in use of these activities was calculated using the cash flow projections drawn up on the basis of the 2020 budget and the 2021-2022 medium-term business plan. Beyond this three-year period, cash flows were projected over the useful lives of the assets based on the reference scenario adopted by the Group.

The main assumptions and key estimates relate primarily to discount rates, estimated demand for electricity and changes in the price of CO₂, fuel and electricity beyond the liquidity period.

Results of the impairment test

At December 31, 2019, the recoverable amount of the Generation Europe goodwill CGU was higher than its carrying amount.

Sensitivity analyses

An increase of 50 basis points in the discount rates used would have a negative 15% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 18% impact on the calculation.

A decrease of 10% in the margin captured by thermal power plants would have a negative 24% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. An increase of 10% in the margin captured would have a positive 24% impact on this calculation.

13.3.2.3 Other significant goodwill CGUs

For the other significant goodwill CGUs, there is a considerable difference between their recoverable amount and their carrying amount at December 31, 2019.

13.4 Goodwill segment information

The carrying amount of goodwill can be analyzed as follows by reportable segment:

<i>In millions of euros</i>	Dec. 31, 2019
France excluding Infrastructures	3,705
France Infrastructures	5,006
Rest of Europe	6,713
Latin America	820
USA & Canada	1,103
Middle East, Asia & Africa	741
Others	576
TOTAL	18,665

NOTE 14 INTANGIBLE ASSETS

Accounting standards

Initial measurement

Intangible assets are carried at cost less any accumulated amortization and any accumulated impairment losses.

Amortization

Intangible assets are amortized on the basis of the expected pattern of consumption of the estimated future economic benefits embodied in the asset. Amortization is calculated mainly on a straight-line basis over the following useful lives:

Main depreciation periods (years)	Useful life	
	Minimum	Maximum
Concession rights	10	30
Customer portfolio	10	40
Other intangible assets	1	50

Intangible assets with an indefinite useful life are not amortized but are tested for impairment annually.

Risk of impairment

In accordance with IAS 36, impairment tests are carried out on items of property, plant and equipment and intangible assets where there is an indication that the assets may be impaired. Such indications may be based on events or changes in the market environment, or on internal sources of information. Intangible assets that are not amortized are tested for impairment annually.

Impairment indicators

Property, plant and equipment and intangible assets with finite useful lives are only tested for impairment when there is an indication that they may be impaired. This is generally the result of significant changes in the environment in which the assets are operated or when economic performance is lower than expected.

Main impairment indicators used by the Group are described in Note 13 "Goodwill".

Impairment

Items of property, plant and equipment and intangible assets are tested for impairment at the level of the individual asset or cash-generating unit (CGU), as appropriate and, determined in accordance with IAS 36. If the recoverable amount of an asset is lower than its carrying amount, the carrying amount is written down to the recoverable amount by recording an impairment loss. Upon recognition of an impairment loss, the depreciable amount and possibly the useful life of the asset concerned is revised.

Impairment losses recorded in relation to property, plant and equipment or intangible assets may be subsequently reversed if the recoverable amount of the asset increases to exceed the carrying amount. The increased carrying amount of an item of property, plant or equipment following the reversal of an impairment loss may not exceed the carrying amount that would have been determined (net of depreciation/amortization) had no impairment loss been recognized in prior periods.

Measurement of recoverable amount

In order to review the recoverable amount of property, plant and equipment and intangible assets, the assets are grouped, where appropriate, into CGUs and the carrying amount of each CGU is compared with its recoverable amount.

For operating entities which the Group intends to hold on a long-term and going concern basis, the recoverable amount of a CGU corresponds to the higher of its fair value less costs to sell and its value in use. Value in use is primarily determined based on the present value of future operating cash flows including a terminal value. Standard valuation techniques are used based on the following main economic assumptions:

- market perspectives and developments in the regulatory framework;
- discount rates based on the specific characteristics of the operating entities concerned;
- terminal values in line with available market data specific to the operating segments concerned and growth rates associated with these terminal values, not to exceed the inflation rate.

Discount rates are determined on a post-tax basis and applied to post-tax cash flows. The recoverable amounts calculated on the basis of these discount rates are the same as the amounts obtained by applying the pre-tax discount rates to cash flows estimated on a pre-tax basis, as required by IAS 36.

For operating entities which the Group has decided to sell, the related recoverable amount of the assets concerned is based on market value less costs of disposal. Where negotiations are ongoing, this value is determined based on the best estimate of their outcome as of the reporting date.

In the event of a decline in value, the impairment loss is recorded in the consolidated income statement under "Impairment losses".

Intangible rights arising on concession contracts

IFRIC 12 – *Service concession arrangements* deals with the treatment to be applied by the concession operator in respect of certain concession arrangements.

For a concession arrangement to fall within the scope of IFRIC 12, usage of the infrastructure must be controlled by the concession grantor. This requirement is satisfied when the following two conditions are met:

- the grantor controls or regulates what services the operator must provide with the infrastructure, to whom it must provide them, and at what price; and
- the grantor controls any residual interest in the infrastructure at the end of the term of the arrangement, for example retains the right to take back the infrastructure at the end of the concession.

The intangible asset model according to paragraph 17 of IFRIC 12 applies if the operator receives a right (a license) to charge the users, or the grantor, depending on the use made of the public service. There is no unconditional right to receive cash as the amounts depend on the extent to which the public uses the service.

Concession infrastructures that do not meet the requirements of IFRIC 12 are presented as property, plant and equipment. This is the case of gas distribution infrastructures in France. The related assets are recognized in accordance with IAS 16, given that GRDF operates its network under long-term concession arrangements, most of which are mandatorily renewed upon expiration pursuant to French law No. 46-628 of April 8, 1946.

Research and development costs

Research costs are expensed as incurred.

Development costs are capitalized when the asset recognition criteria set out in IAS 38 are met. Capitalized development costs are amortized over the useful life of the intangible asset recognized.

14.1 Movements in intangible assets

<i>In millions of euros</i>	Intangible rights arising on concession contracts	Capacity entitlements	Others	Total
GROSS AMOUNT				
AT DECEMBER 31, 2018 ⁽¹⁾	3,753	2,719	11,000	17,472
IFRS 16 (see Note 1)	(12)	-	-	(12)
AT JANUARY 1, 2019 with IFRS 16	3,741	2,719	11,000	17,460
Acquisitions	152	-	1,120	1,271
Disposals	(13)	(17)	(135)	(165)
Translation adjustments	(3)	-	36	33
Changes in scope of consolidation	(26)	-	5	(21)
Transfer to "Assets classified as held for sale"	-	-	2	2
Other	(14)	160	(43)	103
AT DECEMBER 31, 2019	3,838	2,862	11,984	18,684
ACCUMULATED AMORTIZATION AND IMPAIRMENT				
AT DECEMBER 31, 2018 ⁽¹⁾	(1,550)	(2,087)	(7,117)	(10,754)
IFRS 16 (see Note 1)	5	-	-	5
AT JANUARY 1, 2019 with IFRS 16	(1,545)	(2,087)	(7,117)	(10,749)
Amortization	(138)	(65)	(741)	(943)
Impairment	(14)	-	(128)	(142)
Disposals	12	17	62	91
Translation adjustments	1	-	(20)	(19)
Changes in scope of consolidation	26	-	119	145
Transfer to "Assets classified as held for sale"	-	-	-	-
Other	2	-	(31)	(29)
AT DECEMBER 31, 2019	(1,656)	(2,135)	(7,855)	(11,646)
CARRYING AMOUNT				
AT DECEMBER 31, 2018 ⁽¹⁾	2,204	632	3,883	6,718
AT DECEMBER 31, 2019	2,182	727	4,129	7,038

(1) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

In 2019, the net increase in "Intangible assets" was mainly attributable to investments for a total of €1,271 million, partially offset by amortization for a total of €943 million. Changes in scope of consolidation of €124 million relate mainly to the acquisition of OTTO Luft-und Klimatechnik GmbH & Co for €26 million, of the energy services companies Conti in North America for €34 million and of Certinergy for €51 million.

14.1.1 Impairment

At December 31, 2019, this caption notably relates to impairment losses recognized on Customer relationship in France following the adoption of the law enacting the end of regulated sales tariffs and rising rates of portfolio attrition for €111 million.

14.1.2 Capacity entitlements

The Group has acquired capacity entitlements from power stations operated by third parties. These power station capacity rights were acquired in connection with transactions or within the scope of the Group's involvement in financing the construction of certain power stations. In consideration, the Group received the right to purchase a share of the production over the useful life of the underlying assets. These rights are amortized over the useful life of the underlying assets, not to exceed 50 years. The Group currently holds entitlements in the Chooz B and Tricastin power plants in France and in the virtual power plant (VPP) in Italy.

14.1.3 Other

At December 31, 2019, this caption mainly relates to software and licenses for €1,218 million, as well as intangible assets in progress for €636 million and intangible assets (client portfolio) acquired as a result of business combinations and capitalized acquisition costs for customer contracts for €2,007 million.

14.2 Information regarding research and development costs

Research and development activities primarily relate to various studies regarding technological innovation, improvements in plant efficiency, safety, environmental protection, service quality, and the use of energy resources.

Research and development costs, excluding technical assistance costs, totaled €189 million in 2019, of which €23 million in expenses related to in-house projects in the development phase that meet the criteria for recognition as an intangible asset as defined in IAS 38.

NOTE 15 PROPERTY, PLANT AND EQUIPMENT

Accounting standards

Initial recognition and subsequent measurement

Items of property, plant and equipment are recognized at historical cost less any accumulated depreciation and any accumulated impairment losses.

The carrying amount of these items is not revalued as the Group has elected not to apply the allowed alternative method, which consists of regularly revaluing one or more categories of property, plant and equipment.

Investment subsidies are deducted from the gross value of the assets concerned.

In accordance with IAS 16, the initial cost of the item of property, plant and equipment includes an initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, when the entity has a present, legal or constructive obligation to dismantle the item or restore the site. A corresponding provision for this obligation is recorded for the amount of the asset component.

Borrowing costs that are directly attributable to the construction of the qualifying asset are capitalized as part of the cost of that asset.

Leases

Until December 31, 2018, only leases classified as finance leases for which the Group acts as a lessee, were recorded as an asset in the balance sheet in accordance with the principles of IAS 17 – *Leases*. A lease qualifies as a finance lease when all the risks and rewards incidental to the ownership of the related asset are substantially transferred to the lessee.

As indicated in Note 1.1.1 “IFRS Standards, amendments or IFRIC interpretations applicable in 2019” from January 1, 2019 the Group applies IFRS 16 – *Leases* to account for lease contracts where the Group acts as a lessee.

In accordance with IFRS 16, the Group recognizes a right-of-use asset and a corresponding lease liability with respect to contracts considered as a lease in which the Group acts as lessee, except for leases with a term of 12 months or less (“short-term leases”), and leases for which the underlying asset is of a low value (“low-value asset”). Payments associated with these leases are recognized on a straight-line basis as expenses in profit and loss. The lease contracts in the Group mainly concern real estate, vehicles and other equipment.

The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

The lease liability is initially measured at the present value of the remaining lease payments, discounted using the lessee's incremental borrowing rate. This rate is calculated based on the Group's incremental borrowing rate adjusted in accordance with IFRS 16, taking into account (i) the economic environment of the subsidiaries, and in particular their credit risk, (ii) the currency in which the contract is concluded and (iii) the duration of the contract at inception (or the remaining duration for contracts existing upon the initial application of IFRS 16). The methodology applied to determine the incremental borrowing rate reflects the profile of the lease payments (duration method).

The lease term is assessed, including whether a renewal option is reasonably certain to be exercised or a termination option is reasonably certain not to be exercised, on a case-by-case basis. The lease term is reassessed if a significant event or a significant change in circumstances that is within the control of the lessee occurs and may affect the assessment made. In determining the enforceable period of a lease, the Group applies a broad interpretation of the

term penalty and takes into consideration, not only contractual penalties arising from termination, but also ancillary costs that could arise in case of an early termination of the lease.

Cushion gas

“Cushion” gas injected into underground storage facilities is essential for ensuring that reservoirs can be operated effectively, and is therefore inseparable from these reservoirs. Unlike “working” gas which is included in inventories (see Note 24.2 “Inventories”), cushion gas is reported in other property, plant and equipment.

Depreciation

In accordance with the components approach, each significant component of an item of property, plant and equipment with a different useful life from that of the main asset to which it relates is depreciated separately over its own useful life.

Property, plant and equipment is depreciated mainly using the straight-line method over the following useful lives:

Main depreciation periods (years)	Useful life	
	Minimum	Maximum
Plant and equipment		
• Storage - Production - Transport - Distribution	5	60 ^(*)
• Installation - Maintenance	3	10
• Hydraulic plant and equipment	20	65
Other property, plant and equipment	2	33

(*)Excluding cushion gas.

The range of useful lives is due to the diversity of the assets in each category. The minimum periods relate to smaller equipment and furniture, while the maximum periods concern network infrastructures and storage facilities. In accordance with the law of January 31, 2003 adopted by the Belgian Chamber of Representatives with respect to the gradual phase-out of nuclear energy for the industrial production of electricity, the useful lives of nuclear power stations were reviewed and adjusted prospectively to 40 years as from 2003, except for Tihange 1, Doel 1 and Doel 2 for which the operating lives have been extended by 10 years.

Fixtures and fittings relating to hydro plants operated by the Group are depreciated over the shorter of the contract term and the useful life of the assets, taking into account the renewal of the concession period if such renewal is considered to be reasonably certain.

The right-of-use asset related to leases is depreciated using the straight-line method from the commencement date to the end of the lease term, unless the lease transfers ownership of the underlying asset to the Group by the end of the lease term. In that case the right-of-use asset is depreciated over the useful life of the underlying asset, which is determined on the same basis as that used for property, plant and equipment mentioned above.

Risk of impairment

See Note 14 “Intangible assets”.

Impairment indicators

See Note 13 “Goodwill”.

15.1 Movements in property, plant and equipment

<i>In millions of euros</i>	Land	Buildings	Plant and equipment	Vehicles	Dismantling costs	Assets in progress	Right of use	Other	Total
GROSS AMOUNT									
AT DECEMBER 31, 2018 ⁽¹⁾	671	5,676	81,615	419	2,444	5,469	-	1,015	97,309
IFRS 16 (see Note 1)	-	(230)	(1,161)	(2)	-	-	3,402	223	2,233
AT JANUARY 1, 2019 with IFRS 16	670	5,446	80,455	417	2,444	5,469	3,402	1,239	99,541
Acquisitions/Increases	6	26	596	55	1,124	4,801	539	102	7,250
Disposals	(18)	(61)	(371)	(19)	-	(18)	(78)	(47)	(611)
Translation adjustments	1	29	73	1	1	51	22	7	186
Changes in scope of consolidation	2	(308)	(3,924)	17	(56)	(41)	(43)	21	(4,332)
Transfer to "Assets classified as held for sale"	(2)	-	(100)	-	-	(276)	-	-	(378)
Other	38	357	5,129	(4)	(17)	(5,815)	40	94	(178)
AT DECEMBER 31, 2019	698	5,490	81,857	467	3,496	4,172	3,882	1,417	101,478
ACCUMULATED DEPRECIATION AND IMPAIRMENT									
AT DECEMBER 31, 2018 ⁽¹⁾	(130)	(3,175)	(42,270)	(290)	(1,418)	(367)	-	(742)	(48,392)
IFRS 16 (see Note 1)	-	83	222	-	-	-	(356)	(33)	(85)
AT JANUARY 1, 2019 with IFRS 16	(130)	(3,092)	(42,049)	(289)	(1,418)	(367)	(356)	(775)	(48,476)
Depreciation	(8)	(124)	(2,630)	(49)	(161)	-	(468)	(114)	(3,554)
Impairment	(2)	(12)	(729)	(1)	(662)	(35)	(91)	(1)	(1,532)
Disposals	3	53	273	16	-	2	65	42	455
Translation adjustments	-	(3)	(49)	(1)	(1)	-	(3)	(1)	(58)
Changes in scope of consolidation	2	302	3,077	(5)	38	1	7	(8)	3,414
Transfer to "Assets classified as held for sale"	-	-	7	-	-	-	-	-	7
Other	-	(119)	377	9	(19)	43	(22)	(44)	225
AT DECEMBER 31, 2019	(134)	(2,995)	(41,722)	(320)	(2,223)	(357)	(868)	(901)	(49,520)
CARRYING AMOUNT									
AT DECEMBER 31, 2018 ⁽¹⁾	541	2,501	39,345	129	1,026	5,102	-	273	48,917
AT DECEMBER 31, 2019	564	2,495	40,135	147	1,273	3,815	3,014	515	51,958

(1) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

In 2019, the net increase in "Property, plant and equipment" essentially takes into account :

- maintenance and development investments for a total amount of €5,587 million mainly related to the construction and the development of wind and solar farms in the United States, in Latin America and in India, as well as the extension of the transportation and distribution networks in the France Infrastructure segment;
- changes in the scope of consolidation amounting to a negative €918 million, predominantly related to DBSO ⁽¹⁾ activities relating to wind farms in the United States (negative €234 million), in Mexico (negative €137 million) and in France (negative €195 million), the disposal of the active solar installations of the company Langa (negative €256 million), and the disposal of the coal-fired power plants in Germany and the Netherlands (a negative €280 million), partially offset by the acquisition of a biomethane project in France (positive €92 million);
- positive net translation adjustments of €128 million, mainly resulting from the US dollar (positive impact of €129 million), the pound sterling (positive impact of €87 million) and the Brazilian real (negative impact of €75 million);
- partly offset by depreciation for a total negative impact of €3,554 million;
- the classification under "Assets held for sale" of solar fields in Mexico (negative €285 million) and assets in the renewable energies in France (negative €87 million);
- impairment losses amounting to €1,532 million mainly related to:
 - Belgian nuclear power assets for a negative €1,022 million (see Note 9.1.1 "Impairment losses recognized in 2019");

(1) Develop, Build, Share & Operate.

- the disposal of various coal-fired power plants in the Netherlands and in Germany for a negative €148 million, €108 million of which charged to the entire goodwill allocated to “assets held for sale” and €40 million to property, plant and equipment;
- the coal-fired power plants in Latin America for a negative €165 million due to the planned disconnection and discontinuation of operations of two coal-based energy generation units in Chile combined with the commitment to gradually decommission of coal-fired plants in Chile;
- the gas-steam turbines in the Middle-East, Asia & Africa reportable segment for which a permanent mothballing strategy is adopted due to the poor economic context for a negative €135 million.

15.2 Pledged and mortgaged assets

Items of property, plant and equipment pledged by the Group to guarantee borrowings and debt amounted to €2,261 million at December 31, 2019 compared to €1,298 million at December 31, 2018.

The increase mainly relates to thermoelectric and wind assets in Brazil for €950 million and renewable assets in France for €46 million.

15.3 Contractual commitments to purchase property, plant and equipment

In the ordinary course of their operations, some Group companies have entered into commitments to purchase, and the related third parties to deliver, property, plant and equipment. These commitments relate mainly to orders for equipment, and material related to the construction of energy production units and to service agreements.

Investment commitments made by the Group to purchase property, plant and equipment totaled €1,384 million at December 31, 2019 compared to €1,415 million at December 31, 2018.

15.4 Other information

Borrowing costs for 2019 included in the cost of property, plant and equipment amounted to €106 million at December 31, 2019 compared to €134 million at December 31, 2018.

NOTE 16 FINANCIAL INSTRUMENTS

16.1 Financial assets

Accounting standards

In accordance with the principles of IFRS 9 - *Financial Instruments*, financial assets are recognized and measured either at amortized cost, at fair value through equity or at fair value through profit or loss based on the following two criteria:

- a first criterion relating to the contractual cash flows characteristics of the financial asset. The analysis of contractual cash flow characteristics makes it possible to determine whether these cash flows are “only payments of principal and interest on the outstanding amounts” (known as “SPPI” test or Solely Payments of Principal and Interest);
- a second criterion relating to the business model used by the Group to manage its financial assets. IFRS 9 defines three different business models. A first business model whose objective is to hold assets in order to collect contractual cash flows (hold to collect), a second model whose objective is achieved by both collecting contractual cash flows and selling financial assets (hold to collect and sell) and other business models.

The identification of the business model and the analysis of the contractual cash flows characteristics require judgment to ensure that the financial assets are classified in the appropriate category.

Where the financial asset is an investment in an equity instrument and is not held for trading, the Group may irrevocably elect to present the gains and losses on that investment in other comprehensive income.

Except for trade receivables, which are measured at their transaction price in accordance with IFRS 15, financial assets are measured, on initial recognition, at fair value plus, in the case of a financial asset not at fair value through profit or loss, transaction costs that are directly attributable to their acquisition.

At the end of each reporting period, financial assets measured using the amortized cost method or at fair value through other comprehensive income (with a recycling mechanism) are subject to an impairment test based on the expected credit losses method.

Financial assets also include derivatives that are measured at fair value in accordance with IFRS 9.

In accordance with IAS 1, the Group presents current and non-current assets and current and non-current liabilities separately in the statement of financial position. In view of the majority of the Group's activities, it was considered that the criterion to be used to classify assets is the expected time to realize the asset or settle the liability: the asset is classified as current if this period is less than 12 months and as non-current if it is more than 12 months after the reporting period.

The following table presents the Group's different categories of financial assets, broken down into current and non-current items:

In millions of euros	Notes	Dec. 31, 2019			Dec. 31, 2018		
		Non-current	Current	Total	Non-current	Current	Total
Other financial assets	16.1	7,022	2,546	9,567	6,193	2,290	8,483
Equity instruments at fair value through other comprehensive income		921	-	921	742	-	742
Equity instruments at fair value through income		377	-	377	365	-	365
Debt instruments at fair value through other comprehensive income ⁽¹⁾		1,072	77	1,149	1,108	840	1,947
Debt instruments at fair value through income		871	397	1,268	600	233	832
Loans and receivables at amortized cost		3,782	2,072	5,854	3,378	1,218	4,596
Trade and other receivables	7.2	-	15,180	15,180	-	15,613	15,613
Assets from contracts with customers	7.2	15	7,816	7,831	-	7,411	7,411
Cash and cash equivalents ⁽¹⁾		-	10,519	10,519	-	8,700	8,700
Derivative instruments	16.4	4,137	10,134	14,272	2,693	10,679	13,372
TOTAL		11,174	46,194	57,369	8,886	44,692	53,578

(1) In 2019, the Group modified the accounting of certain financial assets deducted from net financial debt to reflect the Group's management policy regarding investments and liquidity risk of the Group, and thus reclassified these assets as cash and cash equivalents for an amount of €619 million at December 31, 2019. This change had no impact on net financial debt.

16.1.1 Other financial assets

16.1.1.1 Equity instruments at fair value

Accounting standards

Equity instruments at fair value through other comprehensive income (OCI)

Under IFRS 9 an irrevocable election can be made to present in other comprehensive income subsequent changes in the fair value of an investment in an equity instrument that is not held for trading. This choice is made on an instrument-by-instrument basis. Amounts presented in other comprehensive income should not be transferred to profit or loss including proceeds of disposals. However, IFRS 9 authorizes the transfer of the accumulated profits and losses to another component of equity. Dividends from such investments are recognized in profit or loss unless the dividend clearly represents the recovery of a portion of the cost of the investment.

The equity instruments recognized under this line item mainly concern investments in companies that are not controlled by the Group and for which OCI measurement has been selected given their strategic and long-term nature.

Upon initial recognition, these equity instruments are recognized at fair value, which is generally their acquisition cost, plus transaction costs.

At each reporting date, for listed securities, fair value is determined based on the quoted market price at the reporting date. For unlisted securities, fair value is measured using valuation models based primarily on the latest market transactions, the discounting of dividends or cash flows and the net asset value.

Equity instruments at fair value through profit or loss

Equity instruments that are held for trading or for which the Group has not elected for measurement at fair value through other comprehensive income are measured at fair value through profit or loss.

This category mainly includes investments in companies not controlled by the Group.

Upon initial recognition, these equity instruments are recognized at fair value, which is generally their acquisition cost.

At each reporting date, for listed and unlisted securities, the same measurement method as described above should be applied.

<i>In millions of euros</i>	Equity instruments at fair value through other comprehensive income	Equity instruments at fair value through income	Total
AT DECEMBER 31, 2018	742	365	1,107
Increase	226	170	396
Decrease	(111)	(24)	(135)
Changes in fair value	92	(23)	69
Changes in scope of consolidation, translation adjustments and other	(28)	(112)	(140)
AT DECEMBER 31, 2019	921	377	1,297
Dividends	65	7	72

Equity instruments break down as €222 million of listed equity instruments and €1,075 million of unlisted equity instruments. This amount mainly includes shares held by the Group as a minority interest in Nord Stream AG for an amount of €478 million.

16.1.1.2 Debt instruments at fair value

Accounting standards

Debt instruments at fair value through other comprehensive income

Financial assets that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets and for which the contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the outstanding amount (SPPI), are measured at fair value through OCI (with a recycling mechanism). This involves a measurement through profit or loss for interest (at amortized cost using the effective interest method), impairment and foreign exchange gains and losses, and through OCI (with a recycling mechanism) for other gains or losses.

This category mainly includes bonds.

Fair value gains and losses on these instruments are recognized in other comprehensive income, except for the following items which are recognized in profit or loss:

- interest income using the effective interest method;
- expected credit losses and reversals;
- foreign exchange gains and losses.

When the financial asset is derecognized, the cumulative gain or loss that was previously recognized in other comprehensive income is reclassified from equity to profit or loss.

Debt instruments at fair value through profit or loss

Financial assets whose contractual cash flows do not consist solely of payments of principal and interest on the amount outstanding (SPPI) or that are held in view of an "other" business model are measured at fair value through profit or loss.

The Group's investments in UCITS are accounted for in this caption. They are considered as debt instruments, according to IAS 32 - *Financial Instruments: Presentation*, given the existence of an obligation for the issuer to redeem units, at the request of the holder. They are measured at fair value through profit or loss because the contractual cash flows characteristics do not meet the SPPI test.

<i>In millions of euros</i>	Debt instruments at fair value through other comprehensive income	Liquid debt instruments held for cash investment purposes at fair value through other comprehensive income	Debt instruments at fair value through income	Liquid debt instruments held for cash investment purposes at fair value through income	Total
AT DECEMBER 31, 2018	1,025	922	525	307	2,779
Increase	647	10	430	197	1,284
Decrease	(617)	(306)	(269)	-	(1,193)
Changes in fair value	102	-	75	3	181
Changes in scope of consolidation, translation adjustments and other ⁽¹⁾	(20)	(614)	-	-	(634)
AT DECEMBER 31, 2019	1,138	11	761	507	2,417

(1) Of which €619 million of financial instruments deducted from net financial debt and reclassified from "Other financial assets" to "Cash and cash equivalents" (see Note 16.1 "Financial assets").

Debt instruments at fair value at December 31, 2019 include bonds and money market funds held by Synatom for €1,846 million and liquid instruments deducted from net financial debt for €518 million (respectively €1,492 million and €1,229 million at December 31, 2018).

16.1.1.3 Loans and receivables at amortized cost

Accounting standards

Loans and receivables held by the Group under a business model consisting in holding the instrument in order to collect the contractual cash flows, and whose contractual cash flows consist solely of payments of principal and interest on the principal amount outstanding (SPPI test) are measured at amortized cost. Interest is calculated using the effective interest method.

The following items are recognized in profit or loss:

- interest income using the effective interest method;
- expected credit losses and reversals;
- foreign exchange gains and losses.

The Group enters into services or take-or-pay contracts that are or contain a lease and under which the Group acts as lessor and its customers as lessees. Leases are analyzed in accordance with IFRS 16 in order to determine whether they constitute an operating lease or a finance lease. Whenever the terms of the lease transfer substantially all the risk and rewards of ownership of the related asset, the contract is classified as a finance lease and a finance receivable is recognized to reflect the financing deemed to be granted by the Group to the customer.

Leasing security deposits are presented in this caption and recognized at their nominal value.

Please refer to Note 17 "Risks arising from financial instruments" regarding the assessment of counterparty risk.

<i>In millions of euros</i>	Dec. 31, 2019			Dec. 31, 2018		
	Non-current	Current	Total	Non-current	Current	Total
Loans granted to affiliated companies	2,293	172	2,465	1,498	121	1,619
Other receivables at amortized cost	302	1,697	1,998	675	940	1,614
Amounts receivable under concession contracts	588	65	653	544	68	612
Amounts receivable under finance leases	599	138	738	661	89	750
TOTAL	3,782	2,072	5,854	3,378	1,218	4,596

"Loans and receivables at amortized cost" includes notably the €311 million loan granted to Neptune Energy as part of the sale of the exploration-production business. This item also includes the financing of the Nord Stream 2 pipeline project for

a nominal amount of €298 million (excluding capitalized interest and expected credit losses) for the first tranche and €433 million for the second tranche.

Impairment and expected credit losses against loans and receivables at amortized cost stood at €139 million at December 31, 2019 (€319 million at December 31, 2018). This amount includes notably the impairment on the Argentine State receivable related to the concessions granted to Aguas Provinciales de Santa Fe, attributable to SUEZ (see Note 25.4.1 Concessions in Buenos Aires and Santa Fe).

Net gains and losses recognized in the income statement relating to loans and receivables at amortized cost break down as follows:

<i>In millions of euros</i>	Interest income	Post-acquisition measurement	
		Foreign currency translation	Expected credit loss
At December 31, 2019	233	(38)	4
At December 31, 2018	263	(21)	(41)

No material expected credit losses were recognized against loans and receivables at amortized cost at December 31, 2019 and December 31, 2018.

Amounts receivable under finance leases

These contracts refer to lease contracts in which ENGIE acts as lessor, classified as finance leases in accordance with IFRS 16. They concern (i) energy purchase and sale contracts where the contract conveys an exclusive right to use a production asset; and (ii) certain contracts with industrial customers relating to assets held by the Group.

The Group has recognized finance lease receivables, notably for cogeneration plants for Wapda and NTDC (Uch - Pakistan) and Lanxess (Electrabel - Belgium).

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018
Undiscounted future minimum lease payments	878	919
Unguaranteed residual value accruing to the lessor	8	27
TOTAL GROSS INVESTMENT IN THE LEASE	886	946
Unearned financial income	94	170
NET INVESTMENT IN THE LEASE (STATEMENT OF FINANCIAL POSITION)	792	777
<i>Of which present value of future minimum lease payments</i>	787	758
<i>Of which present value of unguaranteed residual value</i>	6	19

Undiscounted minimum lease payments receivable under finance leases can be analyzed as follows:

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018
Year 1	118	182
Years 2 to 5 inclusive	470	420
Beyond year 5	290	317
TOTAL	878	919

16.1.2 Trade and other receivables, assets from contracts with customers

Information on trade and other receivables and assets from contracts with customers are provided in Note 7.2. "Trade and other receivables, assets and liabilities from contracts with customers".

16.1.3 Cash and cash equivalents

Accounting standards

This item includes cash equivalents as well as short-term investments that are considered to be readily convertible into a known amount of cash and where the risk of a change in their value is deemed to be negligible based on the criteria set out in IAS 7.

Bank overdrafts are not included in the calculation of cash and cash equivalents and are recorded under "Short-term borrowings".

Cash and cash equivalent items are subject to impairment tests in accordance with the expected credit losses model of IFRS 9.

Cash and cash equivalents totaled €10,519 million at December 31, 2019 (€8,700 million at December 31, 2018).

This amount included funds related to the green bond issues, which remain unallocated to the funding of eligible projects (*see section 5 of the Universal Registration Document*).

At December 31, 2019, this amount also included €86 million in cash and cash equivalents subject to restrictions (€121 million at December 31, 2018), including €63 million of cash equivalents set aside to cover the repayment of borrowings and debt as part of project financing arrangements in certain subsidiaries.

Gains recognized in respect of "Cash and cash equivalents" amounted to €76 million at December 31, 2019 compared to €73 million at December 31, 2018.

16.1.4 Financial assets set aside to cover the future costs of dismantling nuclear facilities and managing radioactive fissile material

As indicated in Note 19.2 "Obligations relating to nuclear power generation activities", the Belgian law of April 11, 2003, amended by the law of April 25, 2007, granted the Group's wholly-owned subsidiary Synatom responsibility for managing and investing funds received from operators of nuclear power plants in Belgium and designed to cover the costs of dismantling nuclear power plants and managing radioactive fissile material.

Pursuant to the law, Synatom may lend up to 75% of these funds to nuclear power plant operators provided that certain credit quality criteria are met. The funds that cannot be lent to nuclear operators are invested in assets to cover the liabilities.

Following the triennial review of nuclear provisions carried out by Belgium's Commission for Nuclear Provisions (*see Note 19.2 "Obligations relating to nuclear power generation activities"*), Electrabel undertook not to take out any further loans in respect of provisions for the back-end nuclear fuel cycle and to repay all of the loans taken out for that purpose by 2025. Over the next five years, therefore, Synatom will invest in financial assets to cover future costs of managing radioactive fissile material, up to the amount of the corresponding provisions, i.e., about €6 billion more than the assets set aside to cover those provisions at December 31, 2019, plus the annual recurring charge arising from the unwinding of the discount on those provisions and the additional quantities of fuel consumed.

The financial assets covering future costs of dismantling nuclear facilities and managing radioactive fissile material are either loans to legal entities that meet the credit quality criteria required by law or other external assets with sufficient diversification and spread to minimize the risk. The Commission for Nuclear Provisions issues an opinion on the asset classes in which Synatom may invest. Synatom has also undertaken to develop an Investment Department, appoint two outside directors to its Board and set up an Audit Committee.

Loans to entities outside the Group and other cash investments are shown in the table below:

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018
Loans to third parties	467	512
Loan to Eso/Elia	453	454
Loan to Ores Assets	-	40
Loan to Sibelga	14	18
Others loans and receivables at amortized cost	85	163
Debt instruments - restricted cash	85	163
Equity and debt instruments at fair value	2,054	1,539
Equity instruments at fair value through other comprehensive income	207	47
Debt instruments at fair value through other comprehensive income	1,138	1,025
Debt instruments at fair value through income	709	467
TOTAL	2,606	2,214

Loans to entities outside the Group and the cash subject to restriction held by money market funds are shown in the statement of financial position as “Loans and receivables at amortized cost”. Bonds and money market funds held by Synatom are shown as “equity instruments at fair value through other comprehensive income”, “debt instruments at fair value through other comprehensive income” or “debt instruments at fair value through income” (see Note 16.1 “Financial assets”).

16.1.5 Transfer of financial assets

At December 31, 2019, the outstanding amount of transferred financial assets (as well as the risks to which the Group remains exposed following the transfer of those financial assets) as part of transactions leading to either (i) all or part of those assets being retained in the statement of financial position, or (ii) their full deconsolidation while retaining a continuing involvement in these financial assets, was not material in terms of the Group's indicators.

In 2019, the Group carried out disposals without recourse to financial assets as part of transactions leading to full derecognition, for an outstanding amount of €944 million at December 31, 2019.

16.1.6 Financial assets and equity instruments pledged as collateral for borrowings and debt

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018
Financial assets and equity instruments pledged as collateral	4,471	3,447

This item mainly includes the carrying amount of equity instruments pledged as collateral for borrowings and debt.

16.2 Financial liabilities

Accounting standards

Borrowings and other financial liabilities are measured at amortized cost using the effective interest rate method.

On initial recognition, any issue or redemption premiums and discounts and issuing costs are added to/deducted from the nominal value of the borrowings concerned. These items are taken into account when calculating the effective interest rate and are therefore recorded in the consolidated income statement over the life of the borrowings using the amortized cost method.

As regards structured debt instruments that do not have an equity component, the Group may be required to separate an “embedded” derivative instrument from its host contract. When an embedded derivative is separated from its host contract, the initial carrying amount of the structured instrument is broken down into an embedded derivative component, corresponding to the fair value of the embedded derivative, and a financial liability component, corresponding to the difference between the amount of the issue and the fair value of the embedded derivative. The separation of components upon initial recognition does not give rise to any gains or losses.

The debt is subsequently recorded at amortized cost using the effective interest method while the derivative is measured at fair value, with changes in fair value recognized in profit or loss.

Financial liabilities are recognized either:

- as “Amortized cost liabilities” for borrowings, trade payables and other creditors, and other financial liabilities;
- as “Liabilities measured at fair value through profit or loss” for derivative financial instruments and for financial liabilities designated as such.

The following table presents the Group’s different financial liabilities at December 31, 2019, broken down into current and non-current items:

In millions of euros	Notes	Dec. 31, 2019			Dec. 31, 2018 ⁽¹⁾		
		Non-current	Current	Total	Non-current	Current	Total
Borrowings and debt		30,002	8,543	38,544	26,434	5,745	32,178
Trade and other payables	16.2	-	19,109	19,109	-	19,759	19,759
Liabilities from contracts with customers	7.2	45	4,286	4,330	36	3,598	3,634
Derivative instruments	16.4	5,129	10,446	15,575	2,785	11,510	14,295
Other financial liabilities		38	-	38	46	-	46
TOTAL		35,213	42,383	77,596	29,301	40,612	69,913

(1) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 (see Note 1 “Accounting framework and basis for preparing the consolidated financial statements”).

16.2.1 Trade and other payables

In millions of euros	Dec. 31, 2019	Dec. 31, 2018
Trade payables	18,683	19,192
Payable on fixed assets	426	568
TOTAL	19,109	19,759

The carrying amount of these financial liabilities represents a reasonable estimate of their fair value.

16.2.2 Liabilities from contracts with customers

Information on liabilities from contracts with customers are provided in Note 7.2. "Trade and other receivables, assets and liabilities from contracts with customers".

16.3 Net financial debt

16.3.1 Net financial debt by type

In millions of euros		Dec. 31, 2019			Dec. 31, 2018 ⁽¹⁾		
		Non-current	Current	Total	Non-current	Current	Total
Borrowings and debt	Bond issues	23,262	2,753	26,015	21,444	1,202	22,645
	Bank borrowings	4,229	1,063	5,292	4,272	349	4,620
	Negotiable commercial paper		3,233	3,233		2,894	2,894
	Lease liabilities ⁽²⁾	1,935	578	2,512	262	118	380
	Other borrowings ⁽³⁾	576	668	1,244	456	718	1,174
	Bank overdrafts and current account	-	247	247	-	464	464
	BORROWINGS AND DEBT	30,002	8,543	38,544	26,434	5,745	32,178
Other financial assets	Other financial assets deducted from net financial debt ⁽⁴⁾	(213)	(1,289)	(1,502)	(288)	(1,694)	(1,982)
Cash and cash equivalents	Cash and cash equivalents ⁽⁵⁾	-	(10,519)	(10,519)	-	(8,700)	(8,700)
Derivative instruments	Derivatives hedging borrowings ⁽⁶⁾	(521)	(83)	(604)	(419)	24	(395)
NET FINANCIAL DEBT		29,267	(3,348)	25,919	25,727	(4,625)	21,102

(1) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

(2) At December 31, 2018, lease liabilities corresponds to liabilities under finance leases.

(3) This item corresponds to the revaluation of the interest rate component of debt in a qualified fair value hedging relationship.

(4) This item notably corresponds to assets related to financing, liquid debt instruments held for cash investment purposes and margin calls on derivatives hedging borrowings - carried in assets.

(5) Of which €619 million of financial instruments deducted from net financial debt and reclassified from "Other financial assets" to "Cash and cash equivalent". (see Note 16.1 "Financial assets"), with no impact on net financial debt.

(6) This item represents the interest rate component of the fair value of derivatives hedging borrowings in a designated fair value hedging relationship. It also represents the exchange rate and outstanding accrued interest rate components of the fair value of all debt-related derivatives irrespective of whether or not they qualify as hedges.

The fair value of gross borrowings and debt (excluding lease liabilities) amounted to €38,893 million at December 31, 2019, compared with a carrying amount of €35,057 million.

Financial income and expenses related to borrowings and debt are presented in Note 10 "Net financial income/(loss)".

16.3.2 Reconciliation between net financial debt and cash flow from (used in) financing activities

		Dec. 31, 2018 ⁽¹⁾	Cash flow from financing activities	Cash flow from operating and investing activities and variation of cash and cash equivalents	Change in fair value	Translation adjustments	Change in scope of consolidation and others	Dec. 31, 2019
<i>In millions of euros</i>								
Borrowings and debt	Bond issues	22,645	3,210	-	-	170	(10)	26,015
	Bank borrowings	4,620	705	-	-	13	(46)	5,292
	Negotiable commercial paper	2,894	317	-	-	22	-	3,233
	Lease liabilities ⁽²⁾	380	(551)	-	-	9	2,674	2,512
	Other borrowings	1,174	133	-	66	19	(147)	1,244
	Bank overdrafts and current account	464	(150)	-	-	(2)	(65)	247
BORROWINGS AND DEBT		32,178	3,664	-	66	231	2,405	38,544
Other financial assets	Other financial assets deducted from net financial debt ⁽³⁾	(1,982)	(135)	-	(8)	2	620	(1,502)
Cash and cash equivalents	Cash and cash equivalents ⁽³⁾	(8,700)	-	(1,306)	-	(34)	(479)	(10,519)
Derivative	Derivatives hedging borrowings	(395)	(75)	-	25	(155)	(5)	(604)
NET FINANCIAL		21,102	3,454	(1,306)	83	45	2,542	25,919

(1) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

(2) Lease liabilities: the amount of 551 million included into column "Cash flow from financing activities" corresponds to lease payments, excluding interest (total cash outflow for leases amounted to €590 million of which €39 million relating to interest). The amount included in the column "Changes in scope of consolidation and others" mainly correspond to the first-time application of IFRS 16.

(3) Cash and cash equivalents: the amount in column "Changes in scope of consolidation and others" mainly corresponds to the reclassification of financial assets amounting to €619 million from "Other financial assets" to "Cash and cash equivalents" (see Note 16.1 "Financial assets").

16.3.3 Main events of the period

16.3.3.1 Impact of changes in the scope of consolidation and in exchange rates on net financial debt

In 2019, changes in exchange rates resulted in a €45 million increase in net financial debt, including a €88 million increase in relation to the US dollar, which was offset by a €36 million decrease in debt denominated in Brazilian real and €20 million in pounds sterling.

Changes in the scope of consolidation (including the cash impact of acquisitions and disposals) led to a €78 million increase in net financial debt, reflecting:

- disposals of assets over the period, which reduced net financial debt by €3,094 million, notably including the disposal of the interest in GLOW, of coal-fired power plants in Germany and the Netherlands and assets held by Langa in France (see Note 4.1 "Disposals carried out in 2019");
- the classification of renewable energy assets in Mexico and green gas production assets in France under "Assets held for sale" (see Note 4.2 "Assets held for sale") which reduced net financial debt by €26 million;
- acquisitions carried out in 2019 which increased net financial debt by €3,198 million mainly due to the acquisition of a 90% interest in Transportadora Asociada de Gás S.A. (TAG) in Brazil, of Conti in the North America and OTTO Luft-und Klimatechnik GmbH & Co in Germany (see Note 4.3 "Acquisitions carried out in 2019").

16.3.3.2 Financing and refinancing transactions

The Group carried out the following main transactions in 2019:

- on June 21, 2019, ENGIE SA issued €1.5 billion worth of bonds:
 - a €750 million tranche maturing in June 2027 with a 0.375% coupon,
 - a €750 million tranche maturing in June 2039 with a 1.375% coupon;
- on September 4, 2019, ENGIE SA issued €750 million worth of bonds maturing in March 2027 with a 0% coupon;
- on October 24, 2019, ENGIE SA issued €1.5 billion worth of bonds:
 - a €900 million tranche, a green bond maturing in October 2030 with a 0.5% coupon,
 - a €600 million tranche maturing in October 2041 with a 1.25% coupon;
- ENGIE SA redeemed the €775 million worth of bonds that matured on January 24, 2019 with a 6.875% coupon;
- on December 5, 2018, ENGIE SA gave notice that it had exercised the annual prepayment option for the GBP 300 million tranche of deeply-subordinated notes (representing a total amount of €352 million including the accrued coupon) that had previously been recognized in equity in a net amount of €340 million with a 4.625% coupon. ENGIE SA redeemed the bonds on January 10, 2019;
- on May 21, 2019, ENGIE Brasil Energia carried out a bond issue of BRL 2,500 million (€547 million) maturing in November 2020;
- on July 15, 2019, ENGIE Brasil Energia carried out the following refinancing transactions
 - a BRL1 596 million (€360 million) worth of bonds including two tranches of BRL952 million maturing in July 2026 and two tranches of BRL644 million maturing in July 2029,
 - a partial redemption of the bond issued on May 21, 2019 for an amount of BRL1 500 million (€338 million) maturing in November 2020 ;
- on May 17, 2019, ENGIE Brasil Energia took out three bank loans totaling €252 million maturing in May 2022 including two bank loans totaling USD 150 million and a bank loan of BRL 534 million;;
- on November 26, 2019, ENGIE Brasil Energia took out 18 bank loans totaling BRL 1,197 million (€263 million) maturing in December 2038;
- on November 30, 2019, ENGIE Brasil Energia took out a bank loan of BRL 795 million (€176 million) maturing in January 2036.

16.4 Derivative instruments

Accounting standards

Derivative financial instruments are measured at fair value. This fair value is determined on the basis of market data, available from external contributors. In the absence of an external benchmark, a valuation based on internal models recognized by market participants and favoring data directly derived from observable data such as OTC quotations will be used.

The change in fair value of derivative financial instruments is recorded in the income statement except when they are designated as hedging instruments in a cash flow hedge or net investment hedge. In this case, changes in the value of the hedging instruments are recognized directly in equity, excluding the ineffective portion of the hedges.

The Group uses derivative financial instruments to manage and reduce its exposure to market risks arising from fluctuations in interest rates, foreign currency exchange rates and commodity prices, mainly for gas and electricity. The use of derivative instruments is governed by a Group policy for managing interest rate, currency and commodity risks (see Note 17 – *Risks arising from financial instruments*).

Derivative financial instruments are contracts (i) whose value changes in response to the change in one or more observable variables, (ii) that do not require any material initial net investment, and (iii) that are settled at a future date.

Derivative instruments therefore include swaps, options, futures and swaptions, as well as forward commitments to purchase or sell listed and unlisted securities, and firm commitments or options to purchase or sell non-financial assets that involve physical delivery of the underlying.

For purchases and sales of electricity and natural gas, the Group systematically analyzes whether the contract was entered into in the “normal” course of operations and therefore falls outside the scope of IFRS 9. This analysis consists firstly in demonstrating that the contract is entered into and continues to be held for the purpose of physical delivery or receipt of the commodity in accordance with the Group’s expected purchase, sale or usage requirements.

The second step is to demonstrate that the Group has no practice of settling similar contracts on a net basis and that these contracts are not equivalent to written options. In particular, in the case of electricity and gas sales allowing the buyer a certain degree of flexibility concerning the volumes delivered, the Group distinguishes between contracts that are equivalent to capacity sales considered as transactions falling within the scope of ordinary operations and those that are equivalent to written financial options, which are accounted for as derivative financial instruments.

Only contracts that meet all of the above conditions are considered as falling outside the scope of IFRS 9. Adequate specific documentation is compiled to support this analysis.

Embedded derivatives

The main Group contracts that may contain embedded derivatives are contracts with clauses or options potentially affecting the contract price, volume or maturity. This is the case primarily with contracts for the purchase or sale of non-financial assets, whose price is revised based on an index, the exchange rate of a foreign currency or the price of an asset other than the contract’s underlying.

An embedded derivative is a component of a hybrid (combined) instrument that also includes a non-derivative host contract – with the effect that some of the cash flows of the combined instrument vary in a way similar to a stand-alone derivative.

If a hybrid contract contains a host that is an asset within the scope of IFRS 9, the Group applies the presentation and measurements requirements described in paragraph 17.1. to the entire hybrid contract.

Conversely, when a hybrid contract contains a host that is not an asset within the scope of IFRS 9, an embedded derivative shall be separated from the host and accounted for as a derivative if, and only if:

- the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host;
- a separate instrument within the same terms as the embedded derivative would meet the definition of a derivative; and
- the hybrid contract is not measured at fair value with changes in fair value recognized in profit or loss (i.e., a derivative that is embedded in a financial liability at fair value through profit or loss is not separated).

If an embedded derivative is separate from the host contract, it shall be measured at fair value and fair value changes are recognized in profit or loss (except if the embedded derivative is documented in a hedge relationship).

Hedging instruments: recognition and presentation

Derivative instruments qualifying as hedging instruments are recognized in the consolidated statement of financial position and measured at fair value. However, their accounting treatment varies according to whether they are classified as (i) a fair value hedge of an asset or liability; (ii) a cash flow hedge or (iii) a hedge of a net investment in a foreign operation.

Fair value hedges

A fair value hedge is defined as a hedge of the exposure to changes in fair value of a recognized asset or liability such as a fixed-rate loan or borrowing, or of assets, liabilities or an unrecognized firm commitment denominated in a foreign currency. The gain or loss from remeasuring the hedging instrument at fair value is recognized in income. The gain or loss on the hedged item attributable to the hedged risk adjusts the carrying amount of the hedged item and is also recognized in income even if the hedged item is in a category in respect of which changes in fair value are recognized through other comprehensive income. These two adjustments are presented net in the consolidated income statement, with the net effect corresponding to the ineffective portion of the hedge.

Cash flow hedges

A cash flow hedge is a hedge of the exposure to variability in cash flows that could affect the Group's income. The hedged cash flows may be attributable to a particular risk associated with a recognized financial or non-financial asset or a highly probable forecast transaction.

The portion of the gain or loss on the hedging instrument that is determined to be an effective hedge is recognized directly in other comprehensive income, net of tax, while the ineffective portion is recognized in income. The gains or losses accumulated in equity are reclassified to the consolidated income statement under the same caption as the loss or gain on the hedged item – i.e., current operating income for operating cash flows and financial income or expenses for other cash flows – in the same periods in which the hedged cash flows affect income.

If the hedging relationship is discontinued, in particular because the hedge is no longer considered effective, the cumulative gain or loss on the hedging instrument remains recognized in equity until the forecast transaction occurs. However, if a forecast transaction is no longer expected to occur, the cumulative gain or loss on the hedging instrument is immediately recognized in income.

Hedge of a net investment in a foreign operation

In the same way as for a cash flow hedge, the portion of the gain or loss on the hedging instrument that is determined to be an effective hedge of the currency risk is recognized directly in other comprehensive income, net of tax, while the ineffective portion is recognized in income. The gains or losses accumulated in other comprehensive income are transferred to the consolidated income statement when the investment is liquidated or sold.

Hedging instruments: identification and documentation of hedging relationships

The hedging instruments and hedged items are designated at the inception of the hedging relationship. The hedging relationship is formally documented in each case, specifying the hedging strategy, the hedged risk and the method used to assess hedge effectiveness. Only derivative contracts entered into with external counterparties are considered as being eligible for hedge accounting.

Hedge effectiveness is assessed and documented at the inception of the hedging relationship and on an ongoing basis throughout the periods for which the hedge was designated.

Hedge effectiveness is demonstrated both prospectively and retrospectively using various methods, based mainly on a comparison between changes in fair value or cash flows between the hedging instrument and the hedged item. Methods based on an analysis of statistical correlations between historical price data are also used.

Derivative instruments not qualifying for hedge accounting: recognition and presentation

These items mainly concern derivative financial instruments used in economic hedges that have not been – or are no longer – documented as hedging relationships for accounting purposes.

When a derivative financial instrument does not qualify or no longer qualifies for hedge accounting, changes in fair value are recognized directly in income under (i) current operating income for derivative instruments with non-financial assets as the underlying, and (ii) financial income or expenses for currency, interest rate and equity derivatives.

Derivative instruments not qualifying for hedge accounting used by the Group in connection with proprietary commodity trading activities and other derivatives expiring in less than 12 months are recognized in the consolidated statement of financial position in current assets and liabilities, while derivatives expiring after this period are classified as non-current items.

Fair value measurement

The fair value of instruments listed on an active market is determined by reference to the market price. In this case, these instruments are presented in level 1 of the fair value hierarchy.

The fair value of unlisted financial instruments for which there is no active market and for which observable market data exist is determined based on valuation techniques such as option pricing models or the discounted cash flow method.

Models used to evaluate these instruments take into account assumptions based on market inputs:

- the fair value of interest rate swaps is calculated based on the present value of future cash flows;
- the fair value of forward foreign exchange contracts and currency swaps is calculated by reference to current prices for contracts with similar maturities by discounting the future cash flow spread (difference between the forward exchange rate under the contract and the forward exchange rate recalculated in line with the new market conditions applicable to the nominal amount);
- the fair value of currency and interest rate options is calculated using option pricing models;
- commodity derivatives are valued by reference to listed market prices based on the present value of future cash flows (commodity swaps or commodity forwards) and option pricing models (options), for which market price volatility may be a factor. Contracts with maturities exceeding the depth of transactions for which prices are observable, or which are particularly complex, may be valued based on internal assumptions;
- exceptionally, for complex contracts negotiated with independent financial institutions, the Group uses the values established by its counterparties.

These instruments are presented in level 2 of the fair value hierarchy except when the evaluation is based mainly on data that are not observable; in which case they are presented in level 3 of the fair value hierarchy. Most often, this is the case for derivatives with a maturity that falls outside the observability period for market data relating to the underlying or when certain inputs such as the volatility of the underlying are not observable.

Except in case of enforceable master netting arrangements or similar agreements, counterparty risk is included in the fair value of financial derivative instrument assets and liabilities. It is calculated according to the “expected loss” method and takes into account the exposure at default, the probability of default and the loss given default. The probability of default is determined on the basis of credit ratings assigned to each counterparty (“historical probability of default” approach).

Derivative instruments recognized in assets and liabilities are measured at fair value and broken down as follows:

In millions of euros	Dec. 31, 2019						Dec. 31, 2018					
	Assets			Liabilities			Assets			Liabilities		
	Non-current	Current	Total	Non-current	Current	Total	Non-current	Current	Total	Non-current	Current	Total
Derivatives hedging borrowings	705	124	829	183	41	225	678	42	720	259	66	325
Derivatives hedging commodities	2,484	9,993	12,476	3,011	10,360	13,371	1,409	10,608	12,018	1,311	11,405	12,716
Derivatives hedging other items ⁽¹⁾	949	17	966	1,934	45	1,980	606	28	634	1,215	38	1,254
TOTAL	4,137	10,134	14,272	5,129	10,446	15,575	2,693	10,679	13,372	2,785	11,510	14,295

(1) Derivatives hedging other items mainly include the interest rate component of interest rate derivatives (not qualifying as hedges or qualifying as cash flow hedges) that are excluded from net financial debt, as well as net investment hedge derivatives.

16.4.1 Offsetting of derivative instrument assets and liabilities

The net amount of derivative instruments after taking into account enforceable master netting arrangements or similar agreements, whether or not they are set off in accordance with paragraph 42 of IAS 32, are presented in the table below:

In millions of euros		Dec. 31, 2019				Dec. 31, 2018			
		Gross amount	Net amount recognized in the statement of financial position ⁽¹⁾	Other offsetting agreements ⁽²⁾	Total net amount	Gross amount	Net amount recognized in the statement of financial position ⁽¹⁾	Other offsetting agreements ⁽²⁾	Total net amount
Assets	Derivatives hedging commodities	13,121	12,476	(7,704)	4,772	12,588	12,018	(8,409)	3,609
	Derivatives hedging borrowings and other items	1,795	1,795	(399)	1,397	1,354	1,354	(384)	970
Liabilities	Derivatives hedging commodities	(14,015)	(13,371)	9,872	(3,499)	(13,285)	(12,716)	10,449	(2,267)
	Derivatives hedging borrowings and other items	(2,204)	(2,204)	899	(1,305)	(1,579)	(1,579)	601	(978)

(1) Net amount recognized in the statement of financial position after taking into account offsetting agreements that meet the criteria set out in paragraph 42 of IAS 32.

(2) Other offsetting agreements include collateral and other guarantee instruments, as well as offsetting agreements that do not meet the criteria set out in paragraph 42 of IAS 32.

16.5 Fair value of financial instruments by level in the fair value hierarchy

16.5.1 Financial assets

The table below shows the allocation of financial instruments carried in assets to the different levels in the fair value hierarchy:

In millions of euros	Dec. 31, 2019				Dec. 31, 2018			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
Other financial assets (excluding loans and receivables at amortized cost)	3,714	2,069	-	1,645	3,887	1,554	-	2,332
Equity instruments at fair value through other comprehensive income	921	222	-	698	742	62	-	680
Equity instruments at fair value through income	377	-	-	377	365	-	-	365
Debt instruments at fair value through other comprehensive income	1,149	1,138	-	11	1,947	1,025	-	922
Debt instruments at fair value through income	1,268	709	-	559	832	467	-	365
Derivative instruments	14,272	8	12,993	1,270	13,372	38	12,912	422
Derivatives hedging borrowings	829	-	829	-	720	-	720	-
Derivatives hedging commodities - relating to portfolio management activities ⁽¹⁾	3,521	-	2,928	593	2,075	-	2,036	39
Derivatives hedging commodities - relating to trading activities ⁽¹⁾	8,955	8	8,271	677	9,943	38	9,522	383
Derivatives hedging other items	966	-	966	-	634	-	634	-
TOTAL	17,986	2,077	12,993	2,916	17,259	1,593	12,912	2,754

(1) Derivative financial instruments relating to commodities classified in level 3 mainly include long-term gas supply contracts and a power contract that are measured at fair value and relate to trading activities.

A definition of these three levels is presented in Note 16.4 "Derivative instruments".

Other financial assets (excluding loans and receivables at amortized cost)

Changes in level 3 equity and debt instruments at fair value can be analyzed as follows:

In millions of euros	Equity instruments at fair value through other comprehensive income	Debt instruments at fair value through other comprehensive income	Equity instruments at fair value through income	Debt instruments at fair value through income	Other financial assets (excluding loans and receivables)
AT DECEMBER 31, 2018	680	922	365	365	2,332
Acquisitions	43	10	170	231	455
Disposals	(73)	(306)	(24)	(42)	(446)
Changes in fair value	76	-	(23)	5	58
Changes in scope of consolidation, foreign currency translation and other changes ⁽¹⁾	(28)	(614)	(112)	-	(755)
AT DECEMBER 31, 2019	698	11	377	559	1,645
Gains/(losses) recorded in income relating to instruments held at the end of the period					51

(1) Of which €619 million of financial instruments deducted from net financial debt and reclassified from "Other financial assets" to "Cash and cash equivalents" (see Note 16.1 "Financial assets").

Derivative instruments

Changes in level 3 derivative instruments commodities can be analyzed as follows:

<i>In millions of euros</i>	Net Asset/(Liability)
AT DECEMBER 31, 2018	(99)
Changes in fair value recorded in income	178
Settlements	(10)
Transfer out of level 3 to levels 1 and 2	(29)
Net fair value recorded in income	40
Deferred Day-One gains/(losses)	49
AT DECEMBER 31, 2019	89

16.5.2 Financial liabilities

The table below shows the allocation of financial instruments carried in liabilities to the different levels in the fair value hierarchy:

<i>In millions of euros</i>	Dec. 31, 2019				Dec. 31, 2018			
	Total	Level	Level	Level	Total	Level	Level	Level
Borrowings used in designated fair value hedges	6,510	-	6,510	-	5,358	-	5,358	-
Borrowings not used in designated fair value hedges	32,382	22,763	9,620	-	28,293	19,028	9,265	-
Derivative instruments	15,575	102	14,292	1,181	14,295	26	13,764	505
Derivatives hedging borrowings	225	-	225	-	325	-	325	-
Derivatives hedging commodities - relating to portfolio management activities ⁽¹⁾	4,136	-	3,697	440	2,124	-	2,075	49
Derivatives hedging commodities - relating to trading activities ⁽¹⁾	9,234	102	8,391	741	10,592	26	10,110	456
Derivatives hedging other items	1,980	-	1,980	-	1,254	-	1,254	-
TOTAL	54,468	22,865	30,422	1,181	47,946	19,054	28,387	505

(1) Derivative financial instruments relating to commodities classified in level 3 mainly include long-term gas supply contracts and a power contract that are measured at fair value and relating to trading activities.

A definition of these three levels is presented in Note 16.4 "Derivative instruments".

Borrowings used in designated fair value hedges

This caption includes bonds in a designated fair value hedging relationship, which are presented in level 2 in the above table. Only the interest rate component of the bonds is remeasured, with fair value determined by reference to observable inputs.

Borrowings not used in designated fair value hedges

Listed bond issues are included in level 1.

Other borrowings not used in a designated hedging relationship, are presented in level 2 in the above table. The fair value of these borrowings is determined on the basis of future discounted cash flows and relies on directly or indirectly observable data.

NOTE 17 RISKS ARISING FROM FINANCIAL INSTRUMENTS

The Group mainly uses derivative instruments to manage its exposure to market risks. Financial risk management procedures are set out in Chapter 2 “Risk factors” of the Universal Registration Document.

17.1 Market risks

17.1.1 Commodity risk

Commodity risk arises primarily from the following activities:

- portfolio management; and
- trading.

The Group has identified primarily two types of commodity risks: price risk resulting from fluctuations in market prices, and volume risk inherent to the business.

In the ordinary course of its operations, the Group is exposed to commodity risks on natural gas, electricity, coal, oil and oil products, other fuels, CO₂ and other “green” products. The Group is active on these energy markets either for supply purposes or to optimize and secure its energy production chain and its energy sales. The Group also uses derivatives to offer hedging instruments to its clients and to hedge its own positions.

17.1.1.1 Portfolio management activities

Portfolio management seeks to optimize the market value of assets (power plants, gas and coal supply contracts, energy sales and gas storage and transportation) over various timeframes (short-, medium- and long-term). Market value is optimized by:

- guaranteeing supply and ensuring the balance between physical needs and resources;
- managing market risks (price, volume) to unlock optimum value from portfolios within a specific risk framework.

The risk framework aims to safeguard the Group’s financial resources over the budget period and smooth out medium-term earnings (over three or five years, depending on the maturity of each market). It encourages portfolio managers to take out economic hedges on their portfolio.

Sensitivities of the commodity-related derivatives portfolio used as part of the portfolio management activities as at December 31, 2019 are detailed in the table below. They are not representative of future changes in consolidated earnings and equity, insofar as they do not include the sensitivities relating to the purchase and sale contracts for the underlying commodities.

Sensitivity analysis ⁽¹⁾

In millions of euros	Changes in price	Dec. 31, 2019		Dec. 31, 2018	
		Pre-tax impact on income	Pre-tax impact on equity	Pre-tax impact on income	Pre-tax impact on equity
Oil-based products	+USD 10/bbl	40	234	60	-
Natural gas	+€3/MWh	225	471	961	1
Electricity	+€5/MWh	82	(47)	65	(26)
Coal	+USD 10/ton	(2)	-	9	2
Greenhouse gas emission rights	+€2/ton	(89)	19	37	1
EUR/USD	+10%	(25)	(99)	67	(2)
EUR/GBP	+10%	33	-	87	-

(1) The sensitivities shown above apply solely to financial commodity derivatives used for hedging purposes as part of the portfolio management activities.

The sensitivity of shareholders' equity to changes in gas and oil product prices is due to the application of cash flow hedge accounting to certain supply hedges within marketing operations since 2019.

17.1.1.2 Trading activities

The Group's trading activities are primarily conducted within:

- ENGIE Global Markets and ENGIE Energy Management. The purpose of these wholly-owned companies is to (i) assist Group entities in optimizing their asset portfolios; (ii) create and implement energy price risk management solutions for internal and external customers;
- ENGIE SA for the optimization of part of its long-term gas supply contracts, of a power exchange contract and of part of its gas sales contracts with retail entities in France and Benelux and with power generation facilities in France and Belgium.

Revenues from trading activities totaled €684 million at December 31, 2019 (€526 million at December 31, 2018).

The use of Value at Risk (VaR) to quantify market risk arising from trading activities provides a transversal measure of risk taking all markets and products into account. VaR represents the maximum potential loss on a portfolio over a specified holding period based on a given confidence interval. It is not an indication of expected results but is back-tested on a regular basis.

The Group uses a one-day holding period and a 99% confidence interval to calculate VaR, as well as stress tests, in accordance with banking regulatory requirements.

The VaR shown below corresponds to the global VaR of the Group's trading entities.

Value at Risk

In millions of euros	Dec. 31, 2019	2019 average ⁽¹⁾	2019 maximum ⁽²⁾	2019 minimum ⁽²⁾	2018 average ⁽¹⁾
Trading activities	12	14	26	6	10

(1) Average daily VaR.

(2) Maximum and minimum daily VaR observed in 2019.

17.1.2 Hedges of commodity risks

Hedging instruments and sources of hedge ineffectiveness

The Group enters into cash flow hedges, using derivative instruments (firm or option contracts) contracted over the counter or on organized markets, to reduce its commodity risks which relate mainly to future cash flows from contracted or expected sales and purchases of commodities. These instruments may be settled net or involve physical delivery of the underlying.

Sources of hedge ineffectiveness are mainly related to uncertainty regarding the timing and potential mismatches in settlement dates and indices between the derivative instruments and the associated underlying exposures.

The fair values of commodity derivatives are indicated in the table below:

In millions of euros	Dec. 31, 2019				Dec. 31, 2018			
	Assets		Liabilities		Assets		Liabilities	
	Non-current	Current	Non-current	Current	Non-current	Current	Non-current	Current
Derivative instruments relating to portfolio management activities	2,484	1,037	(3,011)	(1,125)	1,409	666	(1,311)	(813)
Cash flow hedges	1,893	292	(1,953)	(557)	46	56	(61)	(129)
Other derivative instruments	591	746	(1,058)	(568)	1,364	610	(1,249)	(684)
Derivative instruments relating to trading activities	-	8,955	-	(9,234)	-	9,943	-	(10,592)
TOTAL	2,484	9,993	(3,011)	(10,360)	1,409	10,608	(1,311)	(11,405)

The fair values shown in the table above reflect the amounts for which assets could be exchanged, or liabilities settled, at the end of the reporting period. They are not representative of expected future cash flows insofar as positions (i) are sensitive to changes in prices; (ii) can be modified by subsequent transactions; and (iii) can be offset by future cash flows arising on the underlying transactions.

17.1.2.1 Cash flow hedges

The fair values of cash flow hedges by type of commodity are as follows:

In millions of euros	Dec. 31, 2019				Dec. 31, 2018			
	Assets		Liabilities		Assets		Liabilities	
	Non-current	Current	Non-current	Current	Non-current	Current	Non-current	Current
Natural gas	1,814	235	(1,937)	(550)	20	15	(1)	(3)
Electricity	14	35	(9)	(5)	1	3	(44)	(120)
Coal	-	1	(1)	-	7	3	-	-
Oil	51	-	-	-	-	-	-	-
Other ⁽¹⁾	14	21	(6)	(2)	18	35	(16)	(6)
TOTAL	1,893	292	(1,953)	(557)	46	56	(61)	(129)

(1) Includes mainly foreign currency hedges on commodities.

Notional amounts (net) ⁽¹⁾

Notional amounts and maturities of cash flow hedges are as follows:

	Unit	2020	2021	2022	2023	2024	Beyond 5 years	Total at Dec. 31, 2019
Natural gas	GWh	212,024	123,387	23,887	4,827	2,147	-	366,272
Electricity	GWh	(4,461)	(3,787)	(1,384)	-	-	-	(9,632)
Coal	Thousands of tons	60	45	20	-	-	-	125
Oil-based products	Thousands of barrels	-	(12,476)	(12,476)	(12,476)	(12,476)	-	(49,902)
Forex	Millions of euros	21	20	4	-	-	-	45
Greenhouse gas emission rights	Thousands of tons	150	-	-	-	-	-	150

(1) Long/short position.

Effects of hedge accounting on the Group's financial position and performance

In millions of euros	Dec. 31, 2019			Dec. 31, 2018		
	Fair Value		Nominal	Fair value		Nominal
	Assets	Liabilities		Total	Total	
Cash flow hedges	2,184	(2,510)	(325)	4,967	(88)	(244)
TOTAL	2,184	(2,510)	(325)	4,967	(88)	(244)

The fair values represented above are positive for assets and negative for liabilities.

In millions of euros	Nominal amount	Fair Value	Change in fair value used for calculating hedge effectiveness	Change in the value of the hedging instrument recognized in equity ⁽¹⁾	Ineffective portion recognized in profit or loss ⁽¹⁾	Amount reclassified from the hedge reserve to profit or loss ⁽¹⁾	Line item of profit or loss
Cash flow hedges							Current operating income including operating MtM
Hedging instruments	4,967	(325)		(781)	-	-	
Hedged items			(744)				

(1) Gains/(losses).

Hedge inefficiency is calculated based on the change in the fair value of the hedging instrument compared to the change in the fair value of the hedged items since inception of the hedge. The fair value of the hedging instruments at

December 31, 2019 reflects the cumulative change in the fair value of the hedging instruments since inception of the hedges.

Maturity of commodity derivatives designated as cash flow hedges

<i>In millions of euros</i>	2020	2021	2022	2023	2024	Beyond 5 years	Dec. 31, 2019	Dec. 31, 2018
Fair Value of derivatives by	(266)	-	(26)	(18)	(16)	-	(326)	(88)

Amounts presented in the statement of changes in equity and the statement of comprehensive income

The following table provides a reconciliation of each component of equity and an analysis of other comprehensive income:

<i>In millions of euros</i>	Cash flow hedge	Derivatives hedging commodities
At December 31, 2018		(71)
Effective portion recognized in equity		(781)
Amount reclassified from hedge reserve to profit or loss		-
Translation differences		-
Changes in scope of consolidation and other		1
At December 31, 2019		(837)

17.1.2.2 Other commodity derivatives

Other commodity derivatives include:

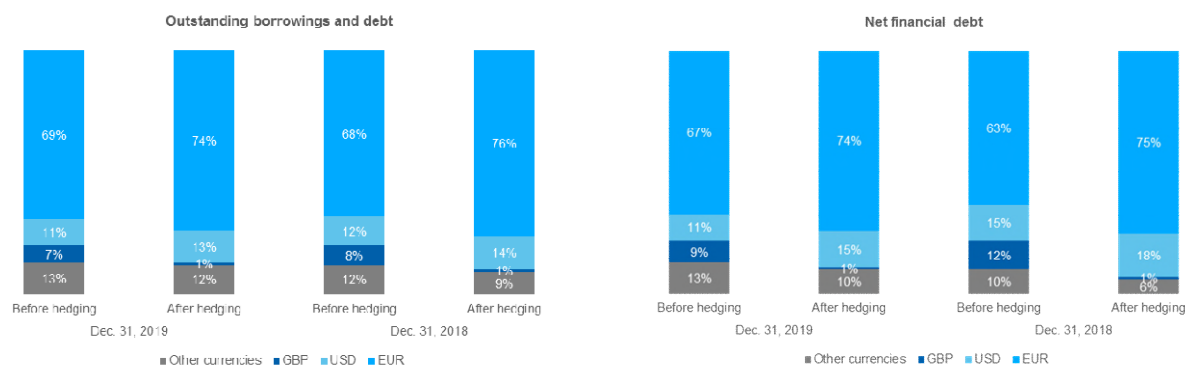
- commodity purchase and sale contracts that were not entered into or are no longer held for the purpose of the receipt or delivery of commodities in accordance with the Group's expected purchase, sale or usage requirements;
- embedded derivatives; and
- derivative financial instruments that are not eligible for hedge accounting in accordance with IFRS 9 or for which the Group has elected not to apply hedge accounting.

17.1.3 Currency risk

The Group is exposed to currency risk, defined as the impact on its statement of financial position and income statement of fluctuations in exchange rates affecting its operating and financing activities. Currency risk comprises (i) transaction risk arising in the ordinary course of business, (ii) specific transaction risk related to investments, mergers and acquisitions or disposal projects, and (iii) translation risk arising from the conversion into euros of income statement and statement of financial position items from subsidiaries with a functional currency other than the euro. The main translation risk exposures correspond, in order, to assets in US dollars, Brazilian real and pounds sterling.

17.1.3.1 Financial instruments by currency

The following tables present a breakdown by currency of outstanding borrowings and debt and net financial debt, before and after hedging:



17.1.3.2 Currency risk sensitivity analysis

A sensitivity analysis to currency risk on financial income/(loss) – excluding the income statement translation impact of foreign subsidiaries – was performed based on all financial instruments managed by the treasury department and representing a currency risk (including derivative financial instruments).

A sensitivity analysis to currency risk on equity was performed based on all financial instruments qualified as net investment hedges at the reporting date.

For currency risk, sensitivity corresponds to a 10% rise or fall in exchange rates of foreign currencies against the euro compared to closing rates.

In millions of euros	Dec. 31, 2019		
	Impact on income		Impact on equity
	+10% ⁽¹⁾	-10% ⁽¹⁾	+10% ⁽¹⁾
Exposures denominated in a currency other than the functional currency of companies carrying the liabilities on their statements of financial position ⁽²⁾	(20)	20	NA
Financial instruments (debt and derivatives) qualified as net investment hedges ⁽³⁾	NA	NA	216

(1) +(-)10%: depreciation (appreciation) of 10% of all foreign currencies against the euro.

(2) Excluding derivatives qualified as net investment hedges.

(3) This impact is countered by the offsetting change in the net investment hedged.

17.1.4 Interest rate risk

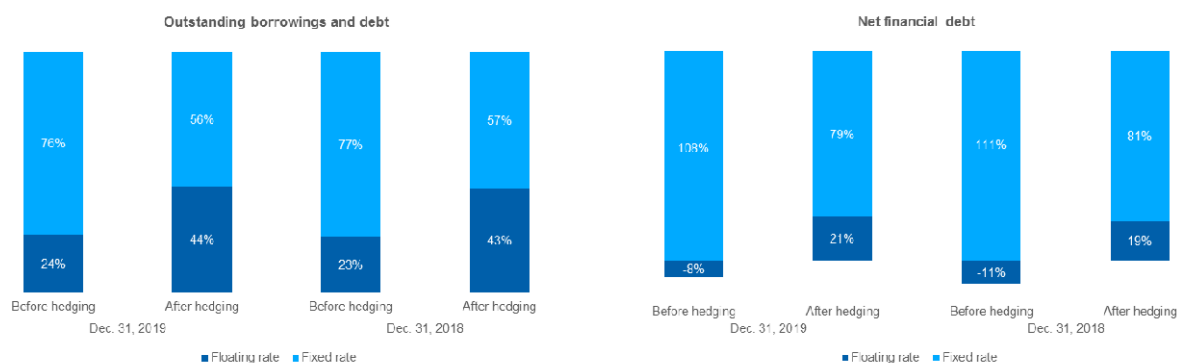
The Group seeks to manage its borrowing costs by limiting the impact of interest rate fluctuations on its income statement. The Group's policy is therefore to arbitrate between fixed rates, floating rates and capped floating rates for its net debt. The interest rate mix may shift within a range defined by the Group Management in line with market trends.

In order to manage the interest rate structure for its net debt, the Group uses hedging instruments, particularly interest rate swaps and options. At December 31, 2019, the Group had a portfolio of interest rate options (caps) protecting it from a rise in short-term interest rates for the euro.

The Group has a portfolio of 2020 and 2021 forward interest rate pre-hedges with respective 10- and 20/21-year maturities to protect the refinancing interest rate on a portion of its debt.

17.1.4.1 Analysis of financial instruments by type of interest rate

The following tables present a breakdown by type of interest rate of outstanding borrowings and debt and net financial debt before and after hedging.



17.1.4.2 Interest rate risk sensitivity analysis

Sensitivity was analyzed based on the Group's net debt position (including the impact of interest rate and foreign currency derivatives relating to net debt) at the reporting date.

For interest rate risk, sensitivity corresponds to a 100-basis-point rise or fall in the yield curve compared to year-end interest rates.

In millions of euros	Dec. 31, 2019			
	Impact on income		Impact on equity	
	+100 basis points	-100 basis points	+100 basis points	-100 basis points
Net interest expense on floating-rate net debt (nominal amount) and on floating-rate leg of derivatives	(49)	48	NA	NA
Change in fair value of derivatives not qualifying as hedges	78	(98)	NA	NA
Change in fair value of derivatives qualifying as cash flow hedges	NA	NA	403	(513)

17.1.5 Currency and interest rate hedges

17.1.5.1 Currency risk management

Foreign currency exchange risk (or "FX" risk) is reported and managed based on a Group-wide approach, reflected in a dedicated Group policy that is approved by Group Management. The policy distinguishes between the three following main sources of currency risk:

- Regular transaction risk**

Regular transaction risk corresponds to the potential negative financial impact of currency fluctuations on business and financial operations denominated in a currency other than the functional currency.

The management of regular transaction risk is fully delegated to the subsidiaries for their scope of activities, while the risks related to central activities are managed at corporate level.

FX risks related to operational activities are systematically hedged when the related cash flows are certain, with a hedging horizon that corresponds at least to the medium-term plan horizon. For cash flows that are not certain, in their entirety, the hedge is initially based on a "no regret" volume. Exposures are monitored and managed based on the sum of nominal cash flows in FX, including highly probable amounts and related hedges.

For FX risks related to financial activities, all significant exposures related to cash, financial debts, etc. are systematically hedged. Exposures are monitored based on the net sum of balance sheet items in FX.

- **Project transaction risk**

Specific project transaction risk corresponds to the potential negative financial impact of FX fluctuations on specific major operations such as investment projects, acquisitions, disposals and restructuring projects, involving multiple currencies.

The management of these FX risks includes the definition and implementation of hedging transactions, taking into account the likelihood of the risk (including probability of project completion) and its evolution, the availability of hedging instruments and their associated cost. Management's aim is to ensure the viability and the profitability of the transactions.

- **Translation risk**

Translation risk corresponds to the potential negative financial impact of FX fluctuations concerning consolidated entities with a functional currency other than the euro. It relates to the translation of their income and expenses and their net assets.

Translation risk is managed centrally, with a focus on securing the net asset value.

The pertinence of hedging this translation risk is assessed regularly for each currency (as a minimum) or set of assets in the same currency, taking into account notably the value of the assets and the hedging costs.

Hedging instruments and sources of hedge ineffectiveness

The Group principally uses the following risk management levers for mitigating currency risk:

- derivative instruments: these mostly correspond to over-the-counter contracts and include FX forward transactions, FX swaps, currency swaps, cross currency swaps, plain vanilla FX options or combinations (calls, puts or collars);
- monetary items such as debt, cash and loans.

Sources of hedge ineffectiveness are mainly related to uncertainty regarding the timing and in some cases the amount of the future cash flows in foreign currency that are being hedged.

17.1.5.2 Interest rate risk management

The Group is exposed to interest rate risk through its financing and investing activities. Interest rate risk is defined as a financial risk resulting from fluctuations in base interest rates that may increase the cost of debt and affect the viability of investments. Base interest rates are market interest rates, such as EURIBOR, LIBOR, etc., that do not include the borrower's credit spread.

As part of the interest rate benchmark reform, the Group has elected to apply the transition reliefs permitted by the IASB in the amendments of IFRS 7 and IFRS 9 (Phase 1) which allow the uncertainties caused by the interest rate benchmark reform not to be taken into account in the "highly probable" requirement. The Group is following the status of the project prepared by the IASB in order to assess the impact of the interest rate reform (Phase 2). The Group's risk exposure is mainly related to the highly probable requirement in transactions for which the interest rate is based on US LIBOR.

A Group-wide approach on interest rate risk management is reflected in a dedicated Group policy that is approved by Group Management. This policy distinguishes between the two following main sources of interest rate risk:

- **Interest rate risk relating to Group net debt**

Interest rate risk relating to Group net debt designates the financial impact of base rate movements on the debt and cash portfolio from recurring financing activities. This risk is mainly managed centrally.

Risk management objectives are, by order of importance:

- to protect the long term viability of assets;
- to optimize financing costs and ensure competitiveness; and
- to minimize uncertainty on the cost of debt.

Interest rate risk is managed actively by monitoring changes in market rates and their impact on the Group's gross and net debt.

- **Project interest rate risk**

Specific project interest rate risk corresponds to the potential negative financial impact of base rate movements on specific major operations such as investment projects, acquisitions, disposals and restructuring projects. Interest rate risk after the closing of an operation is considered as regular (see "Interest rate risk" above).

Interest rate risk is managed for specific project transactions in order to protect the economic viability of projects, acquisitions, disposals and restructuring initiatives against adverse changes in interest rates. It may include the implementation of hedging transactions, depending on a number of factors including the likeliness of completion, the availability of hedging instruments and their associated cost.

Hedging instruments and sources of hedge ineffectiveness

The Group uses principally the following risk management levers for mitigating interest rate risk:

- derivative instruments: these mostly correspond to over-the-counter contracts that are used to manage base interest rates. Such instruments include:
 - swaps, to change the nature of interest payments on debts, typically from fixed to floating rates or vice versa, and
 - plain vanilla interest rate options;
- caps, floors and collars that allow the impact of interest rate fluctuations to be limited by setting minimum and/or maximum limits on floating interest rates.

Sources of hedge ineffectiveness are mainly related to changes in the credit quality of the counterparties and related charges, as well as potential gaps in settlement dates and in indices between the derivative instruments and the related underlying exposures.

17.1.5.3 Currency and interest rate hedges

The Group has elected to apply hedge accounting whenever possible and suitable for currency risk and interest rate risk management and also manages a portfolio of undesignated derivative instruments, corresponding to economic hedges relating to net debt and foreign currency exposures.

The Group uses the three hedge accounting methods: cash flow hedging, fair value hedging and net investment hedging.

In general, the Group does not frequently reset hedging relationships, does not designate specific risk components as a hedged item and does not designate credit exposures as measured at fair value through income.

The Group qualifies interest rate or cross currency swaps transforming fixed-rate debt into floating-rate debt as fair value hedges.

Cash flow hedges are mainly used to hedge future cash flows in foreign currency, floating-rate debt as well as future refinancing requirements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 17 RISKS ARISING FROM FINANCIAL INSTRUMENTS

Net investment hedging instruments are mainly FX swaps and forwards.

The fair values of derivatives (excluding commodity instruments) are indicated in the table below:

	Dec. 31, 2019				Dec. 31, 2018			
	Assets		Liabilities		Assets		Liabilities	
	Non-current	Current	Non-current	Current	Non-current	Current	Non-current	Current
<i>In millions of euros</i>								
Derivatives hedging borrowings	705	124	(183)	(41)	678	42	(259)	(66)
<i>Fair value hedges</i>	530	81	(54)	(1)	521	1	(29)	(1)
<i>Cash flow hedges</i>	55	-	(93)	(7)	24	-	(191)	-
<i>Derivative instruments not qualifying for hedge accounting</i>	120	43	(36)	(34)	133	42	(39)	(65)
Derivatives hedging other items	949	17	(1,934)	(45)	606	28	(1,215)	(38)
<i>Cash flow hedges</i>	25	-	(571)	(4)	21	1	(284)	(4)
<i>Net investment hedges</i>	33	-	(6)	-	1	-	(5)	-
<i>Derivative instruments not qualifying for hedge accounting</i>	891	17	(1,357)	(41)	583	27	(927)	(34)
TOTAL	1,654	142	(2,118)	(86)	1,283	71	(1,474)	(105)

The fair values shown in the table above reflect the amounts relating to the price that would be received for the sale of an asset or paid for the transfer of a liability between market participants in the normal course of business. They are not representative of expected future cash flows insofar as positions (i) are sensitive to changes in prices or to changes in credit ratings, (ii) can be modified by subsequent transactions, and (iii) can be offset by future cash flows arising on the underlying transactions.

Amount, timing and uncertainty of future cash flows

The following tables provide a profile of the timing at December 31, 2019 of the nominal amount of hedging instruments:

<i>In millions of euros</i>										
Buy/Sell	Interest rate type	Derivative instrument type	Currency	Total	2020	2021	2022	2023	2024	Beyond 5 years
Buy	Fixed	CCS	EUR	(561)	(288)	(271)	(2)	-	-	-
			USD	(3,010)	(1,549)	(1,371)	(45)	(45)	-	-
			GBP	(14,518)	(2,146)	(2,146)	(1,881)	(1,881)	(1,293)	(5,172)
			HKD	(1,212)	(263)	(263)	(263)	(263)	(160)	-
			JPY	(902)	(369)	(369)	(164)	-	-	-
			PEN	(882)	(273)	(262)	(218)	(130)	-	-
			CHF	(737)	(415)	(161)	(161)	-	-	-
			AUD	(535)	(125)	(125)	(125)	(53)	(53)	(53)
			Other currencies	(152)	(51)	(51)	(51)	-	-	-
	Floating	CCS	USD	(413)	(340)	(73)	-	-	-	-
Sale	Fixed	CCS	EUR	17,561	3,138	2,865	2,568	2,277	1,497	5,216
			USD	908	291	265	221	131	-	-
			GBP	545	272	270	2	-	-	-
			Other currencies	158	80	78	-	-	-	-
	Floating	CCS	EUR	2,277	1,180	953	144	-	-	-
		CCS	BRL	1,256	706	550	-	-	-	-

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 17 RISKS ARISING FROM FINANCIAL INSTRUMENTS

In millions of euros

Buy/Sell	Interest rate type	Derivative instrument type	Currency	Total	2020	2021	2022	2023	2024	Beyond 5 years
Buy	Fixed	CAP	EUR	2,000	1,000	1,000	-	-	-	-
			Other currencies	-	-	-	-	-	-	-
		IRS	EUR	37,331	6,295	8,933	7,246	4,986	3,758	6,112
			USD	3,252	999	1,236	299	259	212	248
			GBP	12	4	4	2	1	-	-
			Other currencies	407	111	106	88	64	33	5
	Floating	FRA	EUR	1,650	1,650	-	-	-	-	-
		IRS	EUR	44,229	13,536	11,648	7,387	4,820	3,080	3,758
			BRL	687	379	308	-	-	-	-

The tables presented above exclude currency derivatives (except for cross currency swaps - CCS). These hedges are mainly short term, with maturity dates aligned with those of the hedged items.

Pursuant to the FX and interest rate risk management policy, FX sensitivity is presented in Note 17.1.3.2 "Currency risk sensitivity analysis" and the average cost of debt is 2.70% as presented in Note 10 "Net financial income/(loss)".

Effects of hedge accounting on the Group's financial position and performance

Currency derivatives

<i>In millions of euros</i>	Dec. 31, 2019				Dec. 31, 2018	
	Fair value			Nominal amount	Fair value	Nominal amount
	Assets	Liabilities	Total	Total	Total	Total
Cash flow hedges	77	(381)	(305)	3,814	(335)	3,268
Net investment hedges	33	(6)	27	3,027	(3)	1,114
Derivative instruments not qualifying for hedge accounting	70	(77)	(6)	8,985	(23)	10,996
TOTAL	180	(464)	(284)	15,827	(361)	15,379

Interest rate derivatives

<i>In millions of euros</i>	Dec. 31, 2019				Dec. 31, 2018	
	Fair value			Nominal amount	Fair value	Nominal amount
	Assets	Liabilities	Total	Total	Total	Total
Fair value hedges	611	(55)	556	6,089	491	4,846
Cash flow hedges	-	(290)	(290)	3,649	(98)	1,434
Derivative instruments not qualifying for hedge accounting	998	(1,391)	(393)	21,487	(257)	25,216
TOTAL	1,609	(1,736)	(126)	31,224	136	31,496

The fair values shown in the table above are positive for an asset and negative for a liability.

In millions of euros		Nominal and outstanding amount	Fair value ⁽¹⁾	Change in fair value used for calculating hedge ineffectiveness	Change in the value of the hedging instrument recognized in equity ⁽²⁾	Ineffective portion recognized in profit or loss ⁽²⁾	Amount reclassified from the hedge reserve to profit or loss ⁽²⁾	Line item of the income statement
Fair value hedges	Hedging instruments	6,089	556	556	NA	(3)	NA	Cost of net debt
	Hedged items ^{(3) (4)}	6,034	353	1,152	NA		NA	
Cash flow hedges	Hedging instruments	4,702	(433)	(583)	320	(5)	(82)	Other financial income and expenses / Income/(loss) from operating activities
	Hedged items			580				
Net investment hedges	Hedging instruments	1,114	(3)	36	61	NA	(90)	Other financial income and expenses / Income/(loss) from operating activities
	Hedged items			(36)				

(1) The adjustment of the fair value of hedged items is presented as long term and short-term borrowings and debt for an amount of €353 million.

(2) Gains/(losses)

(3) The difference between the fair value used to determine the ineffective portion relating to hedging instruments and that relating to the hedged items corresponds to the amortized cost of borrowings and debt that are part of a fair value hedge relationship.

(4) Of which €126 million relating to hedging items that have ceased to be adjusted as a result of disqualification as a fair value hedge.

Hedge inefficiency is calculated based on the change in the fair value of the hedging instrument compared to the change in the fair value of the hedged items since inception of the hedge. The fair value of the hedging instruments at December 31, 2019 reflects the cumulative change in the fair value of the hedging instruments since inception of the hedges. For fair value hedges, the same principle applies to the hedged items.

Foreign currency and interest rate derivatives designated as cash flow hedges can be analyzed as follows by maturity

In millions of euros	2020	2021	2022	2023	2024	Beyond 5 years	Total at Dec. 31, 2019	Total at Dec. 31, 2018
Fair value of derivatives by maturity	(9)	(10)	(21)	(27)	(17)	(510)	(594)	(433)

Amounts presented in the statement of changes in equity and the statement of comprehensive income

The following table provides a reconciliation of each component of equity and an analysis of other comprehensive income:

In millions of euros	Cash flow hedge			Net investment hedge
	Derivatives hedging borrowings - currency risk hedging ^{(1) (3)}	Derivatives hedging other items - interest rate risk hedging ^{(1) (3)}	Derivatives hedging other items - currency risk hedging ^{(2) (3)}	Derivatives hedging other items - currency risk hedging ^{(2) (4)}
AT DECEMBER 31, 2018	46	(741)	(28)	(313)
Effective portion recognized in equity	(293)		(27)	(61)
Amount reclassified from the hedge reserve to profit or loss	53		29	90
Translation differences	-	-	-	-
Changes in scope of consolidation and other	-	14	(1)	-
AT DECEMBER 31, 2019	45	(1,010)	16	(284)

(1) Cash flow hedges for given periods.

(2) Cash flow hedges for given transactions.

(3) Of which €-425 million of cash flow hedge reserves for which hedge accounting is no longer applied.

(4) All of the reserves relate to continuing hedging relationships.

17.2 Counterparty risk

Due to its financial and operational activities, the Group is exposed to the risk of default of its counterparties (customers, suppliers, EPC contractors, partners, intermediaries, and banks). Default could affect payments, goods delivery and/or asset performance.

The principles of counterparty risk management are set out in the Group counterparty risk policy, which:

- assigns roles and responsibilities for managing and controlling counterparty risk at different levels (Corporate, BU or entity), and ensures operational procedures are in place and consistent across the Group;
- characterizes counterparty risk and the mechanisms by which it impacts the economic performance and financial statements of the Group;
- defines indicators, reporting and control mechanisms to ensure visibility and to provide tools for financial performance management; and
- provides guidelines on the use of mitigating mechanisms such as collateral and guarantees, which are widely used by some businesses.

Depending on the nature of the business, the Group is exposed to different types of counterparty risk. As a result some businesses use collateral instruments – particularly the Energy Management business, where the use of margin calls and other types of financial collateral (standardized legal framework) is a market standard. In addition, other businesses may request guarantees from their counterparties in certain cases (parent company guarantees, bank guarantees, etc.).

Under the new standard IFRS 9, the Group has defined and applied a Group-wide methodology including the two different approaches:

- a portfolio approach, whereby the Group determines that:
 - coherent customer portfolios and sub-portfolios have to be considered (i.e., portfolios that have comparable credit risk and/or comparable payment behavior), taking into account different aspects:
 - public or private counterparties,
 - residential or BtoB counterparties,
 - geography,
 - type of activity,
 - size of the counterparty,
 - any other aspects the Group may consider relevant, and
 - impairment rates must be determined based on historical aging balances and, when correlation is proven and documentation possible, historical data must be adjusted by forward-looking elements;
- an individualized approach for significant counterparties, for which the Group has set rules for defining the stage of the concerned asset for Expected Credit Loss (ECL) calculations:
 - stage 1 covers financial assets that have not deteriorated significantly since initial recognition. The ECL for stage 1 is calculated on a 12-month basis,
 - stage 2 covers financial assets for which the credit risk has significantly increased. The ECL for stage 2 is calculated on a lifetime basis. The decision to move an asset from stage 1 to stage 2 is based on certain criteria such as:
 - a significant downgrade in the counterparty's creditworthiness and/or its parent company and/or its guarantor (if any),
 - significant adverse change in the regulatory environment,
 - changes in political or country-related risk, and
 - any other aspect the Group may consider relevant.

Regarding financial assets that are more than 30 days past due, the move to stage 2 is not systematically applied as long as the Group has reasonable and supportable information that demonstrates that, even if payments become more than 30 days past due, this does not represent a significant increase in the credit risk since initial recognition.

- stage 3 covers assets for which default has already been observed, such as:
 - when there is evidence of significant and ongoing financial difficulty of the counterparty,
 - when there is evidence of failure in credit support from a parent company to its subsidiary (in this case the subsidiary is the Group's counterparty at risk),
 - when a Group entity has initiated legal proceedings against the counterparty for non-payment.

Regarding financial assets that are more than 90 days past due, the presumption can be rebutted if the Group has reasonable and supportable information that demonstrates that even if payments become more than 90 days past due, this does not indicate counterparty default.

The ECL formula applicable in stages 1 and 2 is $ECL = EAD \times PD \times LGD$, where:

- for 12-month ECL, Exposure At Default (EAD) equals the carrying amount of the financial asset, to which the relevant Probability of Default (PD) and the Loss Given Default (LGD) are applied;
- for lifetime ECL, the calculation method consists in identifying changes in exposure for each year, especially the expected timing and amount of the contractual repayments, and then applying to each repayment the relevant PD and the LGD, and discounting the figures obtained. ECL is then the sum of the discounted figures; and
- probability of default: is the likelihood of default over a particular time horizon (in stage 1, this time horizon is 12 months after the reporting period; in stage 2 this time horizon is the entire lifetime of the financial asset). This information is based on external data from a well-known rating agency. The PD depends on the time horizon and of the rating of the counterparty. The Group uses external ratings if they are available; ENGIE's credit risk experts determine an internal rating for major counterparties with no external rating.

LGD levels are notably based on Basel standards:

- 75% for subordinated assets; and
- 45% for standard assets.

For assets considered to be of strategic importance for the counterparty, such as essential public services or goods, LGD is set at 30%.

The Group has decided that write-offs apply in the following situations:

- assets for which a legal recovery procedure is pending: should not be written off as long as the procedure is ongoing;
- assets for which no legal recovery procedure is pending: should be written off once the trade receivable is 3 years overdue (5 years overdue for public counterparties).

17.2.1 Operating activities

Counterparty risk arising on operating activities is managed via standard mechanisms such as third-party guarantees, netting agreements and margin calls, using dedicated hedging instruments or special prepayment and debt recovery procedures, particularly for retail customers.

Under the Group's policy, each business unit is responsible for managing counterparty risk, although the Group continues to manage the biggest counterparty exposures centrally.

The credit rating of large- and mid-sized counterparties with which the Group has exposures above a certain threshold is measured based on a specific rating process, while a simplified credit scoring process is used for commercial customers with which the Group has fairly low exposures. These processes are based on formally documented, consistent methods across the Group. Consolidated exposures are monitored by counterparty and by segment (credit rating, sector, etc.) using standard indicators (payment risk, mark-to-market exposure).

The Group's Energy Market Risk Committee (CRME) consolidates and monitors the Group's exposure to its main energy counterparties on a quarterly basis and ensures that the exposure limits set for these counterparties are respected.

17.2.1.1 Trade and other receivables, assets from contracts with customers

Total outstanding exposures presented in the tables hereafter do not include impacts relating to VAT or to any other item not subject to credit risk, which amounted to €2,898 million and €1 million respectively for "Trade and other receivables" and "Assets from contract with customers" at December 31, 2019 (compared to €2,547 million and €13 million at December 31, 2018).

Individual approach

		Dec. 31, 2019							
<i>In millions of euros</i>		Individual approach	Level 1: low credit risk	Level 2: increased credit risk	Level 3: impaired assets	Total by risk level	Investment Grade ⁽¹⁾	Other	Total by counterparty type
Trade and other receivables, net	Gross	9,395	8,300	802	294	9,395	7,814	1,581	9,395
	Expected credit losses	(318)	(64)	(66)	(187)	(318)	(172)	(146)	(318)
TOTAL		9,077	8,235	735	107	9,077	7,642	1,436	9,077
Assets from contracts with customers	Gross	2,896	2,672	196	28	2,896	1,782	1,115	2,896
	Expected credit losses	(15)	(13)	(1)	(1)	(15)	(10)	(6)	(15)
TOTAL		2,881	2,659	195	27	2,881	1,772	1,109	2,881

		Dec. 31, 2018							
<i>In millions of euros</i>		Individual approach	Level 1: low credit risk	Level 2: increased credit risk	Level 3: impaired assets	Total by risk level	Investment Grade ⁽¹⁾	Other	Total by counterparty type
Trade and other receivables, net	Gross	10,339	9,694	422	222	10,339	9,161	1,178	10,339
	Expected credit losses	(323)	(109)	(71)	(145)	(323)	(205)	(118)	(323)
TOTAL		10,016	9,586	352	77	10,016	8,956	1,060	10,016
Assets from contracts with customers	Gross	3,052	2,730	261	61	3,052	2,358	694	3,052
	Expected credit losses	(7)	(6)	-	(1)	(7)	(4)	(3)	(7)
TOTAL		3,045	2,725	261	59	3,045	2,354	691	3,045

(1) Investment Grade corresponds to counterparties that are rated at least BBB- by Standard & Poor's.

Collective approach

		Dec. 31, 2019				Total past due assets at Dec. 31, 2019
<i>In millions of euros</i>		Collective approach	0 to 6 months	6 to 12 months	beyond	
Trade and other receivables, net	Gross	4,019	875	113	293	1,281
	Expected credit losses	(754)	(24)	(29)	(159)	(213)
TOTAL		3,265	851	83	134	1,068
Assets from contracts with customers	Gross	4,953	486	4	2	492
	Expected credit losses	(2)	-	-	-	-
TOTAL		4,951	485	4	2	492

		Dec. 31, 2018				Total past due assets at Dec. 31, 2018
In millions of euros		Collective approach	0 to 6 months	6 to 12 months	beyond	
Trade and other receivables, net	Gross	3,804	730	146	368	1,243
	Expected credit losses	(762)	(18)	(19)	(243)	(281)
TOTAL		3,042	711	126	125	962
Assets from contracts with customers	Gross	4,381	43	3	4	51
	Expected credit losses	(1)	-	-	-	-
TOTAL		4,379	43	3	4	51

17.2.1.2 Commodity derivatives

In the case of commodity derivatives, counterparty risk arises from positive fair value. Counterparty risk is taken into account when calculating the fair value of these derivative instruments.

		Dec. 31, 2019		Dec. 31, 2018	
In millions of euros		Investment Grade ⁽¹⁾	Total	Investment Grade ⁽¹⁾	Total
Gross exposure ⁽²⁾		9,849	12,466	9,325	12,027
Net exposure ⁽³⁾		3,501	4,422	2,701	3,683
% of credit exposure to "Investment Grade" counterparties		79.2%		73.4%	

- (1) Investment Grade corresponds to transactions with counterparties that are rated at least BBB- by Standard & Poor's, Baa3 by Moody's, or equivalent by Dun & Bradstreet. "Investment Grade" is also determined based on an internal rating tool that has been rolled out within the Group, and covers its main counterparties.
- (2) Corresponds to the maximum exposure, i.e., the value of the derivatives shown under assets (positive fair value).
- (3) After taking into account the liability positions with the same counterparties (negative fair value), collateral, netting agreements and other credit enhancement techniques.

17.2.2 Financing activities

For its financing activities, the Group has put in place procedures for managing and monitoring risk based on (i) the accreditation of counterparties according to external credit ratings, objective market data (credit default swaps, market capitalization) and financial structure, and (ii) counterparty risk exposure limits.

To reduce its counterparty risk exposure, the Group drew increasingly on a structured legal framework based on master agreements (including netting clauses) and collateralization contracts (margin calls).

The oversight procedure for managing counterparty risk arising from financing activities is managed by a Middle Office that operates independently of the Group's Treasury department and reports to the Finance division.

17.2.2.1 Loans and receivables at amortized cost

The total outstanding exposures presented in the tables hereafter do not include impacts relating to VAT or to any other item not subject to credit risk, which amount at December 31, 2019 to €899 million (compared to €809 million at December 31, 2018).

		Dec. 31, 2019					
In millions of euros		Level 1: low credit risk	Level 2: increased credit risk	Level 3: impaired assets	Total by risk level	Investment Grade ⁽¹⁾	Total by counterparty type
Gross		4,257	564	49	4,870	2,772	4,870
Expected credit losses		(53)	(56)	(30)	(139)	(36)	(139)
TOTAL		4,204	508	19	4,731	2,736	4,731

In millions of euros	Dec. 31, 2018						
	Level 1: low credit risk	Level 2: increased credit risk	Level 3: impaired assets	Total by risk level	Investment Grade ⁽¹⁾	Other	Total by counterparty type
Gross	3,402	466	233	4,100	2,003	2,098	4,100
Expected credit losses	(91)	-	(227)	(319)	(86)	(233)	(319)
TOTAL	3,311	466	5	3,781	1,917	1,865	3,781

(1) Investment Grade corresponds to counterparties that are rated at least BBB- by Standard & Poor's.

17.2.2.2 Counterparty risk arising from investing activities and the use of derivative financial instruments

The Group is exposed to counterparty risk arising from investments of surplus cash and from the use of derivative financial instruments. In the case of financial instruments at fair value through income, counterparty risk arises on instruments with a positive fair value. Counterparty risk is taken into account when calculating the fair value of these derivative instruments.

In millions of euros	Dec. 31, 2019				Dec. 31, 2018			
	Total	Investment Grade ⁽¹⁾	Unrated ⁽²⁾	Non-Investment Grade ⁽²⁾	Total	Investment Grade ⁽¹⁾	Unrated ⁽²⁾	Non-Investment Grade ⁽²⁾
Exposure	10,686	85.7%	4.7%	9.6%	9,634	85.0%	6.0%	8.0%

(1) Investment Grade corresponds to counterparties that are rated at least BBB- by Standard & Poor's or Baa3 by Moody's.

(2) Most of these two exposures is carried by consolidated companies that include non-controlling interests, or by Group companies that operate in emerging countries, where cash cannot be pooled and is therefore invested locally.

Furthermore, at December 31, 2019, Crédit Agricole Corporate and Investment Bank (CACIB) is the main Group counterparty and represents 30% of cash surpluses. This relates mainly to a depositary risk.

17.3 Liquidity risk

In the context of its operating activities, the Group is exposed to a risk of having insufficient liquidity to meet its contractual obligations. As well as the risks inherent in managing working capital requirements (WCR), margin calls are required in certain market activities.

The Group has set up a quarterly committee tasked with managing and monitoring liquidity risk throughout the Group, by maintaining a broad range of investments and sources of financing, preparing forecasts of cash investments and divestments, and performing stress tests on the margin calls put in place when commodity, interest rate and currency derivatives are negotiated.

The Group centralizes virtually all financing needs and cash flow surpluses of the companies it controls, as well as most of their medium- and long-term external financing requirements. Centralization is provided by financing vehicles (long-term and short-term) and by dedicated Group cash pooling vehicles based in France, Belgium and Luxembourg.

Surpluses held by these structures are managed in accordance with a uniform policy. Unpooled cash surpluses are invested in instruments selected on a case-by-case basis in light of local financial market imperatives and the financial strength of the counterparties concerned.

The onslaught of successive financial crises since 2008 and the ensuing rise in counterparty risk prompted the Group to tighten its investment policy with the aim of keeping an extremely high level of liquidity and protecting invested capital and a daily monitoring of performance and counterparty risks for both investment types, allowing the Group to take immediate action where required in response to market developments. Consequently, 76% of cash pooled at December 31, 2019 was invested in overnight bank deposits and standard money market funds with daily liquidity.

The Group's financing policy is based on:

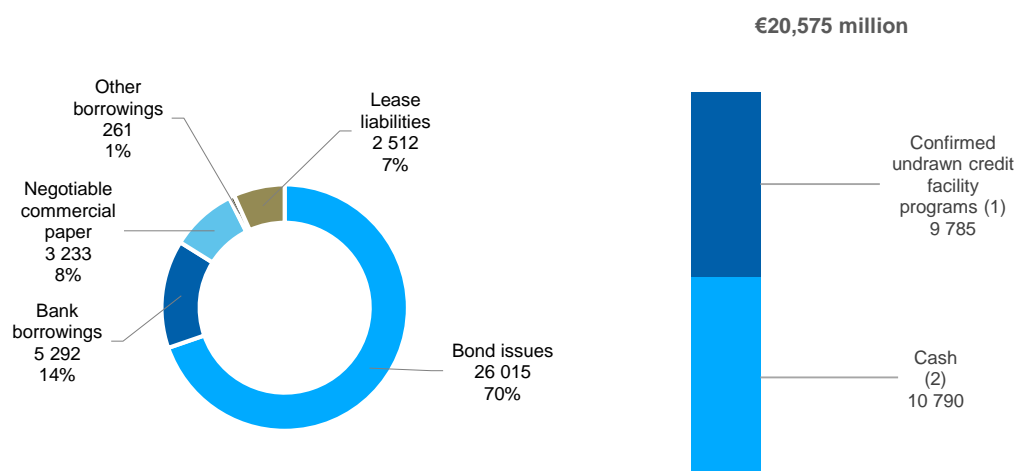
- centralizing external financing;
- diversifying sources of financing between credit institutions and capital markets;

- achieving a balanced debt repayment profile.

The Group seeks to diversify its sources of financing by carrying out public or private bond issues within the scope of its Euro Medium Term Notes program. It also issues negotiable commercial paper in France and in the United States. As negotiable commercial paper is relatively inexpensive and highly liquid, it is used by the Group in a cyclical or structural fashion to finance its short-term cash requirements. However, the refinancing of all outstanding negotiable commercial paper remains secured by confirmed bank lines of credit – mainly centralized – allowing the Group to continue to finance its activities if access to this financing source were to dry up. These facilities are appropriate for the scale of its operations and for the timing of contractual debt repayments.

Diversifying sources of financing and liquidity

In millions of euros



(1) Net amount of negotiable commercial paper.

(2) Cash corresponds to cash and cash equivalents, other financial assets deducted from net financial debt, net of bank overdrafts and current accounts, of which 64% was invested in the Eurozone.

At December 31, 2019, all the entities of the Group whose debt is consolidated complied with the covenants and declarations included in their financial documentation, except for some non-significant entities for which compliance actions are being implemented. None of these centralized facilities contain a default clause linked to covenants or minimum credit ratings.

17.3.1 Undiscounted contractual payments relating to financial activities

Undiscounted contractual payments on outstanding borrowings and debt break down as follows by maturity:

In millions of euros	2020	2021	2022	2023	2024	Beyond 5 years	Total at Dec. 31, 2019	Total at Dec. 31, 2018
Bond issues	2,753	1,805	2,628	2,600	1,156	15,074	26,015	22,645
Bank borrowings	1,063	465	694	368	233	2,469	5,292	4,620
Negotiable commercial paper	3,233	-	-	-	-	-	3,233	2,894
Lease liabilities	491	446	311	245	218	1,075	2,512	380
Other borrowings	33	19	155	6	6	41	261	191
Bank overdrafts and current accounts	247	-	-	-	-	-	247	464

Other financial assets and cash and cash equivalents deducted from net financial debt have a liquidity of less than 1 year.

Undiscounted contractual interest payments on outstanding borrowings and debt break down as follows by maturity:

<i>In millions of euros</i>	2020	2021	2022	2023	2024	Beyond 5 years	Total at Dec. 31, 2019	Total at Dec. 31, 2018
Undiscounted contractual interest flows on outstanding borrowings and debt	1,023	798	703	613	508	6,227	9,872	9,335

Undiscounted contractual payments on outstanding derivatives (excluding commodity instruments) break down as follows by maturity:

<i>In millions of euros</i>	2020	2021	2022	2023	2024	Beyond 5 years	Total at Dec. 31, 2019	Total at Dec. 31, 2018
Derivatives (excluding commodity instruments)	(215)	(136)	(124)	33	(11)	217	(237)	(138)

To better reflect the economic substance of these transactions, the cash flows linked to the derivatives recognized in assets and liabilities shown in the table above relate to net positions.

Group's undrawn credit facility programs

<i>In millions of euros</i>	2020	2021	2022	2023	2024	Beyond 5 years	Total at Dec. 31, 2019	Total at Dec. 31, 2018
Confirmed undrawn credit facility programs	1,200	582	5,837	204	5,000	196	13,019	13,232

Of these undrawn programs, an amount of €3,233 million is allocated to covering commercial paper issues.

At December 31, 2019, no single counterparty represented more than 5% of the Group's confirmed undrawn credit lines.

17.3.2 Undiscounted contractual payments relating to operating activities

The table below provides an analysis of undiscounted fair values due and receivable in respect of commodity derivatives recorded in assets and liabilities at the statement of financial position date.

The Group provides an analysis of residual contractual maturities for commodity derivative instruments included in its portfolio management activities. Derivative instruments relating to trading activities are considered to be liquid in less than one year, and are presented under current items in the statement of financial position.

<i>In millions of euros</i>	2020	2021	2022	2023	2024	Beyond 5 years	Total at Dec. 31, 2019	Total at Dec. 31, 2018
Derivative instruments carried in liabilities								
relating to portfolio management	(1,135)	(2,171)	(360)	(224)	(86)	(452)	(4,428)	(2,114)
relating to trading activities	(9,238)	-	-	-	-	-	(9,238)	(10,579)
Derivative instruments carried in assets								
relating to portfolio management	1,042	1,634	316	120	35	215	3,363	2,080
relating to trading activities	8,954	-	-	-	-	-	8,954	9,952
TOTAL	(376)	(537)	(43)	(104)	(51)	(237)	(1,349)	(661)

17.3.3 Commitments relating to commodity purchase and sale contracts entered into within the ordinary course of business

Some Group operating companies have entered into long-term contracts, some of which include “take-or-pay” clauses. These consist of firm commitments to purchase or sell specified quantities of gas, electricity or steam as well as related services, in exchange for a firm commitment from the other party to deliver or purchase said quantities and services. These contracts were documented as falling outside the scope of IFRS 9. The table below shows the main future commitments arising from contracts entered into by Others (GEM BU) and Latin America (expressed in TWh):

<i>In TWh</i>	2020	2021-2024	Beyond 5 years	Total at Dec. 31, 2019	Total at Dec. 31, 2018
Firm purchases	(370)	(910)	(1,218)	(2,498)	(3,070)
Firm sales	480	613	480	1,573	1,329

NOTE 18 EQUITY

18.1 Share capital

	Number of shares			Value (in millions of euros)		
	Total	Treasury stock	Outstanding	Share capital	Additional paid-in capital	Treasury stock
AT DECEMBER 31, 2018	2,435,285,011	(23,891,170)	2,411,393,841	2,435	32,565	(460)
Dividend paid in cash	-	-	-	-	(1,096)	-
Purchase/disposal of treasury stock	-	1,737,451	1,737,451	-	-	29
Delivery of treasury stock (bonus)	-	-	-	-	-	-
Revaluation	-	-	-	-	-	128
AT DECEMBER 31, 2019	2,435,285,011	(22,153,719)	2,413,131,292	2,435	31,470	(303)

Changes in the number of shares during 2019 result solely from the disposal of for 1.7 million treasury shares, as part of bonus share plans.

18.1.1 Potential share capital and instruments providing a right to subscribe for new ENGIE SA shares

Since 2017, the Group no longer has any stock purchase option plan.

Shares to be allocated under the performance share award plans described in Note 21 "Share-based payments" are covered by existing ENGIE SA shares.

18.1.2 Treasury stock

Accounting standards

Treasury shares are recognized at acquisition cost and deducted from equity. Gains and losses on disposals of treasury shares are recorded directly in equity and do not therefore impact income for the period.

The Group has a stock repurchase program as a result of the authorization granted to the Board of Directors by the Ordinary and Extraordinary Shareholders' Meeting of May 17, 2019. This program provides for the repurchase of up to 10% of the shares comprising the share capital of ENGIE SA at the date of the said Shareholders' Meeting. The aggregate amount of acquisitions net of expenses under the program may not exceed €7.3 billion, and the purchase price must be less than €30 per share excluding acquisition costs.

At December 31, 2019, the Group held 22.2 million treasury shares. To date, 20.4 million shares have been allocated to cover the Group's share commitments to employees and corporate officers.

The liquidity agreement signed with an investment service provider assigns to the latter the role of operating on the market on a daily basis, to buy or sell ENGIE SA shares, in order to ensure liquidity and an active market for the shares on the Paris and Brussels stock exchanges. To date, the resources allocated to the implementation of this agreement amount to €150 million.

18.2 Other disclosures concerning additional paid-in capital, consolidated reserves and issuance of deeply-subordinated perpetual notes (Group share)

Total additional paid-in capital, consolidated reserves and issuance of deeply-subordinated perpetual notes (including net income for the fiscal year), amounted to €34,014 million at December 31, 2019, including €31,470 million in additional paid-in capital.

Consolidated reserves include the cumulative income of the Group, the legal and statutory reserves of ENGIE SA, cumulative actuarial gains and losses, net of tax and the change in fair value of equity instruments at fair value through OCI.

Under French law, 5% of the net income of French companies must be allocated to the legal reserve until the latter reaches 10% of share capital. This reserve can only be distributed to shareholders in the event of liquidation. The ENGIE SA legal reserve amounts to €244 million.

18.2.1 Issuance of deeply-subordinated perpetual notes

On January 28, 2019, ENGIE SA carried out an early refinancing of deeply-subordinated perpetual notes, resulting in:

- an issue of green deeply-subordinated perpetual notes for an amount of €1 billion offering a coupon of 3.25% with an annual reimbursement option from February 2025, accounted for in equity for a net amount of €983 million;
- notification of a partial early redemption proposal for the €1 billion tranche (coupon 3%) for a total amount of €839 million. The first reimbursement option for this hybrid debt was planned for June 2019. The Group made a squeeze-out for the balance of €161 million since it reimbursed more than 80% of this hybrid debt. ENGIE SA reimbursed the balance on March 12, 2019.

On July 8, 2019, ENGIE SA also carried out a second early refinancing of deeply-subordinated perpetual notes, resulting in:

- an issue of a green deeply-subordinated perpetual notes for an amount of €500 million offering a coupon of 1.625% with an annual reimbursement option from July 2025, accounted for in equity for a net amount of €495 million;
- notification of a partial early redemption proposal for €750 million (4.75% coupon) for a total amount of €337 million. The first reimbursement option for this hybrid debt was planned for July 2021.

In accordance with the provisions of IAS 32 – *Financial Instruments – Presentation*, and given their characteristics, these new instruments were accounted for in equity in the Group's consolidated financial statements for a total amount of €1,478 million.

At December 31, 2019 the nominal value of the deeply-subordinated notes amounted to €3,913 million.

In 2019, the Group paid €150 million to the owners of these notes, including €108 million relating to coupons and €42 million for early repayment compensation. This amount is accounted for as a deduction from equity in the Group's consolidated financial statements; the relating tax saving is accounted for in the income statement.

18.2.2 Distributable capacity of ENGIE SA

ENGIE SA's distributable capacity totaled €31,290 million at December 31, 2019 (compared with €33,320 million at December 31, 2018), after deducting the interim dividend paid on May 23, 2019 for a total amount of €1,833 million, including €31,470 million of additional paid-in capital.

18.2.3 Dividends

The table below shows the dividends and interim dividends paid by ENGIE SA in respect of 2018 and 2019.

	Amount distributed (in millions of euros)	Net dividend per share (in euros)
In respect of 2018		
Interim dividend (paid on October 12, 2018)	892	0.37
Remaining dividend for 2018 (paid on May 23, 2019)	917	0.38
Exceptional dividend for 2018 (paid on May 23, 2019)	893	0.37
Remaining additional dividend for 2018 (paid on May 23, 2019)	24	0.11
In respect of 2019		
Interim dividend	-	-

The Shareholders' Meeting of May 17, 2019 approved the distribution of a total dividend of €1.12 per share in respect of 2018. In accordance with Article 26.2 of the bylaws, a dividend increase of 10% (€0.11 per share) has been allocated to shares registered in the name of the holder for at least two years at December 31, 2018, provided they are held in this form by the same shareholder until the payment date. This 10% increase may only apply, for any one shareholder, for a number of shares not representing more than 0.5% of the capital.

As an interim dividend of €0.37 per share was paid on October 12, 2018, for an amount of €892 million. ENGIE SA settled the remaining dividend balance of €0.75 per share in cash on May 23, 2019, for an amount of €1,810 million, for shares benefiting from an ordinary dividend, as well as the remaining €0.86 per share for shares benefiting from the bonus dividend for an amount of €24 million, i.e., a total dividend of €1,833 million.

Proposed dividend in respect of 2019

Shareholders at the Shareholders' Meeting convened to approve the ENGIE Group financial statements for the year ended December 31, 2019, will be asked to approve a dividend of €0.80 per share, representing a total payout of €1,931 million based on the number of shares outstanding at December 31, 2019. It will be increased by 10% for all shares held for at least two years on December 31, 2019 and up to the 2019 dividend payment date. Based on the number of outstanding shares on December 31, 2019, this increase is valued at €17 million.

Subject to approval by the Shareholders' Meeting of May 14 2020, this dividend, net of the interim dividend paid will be detached on May 18, 2020 and paid on May 20, 2020. It is not recognized as a liability in the financial statements at December 31, 2019, since the financial statements at the end of 2019 were presented before the appropriation of earnings.

18.3 Total gains and losses recognized in equity (Group share)

All items shown in the table below correspond to cumulative gains and losses (Group share) at December 31, 2019 and December 31, 2018, which are recyclable to income in subsequent periods.

In millions of euros	Dec. 31, 2019	Dec. 31, 2018
Debt instruments	76	28
Net investment hedges	(284)	(313)
Cash flow hedges (excl. commodity instruments)	(958)	(725)
Commodity cash flow hedges	(837)	(30)
Deferred taxes on the items above	505	244
Share of equity method entities in recyclable items, net of tax	(462)	(223)
TOTAL RECYCLABLE ITEMS BEFORE TRANSLATION ADJUSTMENTS	(1,961)	(1,019)
Translation adjustments	(1,098)	(1,130)
TOTAL RECYCLABLE ITEMS	(3,060)	(2,149)

18.4 Capital management

ENGIE SA seeks to optimize its financial structure at all times by pursuing an optimal balance between its net financial debt and its EBITDA. The Group's key objective in managing its financial structure is to maximize value for shareholders

and reduce the cost of capital, while ensuring that the Group has the financial flexibility required to continue its expansion. The Group manages its financial structure and makes any necessary adjustments in light of prevailing economic conditions. In this context, it may choose to adjust the amount of dividends paid to shareholders, reimburse a portion of capital, carry out share buybacks (see *Note 18.1.2 "Treasury stock"*), issue new shares, launch share-based payment plans, recalibrate its investment budget, or sell assets in order to scale back its net debt.

The Group's policy is to maintain an "A" rating by the rating agencies. To achieve this, it manages its financial structure in line with the indicators usually monitored by these agencies, namely the Group's operating profile, financial policy and a series of financial ratios. One of the most commonly used ratios is the ratio where the numerator includes operating cash flows less net financial expense and taxes paid, and the denominator includes adjusted net financial debt. Net financial debt is mainly adjusted for nuclear provisions, provisions for unfunded pension plans and operating lease commitments.

The Group's objectives, policies and processes for managing capital have remained unchanged over the past few years.

ENGIE SA is not obliged to comply with any minimum capital requirements except those provided for by law.

NOTE 19 PROVISIONS

Accounting standards

General principles related to the recognition of a provision

The Group recognizes a provision where it has a present obligation (legal or constructive) towards a third party arising from past events and where it is probable that an outflow of resources will be necessary to settle the obligation with no expected consideration in return.

A provision for restructuring costs is recognized when the general criteria for setting up a provision are met, i.e. when the Group has a detailed formal plan relating to the restructuring and has raised a valid expectation in those affected that it will carry out the restructuring by starting to implement that plan or announcing its main features to those affected by it.

Provisions with a maturity of over 12 months are discounted when the effect of discounting is material. The Group's main long-term provisions are provisions for the back-end of the nuclear fuel cycle, provisions for dismantling facilities and provisions for site restoration costs. The discount rates used reflect current market assessments of the time value of money and the risks specific to the liability concerned. Expenses with respect to unwinding the discount on the provision are recognized as other financial income and expenses.

Estimates of provisions

Factors having a significant influence on the amount of provisions, and particularly, but not solely, those relating to the back-end of the nuclear fuel cycle, to the dismantling of nuclear facilities and of gas infrastructures in France, include:

- cost estimates (notably the retained scenario for managing radioactive nuclear fuel consumed) (*see Note 19.2*);
- the timing of expenditure (notably, for nuclear power generation activities, the timetable for reprocessing radioactive nuclear fuel consumed and for dismantling facilities as well as the timetable for the end of gas operations regarding the main gas infrastructure businesses in France) (*see Notes 19.2 and 19.3*); and
- the discount rate applied to cash flows.

These factors are based on information and estimates deemed by the Group to be the most appropriate as of today.

Modifications to certain factors could lead to a significant adjustment in these provisions.

NOTE 19 PROVISIONS

<i>In millions of euros</i>	Post-employment and other long-term benefits	Back-end of the nuclear fuel cycle	Dismantling of plant and equipment ⁽²⁾ and Site rehabilitation	Other contingencies	Total
AT DECEMBER 31, 2018 ⁽¹⁾	6,371	6,170	6,303	2,969	21,813
IFRS 16 & IFRIC 23 (see Note 1)	-	-	-	(301)	(301)
AT JANUARY 1, 2019 with IFRS 16 & IFRIC 23	6,371	6,170	6,303	2,667	21,512
Additions	285	1,362	72	467	2,187
Utilizations	(331)	(164)	(150)	(677)	(1,322)
Reversals	(1)	-	(1)	(47)	(48)
Changes in scope of consolidation	(41)	-	(73)	60	(54)
Impact of unwinding discount adjustments	123	220	213	24	580
Translation adjustments	-	-	5	2	6
Other	1,075	23	1,196	(40)	2,254
AT DECEMBER 31, 2019	7,481	7,611	7,566	2,458	25,115
Non-current	7,346	7,487	7,550	433	22,817
Current	135	123	15	2,024	2,298

(1) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 and IFRIC 23 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

(2) Of which €6,573 million in provisions for dismantling nuclear facilities, compared to €5,337 million at December 31, 2018.

The impact of unwinding discount adjustments in respect of post-employment and other long-term benefits relates to the interest expense on the benefit obligation, net of the interest income on plan assets.

The "Other" line mainly comprises actuarial gains and losses arising on post-employment benefit obligations in 2019, which are recorded in "Other comprehensive income" as well as provisions recorded against a dismantling or site rehabilitation asset.

Additions, utilizations, reversals and the impact of unwinding discount adjustments are presented as follows in the consolidated income statement:

<i>In millions of euros</i>	Dec. 31, 2019
Income/(loss) from operating activities	(823)
Other financial income and expenses	(573)
TOTAL	(1,397)

The different types of provisions and the calculation principles applied are described below.

19.1 Post-employment benefits and other long-term benefits

See Note 20 "Post-employment benefits and other long-term benefits".

19.2 Obligations relating to nuclear power generation activities

In the context of its nuclear power generation activities, the Group assumes obligations relating to the management of the back-end nuclear fuel cycle and the dismantling of nuclear facilities.

19.2.1 Legal framework

The Belgian law of April 11, 2003 granted Group subsidiary Synatom responsibility for managing provisions set aside to cover the costs of dismantling nuclear power plants and managing spent nuclear fuel in those plants. The tasks of the Commission for Nuclear Provisions (CNP) set up pursuant to the above-mentioned law is to oversee the process of computing and managing these provisions.

To enable the Commission for Nuclear Provisions to carry out its work in accordance with the above-mentioned law, Synatom is required to submit a report every three years describing the core inputs used to measure these provisions. If any changes are observed from one triennial report to another that could materially impact the financial inputs used, i.e., the industrial scenario, estimated costs and timing, the Commission may revise its opinion.

Synatom submitted its triennial report to the Commission on September 12, 2019. The Commission issued its opinion on December 12, 2019 based on the opinion given by ONDRAF, the Belgian agency for radioactive waste and enriched fissile material. The CNP's findings take into account:

- the impact of the new baseline scenario for the long-term management of Class B and C radioactive waste (medium and high level) in Belgium, agreed by ONDRAF in June 2018, which is estimated at a gross amount of €10.7 billion;
- ONDRAF's recommendations as regards including various certain or probable costs;
- the scenario prepared ahead of the shutdown and dismantling of nuclear power plants based on industrial experience, and in particular the ongoing dismantling in Germany;
- the financial calculation based on lower discount rates to obtain a prudent estimate of the provisions required today to cover expenditure that will only be incurred in some cases in more than 70 years' time.

The CNP's decision includes a decrease in discount rates to reflect the current low interest rate environment. This means that Belgian nuclear plant owners will have to set aside larger amounts as of now. Discount rates, which were set at 3.50% at December 31, 2018, have been reduced at December 31, 2019 to 2.5% for dismantling, for which expenditure will begin as of next year, and 3.25% for spent nuclear fuel, for which expenditure will be incurred over the coming decades.

All in all, the opinion of the Commission for Nuclear Provisions and the obligations related to projects to dispose of nuclear waste have resulted in a €2.1 billion increase in the ENGIE Group's nuclear provisions, in addition to the recurring annual discount unwinding charge and provisions for additional quantities of fuel consumed during the year.

The provisions recognized by the Group were measured taking into account the prevailing contractual and legal framework, which sets the operating life of the Tihange 1 reactor and the Doel 1 and 2 reactors at 50 years, and the other reactors at 40 years.

The provisions set aside take into account all existing or planned environmental regulatory requirements on a European, national and regional level. If new legislation were to be introduced in the future, the cost estimates used as a basis for the calculations could vary. However, the Group is not aware of any planned legislation on this matter that could materially impact the amount of the provisions.

The estimated provision amounts include margins for contingencies and other risks that may arise in connection with dismantling and radioactive spent fuel management procedures. The contingency margins relating to the disposal of waste are determined by ONDRAF and built into its fees. The Group also estimates appropriate margins for each cost category.

The Group considers that, to the best of its knowledge, the provisions approved by the Commission take into account all currently available information to manage the contingencies and other risks associated with processes such as dismantling nuclear facilities and managing radioactive spent fuel.

19.2.2 Provisions for the back-end of the nuclear fuel cycle

Accounting standards

Allocations to the provisions for the back-end of the nuclear fuel cycle are computed based on the average unit cost of the quantities expected to be used up to the end of the operating life of the plants, applied to quantities used at the closing date. An annual allocation is also recognized with respect to unwinding the discount on the provisions.

When spent nuclear fuel is removed from a reactor and temporarily stored on-site, it requires conditioning and potentially reprocessing to separate the most active radionuclides, before being consigned to long-term storage.

ONDRAF proposed on February 9, 2018 that geological storage be adopted as the national policy for managing high-level and/or long-lived radioactive waste. The proposal is subject to the approval of the Belgian government after obtaining the opinion of the Federal Agency for Nuclear Control (*Agence Fédérale de Contrôle Nucléaire – AFCN*).

In addition, ENGIE considers that the “mixed” scenario adopted by the Commission for Nuclear Provisions continues to apply, whereby the fuel containing the most active radionuclides is reprocessed, and the rest disposed of directly without reprocessing.

The provisions booked by the Group for nuclear fuel processing and storage cover all of the costs linked to the “mixed” scenario, including on-site storage, transportation, reprocessing, conditioning, storage and geological disposal. They are calculated based on the following principles and inputs:

- storage costs primarily comprise the costs of building and operating additional dry storage facilities and operating existing facilities, along with the costs of purchasing containers;
- part of the radioactive spent fuel is transferred for reprocessing. The resulting plutonium and uranium is sold to a third party;
- radioactive spent fuel that has not been reprocessed is to be conditioned, which requires conditioning facilities to be built according to ONDRAF's approved criteria. ONDRAF's recommendations as regards the cost of these facilities have been fully taken into account;
- the reprocessing residues and conditioned spent fuel are transferred to ONDRAF; the cost of burying fuel in deep geological repositories is estimated by ONDRAF and evaluated not based on the amount of the fees set by ONDRAF in 2018 based on a total disposal facility cost of €8.0 billion²⁰¹⁷, but using a “virtual prudential tariff” established by ONDRAF at the request of the Commission for Nuclear Provisions, based on a total disposal facility cost of €10.7 billion²⁰¹⁷ excluding potential areas for optimization subject to appraisal; The estimated cost of the AFCN's preliminary recommendation as regards an additional well has also been included based on ONDRAF recommendations.
- the long-term obligation is calculated using estimated internal costs and external costs assessed based on offers received from third parties;
- the new baseline scenario includes ONDRAF's updated scenario, which is delayed by about 30 years compared with the scenario used in 2016, with geological storage beginning in about 2070 and ending in about 2135, and the intermediate reprocessing and conditioning storage delayed accordingly;
- the discount rate used is reduced to 3.25%. It takes into account (i) an analysis of trends in long-term benchmark rates and their historical and forecast averages, (ii) the extension of the life of the liabilities based on the new ONDRAF scenario, and (iii) the undertakings relating to the funding of those provisions made by Electrabel to Synatom (see Note 16.1.4 “Financial assets set aside to cover the future costs of dismantling nuclear facilities and managing radioactive fissile material”);
- an inflation rate assumption of 2.0% (actual rate of 1.25%).

The costs effectively incurred in the future may differ from the estimates in terms of their nature and timing of payment. In its opinion to the Commission for Nuclear Provisions, ONDRAF pointed out the uncertainty over some costs, which in principle are covered by the contingency margins, but for which the Commission will set up a work and further analysis program as of 2020. The provisions may be subsequently adjusted in line with changes in the above-mentioned inputs and related cost estimates. Belgium's current legal framework does not permit partial reprocessing and has not yet confirmed the adoption of geological storage as the policy for managing medium and high level nuclear waste.

As regards the partial reprocessing scenario, following a resolution adopted by the House of Representatives in 1993, reprocessing contracts that had not already begun were suspended and then terminated in 1998. The scenario adopted is based on the assumption that the Belgian government will allow Synatom to reprocess spent fuel and that an agreement will be reached between Belgium and France designating Orano (formerly Areva) as responsible for these reprocessing operations. A scenario assuming the direct disposal of waste without reprocessing would lead to a decrease in the provision compared to the provision resulting from the “mixed” scenario currently used and approved by the Commission for Nuclear Provisions.

The Belgian government has not yet taken a decision as to whether the waste should be buried in a deep geological repository or stored over the long term. On November 27, 2019, the European Commission sent a reasoned opinion to Belgium under the breach procedure provided for in Article 258 of the Treaty on the Functioning of the European Union, on the grounds that Belgium had not adopted a national program for managing radioactive waste in compliance with various requirements set out in the directive on spent fuel and radioactive waste (Council directive 2011/70/Euratom). At this stage, therefore, there is only one national program for the safe storage of spent fuel pending reprocessing or long-term storage.

The scenario adopted by the Commission for Nuclear Provisions is based on the assumption that the waste will be buried in a deep geological repository at a site yet to be identified and classified in Belgium.

Sensitivity

Provisions for the back-end of the nuclear fuel cycle remain sensitive to assumptions regarding costs, the timing of operations and expenditure, as well as to discount rates:

- a 10% increase in ONDRAF fees above the virtual prudential tariff requested by the Commission for Nuclear Provisions for the removal of high-level and/or long-lived waste would lead to an increase in provisions of approximately €170 million based on unchanged contingency margins;
- a five-year advance in ONDRAF's expenditure on temporary storage, conditioning and long-term storage for high-level and/or long-lived radioactive waste would lead to an increase in provisions of approximately €165 million. A five-year delay in the payment schedule for these various expenses would lead to a decrease of less than €165 million;
- a change of 10 basis points in the discount rate used could lead to an adjustment of approximately €250 million in provisions for the back-end of the nuclear fuel cycle. A fall in discount rates would lead to an increase in outstanding provisions, while a rise in discount rates would reduce the provision amount.

These sensitivities are calculated on a purely financial basis and should therefore be interpreted with appropriate caution in view of the variety of other inputs – some of which may be interdependent – included in the evaluation.

19.2.3 Provisions for dismantling nuclear facilities

Accounting standards

A provision is recognized when the Group has a present legal or constructive obligation to dismantle facilities or to restore a site. The present value of the engagement at the time of commissioning represents the initial amount of the provision for dismantling with, as counterpart, an asset for the same amount, which is included in the carrying amount of the facilities concerned. This asset is depreciated over the operating life of the facilities. Adjustments to the provision due to subsequent changes in (i) the expected outflow of resources, (ii) the timing of dismantling expenses or (iii) the discount rate, are deducted from or, subject to specific conditions, added to the cost of the corresponding asset. The impacts of unwinding the discount are recognized in expenses for the period.

A provision is also recorded for nuclear units for which the Group holds a capacity right up to its share of the expected decommissioning costs to be borne by the Group.

Nuclear power plants have to be dismantled at the end of their operating life. Provisions are set aside in the Group's financial statements to cover all costs relating to (i) the shutdown phase, which involves removing radioactive spent fuel from the site and (ii) the dismantling phase, which consists of decommissioning and cleaning up the site.

The dismantling strategy is based on the facilities being dismantled (i) immediately after the reactor is shut down, (ii) on a mass basis rather than on a site-by-site basis, and (iii) completely, the land being subsequently returned to greenfield status.

Provisions for dismantling nuclear facilities are calculated based on the following principles and inputs:

- costs payable over the long term are calculated by reference to the estimated costs for each nuclear facility, based on a study conducted by independent experts under the assumption that the facilities will be dismantled on a mass basis;
- fees for handling Class A and B dismantling waste are determined using the 'virtual prudential tariff' established by ONDRAF at the request of the Commission for Nuclear Provisions and include the margins recommended by ONDRAF for waste reclassification risk given the uncertainty over the definition of the criteria for classification in those classes;

- for the various phases, margins for usual contingencies, reviewed by ONDRAF and the Commission for Nuclear Waste, are included;
- an inflation rate of 2.0% is applied until the dismantling obligations expire in order to determine the value of the future obligation;
- a discount rate reduced to 2.5% (including inflation of 2.0%) is applied to determine the present value (NPV) of the obligation. It is different from the rate used to calculate the provision for processing spent nuclear fuel due to the major differences in horizon of the two liabilities after taking into account ONDRAF's new scenario;
- the operating life is 50 years for Tihange 1 and Doel 1 and 2, and 40 years for the other facilities;
- the start of the technical shutdown procedures depends on the facility concerned and on the timing of operations for the nuclear reactor as a whole. The shutdown procedures are immediately followed by dismantling operations.

The costs effectively incurred in the future may differ from the estimates in terms of their nature and timing of payment. In its opinion to the Commission for Nuclear Provisions, ONDRAF pointed out the uncertainty over some costs, which in principle are covered by the contingency margins, but for which the Commission will set up a work and further analysis program as of 2020. The provisions may be subsequently adjusted in line with changes in the above-mentioned inputs. However, these inputs and assumptions are based on information and estimates which the Group deems reasonable to date and which have been approved by the Commission for Nuclear Provisions.

The scenario adopted is based on a dismantling program and on timetables that have to be approved by the nuclear safety authorities.

Sensitivity

Based on currently applied inputs for estimating costs and the timing of payments, a change of 10 basis points in the discount rate used could lead to an adjustment of approximately €60 million in dismantling provisions. A fall in discount rates would lead to an increase in outstanding provisions, while a rise in discount rates would reduce the provision amount.

This sensitivity is calculated on a purely financial basis and should therefore be interpreted with appropriate caution in view of the variety of other inputs – some of which may be interdependent – included in the evaluation.

19.3 Dismantling of non-nuclear plant and equipment and site rehabilitation

19.3.1 Dismantling obligations arising on other non-nuclear plant and equipment

Certain plant and equipment, including conventional power stations, transmission and distribution pipelines, storage facilities and LNG terminals, have to be dismantled at the end of their operational lives. This obligation is the result of prevailing environmental regulations in the countries concerned, contractual agreements, or an implicit Group commitment.

Based on estimates of proven and probable gas reserves through 2260 using current production levels, dismantling provisions for gas infrastructures in France have a present value near zero.

19.3.2 Hazelwood Power Station & Mine (Australia)

The Group and its partner Mitsui announced in November 2016 their decision to close the coal-fired Hazelwood Power Station, and cease coal extraction operations from the adjoining mine from late March 2017. The Group holds a 72% interest in the former 1,600 MW power station and adjoining mine, which was previously fully consolidated and has been consolidated on joint operation since September 2018.

At December 31, 2019, the Group's share (72%) of the provision covering the obligation to dismantle and rehabilitate the mine amounted to €280 million.

Dismantling and site rehabilitation work commenced in 2017 and focused on: managing site contamination; planning site-wide environmental clean-up; the demolition and dismantling of all of the site's industrial facilities, including the former

power station; and ongoing aquifer pumping and designated earthworks within the mine to ensure mine floor and batter stability with a view to long-term rehabilitation into a pit lake.

Several laws that have a direct or indirect impact on mine rehabilitation and on the agencies that administer the laws are currently being reformed. Consequently, the ultimate regulatory obligations are likely to be revised during the life of the project and could therefore have an impact on provisions.

The average discount rate used to determine the amount of the provisions is 3.17%.

The amount of the provision recognized is based on the Group's best current estimate of the demolition and rehabilitation costs that Hazelwood is expected to incur. However, the amount of this provision may be adjusted in the future to take into account any changes in the key inputs.

19.4 Other contingencies

This caption includes essentially provisions for commercial litigation, tax claims and disputes (except income tax, under the rule of IFRIC 23) as well as provisions for onerous contracts relating to storage and transport capacity reservation contracts.

NOTE 20 POST-EMPLOYMENT BENEFITS AND OTHER LONG-TERM BENEFITS

Accounting standards

Depending on the laws and practices in force in the countries where the Group operates, Group companies have obligations in terms of pensions, early retirement payments, retirement bonuses and other benefit plans. Such obligations generally apply to all employees within the companies concerned.

The Group's obligations in relation to pensions and other employee benefits are recognized and measured in compliance with IAS 19. Accordingly:

- the cost of defined contribution plans is expensed based on the amount of contributions payable in the period;
- the Group's obligations concerning pensions and other employee benefits payable under defined benefit plans are assessed on an actuarial basis using the projected unit credit method. These calculations are based on assumptions relating to mortality, staff turnover and estimated future salary increases, as well as the economic conditions specific to each country or entity of the Group. Discount rates are determined by reference to the yield, at the measurement date, on investment grade corporate bonds in the related geographical area (or on government bonds in countries where no representative market for such corporate bonds exists).

Pension commitments are measured on the basis of actuarial assumptions. The Group considers that the assumptions used to measure its obligations are relevant and documented. However, any change in these assumptions could have a significant impact on the resulting calculations.

Provisions are recorded when commitments under these plans exceed the fair value of plan assets. Where the value of plan assets (capped where appropriate) is greater than the related commitments, the surplus is recorded as an asset under "Other assets" (current or non-current).

As regards post-employment benefit obligations, actuarial gains and losses are recognized in other comprehensive income. Where appropriate, adjustments resulting from applying the asset ceiling to net assets relating to overfunded plans are treated in a similar way. However, actuarial gains and losses on other long-term benefits such as long-service awards, are recognized immediately in income.

Net interest on the net defined benefit liability (asset) is presented in net financial income/(loss).

20.1 Description of the main pension plans

20.1.1 Companies belonging to the Electricity and Gas Industries sector in France

Since January 1, 2005, the CNIEG (*Caisse Nationale des Industries Électriques et Gazières*) has operated the pension, disability, death, occupational accident and occupational illness benefit plans for electricity and gas industry (hereinafter "EGI") companies in France. The CNIEG is a social security legal entity under private law placed under the joint responsibility of the ministries in charge of social security and the budget.

Employees and retirees of EGI sector companies have been fully affiliated to the CNIEG since January 1, 2005. The main affiliated Group entities are ENGIE SA, GRDF, GRTgaz, Elengy, Storengy, ENGIE Thermique France, CPCU, CNR and SHEM.

Following the funding reform of the special EGI pension plan introduced by Law No. 2004-803 of August 9, 2004 and its implementing decrees, specific benefits (pension benefits on top of the standard benefits payable under ordinary law) already vested at December 31, 2004 ("past specific benefits") were allocated between the various EGI entities. Past

specific benefits (benefits vested at December 31, 2004) relating to regulated transmission and distribution businesses ("regulated past specific benefits") are funded by the levy on gas and electricity transmission and distribution services (*Contribution Tarifaire d'Acheminement*) and therefore no longer represent an obligation for the ENGIE Group. Unregulated past specific benefits (benefits vested at December 31, 2004) are funded by EGI sector companies to the extent defined by Decree No. 2005-322 of April 5, 2005.

The special EGI pension plan is a legal pension plan available to new entrants.

The specific benefits vested under the plan since January 1, 2005 are wholly financed by EGI sector companies in proportion to their respective weight in terms of payroll costs within the EGI sector.

As this plan represents a defined benefit plan, the Group has set aside a pension provision in respect of specific benefits payable to employees of unregulated activities and specific benefits vested by employees of regulated activities since January 1, 2005. This provision also covers the Group's early retirement obligations. The provision amount may be subject to fluctuations based on the weight of the Group's companies within the EGI sector.

Pension benefit obligations and other "mutualized" obligations are assessed by the CNIEG.

At December 31, 2019, the projected benefit obligation in respect of the special pension plan for EGI sector companies amounted to €3.7 billion.

The duration of the pension benefit obligation of the EGI pension plan is 22 years.

20.1.2 Companies belonging to the electricity and gas sector in Belgium

In Belgium, the rights of employees in electricity and gas sector companies, principally Electrabel, Laborelec and some ENGIE Energy Management Trading and ENGIE CC employee categories, are governed by collective bargaining agreements.

These agreements, applicable to "wage-rated" employees recruited prior to June 1, 2002 and managerial staff recruited prior to May 1, 1999, specify the benefits entitling employees to a supplementary pension equivalent to 75% of their most recent annual income, for a full career and in addition to the statutory pension. These top-up pension payments provided under defined benefit plans are partly reversionary. In practice, the benefits are paid in the form of a lump sum for the majority of plan participants. Most of the obligations resulting from these pension plans are financed through pension funds set up for the electricity and gas sector and by certain insurance companies. Pre-funded pension plans are financed by employer and employee contributions. Employer contributions are calculated annually based on actuarial assessments.

The projected benefit obligation relating to these plans represented around 15% of total pension obligations and related liabilities at December 31, 2019. The average duration is nine years.

"Wage-rated" employees recruited after June 1, 2002 and managerial staff (i) recruited after May 1, 1999 or (ii) having opted for the transfer through defined contribution plans, are covered under defined contribution plans. Prior to January 1, 2017, the law specified a minimum average annual return (3.75% on wage contributions and 3.25% on employer contributions) when savings are liquidated.

The law on supplementary pensions, approved on December 18, 2016 and enforced on January 1, 2017 henceforth specifies a minimum rate of return, depending on the actual rate of return of Belgian government bonds, within a range of 1.75%-3.25% (the rates are now identical for employee and employer contributions). In 2019, the minimum rate of return stood at 1.75%.

An expense of €36 million was recognized in 2019 in respect of these defined contribution plans (€24 million in 2018).

20.1.3 Multi-employer plans

Employees of some Group companies are affiliated to multi-employer pension plans.

Under multi-employer plans, risks are pooled to the extent that the plan is funded by a single contribution rate determined for all affiliated companies and applicable to all employees.

Multi-employer plans are particularly common in the Netherlands, where employees are normally required to participate in a compulsory industry-wide plan. These plans cover a significant number of employers, thereby limiting the impact of potential default by an affiliated company. In the event of default, the vested rights are maintained in a special compartment and are not transferred to the other members. Refinancing plans may be set up to ensure the funds are balanced.

The ENGIE Group accounts for multi-employer plans as defined contribution plans.

The expense recognized in 2019 in respect of multi-employer pension plans was stable as compared to 2018 at €71 million.

20.1.4 Other pension plans

Most other Group companies also grant their employees retirement benefits. In terms of financing, pension plans within the Group are almost equally split between defined benefit and defined contribution plans.

The Group's main pension plans outside France, Belgium and the Netherlands concern:

- the United Kingdom: the large majority of defined benefit pension plans is now closed to new entrants and future benefits no longer vest under these plans. All entities run a defined contribution scheme. The pension obligations of International Power's subsidiaries in the United Kingdom are covered by the special Electricity Supply Pension Scheme (ESPS). The assets of this defined benefit scheme are invested in separate funds. Since June 1, 2008, the scheme has been closed and a defined contribution plan has been set up for new entrants;
- Germany: the Group's German subsidiaries have closed their defined benefit plans to new entrants and now offer defined contribution plans;
- Brazil: ENGIE Brasil Energia operates its own pension scheme. This scheme has been split into two parts, one for the (closed) defined benefit plan, and the other for the defined contribution plan that has been available to new entrants since the beginning of 2005.

20.2 Description of other post-employment benefit obligations and other long-term benefits

20.2.1 Other benefits granted to current and former EGI sector employees

Other benefits granted to EGI sector employees are:

Post-employment benefits:

- reduced energy prices;
- end-of-career indemnities;
- bonus leave;
- death capital benefits.

Long-term benefits:

- allowances for occupational accidents and illnesses;
- temporary and permanent disability allowances;
- long-service awards.

The Group's main obligations are described below.

20.2.1.1 Reduced energy prices

Under Article 28 of the national statute for electricity and gas industry personnel, all employees (current and former employees, provided they meet certain length-of-service conditions) are entitled to benefits in kind, which take the form of reduced energy prices known as “employee rates”.

This benefit entitles employees to electricity and gas supplies at a reduced price. For retired employees, this provision represents a post-employment defined benefit. Retired employees are only entitled to the reduced rate if they have completed at least 15 years’ service within EGI sector companies.

In accordance with the agreements signed with EDF in 1951, ENGIE provides gas to all current and former employees of ENGIE and EDF, while EDF supplies electricity to these same beneficiaries. ENGIE pays (or benefits from) the balancing contribution payable in respect of its employees as a result of energy exchanges between the two utilities.

The obligation to provide energy at a reduced price to current and former employees is measured as the difference between the energy sale price and the preferential rate granted.

The provision set aside in respect of reduced energy prices stood at €3.6 billion at December 31, 2019. The duration of the obligation is 23 years.

20.2.1.2 End-of-career indemnities

Retiring employees (or their dependents in the event of death during active service) are entitled to end-of-career indemnities, which increase in line with the length of service within the EGI sector.

20.2.1.3 Compensation for occupational accidents and illnesses

EGI sector employees are entitled to compensation for accidents at work and occupational illnesses. These benefits cover all employees or the dependents of employees who die as a result of occupational accidents or illnesses, or injuries suffered on the way to work.

The amount of the obligation corresponds to the likely present value of the benefits to be paid to current beneficiaries, taking into account any reversionary annuities.

20.2.2 Other benefits granted to employees of the gas and electricity sector in Belgium

Electricity and gas sector companies also grant other employee benefits such as the reimbursement of medical expenses, electricity and gas price reductions, as well as length-of-service awards and early retirement schemes. These benefits are not prefunded, with the exception of the special “*allocation transitoire*” termination indemnity, considered as an end-of-career indemnity.

20.2.3 Other collective agreements

Most other Group companies also grant their staff post-employment benefits (early retirement plans, medical coverage, benefits in kind, etc.) and other long-term benefits such as jubilee and length-of-service awards.

20.3 Defined benefit plans

20.3.1 Amounts presented in the statement of financial position and statement of comprehensive income

In accordance with IAS 19, the information presented in the statement of financial position relating to post-employment benefit obligations and other long-term benefits results from the difference between the gross projected benefit obligation and the fair value of plan assets. A provision is recognized if this difference is positive (net obligation), while a prepaid benefit cost is recorded in the statement of financial position when the difference is negative, provided that the conditions for recognizing the prepaid benefit cost are met.

Changes in provisions for post-employment benefits and other long-term benefits, plan assets and reimbursement rights recognized in the statement of financial position are as follows:

<i>In millions of euros</i>	Provisions	Plan assets	Reimbursement rights
AT DECEMBER 31, 2018	(6,371)	108	168
Exchange rate differences	7	(5)	-
Changes in scope of consolidation and other	96	(39)	8
Actuarial gains and losses	(1,142)	(7)	(18)
Periodic pension cost of continued operations	(427)	(66)	2
Asset ceiling	-	-	-
Contributions/benefits paid	356	63	1
AT DECEMBER 31, 2019	(7,481)	53	161

Plan assets and reimbursement rights are presented in the statement of financial position under “Other non-current assets” or “Other current assets”.

The cost recognized for the period amounted to €492 million in 2019 (€525 million in 2018). The components of this defined benefit cost in the period are set out in Note 20.3.4 “Components of the net periodic pension cost”.

The Eurozone represented 97% of the Group’s net obligation at December 31, 2019, unchanged compared to December 31, 2018).

Cumulative actuarial gains and losses recognized in equity amounted to €4,594 million at December 31, 2019, compared to €3,472 million at December 31, 2018.

Net actuarial differences arising in the period and presented on a separate line in the statement of comprehensive income represented a net actuarial loss of €1,149 million in 2019 and of €231 million in 2018.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 20 POST-EMPLOYMENT BENEFITS AND OTHER
LONG-TERM BENEFITS

20.3.2 Change in benefit obligations and plan assets

The table below shows the amount of the Group's projected benefit obligations and plan assets, changes in these items during the periods presented, and their reconciliation with the amounts reported in the statement of financial position:

In millions of euros	Dec. 31, 2019				Dec. 31, 2018			
	Pension benefit obligations ⁽¹⁾	Other post-employment benefit obligations ⁽²⁾	Long-term benefit obligations ⁽³⁾	Total	Pension benefit obligations ⁽¹⁾	Other post-employment benefit obligations ⁽²⁾	Long-term benefit obligations ⁽³⁾	Total
A - CHANGE IN PROJECTED BENEFIT OBLIGATION								
Projected benefit obligation at January 1	(7,713)	(3,794)	(499)	(12,006)	(7,653)	(3,739)	(539)	(11,931)
Service cost	(291)	(63)	(43)	(397)	(308)	(62)	(42)	(412)
Interest expense	(173)	(76)	(9)	(258)	(165)	(73)	(8)	(245)
Contributions paid	(16)	-	-	(16)	(16)	-	-	(16)
Amendments	(1)	-	-	(1)	(3)	(5)	10	2
Changes in scope of consolidation	172	(5)	(1)	166	(37)	31	49	43
Curtailments/settlements	75	-	1	76	1	-	-	1
Non-recurring items	-	-	-	-	-	2	-	2
Financial actuarial gains and losses	(887)	(698)	(5)	(1,590)	(44)	(35)	(1)	(80)
Demographic actuarial gains and losses	(120)	57	(14)	(76)	101	1	1	103
Benefits paid	373	108	39	521	397	97	40	533
Other (of which translation adjustments)	10	-	-	10	16	(11)	(10)	(5)
Projected benefit obligation at December 31	A (8,570)	(4,470)	(531)	(13,572)	(7,713)	(3,794)	(499)	(12,006)
B - CHANGE IN FAIR VALUE OF PLAN ASSETS								
Fair value of plan assets at January 1	5,767	-	-	5,767	5,904	-	-	5,904
Interest income on plan assets	133	-	-	133	128	-	-	128
Financial actuarial gains and losses	497	-	-	497	(253)	-	-	(253)
Contributions received	197	-	-	197	309	15	-	324
Changes in scope of consolidation	(109)	-	-	(109)	32	-	-	32
Settlements	(28)	-	-	(28)	-	-	-	-
Benefits paid	(282)	-	-	(282)	(341)	(15)	-	(357)
Other (of which translation adjustments)	(7)	-	-	(7)	(11)	-	-	(11)
Fair value of plan assets at December 31	B 6,169	-	-	6,169	5,767	-	-	5,767
C - FUNDED STATUS	A+B (2,402)	(4,470)	(531)	(7,403)	(1,945)	(3,794)	(499)	(6,239)
Asset ceiling	(25)	-	-	(25)	(25)	-	-	(25)
NET BENEFIT OBLIGATION	(2,427)	(4,470)	(531)	(7,428)	(1,970)	(3,794)	(499)	(6,263)
ACCRUED BENEFIT LIABILITY	(2,480)	(4,470)	(531)	(7,481)	(2,078)	(3,794)	(499)	(6,371)
PREPAID BENEFIT COST	53	-	-	53	108	-	-	108

(1) Pensions and retirement bonuses.

(2) Reduced energy prices, healthcare, gratuities and other post-employment benefits.

(3) Length-of-service awards and other long-term benefits.

20.3.3 Change in reimbursement rights

The fair value of reimbursement rights relating to plan assets managed by amounted to €161 million at December 31, 2019 (€168 million at December 31, 2018).

20.3.4 Components of the net periodic pension cost

The net periodic cost recognized in respect of defined benefit obligations for the years ended December 31, 2019 and 2018 breaks down as follows:

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018
Current service cost	397	412
Actuarial gains and losses ⁽¹⁾	19	(1)
Plan amendments	-	(2)
Gains or losses on pension plan curtailments, terminations and settlements	(49)	(1)
Non-recurring items	-	(2)
Total accounted for under current operating income including operating MtM and share in net income of equity method entities	368	407
Net interest expense	125	117
Total accounted for under net financial income/(loss)	125	117
TOTAL	492	525

(1) On the long-term benefit obligation.

20.3.5 Funding policy and strategy

When defined benefit plans are funded, the related plan assets are invested in pension funds and/or with insurance companies, depending on the investment practices specific to the country concerned. The investment strategies underlying these defined benefit plans are aimed at striking the right balance between return on investment and acceptable levels of risk.

The objectives of these strategies are twofold: to maintain sufficient liquidity to cover pension and other benefit payments; and as part of risk management, to achieve a long-term rate of return higher than the discount rate or, where appropriate, at least equal to future required returns.

When plan assets are invested in pension funds, investment decisions are the responsibility of the fund management concerned. For French companies, where plan assets are invested with an insurance company, the latter manages the investment portfolio for unit-linked policies or euro-denominated policies, in a manner adapted to the risk and long-term profile of the liabilities.

The funding of these obligations at December 31 for each of the periods presented can be analyzed as follows:

<i>In millions of euros</i>	Projected benefit obligation	Fair value of plan assets	Asset ceiling	Total net obligation
Underfunded plans	(7,399)	5,616	(25)	(1,809)
Overfunded plans	(517)	553	-	36
Unfunded plans	(5,655)	-	-	(5,655)
AT DECEMBER 31, 2019	(13,571)	6,169	(25)	(7,428)
Underfunded plans	(5,648)	4,294	(23)	(1,377)
Overfunded plans	(1,375)	1,473	(2)	96
Unfunded plans	(4,977)	-	-	(4,977)
AT DECEMBER 31, 2018	(12,000)	5,767	(25)	(6,258)

The allocation of plan assets by principal asset category can be analyzed as follows:

In %	Dec. 31, 2019	Dec. 31, 2018
Equity investments	27	27
Sovereign bond investments	26	25
Corporate bond investments	27	27
Money market securities	3	4
Real estate	2	2
Other assets	15	15
TOTAL	100	100

All plan assets were quoted on an active market at December 31, 2019.

The actual return on assets of EGI sector companies stood at a positive 9% in 2019.

In 2019, the actual return on plan assets of Belgian entities amounted to approximately 3% in Group insurance and a positive 14% in pension funds.

The allocation of plan asset categories by geographic area of investment can be analyzed as follows:

In %	Europe	North America	Latin America	Asia - Oceania	Rest of the World	Total
Equity investments	58	26	3	10	3	100
Sovereign bond investments	76	1	22	-	2	100
Corporate bond investments	75	18	1	3	2	100
Money market securities	72	-	5	-	23	100
Real estate	86	-	7	-	6	100
Other assets	11	8	3	3	76	100

20.3.6 Actuarial assumptions

Actuarial assumptions are determined individually by country and company in conjunction with independent actuaries. Weighted discount rates for the main actuarial assumptions are presented below:

		Pension benefit obligations		Other post-employment benefit obligations		Long-term benefit obligations		Total benefit obligations	
		2019	2018	2019	2018	2019	2018	2019	2018
Discount rate	Eurozone	1.2%	2.0%	1.2%	2.1%	1.0%	1.6%	1.2%	1.9%
	UK Zone	1.7%	2.5%	-	-	-	-	-	-
Inflation rate	Eurozone	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%
	UK Zone	3.4%	3.3%	-	-	-	-	-	-

20.3.6.1 Discount and inflation rate

The discount rate applied is determined based on the yield, at the date of the calculation, investment grade corporate bonds with maturities mirroring the term of the plan.

The rates were determined for each monetary area based on data for AA corporate bond yields. For the Eurozone, data (from Bloomberg) are extrapolated on the basis of government bond yields for long maturities.

According to the Group's estimates, a 100-basis-point increase or decrease in the discount rate would result in a change of approximately 17% in the projected benefit obligation.

The inflation rates were determined for each monetary area. A 100-basis-point increase or decrease in the inflation rate (with an unchanged discount rate) would result in a change of approximately 16% in the projected benefit obligation.

20.3.6.2 Other assumptions

The increase in the rate of medical costs (including inflation) was estimated at 2.8%.

A 100-basis-point change in the assumed increase in medical costs would have the following impacts:

<i>In millions of euros</i>	100-basis-point increase	100-basis-point decrease
Impact on expenses	-	-
Impact on pension obligations	4	(5)

20.3.7 Estimated employer contributions payable in 2020 under defined benefit plans

The Group expects to pay around €200 million in contributions into its defined benefit plans in 2020, including €121 million for EGI sector companies. Annual contributions in respect of EGI sector companies will be made by reference to rights vested during the year, taking into account the funding level for each entity in order to even out contributions over the medium term.

20.4 Defined contribution plans

In 2019, the Group recorded a €121 million expense in respect of amounts paid into Group defined contribution plans (€133 million in 2018). These contributions are recorded under “Personnel costs” in the consolidated income statement.

NOTE 21 SHARE-BASED PAYMENTS

Accounting standards

Under IFRS 2, share-based payments made in consideration for services provided are recognized as personnel costs. These services are measured at the fair value of the instruments awarded.

The fair value of bonus share plans is estimated by reference to the share price at the grant date, taking into account the fact that no dividend is payable over the vesting period, and based on the estimated turnover rate for the employees concerned and the probability that the Group will meet its performance targets. The fair value measurement also takes into account the non-transferability period associated with these instruments. The cost of shares granted to employees is expensed over the vesting period of the rights and offset against equity.

A Monte Carlo pricing model is used for performance shares granted on a discretionary basis and subject to external performance criteria.

Expenses recognized in respect of share-based payments break down as follows:

In millions of euros	Expense for the year	
	Dec. 31, 2019	Dec. 31, 2018
Employee share issues ⁽¹⁾	(1)	(31)
Bonus/performance share plans ⁽²⁾	(48)	(46)
Other Group companies' plans	(2)	(3)
TOTAL	(51)	(80)

(1) Including Share Appreciation Rights set up within the scope of employee share issues in certain countries.

(2) Of which a reversal of €2 million in 2019 for failure to meet the condition of continuing employment within the Group.

21.1 Performance shares

21.1.1 New awards in 2019

ENGIE Performance Share plan of December 17, 2019

On December 17, 2019, the Board of Directors approved the award of 5 million performance shares to members of the Group's executive and senior management, breaking down into three tranches:

- performance shares vesting on March 14, 2023, subject to a one-year lock-up period;
- performance shares vesting on March 14, 2023, without a lock-up period; and
- performance shares vesting on March 14, 2024, without a lock-up period.

In addition to a condition requiring employees to be employed with the Group at the vesting date, each tranche is made up of instruments subject to three different conditions, excluding the first 150 performance shares granted to beneficiaries (excluding top management), which are exempt from performance conditions. The performance conditions, each of which accounts for one-third of the total grant, are as follows:

- a market performance condition relating to ENGIE's Total Shareholder Return compared to that of a reference panel of ten companies, as assessed between November 2019 and January 2023;
- two internal performance conditions relating to net recurring income Group share and to Return On Capital Employed (ROCE) in 2021 and 2022.

Under this plan, performance shares without conditions were also awarded to the winners of the Innovation and Incubation programs (18,000 shares awarded).

21.1.2 Fair value of bonus share plans with or without performance conditions

The following assumptions were used to calculate the fair value of the new plans awarded by ENGIE in 2019:

Award date	Vesting date	End of the lock-up period	Price at the award date	Expected dividend	Financing cost for the employee	Non-transferability cost	Market-related performance condition	Fair value per unit
December 17, 2019	March 14, 2023	March 14, 2024	14.7	0.75	4.3%	0.44	yes	11.03
December 17, 2019	March 14, 2023	March 14, 2023	14.7	0.75	4.3%	0.44	yes	11.55
December 17, 2019	March 14, 2023	March 14, 2023	14.7	0.75	4.3%	0.56	no	12.45
December 17, 2019	March 14, 2024	March 14, 2024	14.7	0.75	4.3%	0.44	yes	10.84
Weighted average fair value of the December 17, 2019 plan								11.01

21.1.3 Review of internal performance conditions applicable to the plans

In addition to the condition of continuing employment within the Group, eligibility for certain bonus share and performance share plans is subject to an internal performance condition. When this condition is not fully met, the number of bonus shares granted to employees is reduced in accordance with the plans' regulations, leading to a decrease in the total expense recognized in relation to the plans in accordance with IFRS 2. Performance conditions are reviewed at each reporting date.

NOTE 22 RELATED PARTY TRANSACTIONS

This note describes material transactions between the Group and its related parties.

Compensation payable to key management personnel is disclosed in Note 23 “Executive compensation”.

Transactions with joint ventures and associates are described in Note 3 “Investments in equity method entities”.

Only material transactions are described below.

22.1 Relations with the French State and with entities owned or partly owned by the French State

22.1.1 Relations with the French State

The French State’s interest in the Group at December 31, 2019 was unchanged from the previous year at 23.64%. This entitles it to three seats on the Board of Directors out of a total of 14 (compared to four out of a total of 19).

The French State holds 34.23% of the theoretical voting rights (34.47% of exercisable voting rights) compared with 34.51% at end-2018.

On May 22, 2019, the PACTE act (“Action plan for business growth and transformation”) was passed, enabling the French State to dispose of its ENGIE shares without restrictions.

In addition, the French State holds a golden share aimed at protecting France’s critical interests and ensuring the continuity and safeguarding of supplies in the energy sector. The golden share is granted to the French State indefinitely and entitles it to veto decisions taken by ENGIE if it considers they could harm France’s interests.

Public service engagements in the energy sector are defined by the law of January 3, 2003.

Transmission rates on the GRTgaz transportation network and the gas distribution network in France, as well as rates for accessing the French LNG terminals and revenues from storage capacities are all regulated.

The Law on Energy and Climate passed on November 8, 2019 will put an end to regulated gas tariffs and will restrict regulated electricity tariffs for consumers and small businesses. The final date for the discontinuation of regulated gas tariffs is July 1, 2023.

22.1.2 Relations with EDF

Following the creation on July 1, 2004 of the French gas and electricity distribution network operator (EDF Gaz de France Distribution), Gaz de France SA and EDF entered into an agreement on April 18, 2005 setting out their relationship as regards the distribution business. The December 7, 2006 law on the energy sector reorganized the natural gas and electricity distribution networks. Enedis SA (previously ERDF SA), a subsidiary of EDF SA, and GRDF SA, a subsidiary of ENGIE SA, were created on January 1, 2007 and January 1, 2008, respectively, and act in accordance with the agreement previously signed by the two incumbent operators.

22.2 Relations with the CNIEG (*Caisse Nationale des Industries Électriques et Gazières*)

The Group’s relations with the CNIEG, which manages all old-age, death and disability benefits for active and retired employees of the Group who belong to the special EGI pension plan, employees of EDF and Non-Nationalized Companies (*Entreprises Non Nationalisées* – ENN), are described in Note 20 “Post-employment benefits and other long-term benefits”.

NOTE 23 EXECUTIVE COMPENSATION

The executive compensation presented below includes the compensation of the members of the Group's Executive Committee and Board of Directors.

The Executive Committee had 14 members at December 31, 2019 (11 members at December 31, 2018).

Their compensation breaks down as follows:

<i>In millions of euros</i>	Dec. 31, 2019	Dec. 31, 2018
Short-term benefits	21	21
Post-employment benefits	10	6
Share-based payments	5	5
Termination benefits	-	0
TOTAL	36	31

The amount of pension benefit obligations in respect of members of the Group's Executive Committee stood at €37 million at December 31, 2019, being specified that this is an estimated amount as these obligations are, as a rule, not individualized. The Group has a policy of financing pension obligations through hedging assets, without these being specifically allocated to the retirement obligations of a dedicated population.

NOTE 24 WORKING CAPITAL REQUIREMENTS, INVENTORIES, OTHER ASSETS AND OTHER LIABILITIES

Accounting standards

In accordance with IAS 1, the Group's current and non-current assets and liabilities are shown separately in the consolidated statement of financial position. For most of the Group's activities, the breakdown into current and non-current items is based on when assets are expected to be realized, or liabilities extinguished. Assets expected to be realized or liabilities extinguished within 12 months of the reporting date are classified as current, while all other items are classified as non-current.

24.1 Composition of change in working capital requirements

In millions of euros	Change in working capital requirements at Dec. 31, 2019	Change in working capital requirements at Dec. 31, 2018 ⁽¹⁾
Inventories	465	(268)
Trade and other receivables, net	802	(2,311)
Trade and other payables, net	(1,107)	2,177
Tax and employee-related receivables/payables	(36)	237
Margin calls and derivative instruments hedging commodities relating to trading activities	(981)	197
Other	(253)	117
TOTAL	(1,110)	149

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

24.2 Inventories

Accounting standards

Inventories are measured at the lower of cost and net realizable value. Net realizable value corresponds to the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale.

The cost of inventories is determined based on the first-in, first-out method or the weighted average cost formula.

Nuclear fuel purchased is consumed in the process of producing electricity over a number of years. The consumption of this nuclear fuel inventory is recorded based on estimates of the quantity of electricity produced per unit of fuel.

Gas inventories

Gas injected into underground storage facilities includes working gas, which can be withdrawn without adversely affecting the subsequent operation of the reservoirs, and cushion gas, which is inseparable from the reservoirs and essential for their operation (see Note 15 "Property, plant and equipment").

Working gas is classified in inventories and measured at weighted average purchase cost upon entering the transportation network regardless of its source, including any regasification costs.

Group inventory outflows are valued using the weighted average unit cost method.

An impairment loss is recognized when the net realizable value of inventories is lower than their weighted average cost.

Certain inventories are used for trading purposes and are recognized at fair value less the estimated costs necessary to make the sale in accordance with IAS 2. Any changes in this fair value are recognized in the consolidated income statement for the year to which they occur.

Greenhouse gas emissions allowances

European Directive 2003/87/EC establishes a scheme for greenhouse gas (GHG) emissions allowance trading within the European Union. Under the Directive, each year the entities concerned must surrender a number of allowances equal to the total GHG emissions of their installations during the previous year. As there are no specific rules under IFRS dealing with the accounting treatment of GHG emissions allowances, the Group decided to apply the following principles:

- emissions allowances are classified as inventories, as they are consumed in the production process;
- emissions allowances purchased on the market are recognized at acquisition cost;
- emissions allowances granted free of charge are recorded in the statement of financial position for a value of nil.

The Group records a liability at the year-end in the event that it does not have enough emissions allowances to cover its GHG emissions during the year. This liability is measured at the market value of the allowances required to meet its obligations at the year-end or based on the price of future contracts concluded to hedge this lack of emissions allowances.

Energy savings certificates (ESC)

In the absence of current IFRS Standards or IFRIC Interpretations on accounting for energy savings certificates (ESC), the following principles are applied:

- in the event that the number of ESCs held exceeds the obligation at the reporting date, they are accounted for in inventories; otherwise, a liability is recorded;
- ESC inventories are valued at weighted average cost (acquisition cost for ESCs acquired or cost incurred for ESCs generated internally).

In millions of euros	Dec. 31, 2019	Dec. 31, 2018
Inventories of natural gas, net	1,104	1,274
Inventories of uranium	538	595
CO ₂ emissions allowances, green certificates and energy saving certificates, net	682	654
Inventories of commodities other than gas and other inventories, net	1,294	1,635
TOTAL	3,617	4,158

24.3 Other assets and other liabilities

In millions of euros	Dec. 31, 2019				Dec. 31, 2018 ⁽¹⁾			
	Assets		Liabilities		Assets		Liabilities	
	Non-current	Current	Non-current	Current	Non-current	Current	Non-current	Current
Other assets and liabilities	384	10,216	(1,222)	(13,101)	474	9,337	(960)	(12,529)
Tax receivables/payables	-	6,986	-	(7,750)	-	6,999	-	(7,449)
Employee receivables/payables	214	39	(6)	(2,594)	275	72	(5)	(2,461)
Dividend receivables/payables	-	21	-	(104)	-	12	-	(170)
Other	171	3,170	(1,215)	(2,653)	198	2,255	(954)	(2,449)

(1) Published data at December 31, 2018, were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements").

At December 31, 2019, other non-current assets also include a receivable towards EDF Belgium in respect of nuclear provisions amounting to €92 million (€74 million at December 31, 2018).

NOTE 25 LEGAL AND ANTI-TRUST PROCEEDINGS

The Group is party to a number of legal and anti-trust proceedings with third parties or with legal and/or administrative authorities (including tax authorities) in the normal course of its business.

The main disputes and investigations presented hereafter are recognized as liabilities or give rise to contingent assets or liabilities.

In the normal course of its business, the Group is involved in a number of disputes and investigations before state courts, arbitral tribunals or regulatory authorities. The disputes and investigations that could have a material impact on the Group are presented below.

25.1 France excluding Infrastructures

25.1.1 Withholding tax

In their tax deficiency notice dated December 22, 2008, the French tax authorities questioned the tax treatment of the non-recourse sale by SUEZ (now ENGIE) of a withholding tax (*précompte*) receivable in 2005 for an amount of €995 million (receivable relating to the *précompte* paid in respect of the 1999-2003 fiscal years). The Montreuil Administrative Court handed down a judgment in ENGIE's favor in April 2019, which led to the French tax authorities appealing the decision before the Versailles Court of Appeal in May 2019. Exchanges of pleadings between the parties are currently ongoing.

Regarding the dispute over the *précompte* itself, on February 1, 2016, the *Conseil d'État* dismissed the appeal before the Court of Cassation seeking the repayment of the *précompte* in respect of the 1999, 2000 and 2001 fiscal years, and the cases seeking the repayment of the *précompte* in respect of the 2002, 2003 and 2004 fiscal years are still pending before the courts of appeal.

Furthermore, after ENGIE and several French groups lodged a complaint, on April 28, 2016, the European Commission issued a reasoned opinion to the French State as part of infringement proceedings, setting out its view that the *Conseil d'État* did not comply with European Union law when handing down decisions in disputes regarding the *précompte*, such as those involving ENGIE. On July 10, 2017, the European Commission referred the matter to the Court of Justice of the European Union (CJEU) on the grounds of France's failure to comply. On October 4, 2018, the Court of Justice of the European Union ruled partially in favor of the European Commission. Following this decision, France must revisit its methodology in order to determine the *précompte* repayment amounts in closed and pending court cases.

25.2 France Infrastructures

25.2.1 Commissioning

In the dispute between GRDF and various gas suppliers, in a decision dated June 2, 2016, overturning a decision handed down in September 2014 by the Energy Regulatory Commission (*Commission de la Régulation de l'Énergie* – CRE)'s Standing Committee for Disputes and Sanctions (*Comité de règlement des différends et des sanctions* – CoRDs), the Paris Court of Appeal ruled that the transmission services delivered to suppliers should be, and should have been since the market was opened up, delivered to end customers. Prior to these rulings, only distributors provided delivery services to end customers in exchange for payment from the suppliers for customer management services, as there was only one contract.

Because the supplier now also provides customer management services associated with natural gas transmission on the distributors' behalf, the supplier has become the intermediary between the distributor and the end customer for delivery and transmission services. The contractual relations have therefore been completely reorganized, and as a result (i) the risk of unpaid compensation for the "transmission" part of the agreement with the end customer would henceforth be borne by the grid manager and not the gas supplier; (ii) the compensation for customer management services related to

transmission and distribution services provided by the supplier on behalf of the grid manager should be fair and commensurate with the grid manager's cost savings. The Paris Court of Appeal ordered GRDF to bring its transmission agreements into compliance with these principles and ordered the CoRDIS to evaluate the amount of the customer management services. GRDF appealed the decision handed down by the Court of Appeal before the Court of Cassation.

In March 2018, the Court of Cassation referred the case to the Court of Justice of the European Union (CJEU), asking it to rule as to whether the CoRDIS could apply these rulings retroactively under European law. The CJEU's attorney general submitted his conclusions in May 2019. The CJEU delivered its ruling on December 19, 2019, considering that the Gas Directive (Directive 2009/73/EC) does not prohibit dispute settlement authorities from making decisions with retroactive effects dating to before the date of the dispute. Following the ruling of the CJEU, the Court of Cassation has scheduled a hearing for April 2020. The Court of Cassation's ruling could be made before the end of first-half 2020.

In June 2018 the CoRDIS, which has been tasked by the Paris Court of Appeal with evaluating the amount of the customer management services, instructed GRDF to propose to Direct Energie and ENI a new addendum providing for compensation based on the pricing terms established by the CRE in its decisions of October 2017 and January 2018. Both GRDF on the one hand and Direct Energie and ENI on the other have appealed the ruling before the Paris Court of Appeal. GRDF disputes the compensation paid in the past, and in particular asserts that the supplier has already passed on the corresponding amounts to the end customers. On January 23, 2020, the Paris Court of Appeal handed down its decision in which it considered that the suppliers are the mandatory grid service providers for customer management and initiated further discussions on the amount of customer management for Direct Energie and ENI for the period 2005-2018.

Because in 2016 the Paris Court of Appeal considered that ENI had not requested retrospective compensation (its requests prior to 2016 referred only to the future), ENI lodged a claim with the CoRDIS in March 2017 seeking retroactive compensation (€87.8 million for the period from 2008 to 2016) for customer management services. The CoRDIS handed down its decision in July 2019 dismissing ENI's request. ENI has appealed this decision before the Paris Court of Appeal.

In May 2017, Direct Energie also lodged a claim with the Paris Commercial Court for abuse of a dominant position and material inequality in the contractual obligations provided for in the transmission agreements, initially seeking €89.5 million in damages for the period from 2009 to 2016. This claim has since been raised to €140 million. This is a claim for indemnification, unlike the claims before the CoRDIS, which are seeking compensation for customer management services in respect of distribution services.

The Paris Commercial Court handed down a decision in January 2019, ordering GRDF to pay Direct Energie €17 million.

GRDF and Direct Energie have appealed this decision and filed their preliminary submissions in June 2019.

In July 2019, ENI launched proceedings against GRDF before the Paris Commercial Court for abuse of a dominant position and material inequality on the grounds that GRDF had required ENI, without compensation, to perform customer management services in respect of distribution. ENI is seeking a little over €300 million.

Regarding the customer management services carried out on behalf of the grid manager in the electricity sector (in this case ERDF, now ENEDIS), following proceedings brought by ENGIE, in a decision of July 13, 2016, the *Conseil d'État* also ruled that the same principle whereby the grid manager pays compensation to the supplier should apply. In the same decision, the *Conseil d'État* denied the CRE the right to set a customer threshold beyond which the compensation would not be payable, which hitherto prevented ENGIE from receiving any compensation. In light of this decision, ENGIE brought an action against ENEDIS with the purpose of obtaining payment for these customer management services. The legislature has adopted a decision that retroactively validates the agreements entered into with ENEDIS. In a decision handed down on April 19, 2019, the Constitutional Court ruled that this provision was constitutional. The proceedings against ENEDIS are still underway. ENGIE had also brought action before the *Conseil d'État* against the CRE's decision of October 26, 2017 in respect of the compensation for customer management services in the electricity sector for the period prior to January 1, 2018, but has withdrawn from the proceedings.

25.3 Rest of Europe

25.3.1 Resumption and extension of operations at the nuclear power plants

Various associations have brought actions before the Constitutional Court, the *Conseil d'État* and the ordinary courts against the laws and administrative decisions authorizing the extension of operations at the Doel 1 and 2 and Tihange 1 reactors. The Brussels Court of Appeal dismissed Greenpeace's claims in a decision dated June 12, 2018. Greenpeace appealed this decision before the Court of Cassation. This appeal was rejected by a ruling of the Court of Cassation dated January 9, 2020, such that the decision by the Brussels Court of Appeal dated June 12, 2018 is now final. As for the action brought before the Constitutional Court, on June 22, 2017 the Court referred the case to the Court of Justice of the European Union (CJEU) for a preliminary ruling. In its decision of July 29, 2019, the CJEU ruled that the Belgian law extending the operating lives of the Doel 1 and Doel 2 reactors was adopted without having made the prior environmental evaluations required, but that the effects of the law extending the operating lives may be maintained temporarily in the event of a serious and significant threat of electricity shortage, and then only for the length of time that is strictly necessary to rectify this threat. The decision of the Constitutional Court is expected soon. In addition, the appeal before the *Conseil d'État* is still ongoing.

In addition, some local authorities and various organizations have challenged the authorization to restart operations at the Tihange 2 reactor. On November 9, 2018, the *Conseil d'État* rejected the action brought by some local German authorities seeking the annulment of this decision. Civil proceedings are still ongoing before the Brussels Court of First Instance.

25.3.2 Claim by the Dutch tax authorities related to interest deductibility

Based on a disputable interpretation of a statutory modification that came into force in 2007, the Dutch tax authorities refuse the deductibility of a portion (€1.1 billion) of the interest paid on financing contracted for the acquisition of investments made in the Netherlands since 2000. Following the Dutch tax authorities' rejection of the administrative claim against the 2007 tax assessment, action was brought before the Arnhem Court of First Instance in June 2016. On October 4, 2018, the court ruled in favor of the tax authorities. However, given that ENGIE Energie Nederland Holding BV considers the court's reasoning to be contradictory and disputable, both in light of Dutch and European law, it has appealed the decision.

25.3.3 Claim by the Dutch tax authorities related to power plant impairment losses

The Dutch tax authorities have disallowed the tax deduction of asset impairment losses reported by ENGIE Energie Nederland NV on its 2010-2013 tax returns. The authorities challenged both the period of coverage of the impairment losses and the amount. Accordingly, they added back the full amount of the accumulated asset impairment losses over the abovementioned period, i.e., an amount of €1.9 billion. ENGIE has contested the tax authorities position as regards both the period and the amount and filed an administrative appeal in November 2018, which was rejected in February 2019. ENGIE is considering whether to launch legal proceedings.

25.3.4 Transfer price of gas

The Belgian tax authorities' Special Tax Inspectorate has issued two tax deficiency notices in respect of taxable income for fiscal years 2012 and 2013 for an aggregate amount of €706 million, considering that the price applied for the supply of gas by ENGIE (then GDF SUEZ) to Electrabel S.A. was excessive. ENGIE and Electrabel S.A. are challenging this adjustment. Belgium and France have begun conciliation proceedings to settle the dispute.

25.3.5 Spain – Punica

In the Punica case (investigation into the awarding of contracts), 12 Cofely España employees, as well as the company itself were placed under investigation by the examining judge in charge of the case. The criminal investigation is in progress and is scheduled to be closed by June 6, 2020.

25.3.6 Italy – Vado Ligure

On March 11, 2014, the Court of Savona seized and closed down the VL3 and VL4 coal-fired production units at the Vado Ligure thermal power plant belonging to Tirreno Power S.p.A. (TP), a company which is 50%-owned by the ENGIE Group. This decision was taken as part of a criminal investigation against the present and former executive managers of TP into environmental infringements and public health risks. The investigation was closed on July 20, 2016. The case was referred to the Savone Court to be tried on the merits. The proceedings began on December 11, 2018 and will continue through 2020.

25.3.7 Italy – Tax dispute relating to excise duties and ENGIE Italia VAT (formerly GDF SUEZ Energie)

In 2017, the Italian tax authorities challenged the excise duty waiver for gas transfers carried out by ENGIE Italia for industrial customers in Italy on the grounds that it did not have a certificate for these customers. The authorities plan to issue a tax reassessment for a total amount of €126 million (excise duties, VAT, late payment penalties and interest). ENGIE Italia has challenged the legality of this procedure both in light of Italian and European law and in any event deems the sanction to be disproportionate compared to a formal requirement.

In 2018, ENGIE Italia launched an appeal with the Perugia Court of First Instance requesting the cancellation of the tax reassessment notice.

In October 2018, the Court of First Instance dismissed the cancellation request, simply applying an outdated ministerial decree and ignoring ENGIE Italia's legal arguments.

ENGIE Italia appealed the ruling in November 2018 and the Court of Appeal ruled in its favor in November 2019 on the grounds that the documents requested by the Italian tax authorities were not legal and that the authorities needed to take into account the factual situation of the taxpayer to determine its requirement to pay excise duties. The Italian tax authorities may refer the case to the Court of Cassation.

25.3.8 Italy – Competition procedure

On May 9, 2019, a fine of €38 million was jointly and severally imposed on ENGIE Servizi SpA and ENGIE Energy Services International S.A. by the Italian Competition Authority for certain alleged anti-competitive practices relating to the award of the Consip FM4 2014 contract. An appeal has been lodged with the Regional Administrative Court of Lazio (TAR Lazio). The TAR Lazio has suspended payment of the fine. The appeal proceedings are pending.

25.4 Latin America

25.4.1 Concessions in Buenos Aires and Santa Fe

In 2003, ENGIE and its joint shareholders, water distribution concession operators in Buenos Aires and Santa Fe, initiated two arbitration proceedings against the Argentinean State before the International Center for Settlement of Investment Disputes (ICSID). The purpose of these proceedings was to obtain compensation for the loss in value of investments made since the start of the concession, in accordance with bilateral investment protection treaties.

As a reminder, prior to the stock market listing of SUEZ Environnement Company, ENGIE and SUEZ (formerly SUEZ Environnement) entered into an agreement providing for the economic transfer to SUEZ of the rights and obligations relating to the ownership interests held by ENGIE in Aguas Argentinas and Aguas Provinciales de Santa Fe, including the rights and obligations resulting from the arbitration proceedings.

On April 9, 2015, the ICSID ordered the Argentinean State to pay USD 405 million in respect of the termination of the Buenos Aires water distribution and treatment concession contracts (including USD 367 million to ENGIE and its subsidiaries), and on December 4, 2015, to pay USD 225 million in respect of the termination of the Santa Fe concession

contracts. The Argentinean State sought the annulment of these awards. By decision dated May 5, 2017, the claim for the annulment of the Buenos Aires award was rejected. The claim to annul the award in the Santa Fe case was rejected by a decision dated December 14, 2018. Consequently, the two ICSID awards, which are a step in the settlement of the dispute, are now final.

The Argentinean government and the various shareholders of Aguas Argentinas entered into and implemented a settlement agreement in accordance with the arbitral award of April 9, 2015, handed down in respect of the water distribution and treatment concession contracts in Buenos Aires. In accordance with the above-mentioned agreement concerning the economic transfer to SUEZ of ENGIE's rights and obligations, SUEZ and its subsidiaries received €224.1 million in cash. Furthermore, the December 14, 2018 ruling pertaining to the water distribution and wastewater treatment concessions granted to Aguas Provinciales de Santa Fe has yet to be applied.

25.4.2 Planned construction of an LNG terminal in Uruguay

GNLS SA, a joint subsidiary of Marubeni and ENGIE, was selected in 2013 to build an offshore LNG terminal in Uruguay. On November 20, 2013, GNLS contracted out the design and construction of the terminal to Construtora OAS SA. Following a number of problems and defects, GNLS terminated the contract in March 2015 and made use of its guarantees. OAS challenged the termination of the contract but did not take action against GNLS. OAS went bankrupt in Uruguay on April 8, 2015. In September 2015, GNLS and the authorities agreed to cancel the planned construction.

On May 24, 2017, OAS and GNLS appeared before the Uruguayan courts in a conciliation process at the request of OAS. The conciliation process was unsuccessful. OAS then threatened to call GNLS before the Uruguayan courts to claim damages.

Since GNLS had incurred significant losses as a result of the termination of the contract, it filed a request for arbitration on August 22, 2017 in accordance with the terms of the contract providing for dispute resolution in Madrid by the ICC International Court of Arbitration, claiming a principal amount of USD 373 million. OAS responded by summoning GNLS before the Montevideo Commercial Court, claiming USD 311 million in damages. ENGIE was officially named as a party to the proceedings on December 5, 2018. Both proceedings are still pending.

25.4.3 Claim against sales tax adjustments in Brazil

On December 14, 2018, the Brazilian Tax Administration sent ENGIE Brasil Energia notices of tax assessment for the 2014, 2015 and 2016 fiscal years believing that the company was liable for PIS and COFINS taxes (federal value added taxes) on reimbursement of certain fuels used in the production of energy by thermoelectric plants. The adjustments amounted to a total of 492 million Brazilian reais, including 229 million Brazilian reais in taxes to which are added fines and interest.

ENGIE Brasil Energia disputes these notices of tax assessment and introduced tax claims in 2019, which the tax authorities have rejected, however. A final claim at administrative level (prior to possible appeals before tax courts at judicial level) was filed by ENGIE Brasil Energia in January 2020.

25.5 Other

25.5.1 Luxembourg – State aid investigation

On September 19, 2016, the European Commission announced its decision to open an investigation into whether or not two private rulings granted by the Luxembourg State in 2008 and 2010 covering two similar transactions between several of the Group's Luxembourg subsidiaries constituted State aid. On June 20, 2018, the European Commission adopted a final, unfavorable decision deeming that Luxembourg had provided ENGIE with State aid. On September 4, 2018, ENGIE requested the annulment of the decision before the European Courts, thereby challenging the existence of a selective advantage. As these proceedings do not have a suspensive effect, ENGIE paid a sum of €123 million into an escrow account on October 22, 2018 in respect of one of the two transactions in question, since no aid was actually received for

the other. Following the proceedings before the European Courts, this sum will be returned to ENGIE or paid to the Luxembourg State depending on whether or not the Commission's decision is annulled.

25.5.2 Poland – Competition procedure

On November 7, 2019, a fine of 172 million Polish zloty (€40 million) was imposed on ENGIE Energy Management Holding Switzerland AG (EEMHS) for failing to respond to a request for disclosure of documents from the Polish Competition Authority (UOKiK) in a proceeding initiated by the UOKiK which suspected a potential failure to notify by EEMHS and other financial investors involved in the financing of the Nord Stream 2 pipeline. EEMHS filed an appeal with the Competition Protection Court. The appeal proceedings are pending.

NOTE 26 SUBSEQUENT EVENTS

On January 22, 2020, the Group announced a partnership with Edelweiss Infrastructure Yield Plus Fund (EIYP) to sell the majority of its stake in solar assets in India. The completion of this transaction is expected to occur during the first half of 2020 and will allow ENGIE to reduce its net debt by more than €400 million.

In addition, on January 23, 2020, the Group announced that it had won a competitive tender launched by Sterlite for the acquisition of a 30-year greenfield concession project. The project comprises the construction, operation and maintenance of a 1,800 km electric power transmission line, a new substation and the expansion of three additional substations in northern Brazil. All necessary installation licenses have been secured to start construction in 2020. The total investment cost of the project is expected to be €750 million.

NOTE 27 FEES PAID TO THE STATUTORY AUDITORS AND TO MEMBERS OF THEIR NETWORKS

Pursuant to Article 222-8 of the General Regulations of the French Financial Markets Authority (AMF), the following table presents information on the fees paid by ENGIE SA, its fully consolidated subsidiaries and joint operations to each of the auditors in charge of auditing the annual and consolidated financial statements of the ENGIE Group.

The Shareholders' Meeting of ENGIE SA of April 28, 2014 decided to renew the terms of office of Deloitte and EY as Statutory Auditors for a six-year period from 2014 to 2019.

In millions of euros	Deloitte			EY			Total
	Deloitte & Associés	Network	Total	EY & others	Network	Total	
Statutory audit and review of consolidated and parent company financial statements	5.5	6.7	12.2	5.9	7.0	12.9	25.1
ENGIE SA	2.2	-	2.2	2.7	-	2.7	5.0
Controlled entities	3.3	6.7	10.0	3.2	7.0	10.2	20.2
Non-audit services	0.8	1.4	2.3	0.8	0.9	1.8	4.0
ENGIE SA	0.6	-	0.6	0.7	-	0.7	1.3
Of which services related to legal and regulatory requirements	0.4	-	0.4	0.3	-	0.3	0.7
Of which other audit services	0.2	-	0.2	0.4	-	0.4	0.6
Of which reviews of internal control	-	-	-	-	-	-	-
Of which due diligence services	-	-	-	-	-	-	-
Of which tax services	0.0	-	0.0	0.0	-	0.0	0.0
Controlled entities	0.2	1.4	1.7	0.1	0.9	1.0	2.7
Of which services related to legal and regulatory requirements	-	0.5	0.5	0.1	0.3	0.3	0.9
Of which other audit services	0.1	0.1	0.2	0.0	0.2	0.2	0.4
Of which reviews of internal control	0.0	0.0	0.1	-	-	-	0.1
Of which due diligence services	0.1	0.2	0.3	-	0.0	0.0	0.3
Of which tax services	0.0	0.6	0.6	0.0	0.5	0.5	1.0
Total	6.4	8.1	14.5	6.8	7.9	14.7	29.2

NOTE 28 INFORMATION REGARDING LUXEMBOURG AND DUTCH COMPANIES EXEMPTED FROM THE REQUIREMENTS TO PUBLISH ANNUAL FINANCIAL STATEMENTS

Some companies in the Rest of Europe and Others reportable segments do not publish annual financial statements pursuant to domestic provisions in Luxembourg law (Article 70 of the Law of December 19, 2002) and Dutch law (Article 403 of the Civil Code) relating to the exemption from the requirement to publish audited annual financial statements.

The companies exempted are notably: ENGIE Energie Nederland NV, ENGIE Energie Nederland Holding BV, ENGIE Nederland Retail BV, ENGIE United Consumers Energie BV, Epon Eemscentrale III BV, Epon Eemscentrale IV BV, Epon Eemscentrale V BV, Epon Eemscentrale VI BV, Epon Eemscentrale VII BV, Epon Eemscentrale VIII BV, Epon International BV, Epon Power Engineering BV, ENGIE Portfolio Management BV, IPM Energy Services BV, Electrabel Invest Luxembourg, ENGIE Corp Luxembourg SARL, ENGIE Treasury Management SARL and ENGIE Invest International SA.

04 STATUTORY AUDITORS' REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

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ENGIE

Société anonyme

1, place Samuel de Champlain
92400 Courbevoie

Statutory auditors' report on the consolidated financial statements

Year ended December 31, 2019

This is a free translation into English of the statutory auditors' report on the consolidated financial statements of the Company issued in French and it is provided solely for the convenience of English-speaking users.

This statutory auditors' report includes information required by European regulation and French law, such as information about the appointment of the statutory auditors or verification of the information concerning the Group presented in the management report.

This report should be read in conjunction with, and construed in accordance with, French law and professional auditing standards applicable in France.

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S.A.S au capital de € 2.188.160
572 028 051 R.C.S Nanterre

Commissaire aux Comptes
Membre de la compagnie
régionale de Versailles

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Membre de la compagnie
régionale de Versailles

ENGIE

Société anonyme

1, place Samuel de Champlain
92400 Courbevoie

Statutory auditors' report on the consolidated financial statements

Year ended December 31, 2019

To the Shareholders' Meeting of ENGIE,

Opinion

In compliance with the engagement entrusted to us by your Shareholder's Meeting, we have audited the accompanying financial statements of ENGIE ("the Company") for the year ended December 31, 2019.

In our opinion, the financial statements give a true and fair view of the assets and liabilities and of the financial position of the Company as of December 31, 2019 and of the results of its operations for the year then ended in accordance with International Financial Reporting Standards as adopted by the European Union.

The audit opinion expressed above is consistent with our report to the Audit Committee.

Basis for opinion

Audit framework

We conducted our audit in accordance with professional standards applicable in France. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Our responsibilities under those standards are further described in the "Statutory Auditors' Responsibilities for the Audit of the consolidated Financial Statements" section of our report.

Independence

We conducted our audit in compliance with independence rules applicable to us, for the period from January 1, 2019 to the date of our report and specifically we did not provide any prohibited non-audit services referred to in Article 5(1) of Regulation (EU) No 537/2014 or in the French Code of Ethics (*Code de déontologie*) for statutory auditors.

Emphasis of matter

We draw attention to the following matter described in Note 1 to the consolidated financial statements relating to the change in accounting method relating to the first-time application from January 1st, 2019 of IFRS 16 "Lease Contracts" and the impacts of IFRIC's March 2019 decision related to the "physical settlement of contracts to buy or sell a non-financial item". Our opinion is not modified in respect of this matter.

Justification of Assessments - Key Audit Matters

In accordance with the requirements of Articles L.823-9 and R.823-7 of the French Commercial Code (*Code de commerce*) relating to the justification of our assessments, we inform you of the key audit matters relating to risks of material misstatement that, in our professional judgment, were of most significance in our audit of the financial statements of the current period, as well as how we addressed those risks.

These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon. We do not provide a separate opinion on specific elements, accounts or items of the consolidated financial statements.

■ Measurement of the recoverable amount of goodwill, intangible assets and property, plant & equipment

[notes 13, 14 and 15]

Key audit matter	Our response
<p>As of December 31, 2019, the net carrying amount of fixed assets (goodwill, intangible assets and property, plant & equipment) amounted to €77.7 billion (after recognition of impairment losses of €1.8 billion), or 48.6% of total assets.</p> <p>Fixed assets are comprised of:</p> <ul style="list-style-type: none"> – €18.7 billion of goodwill, mainly allocated to the Cash-Generating Units (CGU) Benelux (€4.3 billion), GRDF (€4 billion), France Renewable Energy (€1.2 billion), United Kingdom (€1.1 billion), France B to B (€1 billion) and France B to C (€1 billion); – €7 billion of intangible assets; – €52 billion of property, plant & equipment; <p>For operating entities which your Group intends to hold on a long-term and going concern basis, the recoverable amount corresponds, in most cases, to the value in use, determined based on :</p> <ul style="list-style-type: none"> – cash flow projections on the basis of the 2020 budget and 2021-2022 medium-term business plan approved by the Group's Executive Committee and the Board of Directors and, – beyond this time frame, extrapolated future cash flow projections determined on the basis of macroeconomic assumptions (inflation, exchange rates and growth rates) and price projections featured in the Group's reference scenario for 2023-2040 approved by the Executive Committee. <p>These recoverable amounts are based on key assumptions relating to market outlook and changes in the regulatory environment of which any modification could have a material impact on the amount of impairment losses to be recognized. Concerning the goodwill of the main CGU, measurement is based on the following assumptions :</p>	<p>We examined the definition of CGU as well as the allocation of goodwill to the different CGU.</p> <p>We assessed the Group's measures aiming to identify indications of impairment losses as well as Management's procedures for approving the estimates.</p> <p>We examined the data and the key assumptions used to determine the recoverable amount of assets, assessed the sensitivity of the measurements to these assumptions and verified the calculations performed by the Group with the support of our valuation experts.</p> <p>Our work mainly covered;</p> <ul style="list-style-type: none"> – the assumptions of the Group's long-term reference scenario (trends in electricity and gas prices and demand, price of CO₂, coal and oil, inflation) for which we have assessed the consistency with external studies carried out by international organizations or energy experts; – the operational and regulatory assumptions used to prepare cash flow forecasts for which we assessed the consistency of the asset's operating conditions and their intrinsic performance as well as the applicable regulations to date and their expected changes; – methods for determining cash flow forecasts for which we assessed: <ul style="list-style-type: none"> ○ the consistency of the baseline data with the budget, the medium-term business plan and beyond, the Group's long-term scenario ; ○ the consistency with past performances and market outlook ; – the discount rates for which we have examined the determination methods and the consistency with the underlying market assumptions, using internal specialists; – Management's sensitivity analysis to the key price, operational and regulatory assumptions for which we assessed the relevance;

- for the Benelux CGU, expected trends in the long-term electricity and gas demand, the price of CO₂, the price of electricity and fuel as well as changes in the regulatory environment for nuclear capacities in Belgium beyond 2025 and the extension of drawing rights agreements for French nuclear plants beyond their current legal terms ;
- for the Renewable Energy CGU, prospects and conditions of renewing the hydropower concession agreements in France ;
- the assessment of the highly probable nature of disposals decided by the Group and the elements considered to measure the recoverable amount;
- the appropriateness of the disclosure given in the notes, notably on sensitivity analyses carried out by the Group.

These measurements are sensitive to the applied macro-economic assumptions (inflation and discount rates).

For operating entities which the Group has decided to sell, the related recoverable amount of the assets concerned is based on market value less costs of disposal.

We considered the measurement of the recoverable amount of goodwill, intangible assets and property, plant & equipment to be a key audit matter due to their materiality in the Group's financial statements and because they require the use of assumptions and estimates to be assessed in a context which remains sensitive to trends in the energy market and whose consequences make the medium-term economic outlook difficult to anticipate.

■ **Measurement of provisions relating to the back-end of nuclear fuel cycle and to the dismantling of nuclear facilities in Belgium**

[note 19 and 19.2]

Key audit matter	Our response
<p>Your Group has obligations relating to the reprocessing and storage of radioactive nuclear fuel consumed and the dismantling of nuclear facilities operated in Belgium. Pursuant to the Belgian law of April 11, 2003, the management of corresponding provisions is entrusted to the Group's wholly-owned subsidiary Synatom which submits a report every three years to the Commission for Nuclear Provisions (CNP) describing the core inputs used to measure these provisions. The CNP issues its opinion based on the opinion issued by the Belgian agency for radioactive waste and enriched fissile material (ONDRAF) which reviews all of the characteristics and technical parameters of the report.</p> <p>The provisions, for the management of radioactive nuclear fuel and for the dismantling of nuclear facilities, are estimated from the current legal and contractual framework and on the basis of the opinion issued by the CNP on December 12, 2019.</p> <p>We considered the measurement of these provisions to be a key audit matter due to their amounts and their sensitivity to industrial scenarios used and estimates of related costs such as, in particular:</p> <ul style="list-style-type: none"> – concerning provisions relating to the back-end of nuclear fuel cycle, the decisions will be ultimately made by the Belgian government relating to the management of radioactive spent fuel (reprocessing of a portion of spent fuel or direct removal, without prior reprocessing) and long-term management of fuel (cost of burying fuel in deep geological repositories or long-term on-site storage), – concerning the provisions for the dismantling of nuclear facilities, the dismantling program and the timetables approved, or not, by the nuclear safety authorities. 	<p>We analyzed the findings, observations and recommendations made in the opinions of the ONDRAF and the CNP.</p> <p>We examined the basis on which these provisions were measured and assessed the sensitivity of measurements to the technical assumptions and industrial scenarios, notably for the management of radioactive fuel, as well as assumptions relating to costs, operations timetable and discount rates applied to cash flows.</p> <p>Our work mainly consisted in assessing :</p> <ul style="list-style-type: none"> – the consistency of industrial scenarios used with regard to the current legal and regulatory environment for the choice of nuclear policy remaining to be made in Belgium; – the consistency of forecasts of costs by nature and forecasts of cash outflows with available studies and quotes and, for dismantling, with a study of independent experts mandated by Synatom; – the level of margins for uncertainties and contingencies included in the provisions to take into account the degree of technical control over dismantling and management of radioactive fuel; – the consistency of the spent fuel volumes produced to date and the estimates of spent fuel volumes still to be produced with the Group's physical inventory and forecast data; – the methods for determining the discount rates used and their consistency with the underlying market assumptions. – the appropriateness of the disclosure given in the notes to the consolidated financial statements, notably on the sensitivity to measurement of the provisions to changes in key assumptions.

This measurement is sensitive to the applied macro-economic assumptions (inflation and discount rates).

■ **Valuation for provisions relating to commercial litigations, claims and tax risks**
[notes 19, 19.4 and 25]

Key audit matter	Our response
<p>Your Group is party to a number of legal and anti-trust proceedings with third parties or with legal and/or administrative authorities, including tax authorities, investigations before state courts, arbitral tribunals or regulated authorities, in the normal course of its business.</p> <p>The main disputes and investigations potentially having a significant impact on your Group are recognized as liabilities or give rise to contingent liabilities, as it is indicated in Note 25 to the consolidated financial statements.</p> <p>We have considered this topic as a key audit matter, provided the amounts at stake and the judgement required to determine the provisions for commercial litigations claims and tax risks, due to the regulatory context and the continuously changing market environment.</p>	<p>Our audit procedures consisted in:</p> <ul style="list-style-type: none"> – investigating the procedures implemented by your Group in order to identify all the litigations and risk exposures; – corroborating these analyses with the confirmations received from the lawyers; – evaluating the analysis of the probability of occurrence performed by your Group, as well as the assumptions used, and the supporting documentation with, if any, consultations received by third parties. We have recourse to our experts for the most complex analysis; – appreciating the appropriateness of the disclosure given in the notes to the consolidated financial statements.

■ **Estimate of gas and electricity unbilled and un-metered revenues (“energy in the meter”)**

[notes 7.1 and 7.2.1]

Key audit matter	Our response
<p>Your Group uses an estimate in revenue, relating to the sales on networks generated from customers whose energy consumption is metered during the accounting period. Since the meter readings provided by the grid operators and their final allocations to the Group are sometimes only known several months down the line, this means that revenue figures are only an estimate. As of December 31, 2019, the receivables relating to the energy in the meter (gas and electricity un-metered and unbilled revenue) amount to €3.3 billion and mainly concern France and Belgium.</p> <p>These receivables are determined on the basis of a method that takes into account an estimate of customers' consumption based on the previous bill, or the last metering not yet billed, in line with the volume of energy allocated by grid managers, using measurement and modeling tools developed by your Group.</p> <p>The volumes are measured at the average energy price, which takes account of the category of customers and the age of the delivered unbilled energy in the meter.</p> <p>Considering the amount of revenue at stake and the sensitivity of the estimates to assumptions regarding volumes and the average energy price, we considered the estimate of the portion of un-metered revenue at the year-end to be a key audit matter.</p>	<p>Our work, both in France and in Belgium, mainly consisted in:</p> <ul style="list-style-type: none"> – considering the internal control procedures implemented by the Group about the billing process, and the process enabling the reliability of the estimate about the energy in the metered revenue; – evaluating the models used by the Group and investigating the modality of the computation for the estimated volumes; we include a specialist in our audit team. <p>We also:</p> <ul style="list-style-type: none"> – compared the information about the volumes delivered and determined by the Group with the metering data provided by the grid operators; – examined that the modalities of the computation for the average price of the metered power take account of its anteriority and the different kinds of customers; – analyzed the coherence of the volumes delivered with the Energy Balance (which corresponds to the physical reality of the operations of allocations (revenues, injections and stocks) and resources (purchases, withdrawals and stocks) of energy on the networks) prepared by the Group; – assessed the regular clearance of the metered energy during the period; – assessed the age of the delivered but unbilled metered energy at the year-end.

Specific verifications

We have also performed, in accordance with professional standards applicable in France, the specific verifications required by laws and regulations of the information pertaining to the Group presented in the Board of Director's management report.

We have no matters to report as to its fair presentation and its consistency with the consolidated financial statements.

We attest that the consolidated non-financial performance statement provided for by Article L. 225-102-1 of the French Commercial Code (*Code de commerce*) is included in the information pertaining to the Group presented in the management report, it being specified that, in accordance with Article L. 823-10 of said Code, we have not verified the fairness of the information contained in this declaration or its consistency with the consolidated financial statements that has to be subject to a report by an independent third party.

Report on Other Legal and Regulatory Requirements

Appointment of the Statutory Auditors

We were appointed as statutory auditors of ENGIE by your Shareholders' Meeting held on May 19, 2008 for ERNST & YOUNG et Autres and on July 16, 2008 for Deloitte & Associés.

As of December 31, 2019, we were in their twelfth year of total uninterrupted engagement.

ERNST & YOUNG Audit was previously statutory auditor between 1995 and 2007.

Responsibilities of Management and those charged with Governance for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with International Financial Reporting Standards as adopted by the European Union for implementing internal control it deems necessary for the preparation of the consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless it is expected to liquidate the Company or to cease operations.

The Audit Committee is responsible for monitoring the financial reporting process and the effectiveness of internal control and risks management systems and where applicable, its internal audit, regarding the accounting and financial reporting procedures.

The consolidated financial statements were approved by the Board of Directors.

Statutory Auditors' Responsibilities for the Audit of the Consolidated Financial Statements

Objective and audit approach

Our role is to issue a report on the consolidated financial statements. Our objective is to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with professional standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are

considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As specified in Article L. 823-10-1 of the French Commercial Code (*Code de commerce*), our statutory audit does not include assurance on the viability of the Company or the quality of management of the affairs of the Company.

As part of an audit conducted in accordance with professional standards applicable in France, the statutory auditor exercises professional judgment throughout the audit and furthermore:

- Identifies and assesses the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, designs and performs audit procedures responsive to those risks, and obtains audit evidence considered to be sufficient and appropriate to provide a basis for his opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control;
- Obtains an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the internal control;
- Evaluates the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management in the consolidated financial statements;
- Assesses the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. This assessment is based on the audit evidence obtained up to the date of his audit report. However, future events or conditions may cause the Company to cease to continue as a going concern. If the statutory auditor concludes that a material uncertainty exists, there is a requirement to draw attention in the audit report to the related disclosures in the consolidated financial statements or, if such disclosures are not provided or inadequate, to modify the opinion expressed therein.
- Evaluates the overall presentation of the financial statements and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtains sufficient appropriate audit evidence regarding the financial information of the entities or business activities of the Group to express an opinion on the consolidated financial statements. Is responsible for the direction, supervision and performance of the audit of the consolidated financial statements as well as for the audit opinion.

Report to the Audit Committee

We submit to the Audit Committee a report which includes, in particular, a description of the scope of the audit and the relating audit program implemented, as well as the results of our audit procedures. We also report, if any, significant deficiencies in internal control regarding the accounting and financial reporting procedures that we have identified.

Our report to the Audit Committee includes the risks of material misstatement that, in our professional judgment, were of most significance in the audit of the consolidated financial statements of the current period and which are therefore the key audit matters that we are required to describe in this report.

We also provide the Audit Committee with the declaration provided for in Article 6 of Regulation (EU) N° 537/2014, confirming our independence within the meaning of the rules applicable in

France such as they are set in particular by Articles L. 822-10 to L. 822-14 of the French Commercial Code (*Code de commerce*) and in the French Code of Ethics (*Code de déontologie*) for statutory auditors. When appropriate, we discuss with the Audit Committee the risks that may reasonably be thought to bear on our independence, and the related safeguards.

In Paris-La Défense, March 10, 2020

The Statutory Auditors

DELOITTE & ASSOCIÉS

ERNST & YOUNG et Autres

Olivier Broissand

Patrick E. Suissa

Charles-Emmanuel Chosson

Stéphane Pédrón



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2020 MANAGEMENT REPORT AND ANNUAL CONSOLIDATED FINANCIAL STATEMENTS



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1 ENGIE 2020 RESULTS

ENGIE 2020 financial results

Progress at pace on new strategic direction towards accelerating the energy transition
Strong recovery from Q2 levels, with H2 organic performance similar to 2019

Business Highlights

- Major capital projects delivered with €4.0 billion growth Capex ⁽¹⁾
- Strong growth in Renewables with 3 GW commissioned and 2 GW acquired
- Sale of 29.9% shareholding in SUEZ completed
- Client Solutions and further strategic reviews launched towards Group simplification
- Employee consultation launched for potential creation of new leader in multi-technical services
- New ExCom announced
- Continued ESG progress, with commitment to finalize coal exit in Europe by 2025 and globally by 2027
- Decision to stop preparation works that would allow for the 20-year extension of two nuclear units beyond 2025
- Update on new strategic direction alongside Q1 results, on 18 May 2021

Financial performance

- 2020 NRIs in line with guidance, EBITDA and COI ⁽²⁾ above expectations
- Significant impact of COVID-19 in 2020 mainly on Client Solutions and Supply, with c. €1.2 billion total Group impact at COI level
- Negative FX impact of €0.3 billion at COI level, mainly due to BRL depreciation
- Net financial debt at €22.5 billion, down €3.5 billion versus last year, strong liquidity and strong investment grade rating maintained
- Impairment of nuclear assets, partially offset by capital gains on disposals, leading to NIgs of €-1.5 billion
- 2020 proposed dividend of €0.53 per share
- 2021 guidance ⁽³⁾: NRIs expected in the range of €2.3-2.5 billion

1.1 Key Financial figures at December 31, 2020

In billions of euros	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis) ⁽¹⁾
Revenues	55.8	60.1	-7.2%	-5.7%
EBITDA	9.3	10.4	-10.5%	-6.5%
CURRENT OPERATING INCOME (COI)	4.6	5.8	-21.3%	-16.4%
Net recurring income Group share	1.7	2.7	-36.5%	-34.3%
Net income, Group share	(1.5)	1.0	-	-
CAPEX	7.7	10.0	-	-
Cash Flow From Operations (CFFO) ⁽²⁾	7.1	7.6	-	-
Net financial debt	22.5	25.9	-3.5 vs Dec. 31, 2019	-

(1) Organic variation: gross variation without scope and foreign exchange effect

(2) Cash flow from operations = Free cash flow before maintenance Capex.

(1) Net of DBSO (Develop, Build, Share and Operate) and of US tax equity proceeds

(2) New Current Operating Income (COI) definition excludes the non-recurring share in net income of equity method entities

(3) Main assumptions for these targets and indications: average weather in France for 2021, full pass through of supply costs in French regulated gas tariffs, no major regulatory or macro-economic changes, no change in Group accounting policies, market commodity prices as of 12/31/2020, average forex for 2021: €/£: 1.23; €/BRL: 6.27, up to 100 M€ dilution effect at the COI level from disposals not yet signed corresponding to approximately €2 billion reduction in net debt. Projections based on absence of stringent additional lockdown considered and gradual return to normal over 2021.

1.2 Financial targets

The forecasts for the financial year ended December 31, 2021, set forth below are based on data, assumptions and estimates considered to be reasonable by the Group at the date of issuance of this document.

These data and assumptions may evolve or be amended due to uncertainties related to the economic, financial, accounting, competitive, regulatory and tax environment or other factors that the Group may not be aware of at the date of registration of the management report. In addition, the fulfilment of forecasts requires the success of the Group's strategy. The Group therefore makes no commitment or warranty regarding the fulfilment of the forecasts set out in this section.

The forecasts presented below and the underlying assumptions, also been prepared in accordance with the provisions of Delegated Regulation (EU) No 2019/980 supplementing Regulation (EU) No 2017/1129 and the ESMA recommendations on forecasts.

The forecast presented below result from the budget and medium-term plan process as described in Note 13 to the consolidated financial statements at December 31, 2020; they have been prepared on a comparable basis with historical financial information and in accordance with the accounting methods applied to the Group's consolidated financial statements.

1.2.1. Assumptions

- strategy: confirmation and deepening of the Group ambition to establish ENGIE as a leading force in the energy and climate transition. The Group will focus on completing the strategic reviews underway to create value and re-allocate capital towards growth, particularly in Renewables, Networks, and Asset-based Client Solutions;
- sanitary conditions in line with those of Q4 2020, no stringent additional lockdown considered and gradual return to normal over 2021;
- disposals: COI dilution up to €100 million on top of impacts from already announced / closed disposals, corresponding to a € 2 billion net financial debt reduction;
- foreign exchange rates: 2021 average annual €/US Dollar and €/Brazilian real foreign exchange rates at 1.23 and 6.27 respectively;
- regulated tariffs in France Infrastructures:
 - distribution, transport and storage: tariffs as published by the CRE in January 2020,
 - regasification: tariffs as published by the CRE in January 2021;
- regulated gas and power tariffs in France: full pass through of supply costs;
- commodity prices: based on market conditions as of December, 2020 (80% of European outright power is hedged – captured prices: 46€/MWh);
- climate: normalized conditions in France (gas distribution and energy supply + normalized hydro production);
- recurring effective tax rate: 25%;
- employee benefit provisions discount rates: based on market conditions as of December 31, 2020, as disclosed in Note 20 to the consolidated financial statements at December;
- no significant accounting changes compared to 2020;
- no major regulatory and macro-economic changes compared to 2020.

1.2.2. 2021 Guidance

Overall financial performance in 2021 is expected to improve significantly after a COVID-19 impacted 2020, assuming no additional stringent lockdowns and a gradual easing of restrictions over 2021.

For 2021, ENGIE anticipates a Net Recurring Income group share in the range of €2.3 to 2.5 billion. This guidance is based on an indicative EBITDA range of €9.9 to 10.3 billion and a COI range of €5.2 to 5.6 billion.

Expectation by business line:

	Expected drivers for 2021 COI
Renewables	Growth in the US and France should benefit financial performance, partly offset by a lower contribution from rulings in Brazil relating to the recovery of past energy costs and a weaker BRL
Networks	Networks are expected to remain stable with the impact of the new, lower RAB remuneration rates in France offset by reversal of the warm temperature effect of 2020 and growth in Latin America
Client Solutions	Overall Client Solutions should demonstrate strong recovery from COVID-19, albeit with a relatively slower recovery for asset light activities, and benefit from y-o-y accretion from SUEZ and EV-Box disposals
Thermal	Expect normalization after a particularly strong 2020 performance in Europe
Supply	Expect strong recovery from COVID-19 and the reversal of the 2020 warm temperature effect. .
Nuclear	Much improved performance expected driven by better availability following LTO completions and higher achieved prices

Included within this guidance is an estimated impact that follows the extreme cold weather in Texas earlier this month. ENGIE is assessing the situation, which mainly affects Renewables and Supply activities. Overall ENGIE currently estimates a potential net negative impact at the Group COI and Net Recurring Income Group share levels of between €80 to 120 million.

Regarding disposals, ENGIE remains focused on executing at pace to simplify the Group; crystallize value and re-allocate capital towards strategic priorities. This guidance assumes disposals of around €2 billion with a related COI dilution of up to €0.1 billion, in addition to previously signed transactions such as the disposal of EVBox. With respect to investment, ENGIE expects to invest between €5.5 to 6.0 billion growth Capex, with over 90% in Renewables, Networks and Asset-based Client Solutions and €4.0 billion in maintenance including the funding of Belgian nuclear provisions Capex.

ENGIE remains committed to a strong investment grade rating and continues to target a leverage ratio of below or equal to 4.0x economic net debt to EBITDA over the long-term.

ENGIE will update the market on the implementation plan for its new strategic orientation and provide medium-term guidance on 18 May 2021.

1.3 Dividend proposed at top-end of payout ratio

The Board has reaffirmed the Group's dividend policy of NRIs payout ratio in the range of 65 to 75%.

For 2020, the Board has proposed a payout ratio of 75%, at the top end of the policy range. This translates to a dividend of €0.53 per share, which will be proposed for shareholder approval at AGM on the 20th of May.

1.4 Update on Belgian Nuclear Assets

Following the announcements of the Belgium government in Q4 2020, it has been decided to stop all the preparation works that would allow a 20-year extension of half of two units beyond 2025, as it seems unlikely that such an extension can take place given the technical and regulatory constraints. This change in lifetime assumption as well as changes in the commodity price scenario have led to an impairment of €2.9 billion for nuclear assets, which have been accounted as non-recurring items in the 2020 P&L.

ENGIE remains committed to Belgium and to contributing to the country's security of supply. Alongside renewables, the Group is also developing projects of up to 3 GW of gas-fired power plants. These projects could participate in the Belgian Capacity Remuneration Market through auctions in the second half of this year, once approved by the European authorities

1.5 Progress at pace on new strategic orientation

Following the announcement in July of a new strategic orientation to simplify the Group and accelerate growth in Renewables and Infrastructure assets, ENGIE has delivered progress at pace despite the challenging backdrop.

Progress on Group simplification and sharper strategic focus with disposal of SUEZ, launch of strategic reviews and rationalization

The disposal of 29.9% shareholding in SUEZ for €3.4 billion was completed in October, and ENGIE launched strategic reviews of a significant part of Client Solutions activities, GTT and ENGIE EPS.

In addition, ENGIE also progressed on geographic rationalization and strengthening its position in key countries. An example of this is the acquisition of an additional 7% shareholding in ENGIE Energia Chile, thereby reducing the level of minority holdings.

A strategic review of part of Client Solutions was launched towards the potential creation of a new leader in multi-technical services, which would benefit from scale and strong growth prospects. In February 2021, the employee consultation related to the proposed organization design for the new entity was launched. This consultation is expected to conclude by the end of the second quarter of 2021. The Group will consider next steps and review future ownership options for the potential new entity, in the second half of this year. ENGIE will consider all options to maximize value and will act in the interests of all stakeholders.

A new Executive Committee and simplified business organization

In January, the appointment of new Executive Committee (ExCom) was announced reflecting the intention to implement a simplified business organization focused on four businesses: Renewables, Networks, Client Solutions and Thermal & Supply. Along with the ExCom members responsible for functional activities and specific projects, the new leadership team is engaged in executing ENGIE's new strategic direction and enhancing the Group's performance culture.

1.6 Continued operational delivery and €4 billion growth investment, despite challenging backdrop

Operationally, the Group continuously adapted processes to ensure delivery of essential services, while maintaining high health and safety standards. Overall Capex amounted to €7.7 billion in 2020, including €4.0 billion of growth investments, €2.4 billion of maintenance Capex and €1.3 billion of nuclear funding.

See section 4 "Change in net financial debt" of this management report for more details.

1.7 Delivering on ESG goals, commitment to exit coal in Europe by 2025 and globally by 2027

Carbon neutrality is at the heart of ENGIE's purpose and central to its strategic direction.

In 2020, greenhouse gas emissions were reduced by 9% to 68 million tons from power generation benefitting mainly from the disposal of coal plants in Western Europe. ENGIE has today announced the commitment to exit all coal assets in Europe by 2025 and globally by 2027 including coal generation for DHC networks.

As a reminder, coal represents 4 GW of ENGIE's 101 GW centralized power generation portfolio.

ENGIE also increased the share of renewables in its portfolio to 31% in 2020 from 28% at the end of 2019 with the addition of 5 GW of renewables.

On gender diversity, there was a small increase in the number of women in the management and ENGIE had 24% women in management at the end of 2020.

1.8 Operational and financial overview

The Group's activities across Renewables, Networks, Thermal, Nuclear and Other activities demonstrated resilience, however, primarily due to the impacts experienced in H1, ENGIE's results for 2020 were down significantly with an estimated COI impact of c. €1.2 billion from COVID-19. More than 75% of this effect related to Client Solutions and Supply. In addition, warm temperature in France impacted Networks and Supply with a total negative COI impact of €160 million. The impact of foreign exchange was a total negative effect of €293 million, mainly driven by the depreciation of the Brazilian Real (with an average EUR/BRL rate of 5.90 in 2020 vs. 4.42 in 2019, representing a 34% depreciation). Net negative scope effect of €76 million mainly reflects the disposals of Glow in March 2019 and 29.9% shareholding in SUEZ in October 2020, partly offset by the acquisition, alongside with Caisse de Dépôt et Placement du Québec, of 90% of TAG in June 2019 and the remaining 10% in July 2020, together with various acquisitions in Renewables (like Renvico in Italy and in France) as well as in Client Solution (mainly Conti in the US and Powerlines in Europe).

Net recurring income Group share was at the lower end of the guidance range mainly due to higher contributions from entities with minorities (particularly in Latin America) and higher financial costs notably due to inflation and foreign exchange. These results also reflect negative tax effects and the fourth quarter dilution following the disposal of 29.9% shareholding in SUEZ.

1.8.1. COI contribution by reportable segment

COI contribution by reportable segment is presented hereunder and detailed in section 2 "Business trends" of this management report.

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
France	2,229	2,862	-22.1%	-22.2%
<i>France excluding Infrastructures</i>	620	905	-31.5%	-32.0%
<i>France Infrastructures</i>	1,609	1,957	-17.8%	-17.8%
Rest of Europe	648	707	-8.3%	-9.9%
Latin America	1,542	1,696	-9.0%	+2.9%
USA & Canada	124	155	-20.3%	-6.3%
Middle East, Asia & Africa	518	619	-16.4%	+0.2%
Others	(483)	(221)		
TOTAL	4,578	5,819	-21.3%	-16.4%

1.8.2. COI contribution by Business line

COI contribution by Business line is as follows:

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
Client Solutions	459	1,082	-57.5%	-57.6%
Networks	2,063	2,344	-12.0%	-14.0%
Renewables	1,070	1,195	-10.4%	+10.8%
Thermal	1,209	1,320	-8.4%	+1.4%
Nuclear	(111)	(314)	+64.7%	+64.7%
Supply	112	345	-67.7%	-65.5%
Others	(224)	(154)	-45.8%	-37.5%
TOTAL	4,578	5,819	-21.3%	-16.4%

Estimated COVID-19 impacts by Business Lines are as follows:

<i>In billions of euros</i>	Estimates at COI level	Nature
Client Solutions	(0.60)	Loss of revenues / contracts, bad debts, specific purchases
Networks	(0.07)	Lower volumes, lower capitalized costs, specific purchases
Renewables	(0.05)	Lower volumes dispatched
Thermal	(0.04)	Lower demand
Nuclear	(0.06)	Adjusted maintenance operations
Supply	(0.29)	Lower demand, unwinding of hedges, bad debts, lower B2C services
Others	(0.07)	Credit losses
TOTAL	(1.18)	Net of savings / action plans

These estimates have been prepared in accordance with a standard guidance applied across businesses under a dedicated oversight process (losses of revenues being inherently subject to more judgement than the identification of specific costs incurred), considering operating items only and are presented net of savings and mitigating management action plans. By definition these estimates exclude foreign exchange and commodity price effects incurred in the Group's various businesses, whether positive or negative.

1.8.2.1. Renewables

Renewables delivered +11% organic growth.

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
EBITDA	1,559	1,724	-9.6%	+8.7%
COI	1,070	1,195	-10.4%	+10.8%
CAPEX	1,633	2,475	-34.0%	-
DBSO margins (COI contribution) ⁽¹⁾	101.0	189.0	-46.6%	-
Operational KPIs				
Commissioning (GW at 100%)	3.0	3.0	-	-

Renewable COI amounted to €1,070 million, up 11% on an organic basis. This organic growth was driven by: the positive effect from the "GFOM" ruling in Brazil (corresponding to the recovery of past energy costs, following the agreement on renegotiation of hydrological risk, which was finalised at the end of 2020) for approximately €165 million; improved prices for hydro power production in France; higher wind production mainly due to commissioning of new projects and the first effects of the tax equity financing signed in the US in Spring 2020. This organic growth was partly offset by lower DBSO margins and unfavourable energy allocation for hydro in Brazil.

Despite a challenging backdrop, ENGIE repeated the strong operational growth performance achieved in 2019 with the commissioning of 3 GW of renewable capacity in 2020. In addition, the Group also acquired 2 GW of operating assets in Europe: 1.7 GW hydro in Portugal, together with Crédit Agricole Assurances and Mirova, and 0.3 GW wind in Italy and France.

In the last two years, ENGIE's renewable capacity at 100% grew by 32%, mainly thanks to 6.0 GW of capacity commissioned and 2.1 GW acquired, reaching 31.1 GW at the end of 2020. Through renewable energy development, ENGIE provides its public and private customers with renewable energy supply under optimized contractual and financial arrangements, benefitting from the Group's long-term expertise in energy trading. The Group has further strengthened its positioning in the rapidly growing market of long-term corporate renewable power purchase agreements ("Green Corporate PPAs") with more than 1.5 GW of contracts signed in 2020.

With a relatively young portfolio of wind and solar assets (average age of 5 years) benefitting from long-term contracts (average residual duration of 15 years) that provide visibility of earnings, Renewables represent a key long-term growth engine for the Group.

3 GW of Renewables are currently under construction for commissioning in 2021 and ENGIE is on track to achieve its 2019 target of adding 9 GW of new capacity in three years by the end of 2021.

ENGIE and EDP Renováveis finalized the creation of Ocean Winds, a joint venture in the floating and fixed offshore wind energy sector equally. Ocean Winds will act as the exclusive investment vehicle of each partner to capture offshore wind opportunities around the world and aims to become a top five offshore global operator by combining the development potential of both partners. Since its creation, the company already commissioned the first 0.2 GW tranche of a fixed offshore wind farm in Belgium and WindFloat Atlantic, a 25 MW floating wind farm in Portugal. The latter is the world's first semi-submersible floating wind farm and constitutes an important achievement for the sector as floating wind technology contributes to the diversification of energy sources and provides access to untapped marine areas.

ENGIE announced the signing of an agreement to sell 49% of its equity interest in a 2.3 GW US renewables portfolio to Hannon Armstrong, a leading investor in climate change solutions. ENGIE will retain a controlling share in the portfolio and continue to manage the assets. When commissioned, this 2.3 GW portfolio, will comprise 1.8 GW onshore wind and 0.5 GW solar photovoltaic projects. ENGIE has secured nearly USD 2 billion of tax equity commitments for this portfolio. Tax equity financing is the traditional structure used in the US to support the development of renewable projects. This tax equity financing – the largest ever in the US – demonstrates ENGIE's successful development in this market.

ENGIE is also developing projects to drive the long-term energy transition: in early January 2021, ENGIE and Total signed a partnership to develop France's largest site for the production of green hydrogen from 100% renewable electricity. This partnership is one of many green hydrogen projects ENGIE is currently developing.

1.8.2.2. Networks

Networks mainly impacted by warmer temperature and higher D&A in France; international COI up significantly.

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
EBITDA	3,850	4,026	+4.4%	-5.3%
COI	2,063	2,344	+12.0%	-14.0%
CAPEX	2,502	344	+27.4%	-
Operational KPIs				
Temperature effect (COI in millions of euros)	(135)	(36)	-99	-
Smart meters (m)	6.9	4.9	-	-
COVID-19 impacts (COI in billion of euros)	0.07	-	-	-

Networks COI at €2,063 million was down 14% on an organic basis. In France, performance was impacted by unusually mild temperature in H1 and by the negative effect of COVID-19 on distributed volumes, partly offset by lower levels of expenditure during lockdown. Higher D&A due to accelerated amortization of some gas distribution assets in France, which is value neutral over time as it is integrated in the regulated revenue, the non-reiteration of a positive internal Q4 2019 one-off as well as the first effects of the lower Regulated Asset Base (RAB) remuneration rate also contributed to the lower COI for French Networks. Of these impacts, negative volume effects will be recovered in the medium-term under the clawback accounts mechanism.

In Latin America, performance benefitted from higher contributions from TAG and from the two power transmission lines currently under construction in Brazil. In Europe (excluding France) and Asia, Networks faced some headwinds related to price and temperature effects.

Overall, the COVID-19 impact was limited and mainly focused on distribution activities, especially on French Networks.

With a RAB of just over €28 billion, ENGIE is one of the largest gas network operators in Europe, and has a growing networks business in Latin America. ENGIE maintained strong operational performance in 2020 with high levels of network safety and reliability in France and achieved high customer satisfaction rates of 91% for French gas distribution. Also in France, in line with the pick-up in activity levels, gas smart meter installation resumed with the installation of 2.0 million units in 2020 resulting in a total of 6.9 million meters installed at the end of 2020.

The development of renewable gases is a major area of focus for ENGIE. The Group sees a critical role of gas in enabling an affordable and smooth energy transition through the continued use of natural gas, and progressive increase in the use of renewable gases such as biomethane and hydrogen. For example, last year 91 additional biomethane production units

were connected to French gas grids, and over 85% of these were connected to GRDF. Altogether these units can contribute to a yearly production of up to 3.9TWh, equating to the annual gas consumption for heating approximately 1 million new-build homes in France. ENGIE has also started to adapt the existing gas transport networks by commissioning three 'reverse-flow' installations in 2020, that allow biomethane to travel from the distribution grid to gas storage units.

In Latin America, following the acquisition of 90% of TAG in June 2019, ENGIE successfully acquired the remaining 10% in July 2020 with its partner Caisse de Dépôt et Placement du Québec. In addition, ENGIE is also constructing two major electricity transmission lines in Brazil: 1,000 kilometres Gralha Azul project and the 1,800 kilometres Novo Estado project. Both projects include the construction of new substations and upgrades to existing substations and are expected to be commissioned in the second half of 2021.

1.8.2.3. Client Solutions

Client Solutions showed a strong recovery in H2 after a COVID-19 impacted H1.

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
Revenues	20,101	20,957	-4.1%	-6.4%
COI	459	1,082	-57.6%	-57.6%
CAPEX	992	1,624	-38.8%	-
Operational KPIs				
Projects backlog (in billion of euros)	12	11	+5.4%	-
DHC - Net installed capacity (GW)	15.2	13.9	+9.4%	-
COVID-19 impacts (COI in billion of euros)	0.60	-	-	-

Client Solutions had a relatively lower impact at the revenue level compared to COI, which was down significantly, mainly as a result of the COVID-19 crisis with a total estimated impact of c. €600 million for 2020.

A strong impact of COVID-19 was experienced in the Asset-light business model primarily in Europe and the US, mostly driven by loss of revenues and specific additional purchases. Cost-cutting and variabilising measures resulted in total Opex reduction of c. €0.3 billion.

COVID-19 impacted SUEZ results, and the results also reflect the sale of 29.9% shareholding in SUEZ at the beginning of October 2020.

Despite unfavourable temperature, District Heating and Cooling (DHC) and on-site generation activities remained resilient.

Notably, performance in H2 2020 showed a recovery with results similar to H2 2019 excluding the scope-out effect of SUEZ in Q4 2020. The impact of the COVID-19 restrictions was much lower in the second half, as restrictions were eased in France and activity levels were higher. In addition, activities also continued to benefit from cost actions launched in Q2.

Operationally, project backlog in Asset-light activities is higher than end of 2019 with postponed work remaining in the order book and benefitting also from the contribution of acquisitions. This positive KPI evolution provides visibility for 2021 however subject to COVID-19 restrictions.

Driven by decarbonization targets and growth in energy efficiency solutions, ENGIE sees a strong growth potential for heating and cooling networks, on-site generation and green mobility among other Asset-based Client Solutions. The Group already has leadership positions in all of these activities. In DHC networks, ENGIE is an international leader with 100 cooling networks with total installed capacity of 6.1 GW, and 300 heating networks of various size that distribute 19TWh per year.

ENGIE is also growing fast in green mobility with more than 50,000 EV charging points operated.

ENGIE announced in December 2020, that EVBox Group, a start-up acquired in 2017 and now a leading global provider of smart charging solutions for electric vehicles, would be listed on the NYSE in the coming weeks following close of a SPAC (Special Purpose Acquisition Company) transaction. This transaction would combine cash and equity. ENGIE would

retain more than 40% ownership of EVBox. ENGIE expects that the transaction will result in a net debt decrease of ca €0.2 billion and EVBox no longer being consolidated in its accounts, with ENGIE's remaining shareholding accounted by the equity method.

1.8.2.4. Thermal

Thermal delivered 1% organic growth despite material positive one-offs in 2019.

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
EBITDA	1,646	1,763	-6.6%	+2.3%
COI	1,209	1,320	-8.4%	+1.4%

Thermal COI amounted to €1,209 million, up 1% organically despite the non-repeat of favourable operational one-offs in 2019, mainly liquidated damages received in Brazil and Chile. Thermal COI saw limited COVID-19 impact of c. €-40 million, mainly through lower demand in Chile and Peru. These negative impacts were more than offset by a better performance of the European merchant gas fleet driven by the higher contribution of ancillaries, mainly in Italy, as well as to higher spreads captured throughout Europe. Thermal COI also benefitted from the higher performance of the contracted generation activities in the Middle East, from the full-year impact of the commissioning of Pampa Sul in Brazil in June 2019 and from higher volumes dispatched at higher margins in Brazil.

Overall, the Thermal business showed strong resilience, as a result of its highly contracted portfolio outside Europe and the optionality value of its merchant fleet in Europe.

In August and November 2020, the de-mothballing of two CCGT units in the Netherlands for 0.7 GW showed the Thermal fleet's flexibility to take advantage of market opportunities.

In June 2020, the sale of a minority stake in New York's Astoria Energy merchant gas facilities was finalized.

In March 2020, the commissioning of Fadhili's 1.5 GW contracted gas power plant, a cogeneration plant in Saudi Arabia in which ENGIE has a 40% equity ownership, reaffirmed ENGIE's leading position as an independent power producer in the Middle East.

1.8.2.5. Supply

Supply performance impacted by COVID-19 and warm temperature.

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
EBITDA	439	638	-31.2%	-
COI	112	345	+67.7%	+65.5%
French temperature effect (COI in million of euros)	(84)	(24)	(61.0)	-
COVID-19 impacts (COI in billion of euros)	0.29	-	-	-

Supply COI significantly decreased by €-233 million to €112 million. Financial performance was highly affected by COVID-19 (net c. €290 million) in Europe and in the US due to lower gas and electricity consumption during the lockdown periods (primarily B2B). The sharp and unexpected reduction in demand led to a negative volume effect, as related margins had not been booked, together with a negative price effect as power and gas hedged positions had to be unwound in a lower price environment. B2C services provided were also lower during the lockdowns and, as a result of the economic context, level of bad debts increased. Warm temperature in France and Benelux also contributed to the strong decrease.

These effects were only partially offset by various one-offs, dedicated COVID-19 related mitigation actions, better results in Romania and higher B2C gas margins in France.

Operationally, B2C power supply contract base grew by 186,000 in 2020, which contributed to the stability of the global B2C contract base at the level of 24.4 million contracts.

1.8.2.6. Nuclear

Nuclear – improved COI contribution mainly driven by better prices.

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
EBITDA	415	192	+111.6%	+111.6%
COI	(111)	(314)	+64.7%	+64.7%
CAPEX	1,740.0	636.0	-	-
Operational KPIs				
Output (Belgium + France, @ share, TWh)	36.5	41.7	-5,2 TWh	-
Availability (Belgium at 100%)	+62,6%	+79,4%	-1680 bps	-

Nuclear COI reached €-111 million, up 65% organically benefitting mainly from a positive price effect and from lower operational expenditures. These positive effects were partly offset by lower volumes due to the last planned lifetime extension outages of Doel 1, Doel 2 and Tihange 1, and by higher depreciation. Nuclear COI saw COVID-19 impact of c. €-60 million.

1.8.2.7. Others

Others COI of €-224 million was €-70 million lower than in 2019. Year-on-year comparison was negatively impacted by the positive effect of the partial sale of a gas supply contract in 2019 and by the COVID-19 impact due to credit losses for GEM (Global Energy Management). These headwinds were partially offset by GEM's good performance in a context of high market volatility mainly in H1 and by the higher contribution of GTT thanks to a strong past order intake.

1.9 Strong Financial Position and Liquidity

ENGIE has maintained a strong liquidity position with €23.0 billion of liquidity (net cash + undrawn credit facilities – outstanding commercial paper) including €13.3 billion of cash, as of end of December 2020.

ENGIE has strengthened its leadership position in the green bond market having issued having issued €2.4 billion green bonds in 2020, for a total of €12 billion green bonds issued since 2014. With dynamic management of hybrids, ENGIE has an average outstanding amount of €3.9 billion and a current total coupon of €100 million per year, which is down c. -28% since 2017.

Net financial debt is presented in section 4 “Change in net financial debt” of this management report for more details.

Rating

ENGIE maintained a strong investment grade rating:

- On November 9th Moody's lowered its long-term rating to Baa1 with a stable outlook.
- On September 24th Fitch affirmed its long-term rating of A and changed the outlook from stable to negative.
- On April 24th S&P lowered its long-term rating to BBB+ and its short-term rating to A-2.

2 BUSINESS TRENDS

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
Revenues	55,751	60,058	-7.2%	-5.7%
EBITDA	9,276	10,366	-10.5%	-6.5%
Net depreciation and amortization/Other	(4,698)	(4,547)		
CURRENT OPERATING INCOME (COI)	4,578	5,819	-21.3%	-16.4%

REVENUE TRENDS

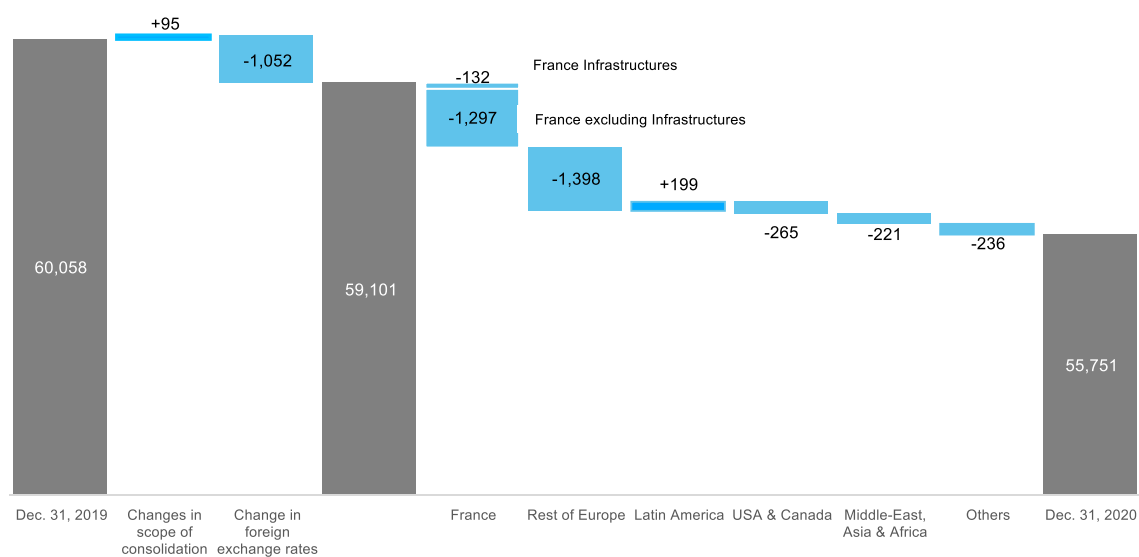
Revenues amounted to €55.8 billion, down 7.2% on a gross basis and 5.7% on an organic basis.

The reported revenue decrease includes a negative foreign exchange effect, mainly due to the depreciation of the Brazilian real against the euro and to a lesser extent to the depreciation of the US dollar, Mexican peso and Argentinian peso against the euro only partly offset by an aggregate positive scope effect. Changes in the scope of consolidation included various acquisitions in Client Solutions, primarily in Europe with Powerlines and in the US with Conti, partly offset by the disposals of the stake in Glow in Thailand in March 2019, the B2C Supply activities in the UK at the beginning of 2020 and the coal assets in Germany and the Netherlands.

The organic revenue decrease was primarily driven by the COVID-19 crisis impacting mainly Supply and Client Solutions activities across all geographies. Mild temperature also weighed on revenues from Supply across Europe and in Australia, from French gas distribution and to a lesser extent from Client Solutions' Asset-based activities.

These impacts were only partly offset by higher revenues in Brazil thanks to construction revenues for the Gralha Azul and Novo Estado power transmission lines and the first full year of operation of the Pampa Sul thermal plant. In France, volume and price effects on power sales also partly offset the decrease in revenues.

In millions of euros



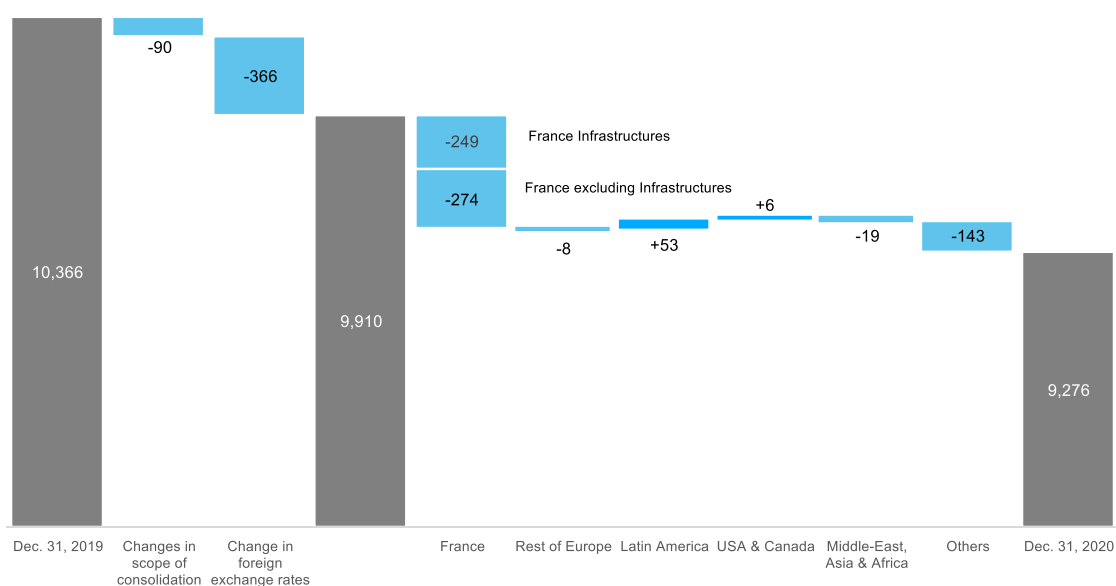
EBITDA TRENDS

EBITDA came in at €9.3 billion, down 10.5% on a gross basis and 6.5% on an organic basis.

These gross and organic changes are overall in line with the decrease in current operating income, except for the increase in depreciation/amortization attributable to (i) the increase in nuclear dismantling assets resulting from the triennial review of Belgian nuclear provisions that took place in late 2019, (ii) LTO works of Belgian first generation reactors and (iii) the amortization certain gas distribution assets in France, none of which are taken into account at EBITDA level.

In addition, the Lean 2021 plan continued to deliver results at EBITDA and COI levels, and is currently slightly exceeding objectives.

In millions of euros



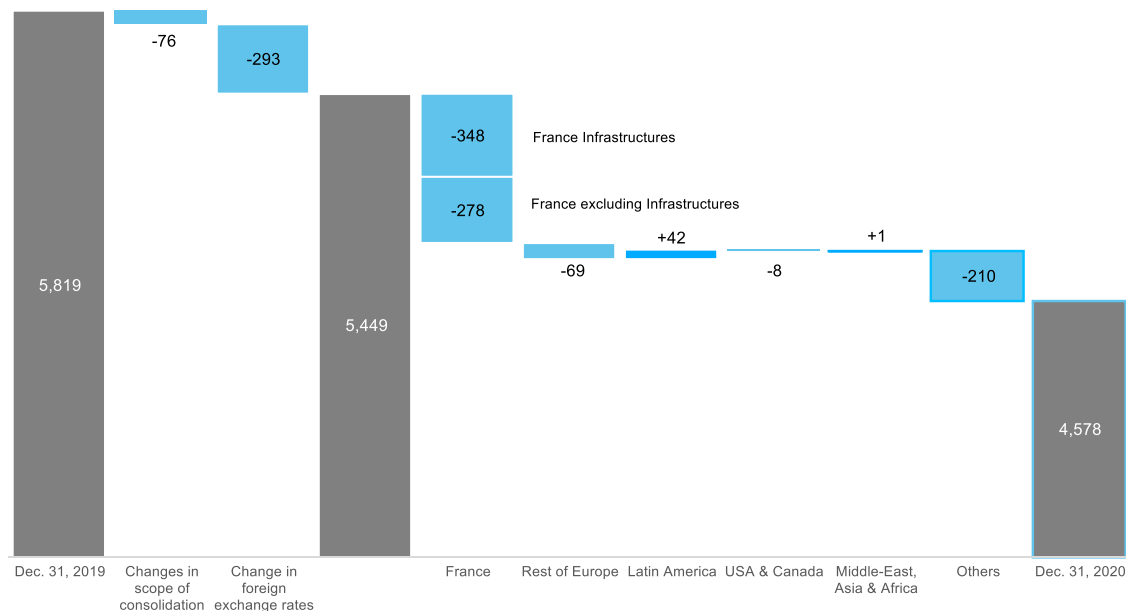
Geography/Business Line matrix

<i>In millions of euros</i>	Client Solutions	Networks	Renewables	Thermal	Nuclear	Supply	Others	Dec. 31, 2020
France	750	3,291	389	-	-	250	-	4,680
Rest of Europe	361	114	140	531	415	190	-	1,750
Latin America	17	445	897	600	-	54	-	2,014
USA & Canada	59	2	97	46	-	39	1	245
Middle East, Asia & Africa	59	4	75	472	-	(10)	-	600
Others	(38)	(6)	(41)	(3)	-	(84)	159	(14)
TOTAL EBITDA	1,208	3,850	1,559	1,646	415	439	159	9,276

<i>In millions of euros</i>	Client Solutions	Networks	Renewables	Thermal	Nuclear	Supply	Others	Dec. 31, 2019
France	959	3,537	422	-	-	294	-	5,212
Rest of Europe	578	137	151	443	192	255	-	1,757
Latin America	35	341	1,035	748	-	62	-	2,221
USA & Canada	42	1	70	32	-	63	61	269
Middle East, Asia & Africa	44	16	94	564	-	6	-	725
Others	178	(8)	(48)	(23)	-	(42)	125	182
TOTAL EBITDA	1,836	4,026	1,724	1,763	192	638	186	10,366

CURRENT OPERATING INCOME (COI) TRENDS

In millions of euros



Geography/Business Line matrix

In millions of euros	Client Solutions	Networks	Renewables	Thermal	Nuclear	Supply	Others	Dec. 31, 2020
France	363	1,610	150	-	-	106	-	2,229
Rest of Europe	131	71	87	370	(111)	100	-	648
Latin America	(3)	384	750	359	-	53	-	1,542
USA & Canada	24	2	62	43	-	(8)	1	124
Middle East, Asia & Africa	41	3	65	441	-	(32)	-	518
Others	(97)	(6)	(43)	(3)	-	(109)	(225)	(483)
TOTAL COI	459	2,063	1,070	1,209	(111)	112	(224)	4,578

In millions of euros	Client Solutions	Networks	Renewables	Thermal	Nuclear	Supply	Others	Dec. 31, 2019
France	575	1,957	182	-	-	149	-	2,862
Rest of Europe	347	96	96	293	(314)	189	-	707
Latin America	(1)	284	851	501	-	61	-	1,696
USA & Canada	8	1	47	26	-	25	49	155
Middle East, Asia & Africa	25	14	70	523	-	(13)	-	619
Others	129	(8)	(50)	(23)	-	(65)	(203)	(221)
TOTAL COI	1,082	2,344	1,195	1,320	(314)	345	(154)	5,819

2.1 France

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
Revenues	20,295	21,423	-5.3%	-6.7%
Total revenues (incl. intra-group transactions)	21,580	22,736	-5.1%	
EBITDA	4,680	5,212	-10.2%	-10.1%
Net depreciation and amortization/Other	(2,451)	(2,350)		
CURRENT OPERATING INCOME (COI)	2,229	2,862	-22.1%	-22.2%

2.1.1. France excluding Infrastructures

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
Revenues	14,856	15,854	-6.3%	-8.2%
EBITDA	1,391	1,673	-16.9%	-16.9%
Net depreciation and amortization/Other	(771)	(768)		
CURRENT OPERATING INCOME (COI)	620	905	-31.5%	-32.0%

Volumes sold

<i>In TWh</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)
Gas sales	74.4	83.2	-10.6%
Electricity sales	39.6	38.8	+2.1%

France climatic adjustment

<i>In TWh</i>	Dec. 31, 2020	Dec. 31, 2019	Total change in TWh
Climate adjustment volumes (negative figure = warm climate, positive figure = cold climate)	(6.7)	(1.9)	(4.8)

Revenues for the France excluding Infrastructures segment amounted to €14,856 million, down 6.3% on a reported basis and 8.2% on an organic basis. The organic drop was driven by Client Solutions, which was affected by the COVID-19 crisis, climate and prices, and by Supply, with negative volume and price effects on gas sales, which were impacted by warm temperatures in the first half of the year. This decrease was only partially offset by positive volume and price effects on power sales. However, 2019 year-end acquisitions in Client Solutions (in particular Powerlines and Pierre Guerin), and the good performance of Renewables partly offset the organic decrease.

Gas sale volumes in the BtoC segment decreased by 8.8 TWh compared to 2019, of which 4.8 TWh related to a negative temperature effect and the remaining decrease due to the end of the commercialization of regulated tariff contracts. The BtoC power portfolio recorded a sales increase of +0.9 TWh in line with growth in the client portfolio. Power volumes sold by France Renewables also increased by +0.1 TWh.

Current operating income came in at €620 million, down 31.5% on a reported basis and 32.0% on an organic basis. The organic decrease was driven by the COVID-19 crisis, lower sell down margins in Renewables, and a warm temperature effect in the Supply and Client Solutions businesses. These decreases were partly offset by higher wind and higher hydro prices.

2.1.2. France Infrastructures

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
Revenues	5,439	5,569	-2.3%	-2.4%
Total revenues (incl. intra-group transactions)	6,359	6,548	-2.9%	
EBITDA	3,290	3,539	-7.0%	-7.0%
Net depreciation and amortization/Other	(1,681)	(1,582)		
CURRENT OPERATING INCOME (COI)	1,609	1,957	-17.8%	-17.8%

Revenues for the France Infrastructures segment amounted to €5,439 million, down 2.3% on a reported basis. The decrease was driven by distribution activities, which were mainly impacted by record high winter temperatures, the adverse impact of the COVID-19 crisis on volumes and civil works revenues, as well as by lower revenues in storage activities impacted by the new ATS2 tariff since April 1 in France. These adverse impacts were partly offset by tariff changes in transmission and distribution activities in 2019 and 2020, and by higher volumes in regasification.

Current operating income for the period came in at €1,609 million, down 17.8% on a reported basis. Besides the decrease in revenues mentioned above, the change in Infrastructures COI was impacted by accelerated amortization in distribution and 2019 year-end positive one-offs. These adverse impacts were partly offset by lower energy expenses.

2.2 Rest of Europe

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
Revenues	15,655	17,267	-9.3%	-8.2%
EBITDA	1,750	1,757	-0.4%	-0.5%
Net depreciation and amortization/Other	(1,102)	(1,050)		
CURRENT OPERATING INCOME (COI)	648	707	-8.3%	-9.9%

Revenues for the Rest of Europe segment amounted to €15,655 million, down 9.3% on a reported basis. This decrease was mainly driven by Supply, Client Solutions and Thermal. Taking into account the negative impact arising from the disposal of the BtoC supply business in the United Kingdom at the beginning of the year and of coal assets in Germany and in the Netherlands, revenues were down organically by 8.2%.

Supply activities decreased organically, impacted by the negative volume effects due to unfavorable climatic conditions and lower consumption related to the COVID-19 crisis. Client Solutions' asset-light activities were significantly affected by the business contraction resulting from the COVID-19 crisis, in particular during the first half of the year, with the main impacts being felt in Belgium and the United Kingdom.

Current operating income amounted to €648 million. The reported decrease of €59 million was mainly driven by Client Solutions and Supply, partly offset by Nuclear and Thermal activities.

Client Solutions reported a significant decrease in the contribution from asset-light activities notably in the UK, Benelux and Italy, mainly as a result of the COVID-19 crisis. **Supply** activities were negatively impacted by the warm climate and the impact of the COVID-19 crisis which entailed a drop in consumption by BtoB and BtoC professionals clients, partly offset by a better performance by Supply in Romania. The **Networks'** contribution decreased in Romania with the negative climate effect, the impact of the COVID-19 crisis on volumes and a reduction in the distribution tariff. On the other hand, **Nuclear** activities benefited from a higher energy margin – mainly thanks to a positive price effect and a higher contribution from French Nuke, partly offset by lower volumes due to planned lifetime extension outages of Doel 1 and Doel 2 – , and from lower operating expenses, these impacts being partly offset by higher depreciation and amortization. **Thermal** activities were also up compared to 2019, despite the disposal of coal activities in 2019, thanks to a good performance in Italy and to higher spreads and ancillaries. **Renewable** activities also recorded good performances mainly driven by the contribution from the Renvico wind portfolio in Italy acquired at the beginning of the year.

2.3 Latin America

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
Revenues	4,774	5,341	-10.6%	+4.4%
EBITDA	2,014	2,221	-9.3%	+2.8%
Net depreciation and amortization/Other	(472)	(525)		
CURRENT OPERATING INCOME (COI)	1,542	1,696	-9.0%	+2.9%

Revenues for the Latin America segment totaled €4,774 million, down 10.6% on a reported basis and up +4.4% organically. The reported decrease includes the negative foreign exchange effects in Brazil with the Brazilian Real depreciating against the Euro by 29%, and negative foreign exchange effects in the rest of Latin America (depreciation of the USD, ARS and MXN). In Brazil, revenues grew organically thanks to the construction ramp up of the Gralha Azul and Novo Estado Power Transmission Lines (Networks) and thanks to Pampa Sul's first full year of operation (Thermal). In Latin America, revenues increased organically, mainly due to lower activity following the impact of the COVID-19 crisis in Thermal and in Asset Light services in all countries. Revenues were also negatively impacted by lower commodities prices in Thermal in Chile, lower PPA prices in Peru and lower prices in BtoB gas supply (with no impact on COI) in Mexico.

Current operating income totaled €1,542 million, down 9.0% on a reported basis and up 2.9% on an organic basis. The reported decrease includes the strong negative foreign exchange impact in Brazil and to a lesser extent in Latin America, partially offset by the positive scope impact of the acquisition of our gas transportation network in Brazil (TAG) in June 2019. Organically, Brazil reported a significant increase (+28.9%), mainly thanks to Renewables with the contribution of the "GFOM" compensation gain (compensation for hydro generation relocation costs), and Networks, which benefited from a better performance by TAG and from the construction margin on Power Transmission Lines. Thermal was relatively stable in Brazil, 2019 one-offs (Pampa Sul Liquidated Damages) being offset by higher coal generation and Pampa Sul (first full year of operation). Besides Brazil, the organic decrease was mainly due to Chile, with a positive one-off in 2019 (IEM plant delay Liquidated Damages) offsetting higher 2020 volumes, to lower power demand and PPA prices in Peru, and to lower gas volumes distributed in Argentina and Mexico

2.4 USA & Canada

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
Revenues	4,229	4,457	-5.1%	-6.2%
EBITDA	245	269	-8.8%	+2.8%
Net depreciation and amortization/Other	(121)	(113)		
CURRENT OPERATING INCOME (COI)	124	155	-20.3%	-6.3%

Revenues for the USA & Canada segment reached €4,229 million, down 5.1% on a reported basis and 6.2% organically. The reported decrease was mainly driven by the expiration of a legacy LNG contract in 2019, the COVID-19 crisis impacting Client Solutions and Supply activities, and negative foreign exchange effects. This drop was partly offset by higher revenues from US universities and Renewable projects which are accelerating and by the positive scope-in effects in 2020 relating to recent acquisitions in Client Solutions, in particular Conti.

Current operating income amounted to €124 million, down 20.3% on a reported basis and 6.3% on an organic basis. The reported decrease was mainly due to the impact of the COVID-19 crisis, in particular in Supply activities and the end of the LNG contract mentioned above. These effects were partly offset by the contributions of several Renewables projects commissioned since last year, net of the 2019 DBSO disposal and an improvement in Thermal activities.

2.5 Middle East, Asia & Africa

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
Revenues	2,382	2,937	-18.9%	-8.6%
EBITDA	600	725	-17.2%	-3.0%
Net depreciation and amortization/Other	(82)	(106)		
CURRENT OPERATING INCOME (COI)	518	619	-16.4%	+0.2%

Revenues for the Middle East, Africa & Asia segment totaled €2,382 million, down 18.9% on a reported basis and 8.6% organically. This reported decrease was mainly due to the disposal of Glow (Thailand) in March 2019, negative foreign exchange effects, and an organic decrease. Organically, Thermal decreased mainly due to the mothballing of the Baymina power plant in Turkey and price effects in Asia-Pacific. Client Solutions and Supply were both impacted by the COVID-19 crisis in Australia in addition to mild weather negatively affecting Supply.

Electricity sales decreased from 16.6 TWh to 14.7 TWh with the reduced volumes mostly due to the mothballing of Baymina power plant.

Current operating income totaled €518 million, down 16.4% on a reported basis and up 0.2% organically. The reported decrease included the negative impact of the disposal of Glow. COI remained stable organically thanks to Client Solutions (especially Tabreed, district heating and cooling supplier in the Middle East). This positive effect was offset by Supply activities in Africa and Australia (facing the COVID-19 crisis) and lower results in Networks in Thailand in relation to the oil price decrease. The stable overall performance of Thermal activities, with a downturn in Asia-Pacific, mainly at Pelican Point (lower prices and provisions), was fully offset by the good performance of our Gulf thermal portfolio in the Middle East.

2.6 Others

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)	% change (organic basis)
Revenues	8,417	8,633	-2.5%	-2.7%
EBITDA	(14)	182	-107.5%	-107.2%
Net depreciation and amortization/Other	(469)	(404)		
CURRENT OPERATING INCOME/(LOSS) (COI)	(483)	(221)	-118.4%	-78.2%

The Others reportable segment includes (i) GEM, (ii) Entreprises & Collectivités (E&C) (iii) Tractebel, (iv) GTT, (v) new businesses, as well as (vi) the Group's holding and corporate activities, which include the entities centralizing the Group's financing requirements and the contribution of SUEZ (until early October 2020) and Touat B.V. (associates).

Revenues for the Others reportable segment amounted to €8,417 million. The 2.5% reported decrease compared to last year was mainly driven by GEM with the reduction in gas prices in market operations as well as the positive one-off in 2019 following the partial sale of a gas supply contract to Shell. Lower sales in E&C due to the COVID-19 crisis and to a mild climate were offset to a large extent by the growth of the portfolio. These impacts were partly offset by higher revenues from GTT resulting from historic growth in the order book intake.

Current operating loss amounted to €483 million, representing a €262 million decrease compared to 2019. This decrease was mainly due the COVID-19 crisis impacting SUEZ and E&C, which was also impacted by a mild climate. GEM was impacted by the COVID-19 crisis, the impact being partly offset by the strong performance of market activities in the context of sharp volatility during the year (mainly in the first half). COI was also down for New Businesses and Tractebel. These negative impacts were partly offset by a stronger contribution from GTT.

3 OTHER INCOME STATEMENT ITEMS

The reconciliation between Current operating income (COI) and Net income/(loss) is presented below:

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	% change (reported basis)
CURRENT OPERATING INCOME (COI)	4,578	5,819	-21.3%
(+) Mark-to-Market on commodity contracts other than trading instruments	199	(426)	
(+) Non-recurring share in net income of equity method entities	(137)	(93)	
Current operating income including operating MtM and share in net income of equity method entities	4,640	5,300	-12.4%
Impairment losses	(3,551)	(1,770)	
Restructuring costs	(343)	(218)	
Changes in scope of consolidation	1,640	1,604	
Other non-recurring items	(886)	(1,240)	
Income/(loss) from operating activities	1,501	3,676	-59.2%
Net financial income/(loss)	(1,678)	(1,387)	
Income tax benefit/(expense)	(715)	(640)	
NET INCOME/(LOSS)	(893)	1,649	-154.1%
Net recurring income/(loss) Group share	1,703	2,683	
Net income/(loss) Group share	(1,536)	984	
Non-controlling interests	644	664	

The reconciliation between Net recurring income/(loss) Group share and Net income/(loss) Group share is presented below:

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Net recurring income/(loss) Group share	1,703	2,683
Impairment & Others	(4,736)	(2,659)
Restructuring costs	(343)	(218)
Changes in scope of consolidation	1,640	1,604
Mark-to-Market on commodity contracts other than trading instruments	199	(426)
Net income/(loss) Group share	(1,536)	984

Income from operating activities amounted to €1,501 million, representing a decrease compared with 2019, mainly due to (i) greater impairment losses, (ii) a deterioration in operating income, (iii) partially offset by lower other non-recurring items.

Income from operating activities was affected by:

- net impairment losses of €3,551 million (compared with €1,770 million in 2019), mainly relating to Belgian nuclear power assets (€2,860 million) due to the operating life of certain power plants not being extended beyond 2025 and updated price scenarios (see Note 9.1);
- restructuring costs of €343 million (compared with €218 million in 2019) (see Note 9.2);
- positive scope effects of €1,640 million, mainly relating to the disposal of 29.9% of ENGIE's interest in SUEZ (see Note 9.3);
- other non-recurring items for a negative €886 million, mainly relating to the initial one-off accounting impact of extending the trading management method launched by the GEM BU in 2017 to the rest of the Group's gas positions in Europe for a negative €726 million, as well as to the impacts of the review of the industrial site dismantling and rehabilitation provisions (see Note 9.4).

The **net financial loss** amounted to €1,678 million in 2020, compared with €1,387 million the previous year (see Note 10) despite a stable average cost of gross debt, due to a lower return on cash and unfavorable exchange rate effects.

The **income tax expense** for 2020 amounted to €715 million (versus €640 million in 2019). Adjusted for non-recurring items, the effective recurring tax rate was 32.5% in 2020, up on the 2019 rate of 28.2% mainly due to the revision of certain deferred tax positions following the updates to taxable income forecasts and regulatory developments in certain geographies. The overall effective tax rate decreased sharply in 2020 (a negative 98.1% versus a positive 35.8% in 2019), also impacted by the non-deductibility of most of the impairment losses recorded over the period and changes in tax risk provisions.

Net recurring income Group share amounted to €1.7 billion compared to €2.7 billion at 31 December 2019. This decrease was mainly due to the decline in current operating income and the increase of recurring financial charges as well as to the increase in the recurring effective tax rate from 28.2% to 32.5%.

Net income Group share amounted to a negative €1.5 billion, down €2.5 billion as a result of the decrease in net recurring income Group share, higher net impairment losses (of €3.6 billion in total) mainly relating to change in lifetime assumption for Belgian nuclear reactors and changes in the commodity price scenario for nuclear assets (€2.9 billion), and the extension of fair value accounting to an European gas contract and its related assets (€0.5 billion).

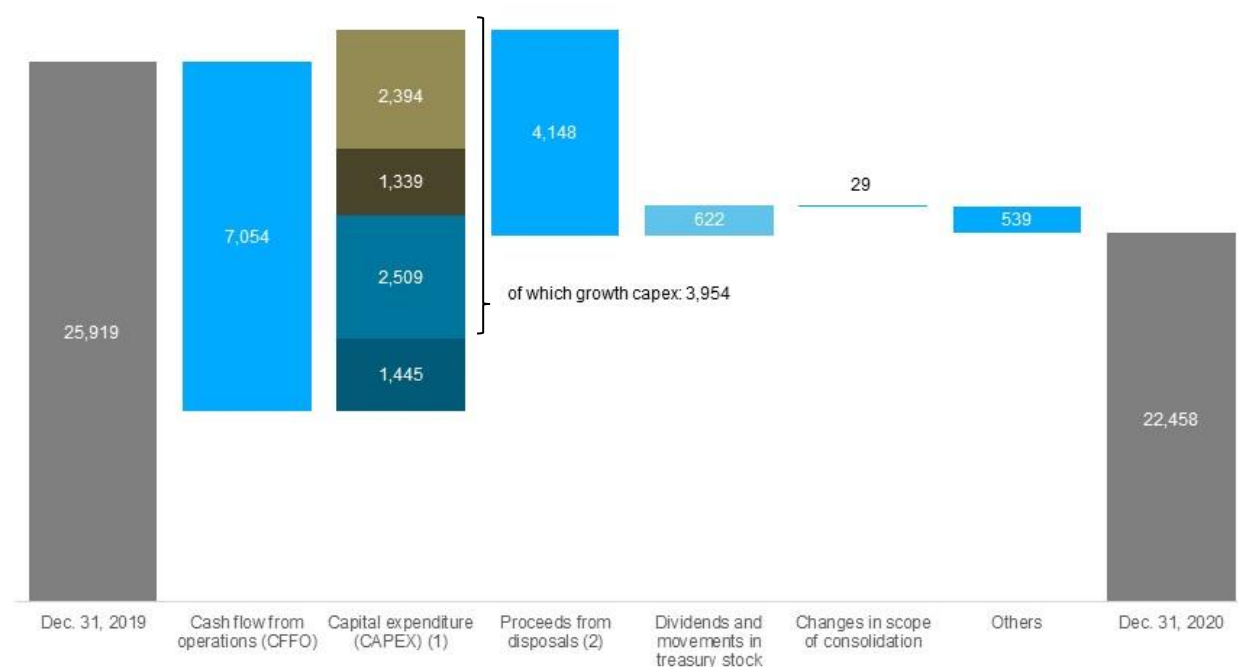
Net income relating non-controlling interests amounted to €644 million, (compared to €664 million in 2019) despite the sharp decrease in net income Group share, due to the relatively good performance of companies with non-controlling interests, particularly in South America.

4 CHANGES IN NET FINANCIAL DEBT

Net financial debt stood at €22.5 billion, down €3.5 billion compared with December 31, 2019. This decrease is mainly attributable to (i) cash flow from operations (€7.1 billion), (ii) the impacts of disposals during the period (€4.2 billion, primarily corresponding to the sale of part of the Group's interest in SUEZ SA for €3.4 billion, and of interests in Astoria 1 and 2 in the United States for €0.4 billion) and (iii) other items (€0.5 billion, mainly related to foreign exchange rates, partially offset by new leased right-of-use assets). These items were partially offset by (i) capital expenditure over the period (€7.7 billion⁽¹⁾), and (ii) dividends paid to non-controlling interests and movements in treasury stock (€0.6 billion). In 2020, ENGIE's dividend payment for the 2019 financial year (i.e. €1.9 billion) was cancelled.

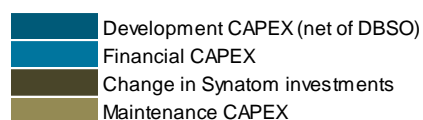
Changes in net financial debt break down as follows:

In millions of euros



(1) Capital expenditure net of DBSO proceeds.

(2) Excluding DBSO proceeds.



At the end of December 2020, the net financial debt to EBITDA ratio amounted to 2.42, decreasing by 0.1x compared to the end of 2019. The average cost of gross debt was 2.38%, down 32bps compared to the end of 2019. This decrease is mainly explained by the positive effect induced by the deterioration of the exchange rate in Brazil and the lower debt

(1) Net of DBSO proceeds.

exposure in India, having led to a positive mix effect: the share of average centralised debt, which has a lower rate than the local debts, in the total average debt has increased.

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Net financial debt	22,458	25,919
EBITDA	9,276	10,366
NET DEBT/EBITDA RATIO	2.42	2.50

At the end of December 2020, the net economic debt ⁽¹⁾ to EBITDA ratio stood at 4.03, stable compared to the end of 2019.

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Economic net debt	37,420	41,078
EBITDA	9,276	10,366
ECONOMIC NET DEBT/EBITDA RATIO	4.03	3.96

4.1 Cash flow from operations (CFFO)

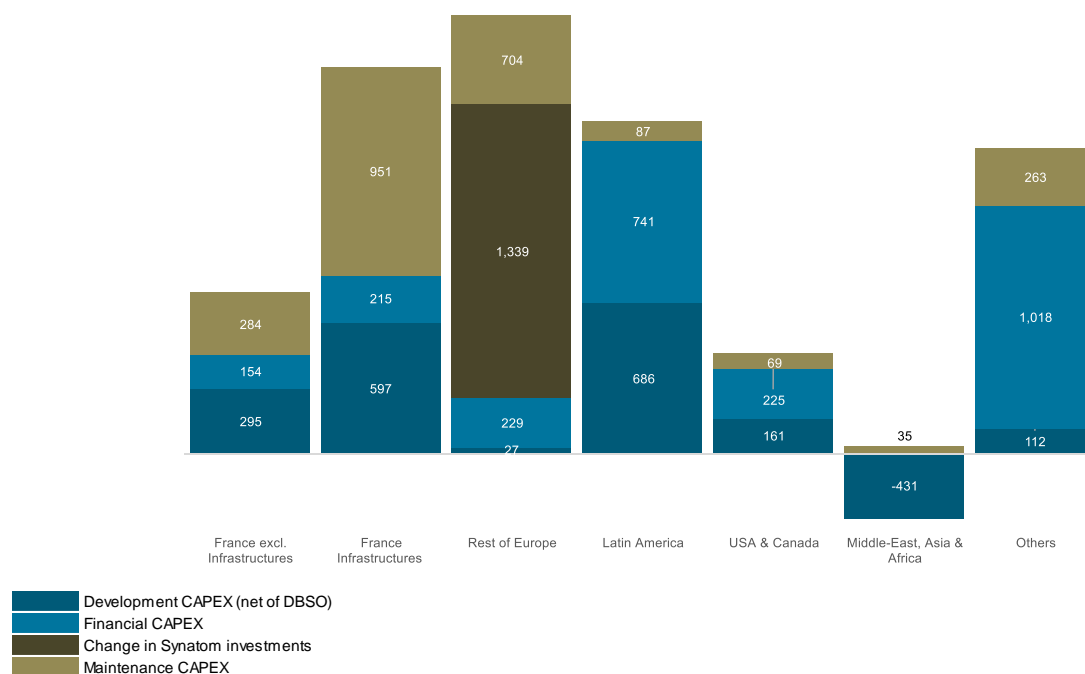
Cash flow from operations amounted to €7.1 billion, down €0.5 billion. This evolution resulted from the €-1.1 billion decrease in operating cash flow, partly offset by a positive variation in change in working capital requirements of €0.5 billion and by slightly lower net interests and tax paid. The positive variation in working capital requirements was mainly due to the variance in commodity related margin calls and financial derivatives for €0.9 billion, partly offset by a €-0.4 billion deterioration in operating working capital change notably due to an increase in Supply inventory partly compensated by a decrease in receivables.

(1) Economic net debt amounted to €37.4 billion at the end of December 2020, down €3.7 billion compared with the level at end of December 2019; it includes, in particular, nuclear provisions and post-employment benefits.

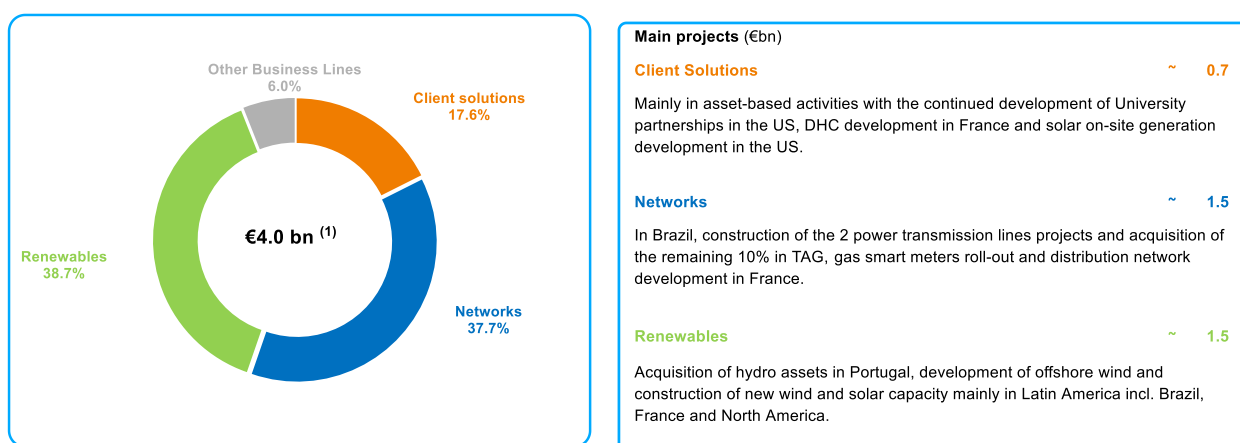
4.2 Net investments

Capital expenditure (CAPEX) amounted to €7,687 million, breaking down as follows by segment.

In millions of euros



Growth capital expenditure amounted to €4,0 billion, breaking down as follows by Business Line. Over 90% of growth investment was dedicated to Renewables, Networks and Asset-based Client Solutions activities in line with the new strategic direction announced in July.



(1) Net of disposals under DBSO operations, excluding Corporate, and Synatom reallocated to maintenance expenditure.

The **geography/Business Line matrix** for capital expenditure is presented hereunder:

<i>In millions of euros</i>	Client Solutions	Networks	Renewables	Thermal	Nuclear	Supply	Others	Dec. 31, 2020
France	384	1,743	247	-	-	123	-	2,496
Rest of Europe	178	83	75	118	1,740	104	-	2,298
Latin America	23	672	649	166	-	4	-	1,514
USA & Canada	268	-	137	1	-	49	-	455
Middle East, Asia & Africa	25	4	(452)	(99)	-	51	-	(470)
Others	112	-	980	1	-	27	272	1,393
TOTAL CAPEX	992	2,502	1,637	187	1,740	357	272	7,687

<i>In millions of euros</i>	Client Solutions	Networks	Renewables	Thermal	Nuclear	Supply	Others	Dec. 31, 2019
France	423	1,709	481	-	-	151	-	2,764
Rest of Europe	416	77	35	174	636	95	-	1,433
Latin America	46	1,651	541	254	-	7	-	2,499
USA & Canada	301	1	968	8	-	73	-	1,351
Middle East, Asia & Africa	80	9	267	-	-	93	-	449
Others	355	-	183	81	-	38	889	1,547
TOTAL CAPEX	1,621	3,446	2,475	517	636	458	889	10,042

Net investments amounted to €4,093 million and include:

- growth capital expenditure for €3,954 million (see above);
- gross maintenance capital expenditure amounting to €2,394 million;
- the €1,339 million increase in Synatom investments;
- new leased right-of-use assets recognized over the period (€584 million);
- changes in the scope of consolidation for the period relating to acquisitions and disposals of subsidiaries for €29 million; and
- proceeds from disposals representing an inflow of €4,148 million, mainly relating to the disposal of part of the Group's interest in SUEZ SA and of its interests in Astoria 1 and 2 in the United States.

4.3 Dividends and movements in treasury stock

Dividends and movements in treasury stock during the period amounted to €622 million (versus €2,522 million in 2019). This change is explained in particular by the cancellation of ENGIE's dividend payment for the 2019 fiscal year for €1.9 billion. Dividends and movements in treasury stock in 2020 include dividends paid by various subsidiaries to their non-controlling interests in an amount of €425 million and the payment of interest on hybrid debt for €187 million.

4.4 Net financial debt at December 31, 2020

Excluding amortized cost but including the impact of foreign currency derivatives, at December 31, 2020 a total of 81% of net financial debt was denominated in euros, 12% in US dollars and 9% in Brazilian real.

Including the impact of financial instruments, 98% of net financial debt is at fixed rates.

The average maturity of the Group's net financial debt is 12.0 years.

At December 31, 2020, the Group had total undrawn confirmed credit lines of €13.7 billion.

5 OTHER ITEMS IN THE STATEMENT OF FINANCIAL POSITION

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	Net change
Non-current assets	93,095	99,297	(6,201)
Of which goodwill	15,943	18,665	(2,722)
Of which property, plant and equipment and intangible assets, net	57,085	58,996	(1,911)
Of which investments in equity method entities	6,760	9,216	(2,456)
Current assets	60,087	60,496	(409)
Of which assets classified as held for sale	1,292	468	823
Total equity	33,856	38,037	(4,181)
Provisions	27,073	25,115	1,958
Borrowings	37,939	38,544	(606)
Other liabilities	54,315	58,097	(3,781)
Of which liabilities directly associated with assets classified as held for sale	488	92	396

The carrying amount of **property, plant and equipment and intangible assets** was €57.1 billion, down €1.9 billion compared with December 31, 2019. This decrease was primarily the result of depreciation and amortization charges (€4.6 billion negative impact), translation adjustments (€2.2 billion negative impact, primarily attributed to the strong depreciation of the Brazilian real and the US dollar), impairment losses (€1.3 billion negative impact, primarily attributed to Belgian nuclear power assets), and the classification of renewable energy assets in India under “Assets classified as held for sale” (€0.6 billion negative impact), partially offset by acquisitions and development capital expenditure (€7.0 billion positive impact).

Goodwill decreased by €2.7 billion to €15.9 billion, mainly due to the recognition of impairment losses on Belgian nuclear power assets (see Note 13).

Investments in equity method entities decreased by €2.5 billion, primarily due to the disposal of a 29.9% stake in SUEZ.

Total equity amounted to €33.9 billion, a decrease of €4.2 billion compared with December 31, 2019. The decrease stemmed mainly from other comprehensive income (€3.0 billion negative impact, including a negative €2.1 billion of translation adjustments primarily attributed to the strong depreciation of the Brazilian real, a negative €1.6 billion of actuarial gains and losses, and a negative €0.4 billion corresponding to a decrease in the share of equity method entities in recyclable items, net of tax) and from net income for the period (€0.9 billion negative impact).

Provisions increased by €2.0 billion compared with December 31, 2019 to €27.1 billion. This increase stemmed mainly from actuarial losses on provisions for post-employment benefits and other long-term benefits (which added €1.5 billion to the provision amount) owing to the fall in discount rates over the period (see Note 20).

At December 31, 2020, assets and liabilities classified under “**Assets classified as held for sale**” and “**Liabilities directly associated with assets classified as held for sale**” mainly comprised renewable energy assets in India and Mexico and the Group’s interest in EV Charged BV (EVBox).

6 PARENT COMPANY FINANCIAL STATEMENTS

The figures provided below relate to the financial statements of ENGIE SA, prepared in accordance with French GAAP and applicable regulations.

Revenues for ENGIE SA in 2020 totaled €19,272 million, an increase compared to 2019 (€17,282 million), both on the gas and electricity markets.

The net operating loss amounted to €1,640 million in 2020, a deterioration of €709 million compared with a loss of €931 million in 2019. Energy margin increased by €205 million, thanks to lower supply costs and continued growth in the electricity business.

Net financial income amounted to €1,440 million, an increase of €248 million compared to 2019 due to higher dividends received and a decrease in the cost of net debt.

Non-recurring items represented a loss of €4,260 million, mainly comprising impairment of equity investments of which €5,186 million in impairment losses on Electrabel shares given the non-extension of the nuclear power plants in Belgium assumption of and unfavorable foreign exchange impact.

The income tax benefit amounted to €532 million versus an income tax benefit of €377 million in 2019, including a tax consolidation benefit of €461 million.

The net loss for the year came out at €3,928 million.

Shareholders' equity amounted to €30,702 million at end-2020 compared with €34,594 million at end-2019. The €3,892 million decrease was mainly due to the 2020 net loss of €3,928 million, since no dividend payment was made during the period.

At December 31, 2020, borrowings and debt stood at €38,158 million, and cash and cash equivalents totaled €11,615 million (of which €8,135 million relating to subsidiaries' current accounts).

Information relating to payment terms

Pursuant to Article D.441-4 of the French Commercial Code, companies whose annual financial statements are subject to a statutory audit must publish information regarding supplier and customer payment terms. The purpose is to demonstrate that there is no significant failure to comply with such terms.

Information relating to supplier and customer payment terms mentioned in Article D.441-4 of the French Commercial Code

	Article D. 441 I.- 1°: Invoices received, unpaid and overdue at the reporting date						Article D. 441 I.- 2°: Invoices issued, unpaid and overdue at the reporting date					
	0 days (indicative)	1 to 30 days	31 to 60 days	61 to 90 days	91 days or more	Total (1 day or more)	0 days (indicative)	1 to 30 days	31 to 60 days	61 to 90 days	91 days or more	Total (1 day or more)
<i>In millions of euros</i>												
(A) By aging category												
Number of invoices	-					24,855	-					5,865,476
Aggregate invoice amount (incl. VAT)	-	22.9	0.5	0.1	107.3	130.9	-	412.0	36.8	29.9	575.8	1,045.5
Percentage of total amount of purchases (incl. VAT) for the period	-	0.10%	0.00%	0.00%	0.46%	0.57%						
Percentage of total revenues (incl. VAT) for the period							-	1.81%	0.16%	0.13%	2.53%	4.64%
(B) Invoices excluded from (A) relating to disputed or unrecognized receivables and payables												
Number of excluded invoices			180						1,316			
Aggregate amount of excluded invoices			5.4						57.6			
(C) Standard payment terms used (contractual or legal terms - Article L. 441-6 or Article L. 443-1 of the French Commercial Code)												
Payment terms used to calculate late payments	Legal payment terms: 30 days						Contractual payment terms: 14 days Legal payment terms: 30 days					

02 CONSOLIDATED FINANCIAL STATEMENTS

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INCOME STATEMENT

<i>In millions of euros</i>	Notes	Dec. 31, 2020	Dec. 31, 2019
REVENUES	6.2 & 7	55,751	60,058
Purchases and operating derivatives	8.1	(34,967)	(39,404)
Personnel costs	8.2	(11,759)	(11,478)
Depreciation, amortization and provisions	8.3	(4,778)	(4,393)
Taxes		(1,265)	(1,654)
Other operating income		1,105	1,670
Current operating income including operating MtM		4,087	4,800
Share in net income of equity method entities	6.2	552	500
Current operating income including operating MtM and share in net income of equity method entities		4,640	5,300
Impairment losses	9.1	(3,551)	(1,770)
Restructuring costs	9.2	(343)	(218)
Changes in scope of consolidation	9.3	1,640	1,604
Other non-recurring items	9.4	(886)	(1,240)
INCOME/(LOSS) FROM OPERATING ACTIVITIES	9	1,501	3,676
Financial expenses		(2,232)	(2,300)
Financial income		553	913
NET FINANCIAL INCOME/(LOSS)	10	(1,678)	(1,387)
Income tax benefit/(expense)	11	(715)	(640)
NET INCOME/(LOSS)		(893)	1,649
Net income/(loss) Group share		(1,536)	984
Non-controlling interests		644	664
BASIC EARNINGS/(LOSS) PER SHARE (EUROS)	12	(0.71)	0.34
DILUTED EARNINGS/(LOSS) PER SHARE (EUROS)	12	(0.71)	0.34

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

STATEMENT OF COMPREHENSIVE INCOME

<i>In millions of euros</i>	Notes	Dec. 31, 2020	Dec. 31, 2019
NET INCOME/(LOSS)		(893)	1,649
Debt instruments	16.1	(46)	48
Net investment hedges	17	128	29
Cash flow hedges (excl. commodity instruments)	17	(249)	(229)
Commodity cash flow hedges	17	872	(744)
Deferred tax on items above		(137)	240
Share of equity method entities in recyclable items, net of tax		(387)	(250)
Translation adjustments		(2,098)	(45)
TOTAL RECYCLABLE ITEMS		(1,916)	(953)
Equity instruments	16.1	43	103
Actuarial gains and losses		(1,569)	(1,128)
Deferred tax on items above		377	255
Share of equity method entities in actuarial gains and losses, net of tax		75	(31)
TOTAL NON-RECYCLABLE ITEMS		(1,073)	(801)
TOTAL RECYCLABLE ITEMS AND NON-RECYCLABLE ITEMS		(2,990)	(1,754)
TOTAL COMPREHENSIVE INCOME/(LOSS)		(3,882)	(105)
<i>Of which owners of the parent</i>		<i>(4,046)</i>	<i>(660)</i>
<i>Of which non-controlling interests</i>		<i>163</i>	<i>555</i>

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

STATEMENT OF FINANCIAL POSITION

ASSETS

<i>In millions of euros</i>	Notes	Dec. 31, 2020	Dec. 31, 2019
Non-current assets			
Goodwill	13	15,943	18,665
Intangible assets, net	14	7,196	7,038
Property, plant and equipment, net	15	49,889	51,958
Other financial assets	16	9,009	7,022
Derivative instruments	16	2,996	4,137
Assets from contracts with customers	7	26	15
Investments in equity method entities	3	6,760	9,216
Other non-current assets	24	396	384
Deferred tax assets	11	880	860
TOTAL NON-CURRENT ASSETS		93,095	99,297
Current assets			
Other financial assets	16	2,583	2,546
Derivative instruments	16	8,069	10,134
Trade and other receivables, net	7	14,295	15,180
Assets from contracts with customers	7	7,738	7,816
Inventories	24	4,140	3,617
Other current assets	24	8,990	10,216
Cash and cash equivalents	16	12,980	10,519
Assets classified as held for sale	4.2	1,292	468
TOTAL CURRENT ASSETS		60,087	60,496
TOTAL ASSETS		153,182	159,793

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

LIABILITIES

<i>In millions of euros</i>	Notes	Dec. 31, 2020	Dec. 31, 2019
Shareholders' equity		28,945	33,087
Non-controlling interests	2	4,911	4,950
TOTAL EQUITY	18	33,856	38,037
Non-current liabilities			
Provisions	19	24,876	22,817
Long-term borrowings	16	30,092	30,002
Derivative instruments	16	3,789	5,129
Other financial liabilities	16	77	38
Liabilities from contracts with customers	7	39	45
Other non-current liabilities	24	2,004	1,222
Deferred tax liabilities	11	4,416	4,631
TOTAL NON-CURRENT LIABILITIES		65,293	63,882
Current liabilities			
Provisions	19	2,197	2,298
Short-term borrowings	16	7,846	8,543
Derivative instruments	16	9,336	10,446
Trade and other payables	16	17,307	19,109
Liabilities from contracts with customers	7	4,315	4,286
Other current liabilities	24	12,545	13,101
Liabilities directly associated with assets classified as held for sale	4.2	488	92
TOTAL CURRENT LIABILITIES		54,034	57,874
TOTAL EQUITY AND LIABILITIES		153,182	159,793

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

STATEMENT OF CHANGES IN EQUITY

<i>In millions of euros</i>	Share capital	Additional paid-in capital	Consolidated reserves	Deeply-subordinated perpetual notes	Changes in fair value and other	Translation adjustments	Treasury stock	Shareholders' equity	Non-controlling interests	Total
EQUITY AT DECEMBER 31, 2018 ⁽¹⁾	2,435	32,565	(590)	3,750	(1,019)	(1,130)	(460)	35,551	5,391	40,941
Normative changes ⁽²⁾	-	-	(7)	-	-	-	-	(7)	(4)	(11)
EQUITY AT JANUARY 1, 2019	2,435	32,565	(597)	3,750	(1,019)	(1,130)	(460)	35,544	5,386	40,930
Net income/(loss)			984					984	664	1,649
Other comprehensive income/(loss)			(735)		(942)	32		(1,645)	(109)	(1,754)
TOTAL COMPREHENSIVE INCOME/(LOSS)			250		(942)	32		(660)	555	(105)
Share-based payment	-	-	50					50	-	50
Dividends paid in cash ⁽³⁾		(1,096)	(738)					(1,833)	(453)	(2,286)
Purchase/disposal of treasury stock			(157)				157	-	-	-
Operations on deeply-subordinated perpetual notes ⁽³⁾			(172)	163				(9)		(9)
Transactions between owners			36					36	4	40
Transactions with impact on non-controlling interests ⁽⁴⁾			-					-	(515)	(515)
Share capital increases and decreases								-	(28)	(28)
Normative changes ⁽⁵⁾			(35)					(35)		(35)
Other changes			(6)		-			(6)	1	(5)
EQUITY AT DECEMBER 31, 2019	2,435	31,470	(1,369)	3,913	(1,961)	(1,098)	(303)	33,087	4,950	38,037

(1) Published data at December 31, 2018 were not restated due to the transition method used for the application of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements" to the consolidated financial statements for the year ended December 31, 2019).

(2) Normative changes related to the impact of IFRS 16 (see Note 1 "Accounting framework and basis for preparing the consolidated financial statements" to the consolidated financial statements for the year ended December 31, 2019).

(3) Transactions of the period are listed in Note 18 "Equity".

(4) Mainly relates to the deconsolidation of GLOW following its disposal (see Note 4.1 "Disposals carried out in 2019" to the consolidated financial statements for the year ended December 31, 2019).

(5) Normative changes related to the application of IFRIC23 at SUEZ.

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

<i>In millions of euros</i>	Share capital	Additional paid-in capital	Consolidated reserves	Deeply-subordinated perpetual notes	Changes in fair value and other	Translation adjustments	Treasury stock	Shareholders' equity	Non-controlling interests	Total
EQUITY AT DECEMBER 31, 2019	2,435	31,470	(1,369)	3,913	(1,961)	(1,098)	(303)	33,087	4,950	38,037
Net income/(loss)			(1,536)					(1,536)	644	(893)
Other comprehensive income/(loss)			(999)		242	(1,752)		(2,509)	(480)	(2,990)
TOTAL COMPREHENSIVE INCOME/(LOSS)			(2,535)	-	242	(1,752)	-	(4,046)	163	(3,882)
Share-based payment			52					52	2	54
Dividends paid in cash ⁽¹⁾		-	-					-	(425)	(425)
Purchase/disposal of treasury stock			(52)				52	-	-	-
Operations on deeply-subordinated perpetual notes ⁽²⁾			(193)					(193)	-	(193)
Transactions between owners			25					25	35	59
Transactions with impact on non-controlling interests			-					-	7	7
Share capital increases and decreases								-	178	178
Other changes		(178)	199					21	1	21
EQUITY AT DECEMBER 31, 2020	2,435	31,291	(3,874)	3,913	(1,719)	(2,850)	(251)	28,945	4,911	33,856

(1) The Shareholders' Meeting of May 14, 2020 approved the resolution relating to the cancellation of the dividend payment in respect of 2019 proposed by the Group in the current context of the COVID-19 crisis (see Note 17.3 "Liquidity risk").

(2) Transactions of the period are listed in Note 18 "Equity".

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

STATEMENT OF CASH FLOWS

In millions of euros	Notes	Dec. 31, 2020	Dec. 31, 2019
NET INCOME/(LOSS)		(893)	1,649
- Share in net income of equity method entities		(552)	(500)
+ Dividends received from equity method entities		740	773
- Net depreciation, amortization, impairment and provisions		8,760	7,083
- Impact of changes in scope of consolidation and other non-recurring items		(1,573)	(1,579)
- Mark-to-market on commodity contracts other than trading instruments		(199)	426
- Other items with no cash impact		111	(18)
- Income tax expense	11	715	640
- Net financial income/(loss)	10	1,678	1,387
Cash generated from operations before income tax and working capital requirements		8,788	9,863
+ Tax paid		(599)	(575)
Change in working capital requirements	24.1	(600)	(1,110)
CASH FLOW FROM OPERATING ACTIVITIES		7,589	8,178
Acquisitions of property, plant and equipment and intangible assets	14 & 15	(5,115)	(6,524)
Acquisitions of controlling interests in entities, net of cash and cash equivalents acquired	4 & 16	(417)	(864)
Acquisitions of investments in equity method entities and joint operations	4 & 16	(1,067)	(1,746)
Acquisitions of equity and debt instruments	16	(1,622)	(595)
Disposals of property, plant and equipment, and intangible assets	14 & 15	154	134
Loss of controlling interests in entities, net of cash and cash equivalents sold	4 & 16	456	2,676
Disposals of investments in equity method entities and joint operations	4 & 16	3,841	14
Disposals of equity and debt instruments	16	21	148
Interest received on financial assets		21	28
Dividends received on equity instruments		57	67
Change in loans and receivables originated by the Group and other	5.6	(374)	(532)
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES		(4,046)	(7,193)
Dividends paid ^{(1) (2)}		(622)	(2,522)
Repayment of borrowings and debt		(6,179)	(3,035)
Change in financial assets held for investment and financing purposes		(608)	(135)
Interest paid		(665)	(780)
Interest received on cash and cash equivalents		53	82
Cash flow on derivatives qualifying as net investment hedges and compensation payments on derivatives and on early buyback of borrowings		25	(114)
Increase in borrowings		7,231	6,622
Increase/decrease in capital		181	107
Purchase and/or sale of treasury stock		-	-
Changes in ownership interests in controlled entities	5.6	23	(12)
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES		(562)	212
Effects of changes in exchange rates and other		(520)	623
TOTAL CASH FLOW FOR THE PERIOD		2,461	1,819
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD		10,519	8,700
CASH AND CASH EQUIVALENTS AT END OF PERIOD		12,980	10,519

(1) The Shareholders' Meeting of May 14, 2020 approved the resolution relating to the cancellation of the dividend payment in respect of 2019 proposed by the Group in the current context of the COVID-19 crisis (see Note 17.3 "Liquidity risk").

(2) The line "Dividends paid" includes the coupons paid to owners of the deeply-subordinated perpetual notes (see Note 18 Equity).

NB: The amounts shown in the tables are expressed in millions of euros. In certain cases, rounding may cause non-material discrepancies in the totals.

03 NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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ENGIE SA, the parent company of the Group, is a French société anonyme with a Board of Directors that is subject to the provisions of Book II of the French Commercial Code (Code de Commerce), as well as to all other provisions of French law applicable to French commercial companies. It was incorporated on November 20, 2004 for a period of 99 years.

It is governed by current and future laws and by regulations applicable to *sociétés anonymes* and its bylaws.

The Group is headquartered at 1 place Samuel de Champlain, 92400 Courbevoie (France).

ENGIE shares are listed on the Paris, Brussels and Luxembourg stock exchanges.

On February 25, 2021, the Group's Board of Directors approved and authorized for issue the consolidated financial statements of the Group for the year ended December 31, 2020.

NOTE 1 ACCOUNTING FRAMEWORK AND BASIS FOR PREPARING THE CONSOLIDATED FINANCIAL STATEMENTS

1.1 Accounting standards

Pursuant to European Regulation (EU) 2019/980 dated March 14, 2019, financial information concerning the assets, liabilities, financial position, and profit and loss of ENGIE has been provided for the last two reporting periods (ended December 31, 2019 and 2020). This information was prepared in accordance with European Regulation (EC) 1606/2002 "on the application of international accounting standards" dated July 19, 2002. The Group's consolidated financial statements for the year ended December 31, 2020 have been prepared in accordance with IFRS Standards as published by the International Accounting Standards Board and endorsed by the European Union ⁽¹⁾.

The accounting standards applied in the consolidated financial statements for the year ended December 31, 2020 are consistent with the policies used to prepare the consolidated financial statements for the year ended December 31, 2019, except for those described below.

1.1.1 IFRS Standards, amendments or IFRIC Interpretations applicable in 2020

- Amendments to IFRS 3 – *Business Combinations*: Definition of a Business;
- Amendments to IAS 1 – *Presentation of Financial Statements* and IAS 8 – *Accounting Policies, Changes in Accounting Estimates and Errors*: Definition of Material;
- Amendments to IFRS 9 – *Financial Instruments*; IAS 39 – *Financial Instruments: recognition and measurement*; IFRS 7 – *Financial Instruments*: Disclosures – Interest Rate Benchmark Reform;
- Amendments to IFRS 16 – *Leases*: COVID-19-related rent concessions.

These amendments have no significant impact on the Group's consolidated financial statements.

(1) Available on the European Commission's website: <http://eur-lex.europa.eu/legal-content/FR/TXT/?uri=CELEX:02002R1606-20080410>.

1.1.2 IFRS Standards, amendments or IFRIC Interpretations effective in 2021 and that the Group has elected to early adopt

- Amendments to IFRS 9 – *Financial Instruments*; IAS 39 – *Financial Instruments*: recognition and measurement; IFRS 7 – *Financial Instruments*: Disclosures; IFRS 4 – *Insurance contracts* and IFRS 16 – *Leases*: Interest Rate Benchmark Reform (Phase 2).

These amendments relating to the interest rate benchmark reform (see *Note 17*) have no significant impact on the Group's consolidated financial statements.

1.1.3 IFRS Standards, amendments or IFRIC Interpretations effective in 2021 and that the Group has elected not to early adopt

- Amendments to IAS 1 – *Presentation of Financial Statements*: Classification of Liabilities as Current or Non-Current ⁽¹⁾
- Amendments to IAS 16 – *Property, Plant and Equipment*: Proceeds before Intended Use ⁽¹⁾;
- Amendments to IAS 37 – *Provisions, Contingent Liabilities and Contingent Assets*: Onerous Contracts – Cost of Fulfilling a Contract ⁽¹⁾;
- Annual Improvements to IFRSs 2018-2020 Cycle ⁽¹⁾;
- IFRS 17 – *Insurance Contracts* (including amendments) ⁽¹⁾.

The impact of these standards and amendments is currently being assessed.

1.2 Measurement and presentation basis

1.2.1 Historical cost convention

The Group's consolidated financial statements are presented in euros and have been prepared using the historical cost convention, except for financial instruments that are accounted for under the financial instrument categories defined by IFRS 9.

1.2.2 Chosen options

1.2.2.1 Reminder of IFRS 1 transition options

The Group used some of the options available under IFRS 1 for its transition to IFRS in 2005. The options that continue to have an impact on the consolidated financial statements are:

- translation adjustments: the Group elected to reclassify cumulative translation adjustments within consolidated equity at January 1, 2004;
- business combinations: the Group elected not to restate business combinations that took place prior to January 1, 2004 in accordance with IFRS 3.

⁽¹⁾ As these standards and amendments have not yet been adopted by the European Union, this is a free translation.

1.2.2.2 Business combinations

Business combinations carried out prior to January 1, 2010 were accounted for in accordance with IFRS 3 prior to the revision. In accordance with IFRS 3 revised, these business combinations have not been restated.

Since January 1, 2010, the Group applies the purchase method as defined in IFRS 3 revised, which consists in recognizing the identifiable assets acquired and liabilities assumed at their fair values at the acquisition date, as well as any non-controlling interests in the acquiree. Non-controlling interests are measured either at fair value or at the entity's proportionate interest in the net identifiable assets of the acquiree. The Group determines on a case-by-case basis which measurement option to be used to recognize non-controlling interests.

1.2.2.3 Consolidated statement of cash flows

The consolidated statement of cash flows is prepared using the indirect method starting from net income.

"Interest received on non-current financial assets" is classified within investing activities because it represents a return on investments. "Interest received on cash and cash equivalents" is shown as a component of financing activities because the interest can be used to reduce borrowing costs. This classification is consistent with the Group's internal organization, where debt and cash are managed centrally by the Group treasury department.

As impairment losses on current assets are considered to be definitive losses, changes in current assets are presented net of impairment.

Cash flows relating to the payment of income tax are presented on a separate line.

1.2.3 Foreign currency transactions

1.2.3.1 Translation of foreign currency transactions

Foreign currency transactions are recorded in the functional currency at the exchange rate prevailing on the date of the transaction.

Functional currency is the currency of the primary economic environment in which an entity operates, which in most cases corresponds to local currency. However, certain entities may have a functional currency different from the local currency when that other currency is used for an entity's main transactions and better reflects its economic environment.

At each reporting date:

- monetary assets and liabilities denominated in foreign currencies are translated at year-end exchange rates. The resulting translation gains and losses are recorded in the consolidated income statement for the year to which they relate;
- non-monetary assets and liabilities denominated in foreign currencies are recognized at the historical cost applicable at the date of the transaction.

1.2.3.2 Translation of the financial statements of subsidiaries with a functional currency other than the euro (the presentation currency)

The statements of financial position of these subsidiaries are translated into euros at the official year-end exchange rates. Income statement and cash flow statement items are translated using the average exchange rate for the year. Any differences arising from the translation of the financial statements of these subsidiaries are recorded under "Translation adjustments" as other comprehensive income.

Goodwill and fair value adjustments arising on the acquisition of foreign entities are classified as assets and liabilities of those foreign entities and are therefore denominated in the functional currencies of the entities and translated at the year-end exchange rate.

1.3 Use of estimates and judgments

1.3.1 Estimates

The preparation of consolidated financial statements requires the use of estimates and assumptions to determine the value of assets and liabilities and contingent assets and liabilities at the reporting date, as well as income and expenses reported during the period.

Developments in the economic and financial environment, particularly relating to COVID-19, have prompted the Group to step up its risk oversight procedures, mainly in measuring financial instruments and performing impairment tests. The estimates used by the Group, among other things, to test for impairment and to measure provisions, take into account this environment and the sharp market volatility.

Accounting estimates are made in a context that remains sensitive to energy market developments, therefore making it difficult to apprehend medium-term economic prospects.

Due to uncertainties inherent in the estimation process, the Group regularly revises its estimates in light of currently available information. Final outcomes could differ from those estimates.

The key estimates used in preparing the Group's consolidated financial statements relate mainly to:

- measurement of the recoverable amount of goodwill (*see Note 13*), intangible assets (*see Note 14*), property, plant and equipment (*see Note 15*), and, in the context of COVID-19, factoring the uncertainty in measuring these recoverable amounts and their sensitivity to potential changes in key assumptions;
- measurement of the fair value of financial assets and liabilities, and, in the context of COVID-19, factoring the uncertainty surrounding the key assumptions used, mainly as regards the estimation of future cash flows (*see Notes 16 and 17*);
- measurement of provisions, particularly for the back-end of the nuclear fuel cycle, dismantling obligations, disputes, and pensions and other employee benefits (*see Notes 19 and 20*);
- measurement of the fair value of assets acquired and liabilities assumed in a business combination (*see Note 4*);
- measurement of un-metered revenues (energy in the meter), for which the valuation techniques have been impacted by changes in certain customers' consumption habits (*see Note 7*);
- measurement of recognized tax loss carry-forwards, taking into account, where applicable, in the context of COVID-19, taxable income revisions and projections (*see Note 11*).

1.3.2 Judgment

As well as relying on estimates, Group management also makes judgments to define the appropriate accounting policies to apply to certain activities and transactions, particularly when the IFRS Standards and IFRIC Interpretations in force do not specifically deal with the related accounting issues.

In particular, the Group exercised its judgment in:

- assessing the type of control (*see Notes 2 and 3*);
- identifying the performance obligations of sales contracts (*see Note 7*);
- determining how revenues are recognized for distribution or transmission services invoiced to customers (*see Note 7*);
- identifying "own use contracts" as defined by IFRS 9 within non-financial purchase and sale contracts (electricity, gas, etc.) (*see Note 16*);
- determining whether arrangements are or contain a lease (*see Notes 15 and 16*);

- grouping operating segments together for the presentation of reportable segments (*see Note 6*).

In the context of the COVID-19 crisis, the Group also exercised its judgment in assessing:

- the existence of a trigger event potentially leading to the impairment of goodwill, property, plant and equipment and/or intangible assets (*see Notes 9, 13, 14 and 15*);
- expected credit losses, mainly in order to update probabilities of default and other inputs in an uncertain context (*see Note 17*);
- the impacts on risks related to financial instruments, mainly liquidity risk and trends in interest rate, commodities and exchange rate markets (*see Note 17*);
- the consequences of hedging, particularly with regard to maintaining the highly probable nature of the hedged item (*see Note 17*);
- the application of enforceable rights and obligations associated with customer contracts, mainly with regard to future payment receipt probabilities and the measurement of the revenue recognized using the percentage of completion method (*see Note 7*).

1.3.3 Impacts of the COVID-19 crisis on the Group's position at December 31, 2020

The impacts of the COVID-19 crisis on the Group's operational and financial performance are presented in the management report.

In the context of the health crisis, the Group has taken special care in determining the accounting treatments applicable to the main issues and impacts of the crisis, for which IFRS accounting principles have been applied consistently with those previously used, particularly in relation to:

- **Impairment losses on non-financial assets**
The potential impairment of non-financial assets, particularly goodwill and investments consolidated using the equity method of accounting, was examined, particularly for those activities most affected by the COVID-19 crisis. In accordance with IAS 36 - *Impairment of Assets*, the Group performed an impairment test on goodwill, as well as on other non-financial assets for which indicators of potential impairment losses existed (*see Note 9.1 "Impairment losses" and Note 13 "Goodwill"*).
- **Impairment losses on financial assets: counterparty risk and expected credit losses**
The COVID-19 crisis gives rise to a potentially increased credit risk and may therefore affect the amount of impairment losses to be recognized in respect of expected credit losses. The Group is therefore monitoring payment receipts and counterparty risk more closely (*see Note 17 "Risks arising from financial instruments"*).
- **Financial assets and liabilities: measurement at fair value**
Faced with the crisis, the financial markets are very volatile, which affects the instruments held by the Group and measured at fair value. The fair value of these instruments incorporates data that reflect the way in which market participants would take into account the impacts of COVID-19, including the uncertainties inherent to the situation generated by the crisis (*see Note 16 "Financial instruments"*).
- **Liquidity risk and market risk**
Liquidity risk and trends in the interest rate, commodities and exchange rate markets were monitored carefully and the related information has been updated based on data available at December 31, 2020 (*see Note 17 "Risks arising from financial instruments"*).
- **Deferred tax assets**
ENGIE's deferred tax asset positions were reviewed in order to ensure their recoverability through future taxable income. The Group also monitored changes to legislation, revisions to income tax rates and other tax measures taken in response to the crisis (*see Note 11 "Income tax expense"*).

- **Provisions**

As certain activities were more impacted by COVID-19 than others, the Group decided to review whether any current obligations were likely to give rise to the recognition of provisions, particularly for onerous contracts (see *Note 19 "Provisions"*).

- **Performance indicators and presentation of COVID-19 impacts in the income statement**

The Group has neither adjusted its performance indicators, nor included new indicators to describe the impacts of COVID-19 (see *Note 5 "Financial indicators used in financial communication"*). Expenses directly related to the crisis are all classified, according to their nature, in current operating income, in accordance with the recommendations given in relation to the crisis, which mainly impacts revenues, irrespective of the Group's practice of items of an unusual, irregular or non-recurring nature below current operating income.

NOTE 2 MAIN SUBSIDIARIES AT DECEMBER 31, 2020

Accounting standards

Controlled entities (subsidiaries) are fully consolidated in accordance with IFRS 10 – *Consolidated Financial Statements*. An investor (the Group) controls an entity and therefore must consolidate it if all of the following three criteria are met:

- it has the ability to direct the relevant activities of the entity;
- it has the rights and is exposed to variable returns from its involvement with the entity;
- it has the ability to use its power over the entity to affect the investor's return.

2.1 List of main subsidiaries at December 31, 2020

The following lists are made available by the Group to third parties, pursuant to Regulation No. 2016-09 of the French accounting standards authority (ANC) issued on December 2, 2016:

- list of companies included in consolidation;
- list of companies excluded from consolidation because their individual and cumulative incidence on the Group's consolidated financial statements is not material. They correspond to entities deemed not significant as regards the Group's main key figures (revenues, total equity, etc), shell companies or entities that have ceased all activities and are undergoing liquidation/closure proceedings;
- list of main non-consolidated interests.

This information is available on the Group's website (www.engie.com, Investors/Regulated information section). Non-consolidated companies are classified under non-current financial assets (see Note 16.1.1.1) under "Equity instruments at fair value".

The list of the main subsidiaries consolidated under the full consolidation method presented below was determined, as regards operating entities, based on their contribution to Group revenues, EBITDA, net income and net debt. The main equity-accounted investments (associates and joint ventures) are presented in Note 3 "Investments in equity method entities".

Some entities such as ENGIE SA, ENGIE Energie Services SA or Electrabel SA comprise both operating activities and headquarters functions which report to management teams of different reportable segments. In the following tables, these operating activities and headquarters functions are shown within their respective reportable segments under their initial company name followed by a (*) sign.

France excluding Infrastructures

Company name	Activity	Country	% interest	
			Dec. 31, 2020	Dec. 31, 2019
ENGIE SA *	Energy sales	France	100.0	100.0
ENGIE Energie Services SA *	Energy services/Networks	France	100.0	100.0
Axima Concept	Systems, facilities and maintenance	France	100.0	100.0
Endel Group	Systems, facilities and maintenance	France	100.0	100.0
INEO Group	Systems, facilities and maintenance	France	100.0	100.0
Compagnie Nationale du Rhône	Electricity distribution and generation	France	50.0	50.0
ENGIE Green	Electricity distribution and generation	France	100.0	100.0
CPCU	Urban heating networks	France	66.5	66.5

France Infrastructures

Company name	Activity	Country	% interest	
			Dec. 31, 2020	Dec. 31, 2019
GRDF	Natural gas distribution	France	100.0	100.0
GRTgaz Group (excluding Elengy)	Natural gas transportation	France, Germany	74.6	74.6
Elengy	Natural gas, LNG	France	61.3	74.6
Fosmax LNG	Natural gas, LNG	France	61.3	54.1
Storengy France	Underground natural gas storage	France	100.0	100.0
Storengy Deutschland GmbH	Underground natural gas storage	Germany	100.0	100.0

Rest of Europe

Company name	Activity	Country	% interest	
			Dec. 31, 2020	Dec. 31, 2019
ENGIE Thermique France	Electricity generation	France	100.0	100.0
Electrabel SA *	Electricity generation, Energy sales	Belgium	100.0	100.0
Synatom	Managing provisions relating to power plants and nuclear fuel	Belgium	100.0	100.0
Cofely Fabricom SA	Systems, facilities and maintenance	Belgium	100.0	100.0
ENGIE Energie Nederland N.V.	Electricity generation, Energy sales	Netherlands	100.0	100.0
ENGIE Services Nederland N.V.	Energy services	Netherlands	100.0	100.0
ENGIE Deutschland GmbH	Energy services	Germany	100.0	100.0
ENGIE Deutschland AG *	Electricity generation	Germany	100.0	100.0
ENGIE Supply Holding UK Limited	Energy sales	United Kingdom	100.0	100.0
First Hydro Holdings Company	Electricity generation	United Kingdom	75.0	75.0
Engie Regeneration	Energy services	United Kingdom	100.0	100.0
ENGIE Services Holding UK Ltd	Energy services	United Kingdom	100.0	100.0
ENGIE Services Limited	Energy services	United Kingdom	100.0	100.0
ENGIE Cartagena	Electricity generation	Spain	100.0	100.0
ENGIE Italia S.p.A *	Energy sales	Italy	100.0	100.0
Engie Servizi S.p.A	Energy services	Italy	100.0	100.0
ENGIE Romania	Natural gas distribution, Energy sales	Romania	51.0	51.0

Latin America

Company name	Activity	Country	% interest	
			Dec. 31, 2020	Dec. 31, 2019
ENGIE Energía Chile Group	Electricity distribution and generation	Chile	60.0	52.8
ENGIE Energía Perú	Electricity distribution and generation	Peru	61.8	61.8
ENGIE Brasil Energia Group	Electricity distribution and generation	Brazil	68.7	68.7

USA & Canada

Company name	Activity	Country	% interest	
			Dec. 31, 2020	Dec. 31, 2019
ENGIE North America	Electricity distribution and generation, Natural gas, LNG, Energy services	United States	100.0	100.0
ENGIE Holding Inc.	Holding - parent company	United States	100.0	100.0
ENGIE Infinity Renewables	Electricity distribution and generation	United States	100.0	100.0
ENGIE Resources Inc.	Energy sales	United States	100.0	100.0
Jupiter Projects	Electricity distribution and generation	United States	51.0	100.0
Conti Service LLC	Energy services	United States	100.0	100.0

Middle East, Asia & Africa

Company name	Activity	Country	% interest	
			Dec. 31, 2020	Dec. 31, 2019
UCH Power Limited	Electricity generation	Pakistan	100.0	100.0
Pelican Point Power Limited	Electricity generation	Australia	72.0	72.0
Simply Energy	Energy sales	Australia	72.0	72.0
Cofely Besix	Systems, facilities and maintenance	UEA	100.0	100.0

Others

Company name	Activity	Country	% interest	
			Dec. 31, 2020	Dec. 31, 2019
ENGIE SA *	Holding - parent company, Energy management trading, Energy sales	France	100.0	100.0
ENGIE Energie Services SA *	Holding	France	100.0	100.0
ENGIE FINANCE SA	Financial subsidiaries	France	100.0	100.0
ENGIE Solar	Solar EPC	France	100.0	100.0
Gaztransport & Technigaz (GTT)	Engineering	France	40.4	40.4
Electrabel SA *	Holding, Electricity generation, Energy management trading	France/Belgium	100.0	100.0
ENGIE Italia S.p.A *	Holding, Energy management trading	Italy	100.0	100.0
ENGIE Deutschland AG *	Holding, Energy management trading	Germany	100.0	100.0
ENGIE Energie Nederland Holding B.V.	Holding, Energy management trading	Netherlands	100.0	100.0
ENGIE Global Markets	Energy management trading	France, Belgium, Singapore	100.0	100.0
ENGIE Energy Management *	Energy management trading	France, Belgium, Italy, United Kingdom	100.0	100.0
ENGIE CC	Financial subsidiaries, Central functions	Belgium	100.0	100.0
Tractebel Engineering	Engineering	Belgium	100.0	100.0
International Power Limited	Holding	United Kingdom	100.0	100.0
ENGIE Energy Management Holding	Holding	Switzerland	100.0	100.0

2.2 Significant judgments exercised when assessing control

The Group primarily considers the following information and criteria when determining whether it has control over an entity:

- governance arrangements: voting rights and whether the Group is represented in the governing bodies, majority rules and veto rights;
- the nature of substantive or protective rights granted to shareholders, relating to the entity's relevant activities;
- deadlock resolution mechanisms;
- whether the Group is exposed, or has rights, to variable returns from its involvement with the entity.

The Group exercised its judgment regarding the entities and sub-groups described below.

Entities in which the Group has the majority of the voting rights

GRTgaz (France Infrastructures): 74.6%

In addition to the analysis of the shareholder agreement with Société d'Infrastructures Gazières, a subsidiary of *Caisse des Dépôts et Consignations* (CDC), which owns 24.8% of the share capital of GRTgaz, the Group also assessed the rights granted to the French Energy Regulatory Commission (*Commission de régulation de l'énergie* – CRE). As a regulated activity, GRTgaz has a dominant position on the gas transportation market in France. Accordingly, since the transposition of the Third European Directive of July 13, 2009 into French law (*Code de l'énergie* – Energy Code) on May 9, 2011, GRTgaz has been subject to independence rules as concerns its directors and senior management team. The French Energy Code confers certain powers on the CRE in the context of its duties to control the proper functioning of the gas markets in France, including verifying the independence of the members of the Board of Directors and senior management and assessing the choice of investments. The Group considers that it exercises control over GRTgaz and its subsidiaries (including Elengy) in view of its current ability to appoint the majority of the members of the Board of Directors and take decisions about the relevant activities, especially in terms of the level of investment and planned financing.

Entities in which the Group does not have the majority of the voting rights

In the entities in which the Group does not have a majority of the voting rights, judgment is exercised with regard to the following items, in order to assess whether there is a situation of *de facto* control:

- dispersion of the shareholding structure: number of voting rights held by the Group relative to the number of rights held respectively by the other vote holders and their dispersion;
- voting patterns at shareholders' meetings: the percentages of voting rights exercised by the Group at shareholders' meetings in recent years;
- governance arrangements: representation in the governing body with strategic and operational decision-making power over the relevant activities;
- rules for appointing key management personnel;
- contractual relationships and material transactions.

The main fully consolidated entities in which the Group does not have the majority of the voting rights are Compagnie Nationale du Rhône (49.98%) and Gaztransport & Technigaz (40.4%).

Compagnie Nationale du Rhône ("CNR" – France excluding Infrastructures): 49.98%

The Group holds 49.98% of the share capital of CNR, with CDC holding 33.2%, and the balance (16.82%) being dispersed among around 200 local authorities. In view of the current provisions of the French "Murcef" law, under which a majority of CNR's share capital must remain under public ownership, the Group is unable to hold more than 50% of the share capital. However, the Group considers that it exercises *de facto* control as it holds the majority of the voting rights exercised at shareholders' meetings due to the widely dispersed shareholding structure and the absence of evidence of the minority shareholders acting in concert.

Gaztransport & Technigaz (“GTT” – Others): 40.4%

Since GTT's initial public offering in February 2014, ENGIE has been the largest shareholder in the company with a 40.4% stake, the free float representing around 59% of the share capital. The Group holds the majority of the seats on the Board of Directors and the majority of the voting rights exercised at shareholders' meetings in view of the widely dispersed shareholding structure and the absence of evidence of minority shareholders acting in concert. The Group therefore considers that it exercises *de facto* control over GTT, based on an IFRS 10 criteria.

2.3 Subsidiaries with material non-controlling interests

The following table shows the non-controlling interests in Group entities that are deemed to be material, the respective contributions to equity and net income at December 31, 2020 and December 31, 2019, as well as the dividends paid to non-controlling interests of these significant subsidiaries:

Corporate name	Activity	Percentage interest of non-controlling interests		Net income/(loss) of non-controlling interests		Equity of non-controlling interests		Dividends paid to non-controlling interests	
		Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2019 ⁽¹⁾	Dec. 31, 2020	Dec. 31, 2019
In millions of euros									
GRTgaz Group (France Infrastructures, France)	Regulated gas transportation activities and management of LNG terminals	25.4	25.4	95	89	1,029	1,076	80	120
ENGIE Energía Chile Group (Latin America, Chile) ⁽¹⁾	Electricity distribution and generation - thermal power plants	40.0	47.2	67	54	716	926	24	52
ENGIE Romania Group (Rest of Europe, Romania)	Distribution of natural gas, Energy sales	49.0	49.0	49	47	563	533	10	14
ENGIE Brasil Energia Group (Latin America, Brazil) ⁽¹⁾	Electricity distribution and generation	31.3	31.3	144	177	411	520	87	94
ENGIE Energía Perú (Latin America, Peru) ⁽¹⁾	Electricity distribution and generation - thermal and hydroelectric power plants	38.2	38.2	29	36	368	393	20	22
ENGIE Jupiter Group (North America, United States)	Electricity distribution and generation	49.0	-	51	-	394	-	-	-
Gaztransport & Technigaz (Other, France) ⁽¹⁾	Naval engineering, cryogenic membrane containment systems for LNG transportation	59.6	59.6	93	75	343	343	94	73
Other subsidiaries with non-controlling interests				115	186	1,087	1,159	109	78
TOTAL				644	664	4,911	4,950	425	453

(1) Engie Energía Chile, Engie Brasil Energia, Gaztransport & Technigaz and Engie Energía Perú are listed in their respective countries.

2.3.1 Condensed financial information on subsidiaries with material non-controlling interests

The condensed financial information concerning these subsidiaries presented in the table below is based on a 100% interest and is shown before intragroup eliminations.

	GRTgaz Group		ENGIE Energía Chile Group		ENGIE Romania Group	
<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2019
Income statement						
Revenues	2,275	2,275	1,107	1,180	1,545	1,436
Net income/(loss)	343	274	142	103	100	95
Net income/(loss) Group share	247	236	75	49	51	49
Other comprehensive income/(loss) – Owners of the parent	(91)	(77)	(88)	9	(10)	(13)
TOTAL COMPREHENSIVE INCOME/(LOSS) – OWNERS OF THE PARENT	157	159	(14)	59	41	36
Statement of financial position						
Current assets	826	689	498	546	520	613
Non-current assets	10,167	10,403	2,677	2,707	843	809
Current liabilities	(1,044)	(1,016)	(252)	(322)	(156)	(277)
Non-current liabilities	(6,113)	(6,097)	(1,146)	(1,025)	(67)	(65)
TOTAL EQUITY	3,836	3,979	1,776	1,907	1,140	1,080
TOTAL NON-CONTROLLING INTERESTS	1,029	1,076	716	926	563	533
Statement of cash flows						
Cash flow from operating activities	1,082	967	308	467	181	71
Cash flow from (used in) investing activities	(410)	(495)	(230)	(144)	(88)	(77)
Cash flow from (used in) financing activities	(673)	(480)	(81)	(171)	(59)	(34)
TOTAL CASH FLOW FOR THE PERIOD ⁽¹⁾	(1)	(8)	(2)	152	34	(40)

(1) Excluding effects of changes in exchange rates and other.

	ENGIE Brasil Energia Group		ENGIE Energía Perú		Gaztransport & Technigaz		Engie Jupiter Group (North America, United States)	
<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2019
Income statement								
Revenues	2,065	2,207	424	479	395	289	20	3
Net income/(loss)	550	623	76	94	156	126	(51)	82
Net income/(loss) Group share	405	446	47	58	63	51	(101)	82
Other comprehensive income/(loss) – Owners of the parent	(687)	(93)	(53)	12	-	(1)	(74)	(1)
TOTAL COMPREHENSIVE INCOME/(LOSS) – OWNERS OF THE PARENT	(282)	353	(6)	70	63	51	(175)	81
Statement of financial position								
Current assets	1,262	1,533	267	295	326	343	314	81
Non-current assets	4,627	5,792	1,550	1,714	428	452	2,663	534
Current liabilities	(859)	(1,345)	(149)	(177)	(140)	(174)	(287)	(42)
Non-current liabilities	(3,434)	(3,757)	(703)	(802)	(39)	(46)	(1,358)	(293)
TOTAL EQUITY	1,596	2,224	965	1,029	575	575	1,332	279
TOTAL NON-CONTROLLING INTERESTS	411	520	368	393	343	343	394	-
Statement of cash flows								
Cash flow from operating activities	869	1,045	197	237	152	139	186	13
Cash flow from (used in) investing activities	(758)	(1,136)	(17)	(22)	(21)	(10)	(151)	(30)
Cash flow from (used in) financing	2	436	(171)	(199)	(158)	(122)	49	88
TOTAL CASH FLOW FOR THE PERIOD ⁽¹⁾	113	345	9	16	(27)	7	83	72

(1) Excluding effects of changes in exchange rates and other.

NOTE 3 INVESTMENTS IN EQUITY METHOD ENTITIES

Accounting standards

The Group accounts for its investments in associates (entities over which the Group has significant influence) and joint ventures using the equity method. Under IFRS 11 – *Joint Arrangements*, a joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement.

The respective contributions of associates and joint ventures in the statement of financial position, the income statement and the statement of comprehensive income at December 31, 2020 and December 31, 2019 are as follows:

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Statement of financial position		
Investments in associates	3,017	4,646
Investments in joint ventures	3,743	4,570
INVESTMENTS IN EQUITY METHOD ENTITIES	6,760	9,216
Income statement		
Share in net income/(loss) of associates	184	255
Share in net income/(loss) of joint ventures	369	245
SHARE IN NET INCOME/(LOSS) OF EQUITY METHOD ENTITIES	552	500
Statement of comprehensive income		
Share of associates in "Other comprehensive income/(loss)"	(28)	(123)
Share of joint ventures in "Other comprehensive income/(loss)"	(284)	(158)
SHARE OF EQUITY METHOD ENTITIES IN "OTHER COMPREHENSIVE INCOME/(LOSS)"	(312)	(281)

Significant judgments

The Group primarily considers the following information and criteria in determining whether it has joint control or significant influence over an entity:

- governance arrangements: whether the Group is represented in the governing bodies, majority rules and veto rights;
- the nature of substantive or protective rights granted to shareholders, relating to the entity's relevant activities. This can be difficult to determine in the case of "project management" or "one-asset" entities, as certain decisions concerning the relevant activities are made upon the creation of the joint arrangement and remain valid throughout the project. Accordingly, the rights' analysis relates to the relevant residual activities of the entity (those that significantly affect the variable returns of the entity);
- deadlock resolution mechanisms;
- whether the Group is exposed, or has rights, to variable returns from its involvement with the entity. This can also involve analyzing the Group's contractual relations with the entity, in particular the conditions in which these contracts are entered into, their duration as well as the management of conflicts of interest that may arise when the entity's governing body casts votes.

The Group exercised its judgment regarding the following entities and sub-groups:

Project management entities in the Middle East

The significant judgments made in determining the consolidation method to be applied to these project management entities related to the risks and rewards relating to contracts between ENGIE and the entity concerned, as well as an analysis of the residual relevant activities over which the entity retains control after its creation. The Group considers that it exercises significant influence or joint control over these entities, since the decisions taken throughout the term of the project about the relevant activities such as refinancing, or the renewal or amendment of significant contracts (sales,

purchases, operating and maintenance services) require, depending on the case, the unanimous consent of two or more parties sharing control.

SUEZ Group

The Group exercised significant influence over SUEZ Group until October 6, 2020, when the Group sold a 29.9% stake in SUEZ (see Note 4.1 "Disposals carried out in 2020").

Joint ventures in which the Group holds an interest of more than 50%

Tihama (60%)

ENGIE holds a 60% stake in the Tihama cogeneration plant in Saudi Arabia and its partner Saudi Oger holds 40%. The Group considers that it has joint control over Tihama since the decisions about its relevant activities, including for example the preparation of the budget and amendments to major contracts, etc., require the unanimous consent of the parties sharing control.

Transportadora Asociada de Gas S.A. ("TAG" - Latin America): 65.0% holding interest (directly and indirectly) representing a net interest in of 54.8%

The Group exercises joint control over TAG since the decisions about its relevant activities, including for example the preparation of the budget and medium-term plan, investments, operations and maintenance, etc., are taken a majority vote requiring the agreement of ENGIE and CDPQ. Consequently, this investment is accounted for using the equity method.

Joint control – difference between joint ventures and joint operations

Classifying a joint arrangement requires the Group to use its judgment to determine whether the entity in question is a joint venture or a joint operation. IFRS 11 requires an analysis of "other facts and circumstances" when determining the classification of jointly controlled entities.

The IFRS Interpretations Committee (IFRS IC) (November 2014) decided that for an entity to be classified as a joint operation, other facts and circumstances must give rise to direct enforceable rights to the assets, and obligations for the liabilities, of the joint arrangement.

In view of this position and its application to our analyses, the Group has no material joint operations at December 31, 2020.

3.1 Investments in associates

3.1.1 Contribution of material associates and of associates that are not material to the Group taken individually

The table hereafter shows the contribution of each material associate along with the aggregate contribution of associates deemed not material taken individually, in the consolidated statement of financial position, income statement, statement of comprehensive income, and the "Dividends received from equity method entities" line of the statement of cash flows.

The Group used qualitative and quantitative criteria to determine material associates. These criteria include the contribution to the consolidated line items "Share in net income/(loss) of associates" and "Investments in associates", the total assets of associates in Group share, and associates carrying major projects in the study or construction phase for which the related investment commitments are material.

Corporate name	Activity	Capacity	Percentage interest of investments in associates		Carrying amount of investments in associates		Share in net income/(loss) of associates		Other comprehensive income/(loss) of associates		Dividends received from associates	
			Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2019
In millions of euros												
SUEZ Group (Other) ⁽¹⁾	Water and waste processing		-	32.06	-	1,953	-	113	-	(37)	-	129
Project management entities in the Middle East (Middle-East, Asia & Africa, Saudi Arabia, Bahrain, Qatar, United Arab Emirates, Oman, Kuwait) ⁽²⁾	Gas-fired power plants and seawater desalination facilities		-		803	950	184	79	(60)	(96)	107	77
Hydroelectric portfolio in Portugal	Hydro power plant	1688 MW	40.00		516		(6)		(11)		-	
Energia Sustentável Do Brasil (Latin America, Brazil)	Hydro power plant	3 750 MW	40.00	40.00	475	659	(17)	(49)	-	-	-	-
GASAG (Rest of Europe, Germany)	Gas and heat networks		31.57	31.57	239	233	12	16	15	(17)	16	9
Other investments in associates that are not material taken individually					984	852	9	96	27	27	145	61
INVESTMENTS IN ASSOCIATES					3,017	4,646	184	255	(28)	(123)	268	277

(1) On October 6, 2020, the Group sold 29.9% of its interest in the SUEZ Group (see Note 4.1 "Disposals carried out in 2020"). Following this disposal, the Group's residual stake in the SUEZ Group is presented in equity instruments.

(2) Investments in associates operating gas-fired power plants and seawater desalination facilities in the Arabian Peninsula have been grouped together under "Project management entities in the Middle East". This includes around 40 associates operating thermal power plants with a total installed capacity of 27,494 MW (at 100%).

These associates have fairly similar business models and joint arrangements: the project management entities selected as a result of a competitive bidding process develop, build and operate power generation plants and seawater desalination facilities. The entire output of these facilities is sold to government-owned companies under power and water purchase agreements, over periods generally spanning 20 to 30 years.

In accordance with their contractual arrangements, the corresponding plants are recognized as property, plant and equipment or as financial receivables whenever substantially all of the risks and rewards associated with the assets are transferred to the buyer of the output. This treatment complies with IFRIC 4 and IFRS 16. The shareholding structure of these entities systematically includes a government-owned company based in the same country as the project management entity. The Group's percentage interest and percentage voting rights in each of these entities varies between 20% and 50%.

The share in net income/(loss) of associates includes a net non-recurring loss for a total amount of €131 million in 2020 (compared to a net non-recurring loss of €79 million in 2019), mainly including changes in the fair value of derivative instruments and disposal gains and losses, net of tax (see Note 5.3 "Net recurring income Group share").

3.1.2 Financial information regarding material associates

The tables below provide condensed financial information for the Group's main associates. The amounts shown have been determined in accordance with IFRS, before the elimination of intragroup items and after (i) adjustments made in line with Group accounting policies and (ii) fair value measurements of the assets and liabilities of the associate performed at the acquisition date at the level of ENGIE, as required by IAS 28. All amounts are presented based on a 100% interest with the exception of "Total equity attributable to ENGIE".

<i>In millions of euros</i>	Revenues	Net income/(loss)	Other comprehensive income/(loss)	Total comprehensive income/(loss)	Current assets	Non-current assets	Current liabilities	Non-current liabilities	Total equity	% interest of Group	Total equity attributable to ENGIE
AT DECEMBER 31, 2020											
Project management entities in the Middle East	4,082	769	(255)	514	2,885	18,321	3,925	14,338	2,944	-	803
Energia Sustentável Do Brasil	454	(41)	-	(41)	153	2,897	1,863	(2)	1,189	40.00	475
Hydroelectric portfolio in Portugal	-	(14)	(26)	(41)	37	2,202	16	934	1,289	40.00	516
GASAG	1,205	40	47	87	921	1,944	1,872	234	758	31.57	239
AT DECEMBER 31, 2019											
SUEZ Group	18,015	352	(58)	294	11,481	24,153	12,098	14,248	9,288	32.06	1,953
Project management entities in the Middle East	3,778	390	(409)	(19)	2,851	21,053	3,543	16,644	3,717	-	950
Energia Sustentável Do Brasil	578	(123)	-	(123)	204	4,137	304	2,388	1,648	40.00	659
GASAG	1,251	51	(54)	(2)	850	1,847	1,757	203	736	31.57	233

(1) The SUEZ group was sold on October 6, 2020 to VEOLIA.

3.1.3 Transactions between the Group and its associates

The data below set out the impact of transactions with associates on the Group's 2020 consolidated financial statements.

<i>In millions of euros</i>	Purchases of goods and services	Sales of goods and services	Net financial income (excluding dividends)	Trade and other receivables	Loans and receivables at amortized cost	Trade and other payables	Borrowings and debt
Project management entities in the Middle East	(1)	178	(1)	33	114	2	-
Contassur ⁽¹⁾	-	-	-	187	2	-	-
Energia Sustentável Do Brasil	109	-	-	-	-	8	-
Hydroelectric portfolio in Portugal	-	3	-	1	120	-	-
Other	-	24	16	27	180	12	32
AT DECEMBER 31, 2020	108	205	15	248	416	21	32

(1) Contassur is a life insurance company accounted for using the equity method. Contassur offers insurance contracts, chiefly with pension funds that cover post-employment benefit obligations for Group employees and also employees of other companies mainly engaged in regulated activities in the electricity and gas sector in Belgium. Insurance contracts entered into by Contassur represent reimbursement rights recorded within "Other assets" in the statement of financial position. These reimbursement rights totaled €187 million at December 31, 2020 (€161 million at December 31, 2019).

3.2 Investments in joint ventures

3.2.1 Contribution of material joint ventures and of joint ventures that are not material to the Group taken individually

The table below shows the contribution of each material joint venture along with the aggregate contribution of joint ventures deemed not material taken individually to the consolidated statement of financial position, income statement, statement of comprehensive income, and the "Dividends received from equity method entities" line of the statement of cash flows.

The Group used qualitative and quantitative criteria to determine material joint ventures. These criteria include the contribution to the line items "Share in net income/(loss) of joint ventures" and "Investments in joint ventures", the Group's

share in the total assets of joint ventures, and joint ventures conducting major projects in the study or construction phase for which the related investment commitments are material.

Corporate name	Activity	Capacity	Percentage interest of investments in joint ventures		Carrying amount of investments in joint ventures		Share in net income/(loss) of joint ventures		Other comprehensive income/(loss) of joint ventures		Dividends received from joint ventures	
			Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2019	Dec. 31, 2020	Dec. 31,	Dec. 31, 2020	Dec. 31, 2019
In millions of euros												
Transportadora Asociada de Gás S.A. (TAG) (Latin America, Brazil)	Gas transmission network		65.00	58.50	803	1,364	177	44	(233)	(71)	231	159
National Central Cooling Company "Tabreed" (Middle-East, Asia & Africa, Abu Dhabi)	District cooling networks		40.00	40.00	702	740	52	42	-	-	27	24
EcoEléctrica (USA & Canada, Puerto Rico)	Combined-cycle gas-fired power plant and LNG terminal	530 MW	50.00	50.00	329	395	35	25	-	-	70	59
Portfolio of power generation assets in Portugal (Rest of Europe, Portugal)	Electricity generation	2 918 MW	50.00	50.00	278	312	34	39	-	(2)	69	50
WSW Energie und Wasser AG (Rest of Europe, Germany)	Electricity distribution and generation	142 MW	33.10	33.10	206	207	6	(4)	-	-	7	4
Iowa University partnership (USA & Canada)	Services		33.10	-	190		2		(1)		-	
Tihama Power Generation Co (Middle-East, Asia & Africa, Saudi Arabia)	Electricity generation	1 599 MW	60.00	60.00	93	108	19	32	(4)	(5)	21	86
Ohio State Energy Partners (USA & Canada)	Services		50.00	50.00	76	114	6	2	(24)	(10)	12	9
Megal GmbH (France Infrastructures, Germany)	Gas transmission network		49.00	49.00	71	79	2	2	-	-	10	14
Transmisora Eléctrica del Norte (Latin America, Chile)	Electricity transmission line		50.00	50.00	67	80	5	7	(13)	(10)	-	-
Other investments in joint ventures that are not material taken individually					929	1,171	32	55	(9)	(61)	15	35
INVESTMENTS IN JOINT VENTURES					3,743	4,570	369	245	(284)	(158)	461	439

The share in net income/(loss) of joint ventures includes non-recurring loss of €6 million in 2020 (non-recurring loss of €14 million in 2019), resulting chiefly from changes in the fair value of derivatives, impairment losses and disposal gains and losses, net of tax (see Note 5.3 "Net recurring income Group share").

3.2.2 Financial information regarding material joint ventures

The amounts shown have been determined in accordance with IFRS before the elimination of intragroup items and after (i) adjustments made in line with Group accounting policies and (ii) fair value measurements of the assets and liabilities of

the joint venture performed at the date of acquisition at the level of ENGIE, as required by IAS 28. All amounts are presented based on a 100% interest with the exception of "Total equity attributable to ENGIE" in the statement of financial position.

Information on the income statement and statement of comprehensive income

<i>In millions of euros</i>	Revenues	Depreciation and amortization on intangible assets and property, plant and equipment	Net financial income/(loss)	Income tax expense	Net income/(loss)	Other comprehensive income/(loss)	Total comprehensive income/(loss)
AT DECEMBER 31, 2020							
Transportadora Asociada de Gás S.A.	1,018	(260)	(245)	(99)	272	(346)	(74)
National Central Cooling Company "Tabreed"	417	(46)	(38)	-	130	-	130
EcoEléctrica	274	(42)	-	(2)	70	-	70
Portfolio of power generation assets in Portugal	307	(65)	(25)	(30)	79	(1)	78
WSW Energie und Wasser AG	703	(13)	(2)	(14)	18	1	19
Iowa University partnership	24	-	(17)	-	5	(3)	3
Tihama Power Generation Co	113	(5)	(16)	(6)	31	(6)	25
Ohio State Energy Partners	165	-	(43)	-	12	(49)	(37)
Megal GmbH	123	(69)	(4)	2	3	-	3
Transmisora Eléctrica del Norte	65	-	(26)	(4)	10	(27)	(18)
AT DECEMBER 31, 2019							
Transportadora Asociada de Gás S.A.	655	(191)	(191)	(52)	88	(121)	(34)
National Central Cooling Company "Tabreed"	370	(41)	(44)	-	105	-	105
EcoEléctrica	308	(69)	-	(2)	50	-	50
Portfolio of power generation assets in Portugal	426	(67)	(29)	(36)	93	(7)	86
WSW Energie und Wasser AG	729	(12)	(2)	6	(11)	-	(11)
Tihama Power Generation Co	42	(5)	(23)	(8)	54	(8)	46
Ohio State Energy Partners	121	-	(44)	-	4	(20)	(15)
Megal GmbH	123	(69)	(4)	3	4	-	4
Transmisora Eléctrica del Norte	76	-	(30)	(5)	15	(21)	(6)

Information on the statement of financial position

<i>In millions of euros</i>	Cash and cash equivalents	Other current assets	Non-current assets	Short-term borrowings	Other current liabilities	Long-term borrowings	Other non-current liabilities	Total equity	% interest of Group	Total equity attributable to ENGIE
AT DECEMBER 31, 2020										
Transportadora Asociada de Gás S.A.	69	277	5,737	514	88	3,524	720	1,235	58.50	803
National Central Cooling Company "Tabreed"	87	131	2,408	-	169	702	-	1,754	40.00	702
EcoEléctrica	26	60	598	(6)	17	-	16	657	50.00	329
Portfolio of power generation assets in Portugal	203	601	891	174	160	635	76	650	50.00	278
WSW Energie und Wasser AG	14	51	812	40	55	87	90	606	33.10	206
Iowa University partnership	5	7	960	1	4	492	3	473	39.10	185
Tihama Power Generation Co	61	129	333	67	45	246	10	155	60.00	93
Ohio State Energy Partners	8	56	1,074	341	20	575	49	153	50.00	76
Megal GmbH	1	5	730	230	43	262	56	145	49.00	71
Transmisora Eléctrica del Norte	42	28	698	28	4	602	-	133	50.00	67
AT DECEMBER 31, 2019										
Transportadora Asociada de	86	329	7,844	595	86	4,616	629	2,331	58.50	1,364
National Central Cooling Company "Tabreed"	-	143	2,671	13	184	765	-	1,851	40.00	740
EcoEléctrica	34	97	701	(7)	29	-	21	789	50.00	395
Portfolio of power generation assets in Portugal	232	635	1,039	176	139	770	92	728	50.00	312
WSW Energie und Wasser AG	19	59	805	37	54	94	92	606	33.10	207
Tihama Power Generation Co	56	124	432	69	26	325	13	179	60.00	108
Ohio State Energy Partners	19	1,055	89	343	25	522	43	229	50.00	114
Megal GmbH	6	2	729	210	41	262	62	162	49.00	79
Transmisora Eléctrica del Norte	43	34	774	42	4	645	-	160	50.00	80

3.2.3 Transactions between the Group and its joint ventures

The data below set out the impact of transactions with joint ventures on the Group's 2020 consolidated financial statements.

<i>In millions of euros</i>	Purchases of goods and services	Sales of goods and services	Net financial income (excluding dividends)	Trade and other receivables	Loans and receivables at amortized cost	Trade and other payables	Borrowings and debt
EcoEléctrica	-	48	-	-	-	-	-
Portfolio of power generation assets in Portugal	-	-	-	1	-	-	-
WSW Energie und Wasser AG	-	8	-	1	-	1	-
Megal GmbH	65	-	-	-	51	-	-
Futures Energies Investissements Holding	8	18	4	9	208	3	-
Ocean Winds	-	-	4	-	398	-	-
Other	25	152	16	30	227	3	34
AT DECEMBER 31, 2020	98	227	24	41	884	7	34

3.3 Other information on investments accounted for using the equity method

3.3.1 Unrecognized share of losses of associates and joint ventures

Cumulative unrecognized losses of associates (corresponding to the cumulative amount of losses exceeding the carrying amount of investments in the associates concerned) including other comprehensive income/(loss), amounted to

€114 million in 2020 (€113 million in 2019). This decrease resulted from (i) unrecognized income for the year 2019 amounting to €0.2 million and (ii) changes in other comprehensive income.

These unrecognized losses correspond to the negative fair value of derivative instruments designated as interest rate and commodity hedges ("Other comprehensive income/(loss)") contracted by associates in the Middle-East, Africa & Asia reportable segment in connection with the financing of construction projects for power generation plants.

3.3.2 Commitments and guarantees given by the Group in respect of equity method entities

At December 31, 2020, the main commitments and guarantees given by the Group in respect of equity method entities concern:

- Energia Sustentável do Brasil ("Jirau"), for an aggregate amount of BRL 4,398 million (€690 million).
At December 31, 2020, the amount of loans granted by Banco Nacional de Desenvolvimento Econômico e Social, the Brazilian Development Bank, to Energia Sustentável do Brasil amounted to BRL 10,680 million (€1,675 million). Each partner stands as guarantor for this debt to the extent of its ownership interest in the consortium;
- TAG for performance bonds and other guarantees for an amount of €172 million;
- The project management entities in the Middle East and Africa, for an aggregate amount of €851 million.

Commitments and guarantees given by the Group in respect of these project management entities chiefly correspond to:

- an equity contribution commitment (capital/subordinated debt) for €89 million. These commitments only concern entities acting as holding companies for projects in the construction phase,
- letters of credit to guarantee debt service reserve accounts for an aggregate amount of €198 million. The project financing set up in certain entities can require those entities to maintain a certain level of cash within the company (usually enough to service its debt for six months). This is particularly the case when the financing is without recourse. This level of cash may be replaced by letters of credit,
- collateral given to lenders in the form of pledged shares in the project management entities, for an aggregate amount of €244 million,
- performance bonds and other guarantees for an amount of €320 million.

NOTE 4 MAIN CHANGES IN GROUP STRUCTURE

Accounting standards

In accordance with IFRS 5 - *Non-Current Assets Held for Sale and Discontinued Operations*, assets or groups of assets held for sale are presented separately on the face of the statement of financial position and are measured and accounted for at the lower of their carrying amount and fair value less costs to sell.

An asset is classified as "held for sale" when its sale is highly probable within twelve months from the date of classification, when it is available for immediate sale under its present condition and when the management is committed to a plan to sell the asset and an active program to locate a buyer and complete the plan has been initiated. To assess whether a sale is highly probable, the Group takes into consideration among other things indications of interest and offers received from potential buyers as well as specific execution risks attached to certain transactions.

Furthermore, assets or group of assets are presented as discontinued operations in the Group's consolidated financial statements when they are classified as "held for sale" and represent a separate major line of business under IFRS 5.

4.1 Disposals carried out in 2020

4.1.1 Impact of the main disposals and sale agreements in 2020

The table below shows the impact of the main disposals and sale agreements of 2020 on the Group's net debt, excluding partial disposals with respect to DBSO ⁽¹⁾ activities:

<i>In millions of euros</i>	Disposal price	Reduction in net debt
Disposal of a share of ENGIE's interest in SUEZ – France	3,348	3,348
Disposal of ENGIE's interest in Astoria 1 and Astoria 2 - United States	375	375
Other disposals that are not material taken individually	425	423
TOTAL	4,148	4,146

Additional disposals in the process of completion at December 31, 2020 are described in Note 4.2 "Assets held for sale" and other significant strategic reviews underway are described in Note 4.3 "Other planned transactions".

4.1.2 Disposal of a portion of ENGIE's interest in SUEZ SA

On October 5, 2020, the Group accepted an offer from the Veolia group to acquire a 29.9% interest in SUEZ SA. After the transaction, which was completed on October 6, 2020, the Group still held a non-consolidated interest of 1.8% in SUEZ SA.

This transaction reduced the Group's net financial debt by €3,348 million. The disposal gain before tax, combined with the revaluation gain on the remaining interest, amounted to €1,735 million in 2020.

4.1.3 Disposal of ENGIE's interests in Astoria 1 and 2 (United States)

On June 18, 2020, the Group completed the sale of its respective 44.8% and 27.5% interests in the Astoria 1 and Astoria 2 gas-fired power plants to a consortium.

⁽¹⁾ Develop, Build, Share and Operate, a model used in renewable energies based on continuous rotation of capital employed.

The effects of the transaction have reduced the Group's net financial debt by €375 million. The disposal gain before tax amounted to €95 million in 2020.

4.2 Assets held for sale

Total "Assets classified as held for sale" and total "Liabilities directly associated with assets classified as held for sale" amounted to €1,292 million and €488 million, respectively, at December 31, 2020.

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Property, plant and equipment, net and intangible assets	992	378
Other assets	299	90
TOTAL ASSETS CLASSIFIED AS HELD FOR SALE	1,292	468
Borrowings and debt	297	26
Other liabilities	190	65
TOTAL LIABILITIES DIRECTLY ASSOCIATED WITH ASSETS CLASSIFIED AS HELD FOR SALE	488	92

The assets related to green gas production in France recorded as "Assets classified as held for sale" at December 31, 2019 were sold in 2020 (see Note 4.1 "Disposals carried out in 2020").

"Assets classified as held for sale" at December 31, 2020 corresponds to renewable energy assets in India and Mexico (the sale of which is highly probable but remains subject to various approvals being obtained), as well as the Group's interest in EV Charged BV (EVBox), for which the plan to sell the majority of the Group's shares was announced in December 2020. These transactions are expected to be completed in 2021. Given the expected capital gains from the disposals, no significant value adjustment has been recorded.

4.3 Other planned transactions

On July 31, 2020, the Group announced a significant increase to its asset portfolio rotation program which, in the medium term, could more than double the previously announced target of around €4 billion.

In this context, the Group has begun a strategic review of its Client Solutions assets with a view to maximizing their value and strengthening their leadership positions to seize future growth opportunities thanks to a consistent scope and appropriate organization, taking into account three main criteria: business model, business type and potential for development in each geographical area. This strategic review will result in: (i) the preservation of Client Solutions businesses focused on the production of low-carbon energy, energy infrastructure and related services providing sophisticated, integrated and large-scale solutions for cities, communities and industries, and (ii) for the other Client Solutions businesses, the creation of a new entity with a leadership position in asset-light businesses and related services, aimed at eventually becoming independent from ENGIE. The entity will specialize in two business models: design and construction projects and recurring operating/maintenance services.

On November 13, 2020, ENGIE also announced that it was beginning a strategic review of its interest in GTT, in which it holds a 40.4% interest. ENGIE will consider selling all or part of its interest, either by way of a formal process of sale to a third party or on the markets.

Given the status of these strategic reviews at December 31, 2020, the conditions for reclassifying the assets in question as "Assets classified as held for sale" have not been met.

4.4 Acquisitions carried out in 2020

In total, acquisitions carried out in 2020 had an impact of €2.5 billion on net financial debt, including in particular:

- ENGIE and Meridiam, its 50/50 partner, finalized the transaction allowing them to operate a 50-year concession with the University of Iowa (UI) relating to energy efficiency, water management and, more generally, sustainability. The company, whose control is shared between the partners, has also issued preference shares held by Hannon

Armstrong. ENGIE has accounted for this investment using the equity method. The impact of the transaction on the Group's net debt was approximately €204 million.

- ENGIE and its partner, Caisse de dépôt et placement du Québec (CDPQ), finalized their acquisition of the remaining 10% stake in Transportadora Associada de Gás S.A. (TAG), previously held by PETROBRAS. This acquisition brought ENGIE's total interest in TAG to 65% (of which half is held by ENGIE Brasil Energia), while CDPQ holds the remaining 35%. Following the transaction, ENGIE retains joint control with CDPQ over the investment, which is still accounted for using the equity method. The impact of the transaction on the Group's net debt was approximately €112 million.
- In addition, with its consortium partners Crédit Agricole Assurances and Mirova (a subsidiary of Natixis Investment Managers), the Group finalized the acquisition of Portugal's second largest hydroelectric portfolio from EDP. ENGIE owns 40% of the consortium, while Crédit Agricole Assurances and Mirova, through managed funds, own 35% and 25%, respectively. The impact of the transaction on ENGIE's net debt was approximately €652 million. This investment is accounted for using the equity method.

The Group carried out various other acquisitions in 2020 which together account for the rest of the €2.5 billion impact, mainly of non-controlling interests in the Fos Cavaou LNG terminal in France, in Renvico in France and Italy, and in a concession in electric power transportation in Brazil.

NOTE 5 FINANCIAL INDICATORS USED IN FINANCIAL COMMUNICATION

The purpose of this note is to present the main non-GAAP financial indicators used by the Group as well as their reconciliation with the indicators of the IFRS consolidated financial statements.

5.1 EBITDA

The reconciliation between EBITDA and current operating income including operating MtM and share in net income of equity method entities is as follows:

<i>In millions of euros</i>	Dec. 31, 2020	Dec 31, 2019
Current operating income including operating MtM and share in net income of equity method entities	4,640	5,300
Mark-to-market on commodity contracts other than trading instruments	(199)	426
Net depreciation and amortization/Other	4,648	4,497
Share-based payments (IFRS 2)	50	51
Non-recurring share in net income of equity method entities	137	93
EBITDA	9,276	10,366

5.2 Current operating income (COI)

From January 1, 2020, in order to be consistent with the definitions of EBITDA and net recurring income Group share, in line with ENGIE's accounting policies, the Group has revised its definition of the performance management indicator "current operating income Recurring" (COI) by excluding from it the non-recurring share of net income of equity method entities.

The reconciliation between the old and the new definition of current operating income (COI) as of December 31, 2019 is presented below:

<i>In millions of euros</i>	Dec 31, 2019 published	Non-recurring share in net income of equity method entities	Dec 31, 2019 restated
CURRENT OPERATING INCOME (COI)	5,726	93	5,819

The reconciliation between current operating income (COI) and current operating income including operating MtM and share in net income of equity method entities is as follows:

<i>In millions of euros</i>	Dec. 31, 2020	Dec 31, 2019
Current operating income including operating MtM and share in net income of equity method entities	4,640	5,300
(-) Mark-to-market on commodity contracts other than trading instruments	(199)	426
(-) Non-recurring share in net income of equity method entities	137	93
CURRENT OPERATING INCOME (COI)	4,578	5,819

5.3 Net recurring income Group share

Net recurring income Group share is a financial indicator used by the Group in its financial reporting to present net income Group share adjusted for unusual or non-recurring items.

The reconciliation of net income/(loss) with net recurring income Group share is as follows:

<i>In millions of euros</i>	Notes	Dec. 31, 2020	Dec 31, 2019
NET INCOME/(LOSS) GROUP SHARE		(1,536)	984
Net income attributable to non-controlling interests		644	664
NET INCOME/(LOSS)		(893)	1,649
Reconciliation items between "Current operating income including operating MtM and share in net income of equity method entities" and "Income/(loss) from operating activities"			
		3,139	1,623
Impairment losses	9.1	3,551	1,770
Restructuring costs	9.2	343	218
Changes in scope of consolidation	9.3	(1,640)	(1,604)
Other non-recurring items	9.4	886	1,240
Other adjusted items		109	154
Mark-to-market on commodity contracts other than trading instruments	8.1	(199)	426
Ineffective portion of derivatives qualified as fair value hedges	10	-	3
Gains/(losses) on debt restructuring and early unwinding of derivative financial instruments	10	29	(6)
Change in fair value of derivatives not qualified as hedges and ineffective portion of derivatives qualified as cash flow hedges	10	158	223
Non-recurring income/(loss) from debt instruments and equity instruments	10	69	(115)
Other adjusted tax impacts		(85)	(470)
Non-recurring income/(loss) included in share in net income of equity method entities		137	93
NET RECURRING INCOME		2,355	3,426
Net recurring income attributable to non-controlling interests		652	743
NET RECURRING INCOME GROUP SHARE		1,703	2,683

5.4 Industrial capital employed

The reconciliation of industrial capital employed with items in the statement of financial position is as follows:

<i>In millions of euros</i>		Dec. 31, 2020	Dec. 31, 2019
(+)	Property, plant and equipment and intangible assets, net	57,085	58,996
(+)	Goodwill	15,943	18,665
(-)	Goodwill Gaz de France - SUEZ and International Power ⁽¹⁾	(7,472)	(7,650)
(+)	IFRIC 4, IFRS 16 and IFRIC 12 receivables	1,827	1,737
(+)	Investments in equity method entities	6,760	9,216
(-)	Goodwill arising on the International Power combination ⁽¹⁾	(141)	(154)
(+)	Trade and other receivables, net	14,295	15,180
(-)	Margin calls ^{(1) (2)}	(1,585)	(2,023)
(+)	Inventories	4,140	3,617
(+)	Assets from contracts with customers	7,764	7,831
(+)	Other current and non-current assets	9,386	10,601
(+)	Deferred tax	(3,536)	(3,771)
(+)	Cancellation of deferred tax on other recyclable items ^{(1) (2)}	(543)	(571)
(-)	Provisions	(27,073)	(25,115)
(+)	Actuarial gains and losses in shareholders' equity (net of deferred tax) ⁽¹⁾	4,553	3,507
(-)	Trade and other payables	(17,307)	(19,109)
(+)	Margin calls ^{(1) (2)}	982	1,996
(-)	Liabilities from contracts with customers	(4,354)	(4,330)
(-)	Other current and non-current liabilities	(14,579)	(14,298)
	INDUSTRIAL CAPITAL EMPLOYED	46,146	54,325

(1) For the purpose of calculating industrial capital employed, the amounts recorded in respect of these items have been adjusted from those appearing in the statement of financial position.

(2) Margin calls included in "Trade and other receivables, net" and "Trade and other payables" correspond to advances received or paid as part of collateralization agreements set up by the Group to manage counterparty risk on commodity transactions.

5.5 Cash flow from operations (CFFO)

The reconciliation of cash flow from operations (CFFO) with items in the statement of cash flows is as follows:

<i>In millions of euros</i>	Dec. 31, 2020	Dec 31, 2019
Cash generated from operations before income tax and working capital requirements	8,788	9,863
Tax paid	(599)	(575)
Change in working capital requirements	(600)	(1,110)
Interest received on financial assets	21	28
Dividends received on equity investments	57	67
Interest paid	(665)	(780)
Interest received on cash and cash equivalents	53	82
CASH FLOW FROM OPERATIONS (CFFO)	7,054	7,574

5.6 Capital expenditure (CAPEX)

The reconciliation of capital expenditure (CAPEX) with items in the statement of cash flows is as follows:

<i>In millions of euros</i>	Dec. 31, 2020	Dec 31, 2019
Acquisitions of property, plant and equipment and intangible assets	5,115	6,524
Acquisitions of controlling interests in entities, net of cash and cash equivalents acquired	417	864
(+) <i>Cash and cash equivalents acquired</i>	60	229
Acquisitions of investments in equity method entities and joint operations	1,067	1,746
Acquisitions of equity and debt instruments	1,622	595
Change in loans and receivables originated by the Group and other	374	532
(+) <i>Other</i>	(5)	8
Change in ownership interests in controlled entities	312	12
(-) Disposal impacts relating to DBSO ⁽¹⁾ activities	(1,276)	(468)
TOTAL CAPITAL EXPENDITURE (CAPEX)	7,687	10,042

(1) *Develop, Build, Share & Operate; including Tax equity financing received (see Note 24 "Working capital requirements, inventories, other assets and other liabilities")*

5.7 Net financial debt

The reconciliation of net financial debt with items in the statement of financial position is as follows:

<i>In millions of euros</i>	Notes	Dec. 31, 2020	Dec. 31, 2019
(+) Long-term borrowings	16.2 & 16.3	30,092	30,002
(+) Short-term borrowings	16.2 & 16.3	7,846	8,543
(+) Derivative instruments - carried in liabilities	16.4	13,115	15,575
(-) <i>Derivative instruments hedging commodities and other items</i>		(12,762)	(15,350)
(-) Other financial assets	16.1	(11,599)	(9,568)
(+) <i>Loans and receivables at amortized cost not included in net financial debt</i>		4,710	4,870
(+) <i>Equity instruments at fair value</i>		1,668	1,297
(+) <i>Debt instruments at fair value not included in net financial debt</i>		3,134	1,899
(-) Cash and cash equivalents	16.1	(12,980)	(10,519)
(-) Derivative instruments - carried in assets	16.4	(11,065)	(14,272)
(+) <i>Derivative instruments hedging commodities and other items</i>		10,299	13,443
NET FINANCIAL DEBT		22,458	25,919

5.8 Economic net debt

Economic net debt is as follows:

<i>In millions of euros</i>	Notes	Dec. 31, 2020	Dec. 31, 2019
NET DEBT	16	22,458	25,919
Provisions for back-end of the nuclear fuel cycle	19	7,948	7,611
Provisions for dismantling of plant and equipment	19	7,604	7,329
Provisions for site rehabilitation	19	238	237
Post-employment benefit – Pension	20	3,174	2,427
<i>(-) Infrastructures regulated companies</i>		(351)	(93)
Post-employment benefit - Reimbursement rights	20	(187)	(160)
Post-employment benefit - Other benefits	20	5,732	5,001
<i>(-) Infrastructures regulated companies</i>		(3,602)	(3,080)
Deferred tax assets for pension and related obligations	11	(2,061)	(1,635)
<i>(-) Infrastructures regulated companies</i>		947	759
Plan assets relating to nuclear provisions, inventories of uranium, related derivative financial instruments and a receivable of Electrabel towards EDF Belgium	16 & 24	(4,479)	(3,236)
ECONOMIC NET DEBT		37,420	41,078

NOTE 6 SEGMENT INFORMATION

As of December 31, 2020, ENGIE was organized into 25 Business Units (BUs) or operating segments , which are essentially geographical, in order to remain close to its customers and foster initiative.

Since 2019, the Group has strengthened this structure by creating four new Global Business Lines (GBLs): Client Solutions, Networks, Renewables and Thermal which are designed to support the local teams and encourage cross-cutting performance by proposing an inter-BU strategy for their business, contributing to decisions on the allocation of resources between BUs, identifying and managing the key cross-cutting digital and excellence programs, identifying and implementing worldwide partnerships, and supporting, measuring and presenting the global performance of their business activities. These GBLs plus the Supply and Nuclear business activities form the Group's six core Business Lines (BLs).

The Group now operates on a matrix structure with the BUs forming the primary axis and the BLs the secondary axis.

In accordance with IFRS 8, these operating segments are grouped into seven reportable segments to present the Group's segment information. These are unchanged as of December 31, 2020: France excluding Infrastructures, France Infrastructures, Rest of Europe, Latin America, USA & Canada, Middle East, Asia & Africa and Others. The data presented as of December 31, 2019 take into account minor changes resulting from internal reorganizations (reallocation of ENGIE Impact and offshore wind projects to the Others segment).

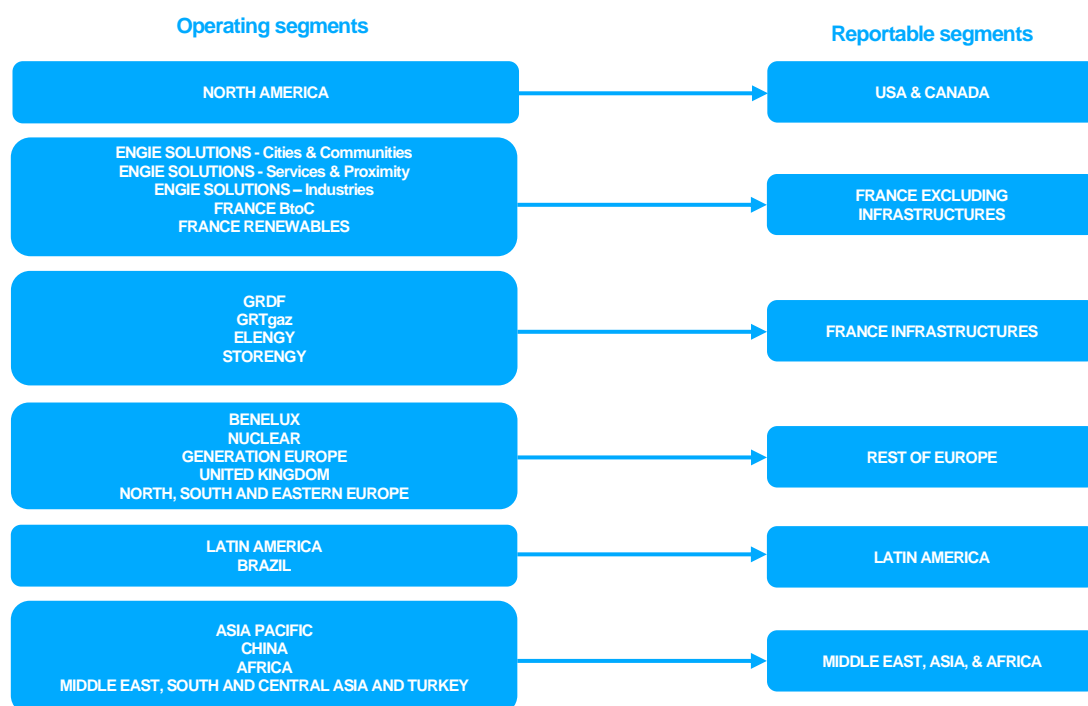
Due to the variety of its businesses and their geographical location, the Group serves a very diverse range of situations and customer types (industry, local authorities and individual customers). Accordingly, no external customer represents individually 10% or more of the Group's consolidated revenues.

6.1 Information by reportable segment

6.1.1 Definition of reportable segments

Each BU corresponds to an “operating segment” whose operational and financial performance is regularly reviewed by the Group’s Executive Committee, which remains the Group’s “chief operating decision maker” within the meaning of IFRS 8. The 25 BUs have now been regrouped into seven reportable segments reflecting the geographic areas where the Group operates:

- one reportable segment corresponding to the USA & Canada operating segment;
- five reportable segments corresponding to groups of operating segments;



- furthermore “Others” comprises the Group’s holding and corporate activities as well as operating segments that cannot be grouped together (Global Energy Management, Tractebel, GTT, Hydrogen) as well as the activities of *Entreprises & Collectivités (E&C)* due to the specific nature of their businesses and markets or due to their particular risk profile.

In order to determine how to group together the operating segments, as set out above, the Group exercised its judgment to decide whether two or more operating segments could be grouped together in the same reportable segment. The following key factors were examined to assess the similarity of the operating segments’ economic characteristics:

- nature of business and services;
- regulatory environment;
- economic environment in which the relevant activities operate (market maturity, growth prospects, political risks, etc.);
- risk profiles of the activities;
- how the activities fit into the Group’s strategy and business model.

The Group decided to organize the operating segments within the reportable segments for the following reasons:

- the ENGIE Solutions (divided into 3 customer segments: Cities and Communities, Services and Proximity and Industries), the France BtoC, and France Renewables operating segments have been grouped together within the **France excluding Infrastructures** reportable segment, which encompasses all the French downstream energy businesses (energy services and gas and electricity sales and distribution to BtoB, BtoT and BtoC customers), and the increasingly decentralized renewable energy generation activities. These are complementary unregulated businesses that are supported by a well-developed local network and primarily aim to develop a combined offering for local customers: energy services, decentralized production resources and combined gas and electricity supply contracts. These BUs also operate within an environment driven by the “energy transition for green growth” law (LTECV);
- the GRDF, GRTgaz, Storengy and Elengy operating segments, which comprise the gas infrastructure businesses mainly in France (distribution, transport, storage and LNG terminals), have been grouped together within the **France Infrastructures** reportable segment, as they are all regulated businesses with similar risk profiles and margins;
- the Benelux, Nuclear, Generation Europe, United Kingdom and North, South and Eastern Europe operating segments have been grouped together within the **Rest of Europe** reportable segment as these BUs, which comprise all of the Group’s European energy activities excluding France, have a similar business mix (energy production, supply, sale and services), operate in mature energy markets, and are undergoing transformation as part of the energy transition, with rapid development in renewable energy and client solutions;
- the Latin America and Brazil operating segments have been grouped together within the **Latin America** reportable segment, as these segments share similar growth prospects with a substantial proportion of their revenue generated by electricity sales under long-term agreements;
- the Asia-Pacific, China, Africa and Middle East, Southern and Central Asia and Turkey operating segments have been grouped together within the **Middle East, Asia & Africa** reportable segment, as all these regions have high power generation requirements and consequently represent significant growth prospects for the Group in the energy and energy services businesses. They operate in markets driven by the energy transition, with rapid development in renewable energy and client solutions.

6.1.2 Description of reportable segments

- **France excluding Infrastructures:** encompasses the activities of the following BUs: (i) ENGIE Solutions: energy sales and services for buildings and industry, cities and regions and major infrastructures and which designs, finances, builds and operates decentralized energy production and distribution facilities (heating and cooling networks) (ii) France BtoC: sales of energy and related services to individual and professional customers, (iii) France Renewables: development, construction, financing, operation and maintenance of all renewable power generation assets in France.
- **France Infrastructures:** encompasses the GRDF, GRTgaz, Elengy and Storengy BUs, which operate natural gas transportation, storage and distribution networks and facilities, and LNG terminals, mainly in France. They also sell access rights to these terminals.
- **Rest of Europe:** encompasses the activities of the following BUs: (i) Nuclear (electricity generation at nuclear power plants), (ii) Benelux (the Group’s business in Belgium, the Netherlands and Luxembourg: renewable electricity generation, sales of natural gas and electricity and energy services activities), (iii) Generation Europe, which comprises the Group’s thermal electricity generation activities in Europe, (iv) United Kingdom (management of renewable energy generation assets and the portfolio of distribution assets, supply of energy services and solutions, etc.) and (v) North, South and Eastern Europe (sales of natural gas and electricity and related energy services and solutions, operation of renewable energy generation assets, management of distribution networks).
- **Latin America:** encompasses the activities of (i) the Brazil BU and (ii) the Latin America BU (Argentina, Chile, Mexico and Peru). The subsidiaries concerned are involved in centralized power generation, including renewable energy, gas chain activities (including infrastructure), and energy services.
- **USA & Canada:** encompasses power generation, energy services and natural gas and electricity sales activities in the United States, Canada and Puerto Rico.
- **Middle East, Asia & Africa:** encompasses the activities of the following BUs: (i) Asia-Pacific (Australia, New Zealand, Thailand, Singapore and Indonesia), (ii) China, (iii) Africa (mainly Morocco and South Africa) and (iv) the Middle East, South and Central Asia and Turkey (including India and Pakistan). In all of these regions, the

Group is active in electricity generation and sales, gas distribution and sales, energy services and seawater desalination in the Arabian Peninsula.

- **Others:** encompasses the activities of (i) GEM, whose role is to manage and optimize, on behalf of the BUs that hold power generation assets, the Group's physical and contractual asset portfolios (excluding gas infrastructure), particularly in the European market, to sell energy to major pan-European and national industrial companies, and to provide solutions related to its expertise in the financial energy markets to third parties, (ii) Tractebel (engineering companies specialized in energy, hydraulics and infrastructure), (iii) GTT (specialized in the design of cryogenic membrane confinement systems for sea transportation and storage of LNG, both onshore and offshore), (iv) Hydrogen (design of renewable hydrogen-based zero carbon energy solutions), as well as (v) the Group's holding and corporate activities which include the entities centralizing the Group's financing requirements, *Entreprises & Collectivités* (E&C) and the contribution of the associate SUEZ until the sale of ENGIE's stake in October 2020.

The main commercial relationships between the reportable segments are as follows:

- relationships between the "France Infrastructures" reportable segment and the users of those infrastructures, i.e. the "France excluding Infrastructures" and "Others" (GEM and E&C) reportable segments: services relating to the use of the Group's gas infrastructures in France are billed based on regulated rates (or revenues) applicable to all users. Revenue and margins related to the GRDF business continue to fall within the scope of "France Infrastructures";
- relationships between the "Others" (GEM) reportable segment and the "France excluding Infrastructures" and "Rest of Europe" reportable segments: GEM manages the Group's natural gas supply contracts and sells gas at market prices to commercial companies within the "France excluding Infrastructures" and "Rest of Europe" reportable segments. As regards electricity, GEM manages and optimizes the power stations and sales portfolios on behalf of entities that hold power generation assets and deducts a percentage of the energy margin in return for providing these services. The revenue and margins related to power generation activities (minus the percentage deducted by GEM) are reported by the segments that hold power generation assets ("France excluding Infrastructures" and "Rest of Europe");
- relationships between the "Generation Europe" operating segment, which is part of the "Rest of Europe" reportable segment, and the commercial entities in the "France excluding Infrastructures" reportable segment: a portion of the power generated by thermal assets within the "Generation Europe" BU is sold to commercial entities from these segments at market prices.

Due to the variety of its businesses and their geographical location, the Group serves a very diverse range of situations and customer types (industry, local authorities and individual customers). Accordingly, no external customer represents individually 10% or more of the Group's consolidated revenues.

6.1.3 Key indicators by reportable segment

REVENUES

In millions of euros	Dec. 31, 2020			Dec. 31, 2019		
	External revenues	Intra-Group Revenues	Total	External revenues	Intra-Group Revenues	Total
France excluding Infrastructures	14,856	366	15,222	15,854	334	16,188
France Infrastructures	5,439	920	6,359	5,569	979	6,548
Total France	20,295	1,286	21,580	21,423	1,313	22,736
Rest of Europe	15,655	1,960	17,615	17,267	1,488	18,756
Latin America	4,774	2	4,776	5,341	1	5,342
USA & Canada	4,229	36	4,264	4,457	1	4,458
Middle East, Asia & Africa	2,382	-	2,382	2,937	-	2,938
Others	8,417	4,661	13,078	8,633	5,995	14,627
Elimination of internal transactions	-	(7,945)	(7,945)	-	(8,798)	(8,798)
TOTAL REVENUES	55,751	-	55,751	60,058	-	60,058

EBITDA

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
France excluding Infrastructures	1,391	1,673
France Infrastructures	3,290	3,539
<i>Total France</i>	4,680	5,212
Rest of Europe	1,750	1,757
Latin America	2,014	2,221
USA & Canada	245	269
Middle East, Asia & Africa	600	725
Others	(14)	182
TOTAL EBITDA	9,276	10,366

DEPRECIATION AND AMORTIZATION

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
France excluding Infrastructures	(769)	(761)
France Infrastructures	(1,681)	(1,581)
<i>Total France</i>	(2,450)	(2,343)
Rest of Europe	(1,097)	(1,041)
Latin America	(471)	(523)
USA & Canada	(121)	(112)
Middle East, Asia & Africa	(81)	(102)
Others	(428)	(377)
TOTAL DEPRECIATION AND AMORTIZATION	(4,648)	(4,497)

SHARE IN NET INCOME OF EQUITY METHOD ENTITIES

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
France excluding Infrastructures	10	18
France Infrastructures	3	3
<i>Total France</i>	13	21
Rest of Europe	128	62
Latin America	165	8
USA & Canada	85	60
Middle East, Asia & Africa	326	246
Others	(165)	103
<i>Of which share in net income of SUEZ</i>	(148)	113
TOTAL SHARE IN NET INCOME OF EQUITY METHOD ENTITIES	552	500

Associates and joint ventures accounted for €184 million and €369 million respectively of share in net income of equity method entities at December 31, 2020, compared to €255 million and €245 million in 2019.

CURRENT OPERATING INCOME (COI)

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019 ⁽¹⁾
France excluding Infrastructures	620	905
France Infrastructures	1,609	1,957
<i>Total France</i>	2,229	2,862
Rest of Europe	648	707
Latin America	1,542	1,696
USA & Canada	124	155
Middle East, Asia & Africa	518	619
Others	(483)	(221)
TOTAL CURRENT OPERATING INCOME (COI)	4,578	5,819

(1) Published data at December 31, 2019 have been restated due to the change in the definition of COI, which now excludes the non-recurring share in net income of equity method entities (see Note 5.2 "Current operating income (COI)").

INDUSTRIAL CAPITAL EMPLOYED

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
France excluding Infrastructures	7,326	7,157
France Infrastructures	19,891	20,172
<i>Total France</i>	27,218	27,329
Rest of Europe	(1,530)	1,805
Latin America	9,494	11,462
USA & Canada	3,500	3,550
Middle East, Asia & Africa	2,818	3,636
Others	4,647	6,542
<i>Of which SUEZ equity value</i>	-	2,027
TOTAL INDUSTRIAL CAPITAL EMPLOYED	46,146	54,325

CAPITAL EXPENDITURE (CAPEX)

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
France excluding Infrastructures	734	1,019
France Infrastructures	1,763	1,745
<i>Total France</i>	2,496	2,764
Rest of Europe	2,298	1,433
Latin America	1,514	2,499
USA & Canada	455	1,351
Middle East, Asia & Africa	(470)	449
Others	1,393	1,547
TOTAL CAPITAL EXPENDITURE (CAPEX)	7,687	10,042

6.2 Key indicators by Business Line

6.2.1 Definition of Business Lines

- **Client Solutions** (excluding BtoC clients): encompasses services and service packages such as design, engineering, works, operation, installation, maintenance and facility management, as well as asset management activities such as heating and cooling networks, dedicated energy generation assets (decentralized energy delivered directly to the client). It also includes the Group's interest in the SUEZ group, partially sold on October 6, 2020 to VEOLIA (see Note 4 "Main changes in Group structure").
- **Networks**: comprises the Group's electricity and gas infrastructure activities and projects. These activities include the management and development of (i) gas and electricity transportation networks in Europe and Latin America and natural gas distribution networks in Europe, Asia and the American continent, (ii) natural gas underground storage in Europe, and (iii) regasification infrastructure in France and Chile. Apart from the historical infrastructure management activities, its asset portfolio also contributes to the challenges of energy decarbonization and network greening (gradual integration of green gas, hydrogen based projects, geothermal projects, energy as a service, etc.).
- **Renewables**: comprises all centralized renewable energy generation activities, including financing, construction and operation of renewable energy facilities, using various energy sources such as hydroelectric, onshore wind, photovoltaic solar, biomass, offshore wind, geothermal and biogas. The energy produced is fed into the grid and sold either on the open or regulated market or through electricity sale agreements.
- **Thermal**: encompasses all the Group's centralized energy generation activities using thermal assets, whether contracted or not. It includes the operation of power plants fueled mainly by gas and coal, as well as pump-operated storage plants. The energy produced is fed into the grid and sold either on the open or regulated market or through electricity sale agreements. It includes the financing, construction and operation of desalination plants, whether or not connected to power plants.
- **Nuclear**: encompasses all of the Group's nuclear power generation activities, with seven reactors in Belgium (four in Doel and three in Tihange) and drawing rights in France.

- **Supply:** encompasses all the Group's activities relating to the sale of gas and electricity to end customers, whether professional or individual. It also includes all the Group's activities in services for residential clients.

Others encompasses (i) energy management and optimization activities, (ii) the GTT BU, and (iii) corporate and holding activities.

6.2.2 Key indicators by Business Line

EBITDA

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Client Solutions	1,208	1,836
Networks	3,850	4,026
Renewables	1,559	1,724
Thermal	1,646	1,763
Nuclear	415	192
Supply	439	638
Others	159	186
TOTAL EBITDA	9,276	10,366

CURRENT OPERATING INCOME (COI)

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019 ⁽¹⁾
Client Solutions	459	1,082
Networks	2,063	2,344
Renewables	1,070	1,195
Thermal	1,209	1,320
Nuclear	(111)	(314)
Supply	112	345
Others	(224)	(154)
TOTAL CURRENT OPERATING INCOME (COI)	4,578	5,819

(1) Published data at December 31, 2019 have been restated due to the change in the definition of COI, which now excludes the non-recurring share in net income of equity method entities (see Note 5.2 "Current operating income (COI)").

CAPITAL EXPENDITURE (CAPEX)

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Client Solutions	992	1,621
Networks	2,502	3,446
Renewables	1,637	2,475
Thermal	187	517
Nuclear	1,740	636
Supply	357	457
Others	272	889
TOTAL CAPITAL EXPENDITURE (CAPEX)	7,687	10,042

6.3 Key indicators by geographic area

The amounts set out below are analyzed by:

- destination of products and services sold for revenues;
- geographic location of consolidated companies for industrial capital employed.

In millions of euros	Revenues		Industrial capital employed	
	Dec. 31, 2020	Dec. 31, 2019 ⁽¹⁾	Dec. 31, 2020	Dec. 31, 2019 ⁽¹⁾
France	22,440	24,223	30,569	31,831
Belgium	5,185	5,894	(9,638)	(6,026)
Other EU countries	9,960	10,428	5,867	8,363
Other European countries	4,420	5,192	2,847	490
North America	5,471	5,273	4,272	4,419
Asia, Middle East & Oceania	3,686	3,867	2,501	3,355
South America	4,201	4,759	8,918	10,920
Africa	387	422	810	971
TOTAL	55,751	60,058	46,146	54,325

(1) Comparative data presented for 2019 have been reclassified following the ratification of the Agreement on the withdrawal of the United Kingdom from the European Union on January 31, 2020.

NOTE 7 REVENUES

7.1 Revenues

Accounting standards

Revenues from contracts with customers concern revenues from contracts that fall within the scope of IFRS 15. Revenues are recognized when the customer obtains control of goods or services promised in the contract, for the amount of consideration to which an entity expects to be entitled in exchange for said promised goods or services.

A contractual analysis of the Group's sale contracts has led to the application of the following revenue recognition principles:

- **Gas, electricity and other energies**

Revenues from sales of gas, electricity and other energies are recognized upon delivery of the power to the retail, business or industrial customer.

Power deliveries are monitored in real time or on a deferred basis for those customers whose energy consumption is metered during the accounting period, in which case the portion of not yet metered revenues "in the meter" is estimated on the closing date.

- **Gas, electrical and other energy infrastructures**

Revenues derived by gas and electricity infrastructure operators upon providing transportation or distribution or storage capacities, are recognized on a straight-line basis over the contract term.

In the countries where the Group acts as an energy provider (supplier) without being in charge of its distribution or transportation, mainly in France and Belgium, an analysis of the energy sales contracts and of the related regulatory framework is carried out to determine whether the distribution or transportation services invoiced to the customers have to be excluded from the revenues recognized under IFRS 15.

Judgment may be exercised by the Group for this analysis in order to determine whether the energy provider acts as an agent or a principal for the gas or electricity distribution or transportation services re-invoiced to the customers. The main criteria used by the Group to exercise its judgment and conclude, in certain countries, that the energy provider acts as an agent of the infrastructure operator are as follows: who is primarily responsible for fulfillment of the distribution or transportation services? Does the energy provider have the ability to commit to capacity reservation contracts towards the infrastructure operator? To what extent does the energy provider have discretion in establishing the price for the distribution or transportation services?

- **Constructions, installations, Operations and Maintenance (O&M), facility management (FM) and other services**

Construction and installation contracts mainly concern assets built on the premises of customers such as cogeneration units, heaters or other energy-efficiency assets. The related revenues are usually recognized according to the percentage of completion on the basis of the costs incurred where the contracts fall within the scope of IFRS 15.

O&M contracts generally require the Group to perform services ensuring the availability of power generating facilities. These services are performed over time and the related revenues are recognized according to the percentage of completion on the basis of the costs incurred.

FM generally involves managing and integrating a large number of different services, outsourced by customers. The consideration due to FM suppliers can either be fixed or variable depending on the number of hours or based on another indicator, irrespective of the nature of the services provided. Hence, the related revenues are recognized according to the percentage of completion on the basis of the costs incurred or of the number of hours performed.

If it is not possible to conclude from the contractual analysis that the contract falls within the scope of IFRS 15, the revenues are accounted for as non-IFRS 15 revenues.

Revenues from other contracts, corresponding to revenues from operations that do not fall within the scope of IFRS 15, presented in the "Others" column include lease or concession income, as well as any financial component of operating services.

The table below shows a breakdown of revenues by type:

<i>In millions of euros</i>	Sales of gas	Sales of electricity and other energies	Sales of services linked to infrastructures	Constructions, installations, O&M, FM and other services	Others	Dec. 31, 2020
France excluding Infrastructures	2,537	4,130	170	8,014	4	14,856
France Infrastructures	25	-	5,210	192	12	5,439
<i>Total France</i>	<i>2,563</i>	<i>4,131</i>	<i>5,380</i>	<i>8,206</i>	<i>16</i>	<i>20,295</i>
Rest of Europe	2,728	5,651	312	6,918	46	15,655
Latin America	433	3,204	281	715	141	4,774
USA & Canada	166	2,506	1	1,553	2	4,229
Middle East, Asia & Africa	351	936	23	978	94	2,382
Others	2,938	3,473	110	1,257	639	8,417
TOTAL REVENUES	9,178	19,901	6,108	19,626	937	55,751

<i>In millions of euros</i>	Sales of gas	Sales of electricity and other energies	Sales of services linked to infrastructures	Constructions, installations, O&M, FM and other services	Others	Dec. 31, 2019
France excluding Infrastructures	3,207	4,160	144	8,338	5	15,854
France Infrastructures	64	1	5,265	218	22	5,569
<i>Total France</i>	<i>3,271</i>	<i>4,160</i>	<i>5,409</i>	<i>8,556</i>	<i>27</i>	<i>21,423</i>
Rest of Europe	3,147	6,403	331	7,321	66	17,267
Latin America	559	3,840	351	457	134	5,341
USA & Canada	465	2,734	2	1,254	3	4,457
Middle East, Asia & Africa	446	1,293	44	1,053	101	2,937
Others	3,464	3,303	106	1,141	619	8,633
TOTAL REVENUES	11,351	21,732	6,244	19,781	949	60,058

7.2 Trade and other receivables, assets and liabilities from contracts with customers

Accounting standards

On initial recognition, trade and other receivables are recorded at their transaction price as defined in IFRS 15.

A contract asset is an entity's right to consideration in exchange for goods or services that have been transferred to a customer but for which payment is not yet due or is contingent on the satisfaction of a specific condition stipulated in the contract. When an amount becomes due, it is transferred to receivables.

A receivable is recorded when the entity has an unconditional right to consideration. A right to consideration is unconditional if only the passage of time is required before payment of that consideration.

A contract liability is an entity's obligation to transfer goods or services to a customer for which the entity has already received consideration from the customer. The liability is derecognized upon recognition of the corresponding revenue.

Trade and other receivables and assets from contracts with customers are tested for impairment in accordance with the provisions of IFRS 9 on expected credit losses.

The impairment model for financial assets is based on the expected credit loss model. To calculate expected losses, the Group uses a matrix approach for trade receivables and assets from contracts with customers, for which the change in credit risk is monitored on a portfolio basis. An individual approach is used for large customers and other large counterparties, for which the change in credit risk is monitored on an individual basis.

See Note 17 "Risks arising from financial instruments" for the Group's assessment of counterparty risk.

7.2.1 Trade and other receivables and assets from contracts with customers

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Trade and other receivables, net	14,295	15,180
Of which IFRS 15	6,897	7,385
Of which non-IFRS15	7,398	7,795
Assets from contracts with customers	7,764	7,831
Accrued income and unbilled revenues	6,754	6,783
Energy in the meter ⁽¹⁾	1,010	1,048

(1) Net of advance payments.

In 2020, the segments reporting the greatest amounts of assets from contracts were France excluding Infrastructures (€2,817 million, mainly ENGIE Solutions and BtoC), Rest of Europe (€2,501 million, mainly in Benelux, Germany and the United Kingdom) and Others (€1,086 million mainly the GEM BU).

<i>In millions of euros</i>	Dec. 31, 2020			Dec. 31, 2019		
	Gross	Allowances and expected credit losses	Net	Gross	Allowances and expected credit losses	Net
Trade and other receivables, net	15,568	(1,273)	14,295	16,277	(1,097)	15,180
Assets from contracts with customers	7,784	(20)	7,764	7,848	(17)	7,831
TOTAL	23,351	(1,292)	22,059	24,125	(1,114)	23,011

Gas and electricity in the meter

For customers whose energy consumption is metered during the accounting period, the gas supplied but not yet metered at the reporting date is estimated based on historical data, consumption statistics and estimated selling prices.

For sales on networks used by a large number of grid operators, the Group is allocated a certain volume of energy transiting through the networks by the grid managers. As the final allocations are sometimes only known several months down the line, revenue figures cannot be determined with absolute certainty. However, the Group has developed measuring and modeling tools allowing it to estimate revenues with a reasonable degree of accuracy and subsequently ensure that risks of error associated with estimating quantities sold and the related revenues can be considered as immaterial.

In France and Belgium, un-metered revenues ("gas in the meter") are calculated using a direct method taking into account customers' estimated consumption based on the last invoice or metering not yet billed. These estimates are in line with the volume of energy allocated by the grid managers over the same period. The average price is used to measure "gas in the meter" and takes account of the category of customer and the age of the delivered unbilled "gas in the meter". The portion of unbilled revenues at the reporting date varies according to the assumptions about volume and average price.

"Electricity in the meter" is also determined using a direct allocation method similar to that used for gas, but taking into account specific factors related to electricity consumption. It is also measured on a customer-by-customer basis or by customer type.

Realized but not yet metered revenues ("un-metered revenues") mainly related to France and Belgium for an amount of €3,079 million at December 31, 2020 (€3,275 million at December 31, 2019).

7.2.2 Liabilities from contracts with customers

<i>In millions of euros</i>	Dec. 31, 2020			Dec. 31, 2019		
	Non-current	Current	Total	Non-current	Current	Total
Liabilities from contracts with customers	39	4,315	4,354	45	4,286	4,330
Advances and downpayments received	15	2,123	2,138	11	2,190	2,201
Deferred revenues	25	2,192	2,217	34	2,096	2,129

In 2020, the segments reporting the greatest amounts of revenues recognized over time due to the time lag between the payments and the performance of the services, are France excluding Infrastructures (€2,332 million, mainly in France BtoB and BtoC) and Rest of Europe (€1,455 million, mainly in Benelux and in Germany).

7.3 Revenues relating to performance obligations not yet satisfied

Revenues relating to performance obligations only partially satisfied at December 31, 2020 amounted to €15,883 million. They mainly concern the United Kingdom (€7,337 million) and ENGIE Solutions (€5,250 million) BUs. These BUs handle a large number of construction, installation, maintenance and facility management contracts under which revenues are recognized over time. The Benelux, Tractebel Engineering and North, South and Eastern Europe BUs will also be recognizing revenues over the next three years for performance obligations satisfied over time.

NOTE 8 OPERATING EXPENSES

Accounting standards

Operating expenses include:

- purchases and operating derivatives including:
 - the purchase of commodities and associated costs (infrastructure, transport, storage, etc.),
 - the realized impact, as well as the change in fair value (MtM), of commodity transactions, with or without physical delivery, that fall within the scope of IFRS 9 - *Financial Instruments* and that do not qualify as trading or hedging. These contracts are set up as part of economic hedges of operating transactions in the energy sector;
- purchases of services and other items such as subcontracting and interim expenses, lease expenses (short-term lease contracts or leases with a low underlying asset value), concession expenses, etc.;
- personnel costs;
- depreciation, amortization, and provisions; and
- taxes.

8.1 Purchases and operating derivatives

In millions of euros	Dec. 31, 2020	Dec. 31, 2019
Purchases and other income and expenses on operating derivatives other than trading ⁽¹⁾	(24,078)	(28,795)
Service and other purchases ⁽²⁾	(10,889)	(10,609)
PURCHASES AND OPERATING DERIVATIVES	(34,967)	(39,404)
<p>(1) Of which net income of €199 million in 2020 relating to MtM on commodity contracts other than trading (compared to a net expense of €426 million in 2019).</p> <p>(2) Of which €175 million in lease expenses, relating to short-term lease contracts and leases with a low underlying asset value in 2020 (compared to €258 million in lease expenses in 2019).</p>		

8.2 Personnel costs

In millions of euros	Notes	Dec. 31, 2020	Dec. 31, 2019
Short-term benefits		(11,191)	(10,933)
Share-based payments	21	(53)	(56)
Costs related to defined benefit plans	20.3.4	(267)	(368)
Costs related to defined contribution plans	20.4	(248)	(121)
PERSONNEL COSTS		(11,759)	(11,478)

8.3 Depreciation, amortization and provisions

In millions of euros	Notes	Dec. 31, 2020	Dec. 31, 2019
Depreciation and amortization	14 & 15	(4,648)	(4,497)
Net change in write-downs of inventories, trade receivables and other assets		(239)	(104)
Net change in provisions	19	110	208
DEPRECIATION, AMORTIZATION AND PROVISIONS		(4,778)	(4,393)

At December 31, 2020, depreciation and amortization mainly break down as €995 million for intangible assets and €3,655 million for property, plant and equipment.

NOTE 9 OTHER ITEMS OF INCOME/(LOSS) FROM OPERATING ACTIVITIES

Accounting standards

Other items of Income/(loss) from operating activities include:

- “Impairment losses”: this line include impairment losses on goodwill, other intangible assets, property, plant and equipment and investments in entities consolidated using the equity method of accounting;
- “Restructuring costs”: this line concern costs corresponding to a restructuring program planned and controlled by management that materially changes either the scope of a business undertaken by the entity, or the manner in which that business is conducted, based on the criteria set out in IAS 37;
- “Changes in the scope of consolidation”. This line includes:
 - direct costs related to acquisitions of controlling interests,
 - in a business combination achieved in stages, remeasurement at fair value at the acquisition date of the previously held interest,
 - subsequent changes in the fair value of contingent consideration,
 - gains or losses from disposals of investments which result in a change of consolidation method, as well as any impact from the remeasurement of retained interests with the exception of gains and losses arising from transactions realized in the framework of “Develop, Build, Share & Operate” (DBSO) or “Develop, Share, Build & Operate” (DSBO) business models. These transactions on renewable activities are recognized in current operating income as they are part of the recurring rotation of the Group’s capital employed;
- “Other non-recurring items”: this line includes other elements of an inhabited, abnormal or infrequent nature..

9.1 Impairment losses

<i>In millions of euros</i>	Notes	Dec. 31, 2020	Dec. 31, 2019
Impairment losses:			
Goodwill	13.1	(2,145)	(116)
Property, plant and equipment and other intangible assets	14 & 15	(1,257)	(1,735)
Investments in equity method entities and related provisions		(237)	-
TOTAL IMPAIRMENT LOSSES		(3,639)	(1,851)
Reversal of impairment losses:			
Property, plant and equipment and other intangible assets		88	61
Investments in equity method entities and related provisions		-	20
TOTAL REVERSALS OF IMPAIRMENT LOSSES		88	81
TOTAL		(3,551)	(1,770)

Net impairment losses amounted to €3,551 million in 2020, relating mainly to goodwill, property, plant and equipment and intangible assets. After taking into account the deferred tax effects and the share of impairment losses attributable to non-controlling interests, the impact of these impairment losses on net income Group share for 2020 amounted to €3,420 million.

Impairment tests are performed in accordance with the conditions described in Note 13.3.

9.1.1 Impairment losses recognized in 2020

Net impairment losses amounted to €3,551 million in 2020 and mainly concerned:

- **Goodwill for the Nuclear CGU** (€2,145 million) and **Belgian nuclear reactors** (€715 million)

Following the announcements made by the Belgian government in Autumn 2020 and the talks held since then, the Group considered that it could no longer justify the assumption that the operating life of half of its second-generation reactors could be extended for 20 years beyond 2025.

The impairment losses over the year take into consideration this major assumption change, the level of forward prices observed in the second half of 2020 and the update of the Group's long-term pricing scenario in light of the latest forecasts for demand, the price of CO₂ and the change in the energy mix.

- Other impairment losses

Other impairment losses recognized by the Group mainly concerned:

- an investment in a gas production asset in Algeria (€123 million);
- thermal power generation assets in the Middle East (€115 million);
- other thermal and renewable power generation assets in Mexico (€70 million), North America (€69 million) and Brazil (€64 million).

9.1.2 Impairment losses recognized in 2019

Net impairment losses amounted to €1,770 million in 2019, and mainly concerned:

- the Belgian nuclear facilities whose operating life may no longer be extended (€1,023 million) following the triennial review of nuclear provisions and the resulting increase in the carrying amount of the related dismantling assets in a context of falling prices;
- other impairment losses relating to thermal power generation assets in Latin America (€165 million) and the Middle East (€135 million), the intangible asset corresponding to the France BtoC client portfolio value (€111 million) and the value adjustments of several coal-fired power plants in Germany and the Netherlands in connection with their disposal (€148 million).

After taking into account the deferred tax effects and the share of impairment losses attributable to non-controlling interests, the impact of these impairment losses on net income Group share for 2019 amounted to €1,579 million.

9.2 Restructuring costs

In 2020, restructuring costs totaled €343 million (versus €218 million in 2019). Restructuring costs in both years mainly included costs related to staff reduction plans and measures to adapt to economic situations, as well as the shutdown or sale of operations, the closure or restructuring of certain facilities and other miscellaneous restructuring costs.

9.3 Changes in scope of consolidation

At December 31, 2020, the impact of changes in the scope of consolidation was a positive €1,640 million and mainly comprised (i) the positive impact of the disposal of the majority of ENGIE's interest in SUEZ for €1,735 million, (ii) the positive impact of the disposal of the Group's interests in Astoria 1 and 2 in the United States for €95 million, partially offset by (iii) a negative impact of €62 million relating to the disposal of MultiTech in Canada and (iv) a negative €51 million change in the earn-out from the disposal of LNG activities to TOTAL in 2018.

At December 31, 2019, the impact of changes in the scope of consolidation was a positive €1,604 million and mainly comprised the positive impact of the sale of Glow for €1,580 million, including €143 million in respect of items of other comprehensive income recycled to the income statement.

9.4 Other non-recurring items

Other non-recurring items at December 31, 2020 totaled a negative €886 million and mainly included, in addition to the impacts of the adjustment to provisions for the dismantling and rehabilitation of industrial sites, the effects of extending the trading management method launched by the GEM BU in 2017 to the rest of the Group's gas positions in Europe:

The management framework for the Group's gas positions in Europe changed in 2017 for the majority of the long-term contracts managed by the GEM BU, shifting to an individual approach per contract based on market conditions rather than as part of a portfolio. In 2020, ENGIE decided to extend this trading management model to the rest of its gas positions, thereby taking full account of the consequences of contractual changes and an expected increase in the volumes available in this area now under the trading business model. The implementation of the new management method to this extended scope has been made possible thanks to the rollout of tools that allow for a better economic vision of the positions. To this end, a new organization was put in place in December 2020.

As a result of this change in management framework, the Group extended fair value accounting to the assets in question, leading to an initial accounting impact of fair value measurement of a negative €726 million. From then on, the Group's results take into account the realized and unrealized gains and losses relating to these gas positions through the trading net margin presented in revenues and current operating income.

At December 31, 2019, other non-recurring items totaling a negative €1,240 million mainly included the non-recurring impact of the nuclear provision review (back-end of the cycle) and other miscellaneous expenses for a negative €1,166 million.

NOTE 10 NET FINANCIAL INCOME/(LOSS)

<i>In millions of euros</i>	Expense	Income	Dec. 31, 2020	Expense	Income	Dec. 31, 2019
<i>Interest expense on gross debt and hedges</i>	(901)	-	(901)	(894)	-	(894)
<i>Foreign exchange gains/losses on borrowings and hedges</i>	(21)	-	(21)	-	30	30
<i>Ineffective portion of derivatives qualified as fair value hedges</i>	-	-	-	(3)	-	(3)
<i>Gains and losses on cash and cash equivalents and liquid debt instruments held for cash investment purposes</i>	-	47	47	-	84	84
<i>Capitalized borrowing costs</i>	103	-	103	106	-	106
Cost of net debt	(819)	47	(772)	(790)	114	(676)
Cost of lease liabilities	(47)	-	(47)	(48)	-	(48)
<i>Cash payments made on the unwinding of swaps</i>	(44)	-	(44)	(62)	-	(62)
<i>Reversal of the negative fair value of these early unwound derivative financial instruments</i>	-	31	31	-	62	62
<i>Expenses on debt restructuring transactions</i>	(16)	-	(16)	-	6	6
Gains/(losses) on debt restructuring and early unwinding of derivative financial instruments	(60)	31	(29)	(62)	68	6
<i>Net interest expense on post-employment benefits and other long-term benefits</i>	(89)	-	(89)	(121)	-	(121)
<i>Unwinding of discounting adjustments to other long-term provisions</i>	(614)	-	(614)	(566)	-	(566)
<i>Change in fair value of derivatives not qualified as hedges and ineffective portion of derivatives qualified as cash flow hedges</i>	(158)	-	(158)	(223)	-	(223)
<i>Income/(loss) from debt instruments and equity instruments</i>	(97)	73	(24)	(34)	212	179
<i>Interest income on loans and receivables at amortized cost</i>	-	178	178	-	169	169
<i>Other</i>	(346)	225	(122)	(457)	350	(107)
Other financial income and expenses	(1,306)	475	(830)	(1,400)	731	(669)
NET FINANCIAL INCOME/(LOSS)	(2,232)	553	(1,678)	(2,300)	913	(1,387)

The cost of net debt is higher compared to December 31, 2019, due to the drop in cash remuneration and a more unfavorable foreign exchange result.

Losses from debt and equity instruments amounted to €24 million. This amount includes the negative change in fair value of money market funds held by Synatom for a negative amount of €66 million (see Note 16.1.1.2 "Debt instruments at fair value").

At December 31, 2020, the average cost of debt after hedging came out at 2.38% compared with 2.70% at December 31, 2019.

NOTE 11 INCOME TAX EXPENSE

Accounting standards

The Group calculates taxes in accordance with prevailing tax legislation in the countries where income is taxable.

In accordance with IAS 12, deferred taxes are recognized according to the liability method on temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and their tax bases, using tax rates that have been enacted or substantively enacted by the reporting date. However, under the provisions of IAS 12, no deferred tax is recognized for temporary differences arising from goodwill for which impairment losses are not deductible for tax purposes, or from the initial recognition of an asset or liability in a transaction which (i) is not a business combination and (ii) at the time of the transaction, affects neither accounting income nor taxable income. In addition, deferred tax assets are only recognized to the extent that it is probable that taxable income will be available against which the deductible temporary differences can be utilized.

A deferred tax liability is recognized for all taxable temporary differences associated with investments in subsidiaries, associates, joint ventures and branches, except if the Group is able to control the timing of the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

Net balances of deferred taxes are calculated based on the tax position of each company or on the total income of companies included within the relevant consolidated tax group, and are presented in assets or liabilities for their net amount per tax entity.

Deferred taxes are reviewed at each reporting date to take into account factors including the impact of changes in tax laws and the prospects of recovering deferred tax assets arising from deductible temporary differences.

Deferred tax assets and liabilities are not discounted.

Tax effects relating to coupon payments on deeply-subordinated perpetual notes are recognized in profit or loss.

11.1 Actual income tax expense recognized in the income statement

11.1.1 Breakdown of actual income tax expense recognized in the income statement

The tax expense recognized in the income statement for 2020 amounts to €715 million (€640 million income tax expense in 2019). It breaks down as follows:

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Current income taxes	(801)	(761)
Deferred taxes	85	121
TOTAL INCOME TAX BENEFIT/(EXPENSE) RECOGNIZED IN INCOME	(715)	(640)

11.1.2 Reconciliation of theoretical income tax expense with actual income tax expense

A reconciliation of theoretical income tax expense with the Group's actual income tax expense is presented below:

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Net income/(loss)	(893)	1,649
Share in net income of equity method entities	552	500
Income tax expense	(715)	(640)
Income/(loss) before income tax expense and share in net income of associates (A)	(730)	1,790
Of which French companies	1,559	285
Of which companies outside France	(2,288)	1,505
Statutory income tax rate of the parent company (B)	32.0%	34.4%
THEORETICAL INCOME TAX EXPENSE (C) = (A) X (B)	234	(616)
Reconciling items between theoretical and actual income tax expense		
Difference between statutory tax rate applicable to the parent and statutory tax rate in force in jurisdictions in France and abroad	(183)	215
Permanent differences ⁽¹⁾	(627)	(23)
Income taxed at a reduced rate or tax-exempt ⁽²⁾	571	533
Additional tax expense ⁽³⁾	(392)	(123)
Effect of unrecognized deferred tax assets on tax loss carry-forwards and other tax-deductible temporary differences ⁽⁴⁾	(638)	(867)
Recognition or utilization of tax income on previously unrecognized tax loss carry-forwards and other tax-deductible temporary differences ⁽⁵⁾	266	212
Impact of changes in tax rates ⁽⁶⁾	(106)	(55)
Tax credits and other tax reductions ⁽⁷⁾	112	101
Other ⁽⁸⁾	47	(16)
INCOME TAX BENEFIT/(EXPENSE) RECOGNIZED IN INCOME	(715)	(640)

- (1) *Mainly includes disallowable impairment losses on goodwill, disallowable operating expenses and the deduction of interest expenses arising from hybrid debt.*
- (2) *Mainly includes capital gains on disposals of securities exempt from tax or taxed at a reduced rate in some tax jurisdictions, the impact of the specific tax regimes used by some entities, disallowable impairment losses and capital losses on securities, and the impact of untaxed income from remeasuring previously-held (or retained) equity interests in connection with acquisitions and changes in consolidation methods.*
- (3) *Mainly includes tax on dividends resulting from the parent company tax regime, withholding tax on dividends and interest levied in several tax jurisdictions, allocations to provisions for income tax, and regional and flat-rate corporate taxes.*
- (4) *Includes (i) the cancellation of the net deferred tax asset position for some tax entities in the absence of sufficient profit being forecast and (ii) the impact of disallowable impairment losses on fixed assets.*
- (5) *Includes the impact of the recognition of net deferred tax asset positions for some tax entities.*
- (6) *Mainly includes the impact of tax rate changes on deferred tax balances in France, the United Kingdom for 2020 and Luxembourg for 2019.*
- (7) *Mainly includes reversals of provisions for tax litigation, tax credits in France and other tax reductions.*
- (8) *Mainly includes the correction of previous tax charges.*

The Group reviewed the net deferred tax positions based on projections of future taxable income, including the expected effects of the COVID-19 crisis and the legal changes approved in 2020. The effects were limited to a few countries.

11.1.3 Analysis of the deferred tax income/(expense) recognized in the income statement, by type of temporary difference

<i>In millions of euros</i>	Impact in the income statement	
	Dec. 31, 2020	Dec. 31, 2019
Deferred tax assets:		
Tax loss carry-forwards and tax credits	(203)	572
Pension and related obligations	(78)	28
Non-deductible provisions	222	(137)
Difference between the carrying amount of PP&E and intangible assets and their tax bases	276	(93)
Measurement of financial instruments at fair value (IAS 32 / IFRS 9)	488	(1,360)
Other	(40)	(36)
TOTAL	666	(1,028)
Deferred tax liabilities:		
Difference between the carrying amount of PP&E and intangible assets and their tax bases	2	(239)
Measurement of financial instruments at fair value (IAS 32 / IFRS 9)	(437)	1,661
Other	(146)	(273)
TOTAL	(581)	1,149
DEFERRED TAX INCOME/(EXPENSE)	85	121

11.2 Deferred tax income/(expense) recognized in “Other comprehensive income”

Net deferred tax income/(expense) recognized in “Other comprehensive income” is broken down by component as follows:

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Equity and debt instruments	(10)	(2)
Actuarial gains and losses	399	256
Net investment hedges	(27)	12
Cash flow hedges on other items	(128)	218
Cash flow hedges on net debt	17	10
TOTAL EXCLUDING SHARE OF EQUITY METHOD ENTITIES	253	494
Share of equity method entities	116	81
TOTAL	369	575

11.3 Deferred taxes presented in the statement of financial position

11.3.1 Change in deferred taxes

Changes in deferred taxes recognized in the statement of financial position, after netting deferred tax assets and liabilities by tax entity, break down as follows:

<i>In millions of euros</i>	Assets	Liabilities	Net position
AT DECEMBER 31, 2019	860	(4,631)	(3,771)
Impact on net income for the year	666	(580)	85
Impact on other comprehensive income items	504	(245)	259
Impact of changes in scope of consolidation	(9)	(19)	(29)
Impact of translation adjustments	(90)	213	122
Transfers to assets and liabilities classified as held for sale	(39)	29	(10)
Other	(723)	530	(193)
Impact of netting by tax entity	(288)	288	-
AT DECEMBER 31, 2020	880	(4,416)	(3,536)

11.3.2 Analysis of the net deferred tax position recognized in the statement of financial position (before netting deferred tax assets and liabilities by tax entity), by type of temporary difference

Accounting standards

Measurement of recognized tax loss carry-forwards

Deferred tax assets are recognized on tax loss carry-forwards when it is probable that taxable profit will be available against which the tax loss carry-forwards can be utilized. The probability that taxable profit will be available against which the unused tax losses can be utilized, is based on taxable temporary differences relating to the same taxation authority and the same taxable entity and estimates of future taxable profits. These estimates and utilizations of tax loss carry-forwards were prepared on the basis of profit and loss forecasts over a six-year tax projection period as included in the medium-term business plan validated by Management, subject to exceptions justified by a particular context and, if necessary, on the basis of additional forecasts.

<i>In millions of euros</i>	Statement of financial position at	
	Dec. 31, 2020	Dec. 31, 2019
Deferred tax assets:		
Tax loss carry-forwards and tax credits	1,771	2,118
Pension obligations	2,061	1,635
Non-deductible provisions	434	268
Difference between the carrying amount of PP&E and intangible assets and their tax bases	953	763
Measurement of financial instruments at fair value (IAS 32 / IFRS 9)	2,148	2,199
Other	444	518
TOTAL	7,810	7,502
Deferred tax liabilities:		
Difference between the carrying amount of PP&E and intangible assets and their tax bases	(8,531)	(8,953)
Measurement of financial instruments at fair value (IAS 32 / IFRS 9)	(2,067)	(1,700)
Other	(748)	(620)
TOTAL	(11,346)	(11,273)
NET DEFERRED TAX ASSETS/(LIABILITIES)	(3,536)	(3,772)

11.4 Unrecognized deferred taxes

At December 31, 2020, the tax effect of tax losses and tax credits eligible for carry-forward but not utilized and not recognized in the statement of financial position amounted to €4,061 million (€3,836 million at December 31, 2019). Most of these unrecognized tax losses relate to companies based in countries which allow losses to be carried forward indefinitely (mainly Belgium, Luxembourg and the Netherlands). These tax loss carry-forwards did not give fully or partially rise to the recognition of deferred tax due to the absence of sufficient profit forecasts in the medium term.

The tax effect of other tax-deductible temporary differences not recorded in the statement of financial position was €823 million at end-December 2020 versus €929 million at end-December 2019.

NOTE 12 EARNINGS PER SHARE

Accounting standards

Basic earnings per share is calculated by dividing net income Group share for the year by the weighted average number of ordinary shares outstanding during the year. The average number of ordinary shares outstanding during the year is the number of ordinary shares outstanding at the beginning of the year, adjusted by the number of ordinary shares bought back or issued during the year.

For the diluted earnings per share calculation, the weighted average number of shares and basic earnings per share are adjusted to take into account the impact of the conversion or exercise of any dilutive potential ordinary shares (options, warrants and convertible bonds, etc.).

In compliance with IAS 33 – *Earnings per Share*, earnings per share and diluted earnings per share are based on net income/(loss) Group share after deduction of payments to bearers of deeply-subordinated perpetual notes (see Note 18.2.1 “Issuance of deeply-subordinated perpetual notes”).

The Group’s dilutive instruments included in the calculation of diluted earnings per share include bonus shares and performance shares granted in the form of ENGIE securities.

	Dec. 31, 2020	Dec. 31, 2019
Numerator (in millions of euros)		
Net income/(loss) Group share	(1,536)	984
Interest from deeply-subordinated perpetual notes	(187)	(165)
Net income/(loss) used to calculate earnings per share	(1,723)	820
Impact of dilutive instruments	-	-
Diluted net income/(loss) Group share	(1,723)	820
Denominator (in millions of shares)		
Average number of outstanding shares	2,416	2,413
Impact of dilutive instruments:		
Bonus share plans reserved for employees	11	12
Diluted average number of outstanding shares	2,427	2,425
Earnings per share (in euros)		
Basic earnings/(loss) per share	(0.71)	0.34
Diluted earnings/(loss) per share	(0.71)	0.34

NOTE 13 GOODWILL

Accounting standards

Upon a business combination, goodwill is measured as the difference between:

- on the one hand the sum of:
 - the consideration transferred;
 - the amount of non-controlling interests in the acquiree; and
 - in a business combination achieved in stages, the acquisition-date fair value of the previously held equity interest in the acquiree;
- on the other hand the net fair value of the identifiable assets acquired and liabilities assumed. The key assumptions and estimates used to determine the fair value of assets acquired and liabilities assumed include the market outlook for the measurement of future cash flows as well as applicable discount rates. These assumptions reflect management's best estimates at the acquisition date.

The amount of goodwill recognized at the acquisition date cannot be adjusted after the end of the 12 month measurement period.

Goodwill relating to interests in associates is recorded under "Investments in equity method entities".

Risk of impairment

Goodwill is not amortized but tested for impairment each year in accordance with IAS 36, or more frequently where an indication of impairment is identified. Impairment tests are carried out at the level of cash-generating units (CGUs) or groups of CGUs, which constitute groups of assets which generate cash flows that are largely independent from cash flows generated by other CGUs.

Goodwill is impaired if the net carrying amount of the CGU to which the goodwill is allocated is greater than the recoverable amount of that CGU. The methods used to carry out these impairment tests are described in Note 13.3.

Impairment losses in relation to goodwill cannot be reversed and are shown as "Impairment losses" in the income statement.

Indicators of goodwill impairment

The main indicators of impairment used by the Group are:

- using external sources of information
 - a decline in an asset's value over the period that is significantly more than would be expected from the passage of time or normal use;
 - significant adverse changes that have taken place over the period, or will take place in the near future, in the technological market, economic or legal environment in which the entity operates or in the market to which an asset is dedicated;
 - an increase over the period in market interest rates or other market rates of return on investments if such increase is likely to affect the discount rate used in calculating an asset's value in use and decrease its recoverable amount materially;
 - the carrying amount of the net assets of the entity exceeds its market capitalization;
- using internal sources of information
 - evidence of obsolescence or physical damage to an asset

- significant changes in the extent to which, or manner in which, an asset is used or is expected to be used, that have taken place in the period or soon thereafter and that will adversely affect it. These changes include the asset becoming idle, plans to dispose of an asset sooner than expected, reassessing its useful life as finite rather than indefinite or plans to restructure the operations to which the asset belongs;
- internal reports that indicate that the economic performance of an asset is, or will be, worse than expected.

13.1 Movements in the carrying amount of goodwill

<i>In millions of euros</i>	Net amount
AT DECEMBER 31, 2019	18,665
Impairment losses	(2,145)
Changes in scope of consolidation and Other	(151)
Translation adjustments	(330)
AT DECEMBER 31, 2020	15,943

Changes during the period mainly comprise impairment of goodwill related to the Nuclear CGU, and the disposal of the Group's interests in Astoria 1 and 2, offset by various acquisitions made during the year (see Note 4 "Main changes in Group structure").

13.2 Goodwill CGUs

The table below shows "material" goodwill CGUs at December 31, 2020:

<i>In millions of euros</i>	Operating segment	Dec. 31, 2020
MATERIAL CGUs		
GRDF	France Infrastructures	4,009
Nuclear	Rest of Europe	797
Engie Solutions	France excl. Infrastructures	1,470
Benelux	Rest of Europe	1,242
France Renewable Energy	France excl. Infrastructures	1,178
United Kingdom	Rest of Europe	1,019
OTHER SIGNIFICANT CGUs		
France BtoC	France excl. Infrastructures	1,050
Northern, Southern and Central Europe	Rest of Europe	863
GRTgaz	France Infrastructures	614
North America	USA & Canada	538
Generation Europe	Rest of Europe	521
OTHER CGUs		2,642
TOTAL		15,943

During 2020, the Group made certain adjustments to its organization structure (see Note 6 "Segment information"):

- the France B2B and France Networks CGUs have been combined into a single CGU called ENGIE Solutions;
- the Benelux BU has been split into three separate CGUs: Nuclear, Renewables and Benelux (energy services, electricity sales and gas sales activities);
- ENGIE Impact's share of the goodwill related to the North America and Tractebel CGUs has been reallocated to the Impact CGU.

13.3 Impairment testing of goodwill CGUs

All goodwill CGUs were tested for impairment. In addition, intangible assets and property plant and equipment were tested at the level of the relevant group of assets, whenever there was an indication of impairment. The current environment, which has been affected by the COVID-19 crisis, has had consequences that are indications of potential impairment, in particular the fall in energy prices, decline in the BtoB sector and fall in the stock markets. The Group did not identify any increased risk of impairment due to the COVID-19 crisis, in particular for assets used in capital-light activities or with little

exposure to short-term changes in market conditions. This is particularly the case for regulated infrastructures, the historical client solutions businesses and the energy sales business.

The impairment tests are based on data as of end-June, plus a review of events arisen in the second half of the year.

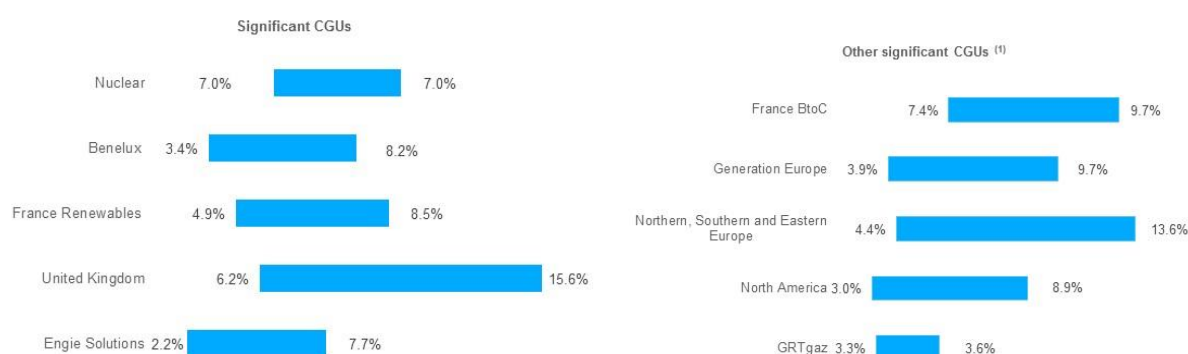
In most cases, the recoverable amount of CGUs is determined by reference to a value in use that is calculated using cash flow projections drawn up on the basis of the 2021 budget and the 2022-2023 medium-term business plan, as approved by the Executive Committee and the Board of Directors, and on extrapolated cash flows beyond that time frame.

Cash flow projections are determined on the basis of macroeconomic assumptions (inflation, exchange rates and growth rates) and price forecasts resulting from the Group's reference scenario for 2024-2040. The forecasts that feature in the reference scenario were approved by the Executive Committee in December 2020. The forecasts and projections included in the reference scenario were determined on the basis of the following inputs:

- forward market prices over the liquidity period for fuel (coal, oil and gas), CO₂ and electricity on each market;
- beyond this period, medium- and long-term energy prices were determined by the Group based on macroeconomic assumptions and fundamental supply and demand equilibrium models, the results of which are regularly compared against forecasts prepared by external energy sector specialists. Long-term projections for CO₂ prices are in line with the 2050 climate neutrality objectives set by the European Commission as part of the "European Green Deal" presented in December 2019. More specifically, medium- and long-term electricity prices were determined by the Group using electricity demand forecasting models, medium- and long-term forecasts of fuel and CO₂ prices, and expected trends in installed capacity and in the technology mix of the production assets within each power generation system.

Discount rate

The discount rates used correspond to the weighted average cost of capital, which is adjusted in order to reflect the business, market, country and currency risk relating to each goodwill CGU reviewed. The discount rates used are consistent with available external information sources. The post-tax rates used in 2020 to measure the value in use of the goodwill CGUs for discounting future cash flows ranged between 2.2% and 15.6%, compared with a range of between 3.1% and 13.1% in 2019. The discount rates used for the main goodwill CGUs are shown below:



(1) The valuation methods used are the discounted cash flows (DCF) method and the discounted dividend model (DDM) method.

13.3.1 Material CGUs

This section presents the method for determining value in use, the key assumptions underlying the valuation, and the sensitivity analyses for the impairment tests on the Group's main goodwill CGUs at December 31, 2020.

13.3.1.1 GRDF CGU

The total amount of goodwill allocated to the GRDF CGU was €4,009 million at December 31, 2020. The GRDF CGU groups together the Group's regulated natural gas distribution activities in France.

The terminal value used to calculate the value in use corresponds to the expected Regulated Asset Base (RAB) with no premium at the end of 2026. The RAB is the value assigned by the French Energy Regulation Commission (CRE) to the assets operated by the distributor. It is the sum of the future pre-tax cash flows, discounted at the pre-tax rate of return guaranteed by the regulator.

The cash flow projections are drawn up based on the tariff for public natural gas distribution networks, known as the "ATRD 6 tariff", which entered into force for a period of four years on July 1, 2020, and on the overall level of investments agreed by the CRE as part of its decision on the "ATRD 6 tariff".

Given the regulated nature of the businesses grouped within the GRDF CGU, a reasonable change in any of the valuation inputs would not result in impairment losses.

13.3.1.2 Nuclear CGU

The goodwill allocated to the Nuclear CGU amounted to €797 million at December 31, 2020. The Group's Nuclear CGU encompasses the power generation activities from its nuclear power plants in Belgium and drawing rights on the Chooz B and Tricastin power plants in France.

Key assumptions used for the impairment test

The cash flow projections for the Nuclear CGU are based on a large number of key assumptions, such as prices of fuel and CO₂, expected trends in electricity demand and prices, availability of power plants, the market outlook, and changes in the regulatory environment (especially concerning nuclear capacities in Belgium and the extension of drawing rights agreements for French nuclear plants). The key assumptions also include the discount rate used to calculate the value in use of this goodwill CGU.

Cash flow projections for the period beyond the medium-term business plan were determined as described below:

Activities	Assumptions applied beyond the term of the business plan ⁽¹⁾
Nuclear power generation in Belgium	For Doel 1, Doel 2 and Tihange 1, cash flow projection over the residual useful life of 50 years. For the second generation reactors Doel 3, Doel 4, Tihange 2 and Tihange 3, cash flow projection over the residual useful life of 40 years without any hypothesis of extension unlike previous years.
Drawing rights on Chooz B and Tricastin power plants	Cash flow projection over the remaining term of existing contract plus assumption that drawing rights will be extended for a further 10 years.

The most important assumptions concerning the Belgian regulatory environment relate to the operating life of existing nuclear reactors.

The impairment test took into account the 10-year extension (through 2025) of the operating life of Tihange 1, Doel 1 and Doel 2, annual royalties totaling €20 million in respect of the extension of Doel 1 and Doel 2, and the new conditions for determining the nuclear contribution that will apply to second-generation reactors (Doel 3 and 4, Tihange 2 and 3) through their 40th year of operation, as defined in the December 29, 2016 law and reviewed by the CREG in 2020.

As regards second-generation reactors, the principle of a gradual phase-out of nuclear power and the schedule for this phase-out, with the shutdown of the reactors of Doel 3 in 2022, Tihange 2 in 2023 and Tihange 3 and Doel 4 in 2025, after 40 years of operation, were first set out in the law of January 31, 2003 on the gradual phase-out of nuclear power for industrial electrical generation, and have been regularly reaffirmed since then in the law of June 18, 2015, the energy pact approved by the government on March 30, 2018, the governmental agreement of September 30, 2020, and the general policy memorandum of November 4, 2020. However, this principle remains combined with analysis mechanisms enabling this decision to be reassessed by end-2021 based on its impacts on the security of supply, the climate, energy prices and the security of power plants subject to a monitoring process. If this monitoring process reveals a potential supply security problem, the 2020 governmental agreement provides for the option of adjusting the phase-out schedule for capacity of up

to 2 GW. However, in view of the Belgian government's announcements in Autumn 2020 and its talks with the Group since then, the Group considered that for the 2020 impairment test, unlike prior years, the operating conditions for carrying out pre-extension work were no longer met and therefore no longer justified the assumption that the life of half of its second generator reactors could be extended for 20 years beyond 2025.

In France, the Nuclear Safety Authority authorized the start-up of Tricastin 1 on December 20, 2019 after its shutdown for its fourth 10-yearly inspection and, on December 3, 2020, published a draft decision setting out the conditions for the 900 MW reactors to continue operating beyond 40 years. Confirmation of a 10-year extension of the operating life of the 900 MW series reactors is therefore expected to be formalized in the next few years, once the conditions for continued operation have been determined by the Nuclear Safety Authority and a public inquiry has been held. The Group therefore included an assumption that the operating life of the Tricastin and Chooz B nuclear plants would be extended for 10 years after their fourth 10-yearly inspection and that, therefore, so would the Group's drawing rights expiring on average in 2021 and 2039 respectively. This assumption had already been made in prior years, as the Group considered, in line with its reference scenario on developments in the French energy mix, that an extension of the operating life of those reactors was the most credible and most probable scenario.

Results of the impairment test

Given the material assumption change described above, the forward prices observed in the second half of 2020, and the Group's long-term pricing scenario updated based on the latest forecasts for demand, CO2 prices and developments in the energy mix, the Group recognized an impairment loss of €715 million against its nuclear assets in Belgium and €2,145 million against the goodwill allocated to the Nuclear CGU at December 31, 2020. The carrying amount of the residual goodwill was €797 million at December 31, 2020.

Sensitivity analyses

A decrease of €10/MWh in electricity prices for all nuclear power generation would lead to an additional impairment loss of around €1.7 billion. Conversely, an increase of €10/MWh in electricity prices would increase the recoverable amount of the CGU by around €1.5 billion.

An increase of 50 basis points in the discount rates would lead to an additional impairment loss of around €0.1 billion. A decrease of 50 basis points in the discount rates used would lead to an increase in the recoverable amount of the CGU of around €0.1 billion.

13.3.1.3 ENGIE Solutions CGU

The goodwill allocated to the ENGIE Solutions CGU amounted to €1,470 million at December 31, 2020. The ENGIE Solutions CGU encompasses the following activities in France: (i) energy services and sales for buildings and industry, cities and regions and major infrastructures, and (ii) design, financing, construction and operation of decentralized energy production and distribution facilities (heating and cooling networks).

The terminal value used to calculate the value in use of the services and energy sales businesses was determined by extrapolating the cash flows beyond the medium-term business plan period using a long-term growth rate of 1.85% per year.

The main assumptions and key estimates relate primarily to discount rates and changes in price beyond the liquidity period.

An increase of 50 basis points in the discount rates used would have a negative 25% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 27% impact on the calculation.

A decrease of 10% in the margin captured by power generation assets would have a negative 20% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. An increase of 10% in the margin captured would have a positive 23% impact on this calculation.

13.3.1.4 Benelux CGU

The total amount of goodwill allocated to the Benelux CGU was €1,242 million at December 31, 2020. The Benelux CGU encompasses (i) energy services, electricity and gas sales in Belgium and the Netherlands, and (ii) energy services in Luxembourg.

The terminal value used to calculate the value in use of the services and energy sales businesses was determined by extrapolating the cash flows beyond the medium-term business plan period using a long-term growth rate of 2% per year.

An increase of 50 basis points in the discount rates used would have a negative 21% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 24% impact on the calculation.

A decrease of 10% in the margin on gas and electricity sales activities would have a negative 15% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. Conversely, an increase of 10% in the margin on gas and electricity sales activities would have a positive 15% impact on the calculation.

A decrease of 10% in the margin on service activities would have a negative 16% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. Conversely, an increase of 10% in the margin on services activities would have a positive 16% impact on the calculation.

13.3.1.5 France Renewable Energy CGU

The goodwill allocated to the France Renewable Energy CGU amounted to €1,178 million at December 31, 2020. The France Renewable Energy CGU groups together the development, construction, financing, operation and maintenance of all of the renewable power generation assets in France (hydraulic, wind and photovoltaic).

For the hydraulics business, the terminal value was determined to calculate the value in use by extrapolating the cash flows beyond the medium-term business plan based on the reference scenario adopted by the Group.

The main assumptions and key estimates relate primarily to discount rates, assumptions on the renewal of the hydropower concession agreements and changes in electricity prices beyond the liquidity period.

Value in use of the Compagnie Nationale du Rhône and SHEM was calculated based on assumptions including the extension or renewal of a tender process for the concession agreements, as well as on the conditions of a potential extension.

The cash flows for the periods covered by the renewal of the concession agreements are based on a number of assumptions relating to the economic and regulatory conditions for operating these assets (royalty rates, required level of investment, etc.) during this period.

A decrease of €10/MWh in electricity prices for hydropower generation would have a negative 105% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. Conversely, an increase of €10/MWh in electricity prices would have a positive 102% impact on the calculation.

An increase of 50 basis points in the discount rates used would have a negative 80% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 97% impact on the calculation.

If the Compagnie Nationale du Rhône hydropower concession agreements are not renewed beyond 2023, this would have a strong adverse impact on the results of the test, with the recoverable amount falling significantly below the carrying amount. In this scenario, the impairment risk would represent around €1 billion.

13.3.1.6 United Kingdom CGU

The goodwill allocated to the United Kingdom CGU amounted to €1,019 million at December 31, 2020. The United Kingdom CGU includes activities in (i) renewable power generation (hydraulic, wind and solar), (ii) gas and electricity sales, and (iii) services to individual and professional customers in the United Kingdom.

The terminal value used to calculate the value in use of the services and energy sales businesses was determined by extrapolating the cash flows beyond the medium-term business plan period using a long-term growth rate of 2% per year.

The main assumptions and key estimates relate primarily to discount rates and changes in price beyond the liquidity period.

An increase of 50 basis points in the discount rates used would have a negative 24% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 27% impact on the calculation.

A decrease of 10% in the margin captured by power generation assets would have a negative 23% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. An increase of 10% in the margin captured would have a positive 23% impact on this calculation.

13.3.2 Other significant CGUs

13.3.2.1 North America CGU

The goodwill allocated to the North America CGU amounted to €538 million at December 31, 2020. The North America CGU mainly comprises:

- Canada, which includes activities in (i) renewable power generation, and (ii) services to individual and professional customers;
- the United States, which includes activities in (i) gas and electricity sales and (ii) services to individual and professional customers;
- Puerto Rico, which includes an investment in EcoElectrica, a key energy industry player in Puerto Rico's economy (see Note 3.2 "Investments in joint ventures"). Despite the difficult financial environment in Puerto Rico, ENGIE does not have any information at December 31, 2020 on the basis of which the Group would modify its valuation assumptions, regarding its share in these assets.

The wind and solar energy production activities in the United States make up an independent goodwill CGU.

The value in use of these activities was calculated using the cash flow projections drawn up on the basis of the 2021 budget and the 2022-2023 medium-term business plan. A terminal value was calculated for the services and energy sales businesses using EBITDA multiples as a basis.

The main assumptions and key estimates relate primarily to discount rates and changes in price beyond the liquidity period.

An increase of 50 basis points in the discount rates used would have a negative 46% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 33% impact on the calculation.

A decrease of 10% in the margin on gas and electricity sales activities would have a negative 50% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. Conversely, an increase of 10% in the margin on gas and electricity sales activities would have a positive 30% impact on the calculation.

A decrease of 10% in the margin on service activities would have a negative 35% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. Conversely, an increase of 10% in the margin on services activities would have a positive 16% impact on the calculation.

13.3.2.2 Generation Europe CGU

The goodwill allocated to the Generation Europe CGU amounted to €521 million at December 31, 2020. The Generation Europe CGU groups together the thermal power generation activities in Europe.

The value in use of these activities was calculated using the cash flow projections drawn up on the basis of the 2021 budget and the 2022-2023 medium-term business plan. Beyond this three-year period, cash flows were projected over the useful lives of the assets based on the reference scenario adopted by the Group.

The main assumptions and key estimates relate primarily to discount rates, estimated demand for electricity and changes in the price of CO₂, fuel and electricity beyond the liquidity period.

Results of the impairment test

At December 31, 2020, the recoverable amount of the Generation Europe goodwill CGU was higher than its carrying amount.

Sensitivity analyses

An increase of 50 basis points in the discount rates used would have a negative 13% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. A reduction of 50 basis points in the discount rates used would have a positive 13% impact on the calculation.

A decrease of 10% in the margin captured by thermal power plants would have a negative 29% impact on the excess of the recoverable amount over the carrying amount of the goodwill CGU. However, the recoverable amount would remain above the carrying amount. An increase of 10% in the margin captured would have a positive 29% impact on this calculation.

13.3.2.3 Other significant goodwill CGUs

For the other significant goodwill CGUs, there is a considerable difference between their recoverable amount and their carrying amount at December 31, 2020.

13.4 Goodwill segment information

The carrying amount of goodwill can be analyzed as follows by reportable segment:

<i>In millions of euros</i>	Dec. 31, 2020
France excluding Infrastructures	3,698
France Infrastructures	5,006
Rest of Europe	4,494
Latin America	706
USA & Canada	650
Middle East, Asia & Africa	667
Others	721
TOTAL	15,943

NOTE 14 INTANGIBLE ASSETS

Accounting standards

Initial measurement

Intangible assets are carried at cost less any accumulated amortization and any accumulated impairment losses.

Amortization

Intangible assets are amortized on the basis of the expected pattern of consumption of the estimated future economic benefits embodied in the asset. Amortization is calculated mainly on a straight-line basis over the following useful lives:

Main depreciation periods (years)	Useful life	
	Minimum	Maximum
Concession rights	10	30
Customer portfolio	3	20
Other intangible assets	1	50

Intangible assets with an indefinite useful life are not amortized but are tested for impairment annually.

Risk of impairment

In accordance with IAS 36, impairment tests are carried out on items of property, plant and equipment and intangible assets where there is an indication that the assets may be impaired. Such indications may be based on events or changes in the market environment, or on internal sources of information. Intangible assets that are not amortized are tested for impairment annually.

Impairment indicators

Property, plant and equipment and intangible assets with finite useful lives are only tested for impairment when there is an indication that they may be impaired. This is generally the result of significant changes in the environment in which the assets are operated or when economic performance is lower than expected.

Main impairment indicators used by the Group are described in Note 13 "Goodwill".

Impairment

Items of property, plant and equipment and intangible assets are tested for impairment at the level of the individual asset or cash-generating unit (CGU), as appropriate and determined in accordance with IAS 36. If the recoverable amount of an asset is lower than its carrying amount, the carrying amount is written down to the recoverable amount by recording an impairment loss. Upon recognition of an impairment loss, the depreciable amount and possibly the useful life of the asset concerned is revised.

Impairment losses recorded in relation to property, plant and equipment or intangible assets may be subsequently reversed if the recoverable amount of the asset increases to exceed the carrying amount. The increased carrying amount of an item of property, plant or equipment following the reversal of an impairment loss may not exceed the carrying amount that would have been determined (net of depreciation/amortization) had no impairment loss been recognized in prior periods.

Measurement of recoverable amount

In order to review the recoverable amount of property, plant and equipment and intangible assets, the assets are grouped, where appropriate, into CGUs and the carrying amount of each CGU is compared with its recoverable amount.

For operating entities which the Group intends to hold on a long-term and going concern basis, the recoverable amount of a CGU corresponds to the higher of its fair value less costs to sell and its value in use. Value in use is primarily determined based on the present value of future operating cash flows including a terminal value. Standard valuation techniques are used based on the following main economic assumptions:

- market perspectives and developments in the regulatory framework;
- discount rates based on the specific characteristics of the operating entities concerned;
- terminal values in line with available market data specific to the operating segments concerned and growth rates associated with these terminal values, not exceeding the inflation rate.

Discount rates are determined on a post-tax basis and applied to post-tax cash flows. The recoverable amounts calculated on the basis of these discount rates are the same as the amounts obtained by applying the pre-tax discount rates to cash flows estimated on a pre-tax basis, as required by IAS 36.

For operating entities which the Group has decided to sell, the related recoverable amount of the assets concerned is based on market value less costs of disposal. Where negotiations are ongoing, this value is determined based on the best estimate of their outcome as of the reporting date.

In the event of a decline in value, the impairment loss is recorded in the consolidated income statement under "Impairment losses".

Intangible rights arising on concession contracts

IFRIC 12 – *Service Concession Arrangements* deals with the treatment to be applied by the concession operator in respect of certain concession arrangements.

For a concession arrangement to fall within the scope of IFRIC 12, usage of the infrastructure must be controlled by the concession grantor. This requirement is satisfied when the following two conditions are met:

- the grantor controls or regulates what services the operator must provide with the infrastructure, to whom it must provide them, and at what price; and
- the grantor controls any residual interest in the infrastructure at the end of the term of the arrangement, for example it retains the right to take back the infrastructure at the end of the concession.

The intangible asset model according to paragraph 17 of IFRIC 12 applies if the operator receives a right (a license) to charge the users, or the grantor, depending on the use made of the public service. There is no unconditional right to receive cash as the amounts depend on the extent to which the public uses the service.

Concession infrastructures that do not meet the requirements of IFRIC 12 are presented as property, plant and equipment. This is the case of gas distribution infrastructures in France. The related assets are recognized in accordance with IAS 16, given that GRDF operates its network under long-term concession arrangements, most of which are mandatorily renewed upon expiration pursuant to French law No. 46-628 of April 8, 1946.

Research and development costs

Research costs are expensed as incurred.

Development costs are capitalized when the asset recognition criteria set out in IAS 38 are met. Capitalized development costs are amortized over the useful life of the intangible asset recognized.

14.1 Movements in intangible assets

<i>In millions of euros</i>	Intangible rights arising on concession contracts	Capacity entitlements	Others	Total
GROSS AMOUNT				
AT DECEMBER 31, 2019	3,838	2,862	11,984	18,684
Acquisitions	158	-	1,111	1,269
Disposals	(5)	(18)	(122)	(146)
Translation adjustments	(99)	-	(196)	(294)
Changes in scope of consolidation	13	-	97	109
Transfer to "Assets classified as held for sale"	-	-	(56)	(56)
Other	2	64	68	134
AT DECEMBER 31, 2020	3,907	2,908	12,886	19,701
ACCUMULATED AMORTIZATION AND IMPAIRMENT				
AT DECEMBER 31, 2019	(1,656)	(2,135)	(7,855)	(11,646)
Amortization	(113)	(75)	(806)	(995)
Impairment	(25)	-	(61)	(85)
Disposals	2	18	71	92
Translation adjustments	10	-	81	91
Changes in scope of consolidation	-	-	(4)	(4)
Transfer to "Assets classified as held for sale"	-	-	7	7
Other	-	-	36	36
AT DECEMBER 31, 2020	(1,781)	(2,193)	(8,532)	(12,505)
CARRYING AMOUNT				
AT DECEMBER 31, 2019	2,182	727	4,129	7,038
AT DECEMBER 31, 2020	2,126	716	4,354	7,196

In 2020, the net increase in "Intangible assets" was mainly attributable to the investments of the period for a total of €1,269 million and to changes in scope of consolidation of €105 million that relate mainly to the acquisition of Novo Estado Transmissora de Energia, which operates in the Brazilian infrastructure sector for €52 million and to three acquisitions in the Engie Solutions business in France and the UK for €25 million, partially offset by amortization for a total of €995 million and a negative foreign exchange impact of €203 million primarily due to the sharp depreciation of the Brazilian real (€132 million).

14.1.1 Impairment

The Group carried out a review of the assets, taking into account the fact that the COVID-19 crisis has consequences that are indications of potential impairment losses (in particular the drop in energy prices, BtoB activity and the stock market, see Note 13 "Goodwill").

At December 31, 2020, the impairment losses allocated to the intangible assets for €85 million were recognized mainly on the ENGIE Solutions BU.

14.1.2 Capacity entitlements

The Group has acquired capacity entitlements from power stations operated by third parties. These power station capacity rights were acquired in connection with transactions or within the scope of the Group's involvement in financing the construction of certain power stations. In consideration, the Group received the right to purchase a share of the production over the useful life of the underlying assets. These rights are amortized over the useful life of the underlying assets, not exceeding 50 years. The Group currently holds entitlements in the Chooz B and Tricastin power plants in France and in the virtual power plant (VPP) in Italy.

14.1.3 Other

At December 31, 2020, this caption mainly relates to software and licenses for €1,388 million, as well as intangible assets in progress for €638 million and intangible assets (client portfolio) acquired as a result of business combinations and capitalized acquisition costs for customer contracts for €2,059 million.

14.2 Information regarding research and development costs

Research and development activities primarily relate to various studies regarding technological innovation, improvements in plant efficiency, safety, environmental protection, service quality, and the use of energy resources.

Research and development costs, excluding technical assistance costs, totaled €190 million in 2020, of which €27 million in expenses related to in-house projects in the development phase that meet the criteria for recognition as an intangible asset as defined in IAS 38.

NOTE 15 PROPERTY, PLANT AND EQUIPMENT

Accounting standards

Initial recognition and subsequent measurement

Items of property, plant and equipment are recognized at historical cost less any accumulated depreciation and any accumulated impairment losses.

The carrying amount of these items is not revalued as the Group has elected not to apply the allowed alternative method, which consists of regularly revaluing one or more categories of property, plant and equipment.

Investment subsidies are deducted from the gross value of the assets concerned.

In accordance with IAS 16, the initial cost of the item of property, plant and equipment includes an initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, when the entity has a present, legal or constructive obligation to dismantle the item or restore the site. A corresponding provision for this obligation is recorded for the amount of the asset component.

Borrowing costs that are directly attributable to the construction of the qualifying asset are capitalized as part of the cost of that asset.

Leases

In accordance with IFRS 16, the Group recognizes a right-of-use asset and a corresponding lease liability with respect to contracts considered as a lease in which the Group acts as lessee, except for leases with a term of 12 months or less ("short-term leases"), and leases for which the underlying asset is of a low value ("low-value asset"). Payments associated with these leases are recognized on a straight-line basis as expenses in profit and loss. The lease contracts in the Group mainly concern real estate, vehicles and other equipment.

The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

The lease liability is initially measured at the present value of the remaining lease payments, discounted using the lessee's incremental borrowing rate. This rate is calculated based on the Group's incremental borrowing rate adjusted in accordance with IFRS 16, taking into account (i) the economic environment of the subsidiaries, and in particular their credit risk, (ii) the currency in which the contract is concluded and (iii) the duration of the contract at inception (or the remaining duration for contracts existing upon the initial application of IFRS 16). The methodology applied to determine the incremental borrowing rate reflects the profile of the lease payments (duration method).

The lease term is assessed, including whether a renewal option is reasonably certain to be exercised or a termination option is reasonably certain not to be exercised, on a case-by-case basis. The lease term is reassessed if a significant event or a significant change in circumstances that is within the control of the lessee occurs and may affect the assessment made. In determining the enforceable period of a lease, the Group applies a broad interpretation of the term penalty and takes into consideration not only contractual penalties arising from termination, but also ancillary costs that could arise in case of an early termination of the lease.

Cushion gas

"Cushion" gas injected into underground storage facilities is essential for ensuring that reservoirs can be operated effectively, and is therefore inseparable from these reservoirs. Unlike "working" gas which is included in inventories (see Note 24.2 "Inventories"), cushion gas is reported in other property, plant and equipment.

Depreciation

In accordance with the components approach, each significant component of an item of property, plant and equipment with a different useful life from that of the main asset to which it relates is depreciated separately over its own useful life.

Property, plant and equipment is depreciated mainly using the straight-line method over the following useful lives:

Main depreciation periods (years)	Useful life	
	Minimum	Maximum
Plant and equipment		
• Storage - Production - Transport - Distribution	5	60 ^(*)
• Installation – Maintenance	3	10
• Hydraulic plant and equipment	20	65
Other property, plant and equipment	2	33

()Excluding cushion gas.*

The range of useful lives is due to the diversity of the assets in each category. The minimum periods relate to smaller equipment and furniture, while the maximum periods concern network infrastructures and storage facilities. In accordance with the law of January 31, 2003 adopted by the Belgian Chamber of Representatives with respect to the gradual phase-out of nuclear energy for the industrial production of electricity, the useful lives of nuclear power stations were reviewed and adjusted prospectively to 40 years as from 2003, except for Tihange 1, Doel 1 and Doel 2 for which the operating lives have been extended by 10 years.

Fixtures and fittings relating to hydro plants operated by the Group are depreciated over the shorter of the contract term and the useful life of the assets, taking into account the renewal of the concession period if such renewal is considered to be reasonably certain.

The right-of-use asset related to leases is depreciated using the straight-line method from the commencement date to the end of the lease term, unless the lease transfers ownership of the underlying asset to the Group by the end of the lease term. In that case the right-of-use asset is depreciated over the useful life of the underlying asset, which is determined on the same basis as that used for property, plant and equipment mentioned above.

Risk of impairment

See Note 14 “Intangible assets”.

Impairment indicators

See Note 13 “Goodwill”.

15.1 Movements in property, plant and equipment

<i>In millions of euros</i>	Land	Buildings	Plant and equipment	Vehicles	Dismantling costs	Assets in progress	Right of use	Other	Total
GROSS AMOUNT									
AT DECEMBER 31, 2019	698	5,490	81,857	467	3,496	4,172	3,882	1,417	101,478
Acquisitions/Increases	8	23	291	50	-	4,625	584	112	5,693
Disposals	(8)	(56)	(352)	(36)	-	(20)	(78)	(48)	(597)
Translation adjustments	(28)	(109)	(2,557)	(8)	(26)	(258)	(152)	(46)	(3,183)
Changes in scope of consolidation	1	(1)	(294)	1	(1)	-	(12)	4	(302)
Transfer to "Assets classified as held for sale"	(4)	-	(629)	-	-	86	(62)	(12)	(620)
Other	(33)	99	3,640	14	124	(3,989)	(12)	15	(141)
AT DECEMBER 31, 2020	633	5,447	81,958	488	3,593	4,616	4,151	1,442	102,327
ACCUMULATED DEPRECIATION AND IMPAIRMENT									
AT DECEMBER 31, 2019	(134)	(2,995)	(41,722)	(320)	(2,223)	(357)	(868)	(901)	(49,520)
Depreciation	(5)	(152)	(2,674)	(49)	(177)	-	(487)	(111)	(3,655)
Impairment	(11)	(17)	(547)	-	(419)	(170)	(8)	-	(1,171)
Disposals	-	48	313	32	5	7	66	42	512
Translation adjustments	10	29	1,047	5	5	13	28	22	1,160
Changes in scope of consolidation	-	1	32	-	-	(1)	-	(3)	28
Transfer to "Assets classified as held for sale"	-	-	40	-	-	-	11	3	54
Other	41	(5)	68	(8)	(165)	198	3	20	153
AT DECEMBER 31, 2020	(99)	(3,090)	(43,444)	(341)	(2,973)	(309)	(1,256)	(928)	(52,439)
CARRYING AMOUNT									
AT DECEMBER 31, 2019	564	2,495	40,135	147	1,273	3,815	3,014	515	51,958
AT DECEMBER 31, 2020	535	2,356	38,514	147	619	4,308	2,895	514	49,889

In 2020, the net decrease in "Property, plant and equipment" essentially takes into account :

- depreciation for a total negative amount of €3,655 million
- impairment losses on property, plant and equipment amounting to €1,171 million mainly relating to:
 - nuclear assets in Belgium (€715 million),
 - renewable assets in Brazil, Mexico, Chile, France and the United States (€193 million),
 - gas-fired power plants in Spain and the United States (€51 million),
 - gas distribution assets in Argentina (€41 million),
 - coal-fired power plants in Brazil and the United Kingdom (€59 million),
- the classification under "Assets held for sale" for a negative €566 million, mainly relating to solar farms in India (€361 million), wind and solar farms in Mexico and Italy (€169 million) and to EV Box (€36 million);
- changes in the scope of consolidation amounting to a negative €274 million, primarily relating to disposals in renewable energies in Australia and France for a total negative amount of €273 million;
- negative foreign exchange effects of €2,023 million, mainly resulting from the sharp depreciation of the Brazilian real (negative impact of €1,063 million), fluctuations in the US dollar (negative impact of €728 million) and the pound sterling (negative impact of €96 million);

partly offset by :

- maintenance and development investments for a total amount of €5,109 million mainly related to the construction and the development of wind and solar farms in the United States, in Latin America and in France (€1,906 million), as well as the extension of the transportation and distribution networks in the France Infrastructure segment (€1,333 million),

15.2 Pledged and mortgaged assets

Items of property, plant and equipment pledged by the Group to guarantee borrowings and debt amounted to €1,749 million at December 31, 2020 compared to €2,261 million at December 31, 2019.

The net decrease mainly relates to :

- thermoelectric and wind assets in Brazil for a negative €416 million, due to the sharp depreciation of the Brazilian real (negative impact of €433 million);
- renewable assets in France for a negative €39 million;
- the entity FHH (Guernsey) Ltd. in the United Kingdom for a negative €42 million mainly due to the depreciation of the pound sterling (negative impact of €34 million).

15.3 Contractual commitments to purchase property, plant and equipment

In the ordinary course of their operations, some Group companies have entered into commitments to purchase, and the related third parties to deliver, property, plant and equipment. These commitments relate mainly to orders for equipment and material related to the construction of energy production units and to service agreements.

Investment commitments made by the Group to purchase property, plant and equipment totaled €2,212 million at December 31, 2020 compared to €1,384 million at December 31, 2019.

The net increase primarily relates to the construction of solar farms in India for an amount of €305 million.

15.4 Other information

Borrowing costs for 2020 included in the cost of property, plant and equipment amounted to €103 million at December 31, 2020 compared to €106 million at December 31, 2019.

NOTE 16 FINANCIAL INSTRUMENTS

16.1 Financial assets

Accounting standards

In accordance with the principles of IFRS 9 - *Financial Instruments*, financial assets are recognized and measured either at amortized cost, at fair value through equity or at fair value through profit or loss based on the following two criteria:

- a first criterion relating to the contractual cash flow characteristics of the financial asset. The analysis of contractual cash flow characteristics makes it possible to determine whether these cash flows are “only payments of principal and interest on the outstanding amounts” (known as the “SPPI” test or Solely Payments of Principal and Interest);
- a second criterion relating to the business model used by the Group to manage its financial assets. IFRS 9 defines three different business models: a first business model whose objective is to hold assets in order to collect contractual cash flows (hold to collect), a second model whose objective is achieved by both collecting contractual cash flows and selling financial assets (hold to collect and sell), and other business models.

The identification of the business model and the analysis of the contractual cash flow characteristics require judgment to ensure that the financial assets are classified in the appropriate category.

Where the financial asset is an investment in an equity instrument and is not held for trading, the Group may irrevocably elect to present the gains and losses on that investment in other comprehensive income.

Except for trade receivables, which are measured at their transaction price in accordance with IFRS 15, financial assets are measured, on initial recognition, at fair value plus, in the case of a financial asset not at fair value through profit or loss, transaction costs that are directly attributable to their acquisition.

At the end of each reporting period, financial assets measured using the amortized cost method or at fair value through other comprehensive income (with a recycling mechanism) are subject to an impairment test based on the expected credit losses method.

Financial assets also include derivatives that are measured at fair value in accordance with IFRS 9.

In accordance with IAS 1, the Group presents current and non-current assets and current and non-current liabilities separately in the statement of financial position. In view of the majority of the Group's activities, it was considered that the criterion to be used to classify assets is the expected time to realize the asset or settle the liability: the asset is classified as current if this period is less than 12 months and as non-current if it is more than 12 months after the reporting period.

The following table presents the Group's different categories of financial assets, broken down into current and non-current items:

In millions of euros	Notes	Dec. 31, 2020			Dec. 31, 2019		
		Non-current	Current	Total	Non-current	Current	Total
Other financial assets	16.1	9,009	2,583	11,592	7,022	2,546	9,567
Equity instruments at fair value through other comprehensive income		1,197	-	1,197	921	-	921
Equity instruments at fair value through income		471	-	471	377	-	377
Debt instruments at fair value through other comprehensive income		1,795	111	1,906	1,072	77	1,149
Debt instruments at fair value through income		1,404	432	1,836	871	397	1,268
Loans and receivables at amortized cost		4,141	2,041	6,182	3,782	2,072	5,854
Trade and other receivables	7.2	-	14,295	14,295	-	15,180	15,180
Assets from contracts with customers	7.2	26	7,738	7,764	15	7,816	7,831
Cash and cash equivalents		-	12,980	12,980	-	10,519	10,519
Derivative instruments	16.4	2,996	8,069	11,065	4,137	10,134	14,272
TOTAL		12,031	45,665	57,696	11,174	46,194	57,369

16.1.1 Other financial assets

16.1.1.1 Equity instruments at fair value

Accounting standards

Equity instruments at fair value through other comprehensive income (OCI)

Under IFRS 9 an irrevocable election can be made to present subsequent changes in the fair value of an investment in an equity instrument that is not held for trading in other comprehensive income. This choice is made on an instrument by instrument basis. Amounts presented in other comprehensive income should not be transferred to profit or loss including proceeds of disposals. However, IFRS 9 authorizes the transfer of the accumulated profits and losses to another component of equity. Dividends from such investments are recognized in profit or loss unless the dividend clearly represents the recovery of a portion of the cost of the investment.

The equity instruments recognized under this line item mainly concern investments in companies that are not controlled by the Group and for which OCI measurement has been selected given their strategic and long-term nature.

Upon initial recognition, these equity instruments are recognized at fair value, which is generally their acquisition cost, plus transaction costs.

At each reporting date, for listed securities, fair value is determined based on the quoted market price at the reporting date. For unlisted securities, fair value is measured using valuation models based primarily on the latest market transactions, the discounting of dividends or cash flows and the net asset value.

Equity instruments at fair value through profit or loss

Equity instruments that are held for trading or for which the Group has not elected for measurement at fair value through other comprehensive income are measured at fair value through profit or loss.

This category mainly includes investments in companies not controlled by the Group.

Upon initial recognition, these equity instruments are recognized at fair value, which is generally their acquisition cost.

At each reporting date, for listed and unlisted securities, the same measurement method as described above should be applied.

<i>In millions of euros</i>	Equity instruments at fair value through other comprehensive income	Equity instruments at fair value through income	Total
AT DECEMBER 31, 2019	921	377	1,297
Increase/Reclassification	291	51	342
Decrease	(78)	(8)	(85)
Changes in fair value	46	3	49
Changes in scope of consolidation, translation adjustments and other	17	48	65
AT DECEMBER 31, 2020	1,197	471	1,668
Dividends	35	8	43

Equity instruments break down as €606 million of listed equity instruments and €1,062 million of unlisted equity instruments. This amount mainly includes shares held by the Group as a minority interest in Nord Stream AG for an amount of €552 million, as well as the Group's residual interest in SUEZ (previously accounted for using the equity method) for €185 million.

16.1.1.2 Debt instruments at fair value

Accounting standards

Debt instruments at fair value through other comprehensive income

Financial assets that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets and for which the contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the outstanding amount (SPPI), are measured at fair value through OCI (with a recycling mechanism). This involves a measurement through profit or loss for interest (at amortized cost using the effective interest method), impairment and foreign exchange gains and losses, and through OCI (with a recycling mechanism) for other gains or losses.

This category mainly includes bonds.

Fair value gains and losses on these instruments are recognized in other comprehensive income, except for the following items which are recognized in profit or loss:

- interest income using the effective interest method;
- expected credit losses and reversals;
- foreign exchange gains and losses.

When the financial asset is derecognized, the cumulative gain or loss that was previously recognized in other comprehensive income is reclassified from equity to profit or loss.

Debt instruments at fair value through profit or loss

Financial assets whose contractual cash flows do not consist solely of payments of principal and interest on the amount outstanding (SPPI) or that are held in view of an "other" business model are measured at fair value through profit or loss.

The Group's investments in UCITS are accounted for in this caption. They are considered as debt instruments, according to IAS 32 - *Financial Instruments: Presentation*, given the existence of an obligation for the issuer to redeem units, at the request of the holder. They are measured at fair value through profit or loss because the contractual cash flow characteristics do not meet the SPPI test.

<i>In millions of euros</i>	Debt instruments at fair value through other comprehensive income	Liquid debt instruments held for cash investment purposes at fair value through other comprehensive income	Debt instruments at fair value through income	Liquid debt instruments held for cash investment purposes at fair value through income	Total
AT DECEMBER 31, 2019	1,138	11	761	507	2,417
Increase	1,521	-	1,017	128	2,667
Decrease	(734)	(2)	(459)	(38)	(1,233)
Changes in fair value	(22)	-	(91)	-	(112)
Changes in scope of consolidation, translation adjustments and other	(8)	2	10	-	4
AT DECEMBER 31, 2020	1,895	11	1,238	598	3,742

Debt instruments at fair value at December 31, 2020 include bonds and money market funds held by Synatom for €3,086 million and liquid instruments deducted from net financial debt for €608 million (respectively €1,846 million and €518 million at December 31, 2019).

Developments regarding the Synatom portfolios

In 2020, in view of the current crisis in the financial markets, in order to limit risks and in accordance with the Group's policies, the various investment managers of the portfolios held by Synatom were required to sell part of the equity portfolio and the bond portfolio, with no material impact on income or equity.

Furthermore, money market funds recorded as debt instruments at fair value through income and equity instruments at fair value through other comprehensive income over the period generated a negative change in fair value of €134 million, respectively recognized in net non-recurring financial income for a negative €87 million, and in equity for a negative €47 million.

16.1.1.3 Loans and receivables at amortized cost

Accounting standards

Loans and receivables held by the Group under a business model consisting in holding the instrument in order to collect the contractual cash flows, and whose contractual cash flows consist solely of payments of principal and interest on the principal amount outstanding (SPPI test) are measured at amortized cost. Interest is calculated using the effective interest method.

The following items are recognized in profit or loss:

- interest income using the effective interest method;
- expected credit losses and reversals;
- foreign exchange gains and losses.

The Group enters into services or take-or-pay contracts that are, or contain, a lease and under which the Group acts as lessor and its customers as lessees. Leases are analyzed in accordance with IFRS 16 in order to determine whether they constitute an operating lease or a finance lease. Whenever the terms of the lease transfer substantially all the risk and rewards of ownership of the related asset, the contract is classified as a finance lease and a finance receivable is recognized to reflect the financing deemed to be granted by the Group to the customer.

Leasing security deposits are presented in this caption and recognized at their nominal value.

Please refer to Note 17 "Risks arising from financial instruments" regarding the assessment of counterparty risk.

<i>In millions of euros</i>	Dec. 31, 2020			Dec. 31, 2019		
	Non-current	Current	Total	Non-current	Current	Total
Loans granted to affiliated companies	2,527	148	2,675	2,293	172	2,465
Other receivables at amortized cost	205	1,740	1,944	301	1,697	1,998
Amounts receivable under concession contracts	853	51	904	588	65	653
Amounts receivable under finance leases	557	101	658	599	138	738
TOTAL	4,141	2,041	6,182	3,782	2,072	5,854

Loans and receivables at amortized cost include the loan relating to the financing of the Nord Stream 2 pipeline project for a total amount of €948 million, including capitalized interest.

The €311 million loan granted to Neptune Energy as part of the sale of the exploration-production business was repaid in an amount of €222 million during the year.

Impairment and expected credit losses against loans and receivables at amortized cost stood at €204 million at December 31, 2020 (versus €139 million at December 31, 2019).

Net gains and losses recognized in the income statement relating to loans and receivables at amortized cost break down as follows:

<i>In millions of euros</i>	Interest income	Post-acquisition measurement	
		Foreign currency translation	Expected credit loss
At December 31, 2020	285	(48)	-
At December 31, 2019	233	(38)	4

No material expected credit losses were recognized against loans and receivables at amortized cost at December 31, 2020 and December 31, 2019.

Amounts receivable under finance leases

These contracts refer to lease contracts in which ENGIE acts as lessor, classified as finance leases in accordance with IFRS 16. They concern (i) energy purchase and sale contracts where the contract conveys an exclusive right to use a production asset; and (ii) certain contracts with industrial customers relating to assets held by the Group.

The Group has recognized finance lease receivables, notably for cogeneration plants for Wapda and NTDC (Uch - Pakistan) and Lanxess (Electrabel - Belgium).

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Undiscounted future minimum lease payments	760	892
Unguaranteed residual value accruing to the lessor	11	8
TOTAL GROSS INVESTMENT IN THE LEASE	771	900
Unearned financial income	62	94
NET INVESTMENT IN THE LEASE (STATEMENT OF FINANCIAL POSITION)	709	806
<i>Of which present value of future minimum lease payments</i>	<i>700</i>	<i>801</i>
<i>Of which present value of unguaranteed residual value</i>	<i>9</i>	<i>6</i>

Undiscounted minimum lease payments receivable under finance leases can be analyzed as follows:

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Year 1	130	118
Years 2 to 5 inclusive	379	470
Beyond year 5	251	304
TOTAL	760	892

16.1.2 Trade and other receivables, assets from contracts with customers

Information on trade and other receivables and assets from contracts with customers are provided in Note 7.2. "Trade and other receivables, assets and liabilities from contracts with customers".

16.1.3 Cash and cash equivalents

Accounting standards

This item includes cash equivalents as well as short-term investments that are considered to be readily convertible into a known amount of cash and where the risk of a change in their value is deemed to be negligible based on the criteria set out in IAS 7.

Bank overdrafts are not included in the calculation of cash and cash equivalents and are recorded under "Short-term borrowings".

Cash and cash equivalent items are subject to impairment tests in accordance with the expected credit losses model of IFRS 9.

"Cash and cash equivalents" totaled €12,980 million at December 31, 2020 (€10,519 million at December 31, 2019).

This amount included funds related to the green bond issues, which remain unallocated to the funding of eligible projects (see section 5 of the *Universal Registration Document*).

At December 31, 2020, this amount also included €68 million in cash and cash equivalents subject to restrictions (€86 million at December 31, 2019), including €48 million of cash equivalents set aside to cover the repayment of borrowings and debt as part of project financing arrangements in certain subsidiaries.

Gains recognized in respect of "Cash and cash equivalents" amounted to €45 million at December 31, 2020 compared to €76 million at December 31, 2019.

16.1.4 Financial assets set aside to cover the future costs of dismantling nuclear facilities and managing radioactive fissile material

As indicated in Note 19.2 "Obligations relating to nuclear power generation activities", the Belgian law of April 11, 2003, amended by the law of April 25, 2007, granted the Group's wholly-owned subsidiary Synatom responsibility for managing and investing funds received from operators of nuclear power plants in Belgium and intended to cover the costs of dismantling nuclear power plants and managing radioactive fissile material.

Pursuant to the law, Synatom may lend up to 75% of these funds to nuclear power plant operators provided that certain credit quality criteria are met. The funds that cannot be lent to nuclear operators are invested in assets to cover the liabilities.

Since October 2019, Electrabel has not taken out any further loans in respect of provisions for the back-end of the nuclear fuel cycle and has undertaken to repay all of the loans taken out for that purpose by 2025. In 2020, Synatom therefore increased its investments in financial assets to cover the future costs of managing radioactive fissile material by nearly €1.3 billion.

The financial assets covering future costs of dismantling nuclear facilities and managing radioactive fissile material are either loans to legal entities that meet the credit quality criteria required by law or other external assets with sufficient diversification and spread to minimize the risk. The Commission for Nuclear Provisions issues an opinion on the asset classes in which Synatom may invest.

Loans to entities outside the Group and other cash investments are shown in the table below:

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Loans to third parties	11	467
Loan to Eso/Elia	-	453
Loan to Sibelga	11	14
Others loans and receivables at amortized cost	332	85
Debt instruments - restricted cash	332	85
Equity and debt instruments at fair value	3,492	2,054
Equity instruments at fair value through other comprehensive income	406	207
Debt instruments at fair value through other comprehensive income	1,895	1,138
Debt instruments at fair value through income	1,191	709
TOTAL	3,835	2,606

Loans to legal entities outside the Group and the cash subject to restrictions held by money market funds are shown in the statement of financial position as "Loans and receivables at amortized cost". Bonds and money market funds held by Synatom are shown as "Equity instruments at fair value through other comprehensive income", "Debt instruments at fair value through other comprehensive income" or "Debt instruments at fair value through income" (see Note 16.1 "Financial assets").

16.1.5 Transfer of financial assets

At December 31, 2020, the outstanding amount of transferred financial assets (as well as the risks to which the Group remains exposed following the transfer of those financial assets) as part of transactions leading to either (i) all or part of those assets being retained in the statement of financial position, or (ii) their full deconsolidation while retaining a continuing involvement in these financial assets, was not material in terms of the Group's indicators.

In 2020, the Group carried out disposals without recourse to financial assets as part of transactions leading to full derecognition, for an outstanding amount of €1,257 million at December 31, 2020.

16.1.6 Financial assets and equity instruments pledged as collateral for borrowings and debt

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Financial assets and equity instruments pledged as collateral	3,716	4,471

This item mainly includes the carrying amount of equity instruments pledged as collateral for borrowings and debt.

16.2 Financial liabilities

Accounting standards

Borrowings and other financial liabilities are measured at amortized cost using the effective interest rate method.

On initial recognition, any issue or redemption premiums and discounts and issuing costs are added to/deducted from the nominal value of the borrowings concerned. These items are taken into account when calculating the effective interest rate and are therefore recorded in the consolidated income statement over the life of the borrowings using the amortized cost method.

As regards structured debt instruments that do not have an equity component, the Group may be required to separate an “embedded” derivative instrument from its host contract. When an embedded derivative is separated from its host contract, the initial carrying amount of the structured instrument is broken down into an embedded derivative component, corresponding to the fair value of the embedded derivative, and a financial liability component, corresponding to the difference between the amount of the issue and the fair value of the embedded derivative. The separation of components upon initial recognition does not give rise to any gains or losses.

The debt is subsequently recorded at amortized cost using the effective interest method while the derivative is measured at fair value, with changes in fair value recognized in profit or loss.

Financial liabilities are recognized either:

- as “Amortized cost liabilities” for borrowings, trade payables and other creditors, and other financial liabilities;
- as “Liabilities measured at fair value through profit or loss” for derivative financial instruments and for financial liabilities designated as such.

The following table presents the Group’s different financial liabilities at December 31, 2020, broken down into current and non-current items:

In millions of euros	Notes	Dec. 31, 2020			Dec. 31, 2019		
		Non-current	Current	Total	Non-current	Current	Total
Borrowings and debt		30,092	7,846	37,939	30,002	8,543	38,544
Trade and other payables	16.2	-	17,307	17,307	-	19,109	19,109
Liabilities from contracts with customers	7.2	39	4,315	4,354	45	4,286	4,330
Derivative instruments	16.4	3,789	9,336	13,125	5,129	10,446	15,575
Other financial liabilities		77	-	77	38	-	38
TOTAL		33,997	38,805	72,802	35,213	42,383	77,596

16.2.1 Trade and other payables

In millions of euros	Dec. 31, 2020	Dec. 31, 2019
Trade payables	16,890	18,683
Payable on fixed assets	417	426
TOTAL	17,307	19,109

The carrying amount of these financial liabilities represents a reasonable estimate of their fair value.

16.2.2 Liabilities from contracts with customers

Information on liabilities from contracts with customers are provided in Note 7.2. “Trade and other receivables, assets and liabilities from contracts with customers”.

16.3 Net financial debt

16.3.1 Net financial debt by type

In millions of euros		Dec. 31, 2020			Dec. 31, 2019		
		Non-current	Current	Total	Non-current	Current	Total
Borrowings and debt	Bond issues	24,724	1,446	26,170	23,262	2,753	26,015
	Bank borrowings	3,136	986	4,123	4,229	1,063	5,292
	Negotiable commercial paper	-	4,024	4,024	-	3,233	3,233
	Lease liabilities	1,892	494	2,386	1,935	578	2,512
	Other borrowings ⁽¹⁾	340	594	935	576	668	1,244
	Bank overdrafts and current account	-	301	301	-	247	247
	BORROWINGS AND DEBT	30,092	7,846	37,939	30,002	8,543	38,544
Other financial assets	Other financial assets deducted from net financial debt ⁽²⁾	(210)	(1,878)	(2,088)	(213)	(1,289)	(1,502)
Cash and cash equivalents	Cash and cash equivalents	-	(12,980)	(12,980)	-	(10,519)	(10,519)
Derivative instruments	Derivatives hedging borrowings ⁽³⁾	(306)	(107)	(413)	(521)	(83)	(604)
NET FINANCIAL DEBT		29,577	(7,119)	22,458	29,267	(3,348)	25,919

(1) This item corresponds to the revaluation of the interest rate component of debt in a qualified fair value hedging relationship for €396 million, margin calls on debt hedging derivatives carried in liabilities for €262 million and the impact of amortized cost for €117 million (compared to, respectively, €353 million, €399 million and €224 million at December 31, 2019).

(2) This item notably corresponds to assets related to financing, liquid debt instruments held for cash investment purposes and margin calls on derivatives hedging borrowings - carried in assets.

(3) This item represents the interest rate component of the fair value of derivatives hedging borrowings in a designated fair value hedging relationship. It also represents the exchange rate and outstanding accrued interest rate components of the fair value of all debt-related derivatives irrespective of whether or not they qualify as hedges.

The fair value of gross borrowings and debt (excluding lease liabilities) amounted to €39,036 million at December 31, 2020, compared with a carrying amount of €35,546 million.

Financial income and expenses related to borrowings and debt are presented in Note 10 "Net financial income/(loss)".

16.3.2 Reconciliation between net financial debt and cash flow from (used in) financing activities

In millions of euros		Dec. 31, 2019	Cash flow from financing activities	Cash flow variation of cash and cash equivalents	Change in fair value	Translation adjustments	Change in scope of consolidation and others	Dec. 31, 2020
Borrowings and debt	Bond issues	26,015	826	-	-	(705)	34	26,170
	Bank borrowings	5,292	(93)	-	-	(582)	(494)	4,123
	Negotiable commercial paper	3,233	859	-	-	(69)	-	4,024
	Lease liabilities ⁽¹⁾	2,512	(573)	-	-	(62)	509	2,386
	Other borrowings	1,244	(378)	-	193	(42)	(82)	935
	Bank overdrafts and current account	247	51	-	-	5	(2)	301
	BORROWINGS AND DEBT	38,544	692	-	193	(1,455)	(35)	37,939
Other financial	Other financial assets deducted from	(1,502)	(608)	-	(2)	24	1	(2,088)
Cash and cash	Cash and cash equivalents	(10,519)	-	(2,952)	-	535	(44)	(12,980)
Derivative	Derivatives hedging borrowings	(604)	380	-	(10)	(182)	3	(413)
NET FINANCIAL		25,919	463	(2,952)	180	(1,078)	(75)	22,458

(1) Lease liabilities: the negative amount of €573 million included in the "Cash flow from financing activities" column corresponds to lease payments, excluding interest (total cash outflow for leases amounted to €616 million, of which €43 million relating to interest).

16.3.3 Main events of the period

16.3.3.1 Impact of changes in the scope of consolidation and in exchange rates on net financial debt

In 2020, changes in exchange rates resulted in a €1,078 million decrease in net financial debt, including a €701 million decrease in relation to the Brazilian real and a €356 million decrease in relation to the US dollar.

Changes in the scope of consolidation (including the cash impact of acquisitions and disposals) led to a €1,925 million decrease in net financial debt, reflecting:

- disposals of assets over the period, which reduced net financial debt by €4,146 million, notably including the disposal of the ENGIE's interests in Astoria 1 and 2 in the United States, and the sale of part of ENGIE's interest in SUEZ to the VEOLIA group (see Note 4.1 "Disposals carried out in 2020");
- the classification of renewable energy assets in India and Mexico, as well as the Group's interest in the EV Charged BV company under "Assets held for sale", which reduced net financial debt by €297 million (see Note 4.2 "Assets held for sale");
- acquisitions carried out in 2020 which increased net financial debt by €2,518 million, mainly due to the creation, on a 50/50 basis with Meridiam, of the company that operates the concession granted by the University of Iowa in the United States, for energy efficiency and water management; the acquisition of the residual 10% stake in Transportadora Asociada de Gás S. A. (TAG) and an electric power transmission concession in Brazil; the acquisition from EDP of the second largest hydroelectric portfolio in Portugal via a consortium 40%-owned by ENGIE; the acquisition of Renvico, which operates in the field of renewable energy in France and Italy; and the acquisition of minority interests in an LNG terminal in France (see Note 4.4 "Acquisitions carried out in 2020").

16.3.3.2 Financing and refinancing transactions

The Group carried out the following main transactions in 2020:

ENGIE SA

- on January 21, 2020 ENGIE SA redeemed €824 million worth of bonds:
 - a €400 million tranche matured with a 2.5% coupon,
 - a €424 million tranche matured with a 3.125% coupon;
- on March 27, 2020, ENGIE SA issued €2.5 billion worth of bonds:
 - a €1,000 million tranche, maturing in March 2025 with a 1.375% coupon,
 - a €750 million tranche, a green bond maturing in March 2028 with a 1.75% coupon,
 - a €750 million tranche, a green bond maturing in March 2032 with a 2.125% coupon;
- ENGIE SA drew down bilateral lines for a total amount of €885 million for a duration of one month:
 - on March 20, 2020 for €300 million,
 - on March 23, 2020 for €200 million,
 - on March 30, 2020 for €385 million;
- on April 16, 2020, ENGIE SA redeemed €200 million worth of bonds that matured with a floating EURIBOR 3M coupon plus a 0.58% mark-up;

- on May 19, 2020 ENGIE SA redeemed €1.2 billion worth of green bonds that matured with a 1.375% coupon;
- on June 11, 2020, ENGIE SA issued €750 million worth of bonds maturing in June 2027 with a 0.375% coupon;
- on October 9, 2020, ENGIE SA redeemed CHF 275 million (€255 million) worth of bonds with a 1.13% coupon at maturity;
- on December 23, 2020, ENGIE SA redeemed a USD 300 million bank loan (€246 million), with a floating US Libor 3 months coupon plus a 0.90% mark-up at maturity;

Other entities of the Group

- on January 28, 2020, ENGIE Energia Chile carried out the following refinancing transactions:
 - issue of USD 500 million (€453 million) worth of bonds, maturing in January 2030 with a 3.4% coupon,
 - redemption of USD 400 million (€363 million) worth of bonds, maturing in January 2021 with a 5.625% coupon,
 - redemption of two bank loans totaling USD 80 million (€72 million) maturing in June 2020;
- on August 1, 2020, ENGIE Brasil Energia took out thirteen bank loans for a total amount of BRL 1,167 million (€197 million) maturing in March 2044;
- on August 10, 2020, ENGIE Brasil Energia took out two bank loans for a total amount of BRL 742 million (€123 million) maturing in May 2044;
- on September 23, 2020, ENGIE Brasil Energia took out two bank loans for a total amount of BRL 340 million (€54 million) including a BRL 102 million loan maturing in April 2028 and a BRL 238 million loan maturing in October 2036;
- on November 15, 2020, ENGIE Brasil Energia took out two bank loans for a total amount of BRL 582 million (€91 million) including a BRL 150 million loan maturing in April 2028 and a BRL 432 million loan maturing in October 2036;
- on November 17, 2020, ENGIE Brasil Energia redeemed the outstanding amount of BRL 965 million (€149 million) worth of bonds at maturity;
- on December 17, 2020, ENGIE Brasil Energia took out eight bank loans for a total amount of BRL 272 million (€43 million) maturing in March 2044.

16.4 Derivative instruments

Accounting standards

Derivative financial instruments are measured at fair value. This fair value is determined on the basis of market data, available from external contributors. In the absence of an external benchmark, a valuation based on internal models recognized by market participants and favoring data directly derived from observable data such as OTC quotations is used.

The change in fair value of derivative financial instruments is recorded in the income statement except when they are designated as hedging instruments in a cash flow hedge or net investment hedge. In this case, changes in the value of the hedging instruments are recognized directly in equity, excluding the ineffective portion of the hedges.

The Group uses derivative financial instruments to manage and reduce its exposure to market risks arising from fluctuations in interest rates, foreign currency exchange rates and commodity prices, mainly for gas and electricity. The use of derivative instruments is governed by a Group policy for managing interest rate, currency and commodity risks (see Note 17 – *Risks arising from financial instruments*).

Derivative financial instruments are contracts (i) whose value changes in response to the change in one or more observable variables, (ii) that do not require any material initial net investment, and (iii) that are settled at a future date.

Derivative instruments include swaps, options, futures and swaptions, as well as forward commitments to purchase or sell listed and unlisted securities, and firm commitments or options to purchase or sell non-financial assets that involve physical delivery of the underlying.

For purchases and sales of electricity and natural gas, the Group systematically analyzes whether the contract was entered into in the “normal” course of operations and therefore falls outside the scope of IFRS 9. This analysis consists firstly in demonstrating that the contract is entered into and continues to be held for the purpose of physical delivery or receipt of the commodity in accordance with the Group’s expected purchase, sale or usage requirements.

The second step is to demonstrate that the Group has no practice of settling similar contracts on a net basis and that these contracts are not equivalent to written options. In particular, in the case of electricity and gas sales allowing the buyer a certain degree of flexibility concerning the volumes delivered, the Group distinguishes between contracts that are equivalent to capacity sales considered as transactions falling within the scope of ordinary operations and those that are equivalent to written financial options, which are accounted for as derivative financial instruments.

Only contracts that meet all of the above conditions are considered as falling outside the scope of IFRS 9. Adequate specific documentation is compiled to support this analysis.

Embedded derivatives

The main Group contracts that may contain embedded derivatives are contracts with clauses or options potentially affecting the contract price, volume or maturity. This is the case primarily with contracts for the purchase or sale of non-financial assets, whose price is revised based on an index, the exchange rate of a foreign currency or the price of an asset other than the contract’s underlying.

An embedded derivative is a component of a hybrid (combined) instrument that also includes a non-derivative host contract – with the effect that some of the cash flows of the combined instrument vary in a way similar to a stand-alone derivative.

If a hybrid contract contains a host that is an asset within the scope of IFRS 9, the Group applies the presentation and measurements requirements described in Note 17.1. to the entire hybrid contract.

Conversely, when a hybrid contract contains a host that is not an asset within the scope of IFRS 9, an embedded derivative shall be separated from the host and accounted for as a derivative if, and only if:

- the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host;
- a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and
- the hybrid contract is not measured at fair value with changes in fair value recognized in profit or loss (i.e., a derivative that is embedded in a financial liability at fair value through profit or loss is not separated).

Where an embedded derivative is separate from the host contract, it is measured at fair value and fair value changes are recognized in profit or loss (except if the embedded derivative is documented in a hedge relationship).

Hedging instruments: recognition and presentation

Derivative instruments qualifying as hedging instruments are recognized in the consolidated statement of financial position and measured at fair value. However, their accounting treatment varies according to whether they are classified as (i) a fair value hedge of an asset or liability; (ii) a cash flow hedge, or (iii) a hedge of a net investment in a foreign operation.

Fair value hedges

A fair value hedge is defined as a hedge of the exposure to changes in fair value of a recognized asset or liability such as a fixed-rate loan or borrowing, or of assets, liabilities or an unrecognized firm commitment denominated in a foreign currency.

The gain or loss from remeasuring the hedging instrument at fair value is recognized in income. The gain or loss on the hedged item attributable to the hedged risk adjusts the carrying amount of the hedged item and is also recognized in income even if the hedged item is in a category in respect of which changes in fair value are recognized through other comprehensive income. These two adjustments are presented net in the consolidated income statement, with the net effect corresponding to the ineffective portion of the hedge.

Cash flow hedges

A cash flow hedge is a hedge of the exposure to variability in cash flows that could affect the Group's income. The hedged cash flows may be attributable to a particular risk associated with a recognized financial or non-financial asset or a highly probable forecast transaction.

The portion of the gain or loss on the hedging instrument that is determined to be an effective hedge is recognized directly in other comprehensive income, net of tax, while the ineffective portion is recognized in income. The gains or losses accumulated in equity are reclassified to the consolidated income statement under the same caption as the loss or gain on the hedged item – i.e., current operating income for operating cash flows and financial income or expenses for other cash flows – in the same periods in which the hedged cash flows affect income.

If the hedging relationship is discontinued, in particular because the hedge is no longer considered effective, the cumulative gain or loss on the hedging instrument remains recognized in equity until the forecast transaction occurs. However, if a forecast transaction is no longer expected to occur, the cumulative gain or loss on the hedging instrument is immediately recognized in income.

Hedge of a net investment in a foreign operation

In the same way as for a cash flow hedge, the portion of the gain or loss on the hedging instrument that is determined to be an effective hedge of the currency risk is recognized directly in other comprehensive income, net of tax, while the ineffective portion is recognized in income. The gains or losses accumulated in other comprehensive income are transferred to the consolidated income statement when the investment is liquidated or sold.

Hedging instruments: identification and documentation of hedging relationships

The hedging instruments and hedged items are designated at the inception of the hedging relationship. The hedging relationship is formally documented in each case, specifying the hedging strategy, the hedged risk and the method used to assess hedge effectiveness. Only derivative contracts entered into with external counterparties are considered as being eligible for hedge accounting

Hedge effectiveness is assessed and documented at the inception of the hedging relationship and on an ongoing basis throughout the periods for which the hedge was designated.

Hedge effectiveness is demonstrated both prospectively and retrospectively using various methods, based mainly on a comparison between changes in fair value or cash flows between the hedging instrument and the hedged item. Methods based on an analysis of statistical correlations between historical price data are also used.

Derivative instruments not qualifying for hedge accounting: recognition and presentation

These items mainly concern derivative financial instruments used in economic hedges that have not been – or are no longer – documented as hedging relationships for accounting purposes.

When a derivative financial instrument does not qualify or no longer qualifies for hedge accounting, changes in fair value are recognized directly in income under (i) current operating income for derivative instruments with non-financial assets as the underlying, and (ii) financial income or expenses for currency, interest rate and equity derivatives.

Derivative instruments not qualifying for hedge accounting used by the Group in connection with proprietary commodity trading activities and other derivatives expiring in less than 12 months are recognized in the consolidated statement of financial position in current assets and liabilities, while derivatives expiring after this period are classified as non-current items.

Fair value measurement

The fair value of instruments listed on an active market is determined by reference to the market price. In this case, these instruments are presented in level 1 of the fair value hierarchy.

The fair value of unlisted financial instruments for which there is no active market and for which observable market data exist is determined based on valuation techniques such as option pricing models or the discounted cash flow method.

The models used to evaluate these instruments take into account assumptions based on market inputs:

- the fair value of interest rate swaps is calculated based on the present value of future cash flows;
- the fair value of forward foreign exchange contracts and currency swaps is calculated by reference to current prices for contracts with similar maturities by discounting the future cash flow spread (difference between the forward exchange rate under the contract and the forward exchange rate recalculated in line with the new market conditions applicable to the nominal amount);
- the fair value of currency and interest rate options is calculated using option pricing models;
- commodity derivatives are valued by reference to listed market prices based on the present value of future cash flows (commodity swaps or commodity forwards) and option pricing models (options), for which market price volatility may be a factor. Contracts with maturities exceeding the depth of transactions for which prices are observable, or which are particularly complex, may be valued based on internal assumptions;
- exceptionally, for complex contracts negotiated with independent financial institutions, the Group uses the values established by its counterparties.

These instruments are presented in level 2 of the fair value hierarchy except when the evaluation is based mainly on data that are not observable, in which case they are presented in level 3 of the fair value hierarchy. Most often, this is the case for derivatives with a maturity that falls outside the observability period for market data relating to the underlying or when certain inputs such as the volatility of the underlying are not observable.

Except in case of enforceable master netting arrangements or similar agreements, counterparty risk is included in the fair value of financial derivative instrument assets and liabilities. It is calculated according to the “expected loss” method and takes into account the exposure at default, the probability of default and the loss given default. The probability of default is determined on the basis of credit ratings assigned to each counterparty (“historical probability of default” approach).

Derivative instruments recognized in assets and liabilities are measured at fair value and broken down as follows:

In millions of euros	Dec. 31, 2020						Dec. 31, 2019					
	Assets			Liabilities			Assets			Liabilities		
	Non-current	Current	Total	Non-current	Current	Total	Non-current	Current	Total	Non-current	Current	Total
Derivatives hedging borrowings	619	147	766	313	39	353	705	124	829	183	41	225
Derivatives hedging commodities	1,163	7,879	9,042	945	9,252	10,197	2,484	9,993	12,476	3,011	10,360	13,371
Derivatives hedging other items ⁽¹⁾	1,214	43	1,257	2,530	45	2,575	949	17	966	1,934	45	1,980
TOTAL	2,996	8,069	11,065	3,789	9,336	13,125	4,137	10,134	14,272	5,129	10,446	15,575

(1) Derivatives hedging other items mainly include the interest rate component of interest rate derivatives (not qualifying as hedges or qualifying as cash flow hedges) that are excluded from net financial debt, as well as net investment hedge derivatives.

16.4.1 Offsetting of derivative instrument assets and liabilities

The net amount of derivative instruments after taking into account enforceable master netting arrangements or similar agreements, whether or not they are offset in accordance with paragraph 42 of IAS 32, are presented in the table below:

In millions of euros	Dec. 31, 2020				Dec. 31, 2019			
	Gross amount	Net amount recognized in the statement of financial position ⁽¹⁾	Other offsetting agreements ⁽²⁾	Total net amount	Gross amount	Net amount recognized in the statement of financial position ⁽¹⁾	Other offsetting agreements ⁽²⁾	Total net amount
Assets								
Derivatives hedging commodities	9,465	9,042	(5,198)	3,844	13,121	12,476	(7,704)	4,772
Derivatives hedging borrowings and other items	2,023	2,023	(200)	1,822	1,795	1,795	(399)	1,397
Liabilities								
Derivatives hedging commodities	(10,621)	(10,197)	6,307	(3,890)	(14,015)	(13,371)	9,872	(3,499)
Derivatives hedging borrowings and other items	(2,928)	(2,928)	1,362	(1,566)	(2,204)	(2,204)	899	(1,305)

(1) Net amount recognized in the statement of financial position after taking into account offsetting agreements that meet the criteria set out in paragraph 42 of IAS 32.

(2) Other offsetting agreements include collateral and other guarantee instruments, as well as offsetting agreements that do not meet the criteria set out in paragraph 42 of IAS 32.

16.5 Fair value of financial instruments by level in the fair value hierarchy

16.5.1 Financial assets

The table below shows the allocation of financial instruments carried in assets to the different levels in the fair value hierarchy:

In millions of euros	Dec. 31, 2020				Dec. 31, 2019			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
Other financial assets (excluding loans and receivables at amortized cost)	5,410	3,693	-	1,718	3,714	2,069	-	1,645
Equity instruments at fair value through other comprehensive income	1,197	421	-	775	921	222	-	698
Equity instruments at fair value through income	471	185	-	286	377	-	-	377
Debt instruments at fair value through other comprehensive income	1,906	1,895	-	11	1,149	1,138	-	11
Debt instruments at fair value through income	1,836	1,191	-	645	1,268	709	-	559
Derivative instruments	11,065	4	10,216	844	14,272	8	12,993	1,270
Derivatives hedging borrowings	766	-	766	-	829	-	829	-
Derivatives hedging commodities - relating to portfolio management activities ⁽¹⁾	1,967	-	1,717	250	3,521	-	2,928	593
Derivatives hedging commodities - relating to trading activities ⁽¹⁾	7,075	4	6,477	594	8,955	8	8,271	677
Derivatives hedging other items	1,257	-	1,257	-	966	-	966	-
TOTAL	16,475	3,697	10,216	2,562	17,986	2,077	12,993	2,916

(1) Derivative financial instruments relating to commodities classified in level 3 mainly include long-term gas supply contracts and a power contract that are measured at fair value and relate to trading activities.

A definition of these three levels is presented in Note 16.4 "Derivative instruments".

Other financial assets (excluding loans and receivables at amortized cost)

Changes in level 3 equity and debt instruments at fair value can be analyzed as follows:

In millions of euros	Equity instruments at fair value through other comprehensive income	Debt instruments at fair value through other comprehensive income	Equity instruments at fair value through income	Debt instruments at fair value through income	Other financial assets (excluding loans and receivables)
AT DECEMBER 31, 2019	698	11	377	559	1,645
Acquisitions	25	-	51	134	211
Disposals	(7)	(2)	(8)	(39)	(55)
Changes in fair value	42	-	3	(4)	41
Changes in scope of consolidation, foreign currency translation and other changes ⁽¹⁾	17	2	(137)	(5)	(124)
AT DECEMBER 31, 2020	775	11	286	645	1,718
Gains/(losses) recorded in income relating to instruments held at the end of the period					46

Derivative instruments

Changes in level 3 commodities derivatives can be analyzed as follows:

<i>In millions of euros</i>	Net Asset/(Liability)
AT DECEMBER 31, 2019	89
Changes in fair value recorded in income ⁽¹⁾	(937)
Settlements	(37)
Transfer out of level 3 to levels 1 and 2	11
Net fair value recorded in income	(874)
Deferred Day-One gains/(losses)	38
AT DECEMBER 31, 2020	(836)

(1) This amount includes the initial impact of the extension of the gas trading management model for gas positions used by the GEM BU for a negative loss of €725 million (see Note 9.4 "Other non-recurring items").

16.5.2 Financial liabilities

The table below shows the allocation of financial instruments carried in liabilities to the different levels in the fair value hierarchy:

<i>In millions of euros</i>	Dec. 31, 2020				Dec. 31, 2019			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
Borrowings used in designated fair value hedges	4,812	-	4,812	-	6,510	-	6,510	-
Borrowings not used in designated fair value hedges	34,223	25,039	9,184	-	32,382	22,763	9,620	-
Derivative instruments	13,125	89	11,355	1,681	15,575	102	14,292	1,181
Derivatives hedging borrowings	353	-	353	-	225	-	225	-
Derivatives hedging commodities - relating to portfolio management activities ⁽¹⁾	1,694	4	1,428	261	4,136	-	3,697	440
Derivatives hedging commodities - relating to trading activities ⁽¹⁾	8,503	85	6,999	1,419	9,234	102	8,391	741
Derivatives hedging other items	2,575	-	2,575	-	1,980	-	1,980	-
TOTAL	52,160	25,128	25,352	1,681	54,468	22,865	30,422	1,181

(1) Derivative financial instruments relating to commodities classified in level 3 mainly include long-term gas supply contracts and a power contract that are measured at fair value and relate to trading activities.

A definition of these three levels is presented in Note 16.4 "Derivative instruments".

Borrowings used in designated fair value hedges

This caption includes bonds in a designated fair value hedging relationship, which are presented in level 2 in the above table. Only the interest rate component of the bonds is remeasured, with fair value determined by reference to observable inputs.

Borrowings not used in designated fair value hedges

Listed bond issues are included in level 1.

Other borrowings not used in a designated hedging relationship, are presented in level 2 in the above table. The fair value of these borrowings is determined on the basis of future discounted cash flows and relies on directly or indirectly observable data.

NOTE 17 RISKS ARISING FROM FINANCIAL INSTRUMENTS

The Group mainly uses derivative instruments to manage its exposure to market risks. Financial risk management procedures are set out in Chapter 2 “Risk factors” of the Universal Registration Document.

17.1 Market risks

17.1.1 Commodity risk

Commodity risk arises primarily from the following activities:

- portfolio management; and
- trading.

The Group has identified primarily two types of commodity risks: price risk resulting from fluctuations in market prices, and volume risk inherent to the business.

In the ordinary course of its operations, the Group is exposed to commodity risks on natural gas, electricity, coal, oil and oil products, other fuels, CO₂ and other “green” products. The Group is active on these energy markets either for supply purposes, or to optimize and secure its energy production chain and its energy sales. The Group also uses derivatives to offer hedging instruments to its clients and to hedge its own positions.

17.1.1.1 Portfolio management activities

Portfolio management seeks to optimize the market value of assets (power plants, gas and coal supply contracts, energy sales and gas storage and transportation) over various timeframes (short-, medium- and long-term). Market value is optimized by:

- guaranteeing supply and ensuring the balance between physical needs and resources;
- managing market risks (price, volume) to unlock optimum value from portfolios within a specific risk framework.

The risk framework aims to safeguard the Group’s financial resources over the budget period and smooth out medium-term earnings (over three or five years, depending on the maturity of each market). It encourages portfolio managers to take out economic hedges on their portfolio.

Sensitivities of the commodity-related derivatives portfolio used as part of the portfolio management activities as at December 31, 2020 are detailed in the table below. They are not representative of future changes in consolidated earnings and equity, insofar as they do not include the sensitivities relating to the purchase and sale contracts for the underlying commodities.

Sensitivity analysis ⁽¹⁾

In millions of euros	Changes in price	Dec. 31, 2020		Dec. 31, 2019	
		Pre-tax impact on income	Pre-tax impact on equity	Pre-tax impact on income	Pre-tax impact on equity
Oil-based products	+USD 10/bbl	119	266	40	234
Natural gas	+€3/MWh	379	537	225	471
Electricity	+€5/MWh	(90)	(39)	82	(47)
Coal	+USD 10/ton	-	1	(2)	-
Greenhouse gas emission rights	+€2/ton	(116)	1	(89)	19
EUR/USD	+10%	37	-	(25)	(99)
EUR/GBP	+10%	(6)	7	33	-

(1) The sensitivities shown above apply solely to financial commodity derivatives used for hedging purposes as part of the portfolio management activities.

The COVID-19 crisis has significantly increased the volatility of financial markets. This volatility resulted in a decline in commodity prices, which contributed to significant changes in the fair value of our financial instruments, thereby impacting the income statement (see Note 8.1 "Purchases and operating derivatives") as well as the Group's other comprehensive income (see "Statement of comprehensive income").

The COVID-19 crisis did not have a major impact on the sensitivity of other items of comprehensive income. No significant impact in terms of ineffectiveness or disqualification of certain hedges qualifying as cash flow hedges was recognized at the year-end.

17.1.1.2 Trading activities

The Group's trading activities are primarily conducted within:

- ENGIE Global Markets and ENGIE Energy Management. The purpose of these wholly-owned companies is to (i) assist Group entities in optimizing their asset portfolios; and (ii) create and implement energy price risk management solutions for internal and external customers;
- ENGIE SA for the optimization of part of its long-term gas supply contracts, of a power exchange contract and of part of its gas sales contracts with retail entities in France and Benelux and with power generation facilities in France and Belgium.

Revenues from trading activities totaled €629 million at December 31, 2020 (€684 million at December 31, 2019).

The use of Value at Risk (VaR) to quantify market risk arising from trading activities provides a transversal measure of risk, taking all markets and products into account. VaR represents the maximum potential loss on a portfolio over a specified holding period based on a given confidence interval. It is not an indication of expected results but is back-tested on a regular basis.

The Group uses a one-day holding period and a 99% confidence interval to calculate VaR, as well as stress tests, in accordance with banking regulatory requirements.

The VaR shown below corresponds to the global VaR of the Group's trading entities.

Value at Risk

In millions of euros	Dec. 31, 2020	2020 average ⁽¹⁾	2020 maximum ⁽²⁾	2020 minimum ⁽²⁾	2019 average ⁽¹⁾
Trading activities	7	10	19	3	14

(1) Average daily VaR.

(2) Maximum and minimum daily VaR observed in 2020.

17.1.2 Hedges of commodity risks

Hedging instruments and sources of hedge ineffectiveness

The Group enters into cash flow hedges, using derivative instruments (firm or option contracts) contracted over the counter or on organized markets, to reduce its commodity risks, which relate mainly to future cash flows from contracted or expected sales and purchases of commodities. These instruments may be settled net or involve physical delivery of the underlying.

Sources of hedge ineffectiveness are mainly related to uncertainty regarding the timing and potential mismatches in settlement dates and indices between the derivative instruments and the associated underlying exposures.

The fair values of commodity derivatives are indicated in the table below:

<i>In millions of euros</i>	Dec. 31, 2020				Dec. 31, 2019			
	Assets		Liabilities		Assets		Liabilities	
	Non-current	Current	Non-current	Current	Non-current	Current	Non-current	Current
Derivative instruments relating to portfolio management activities	1,163	804	(945)	(749)	2,484	1,037	(3,011)	(1,125)
<i>Cash flow hedges</i>	225	291	(250)	(205)	1,893	292	(1,953)	(557)
<i>Other derivative instruments</i>	938	514	(695)	(544)	591	746	(1,058)	(568)
Derivative instruments relating to trading activities	-	7,075	-	(8,503)	-	8,955	-	(9,234)
TOTAL	1,163	7,879	(945)	(9,252)	2,484	9,993	(3,011)	(10,360)

The fair values shown in the table above reflect the amounts for which assets could be exchanged, or liabilities settled, at the end of the reporting period. They are not representative of expected future cash flows insofar as positions (i) are sensitive to changes in prices; (ii) can be modified by subsequent transactions; and (iii) can be offset by future cash flows arising on the underlying transactions.

17.1.2.1 Cash flow hedges

The fair values of cash flow hedges by type of commodity are as follows:

<i>In millions of euros</i>	Dec. 31, 2020				Dec. 31, 2019			
	Assets		Liabilities		Assets		Liabilities	
	Non-current	Current	Non-current	Current	Non-current	Current	Non-current	Current
Natural gas	168	236	(178)	(159)	1,814	235	(1,937)	(550)
Electricity	1	3	(3)	(5)	14	35	(9)	(5)
Coal	-	-	-	-	-	1	(1)	-
Oil	54	50	(68)	(41)	51	-	-	-
Other ⁽¹⁾	2	2	(1)	-	14	21	(6)	(2)
TOTAL	225	291	(250)	(205)	1,893	292	(1,953)	(557)

(1) Includes mainly foreign currency hedges on commodities.

Notional amounts (net) ⁽¹⁾

Notional amounts and maturities of cash flow hedges are as follows:

	<i>Unit</i>	2021	2022	2023	2024	2025	Beyond 5 years	Total at Dec. 31, 2020
Natural gas	<i>GWh</i>	99,240	52,651	24,945	8,667	733	-	186,236
Electricity	<i>GWh</i>	(4,150)	(2,693)	(1,227)	7	-	-	(8,063)
Coal	<i>Thousands of tons</i>	52	23	-	-	-	-	75
Oil-based products	<i>Thousands of barrels</i>	(16,723)	(11,381)	(11,410)	(11,508)	-	-	(51,022)
Forex	<i>Millions of euros</i>	19	4	-	-	-	-	24
Greenhouse gas emission rights	<i>Thousands of tons</i>	188	117	73	12	-	-	390

(1) Long/(short) position.

Effects of hedge accounting on the Group's financial position and performance

<i>In millions of euros</i>	Dec. 31, 2020			Dec. 31, 2019		
	Fair Value		Total	Nominal	Fair value	Nominal
	Assets	Liabilities		Total	Total	Total
Cash flow hedges	515	(455)	61	126,189	(325)	4,967
TOTAL	515	(455)	61	126,189	(325)	4,967

The fair values represented above are positive for assets and negative for liabilities.

<i>In millions of euros</i>		Nominal amount	Fair Value	Change in fair value used for calculating hedge effectiveness	Change in the value of the hedging instrument recognized in equity ⁽¹⁾	Ineffective portion recognized in profit or loss ⁽¹⁾	Amount reclassified from the hedge reserve to profit or loss ⁽¹⁾	Line item of profit or loss
Cash flow hedges								Current operating income
	Hedging instruments	126,189	61		154	-	698	
	Hedged items			748				

(1) Gains/(losses).

Hedge inefficiency is calculated based on the change in the fair value of the hedging instrument compared to the change in the fair value of the hedged items since inception of the hedge. The fair value of the hedging instruments at December 31, 2020 reflects the cumulative change in the fair value of the hedging instruments since inception of the hedges.

Maturity of commodity derivatives designated as cash flow hedges

<i>In millions of euros</i>	2021	2022	2023	2024	2025	Beyond 5 years	Dec. 31, 2020	Dec. 31, 2019
Fair Value of derivatives by maturity	168	39	(40)	(33)	17	3	154	(325)

Amounts presented in the statement of changes in equity and the statement of comprehensive income

The following table provides a reconciliation of each component of equity and an analysis of other comprehensive income:

<i>In millions of euros</i>	Cash flow hedge	Derivatives hedging commodities
At December 31, 2019		(837)
Effective portion recognized in equity		189
Amount reclassified from hedge reserve to profit or loss		704
Translation differences		-
Changes in scope of consolidation and other		(1)
At December 31, 2020		54

17.1.2.2 Other commodity derivatives

Other commodity derivatives include:

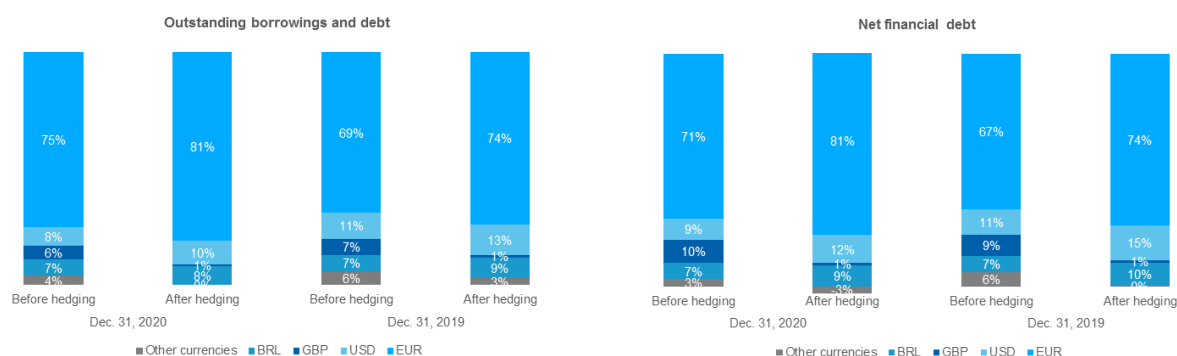
- commodity purchase and sale contracts that were not entered into or are no longer held for the purpose of the receipt or delivery of commodities in accordance with the Group's expected purchase, sale or usage requirements;
- embedded derivatives; and
- derivative financial instruments that are not eligible for hedge accounting in accordance with IFRS 9 or for which the Group has elected not to apply hedge accounting.

17.1.3 Currency risk

The Group is exposed to currency risk, defined as the impact on its statement of financial position and income statement of fluctuations in exchange rates affecting its operating and financing activities. Currency risk comprises (i) transaction risk arising in the ordinary course of business, (ii) specific transaction risk related to investments, mergers and acquisitions or disposal projects, and (iii) translation risk arising from the conversion into euros of income statement and statement of financial position items from subsidiaries with a functional currency other than the euro. The main translation risk exposures correspond, in order, to assets in US dollars, Brazilian real and pounds sterling.

17.1.3.1 Financial instruments by currency

The following tables present a breakdown by currency of outstanding borrowings and debt and net financial debt, before and after hedging:



17.1.3.2 Currency risk sensitivity analysis

A sensitivity analysis to currency risk on financial income/(loss) – excluding the income statement translation impact of foreign subsidiaries – was performed based on all financial instruments managed by the treasury department and representing a currency risk (including derivative financial instruments).

A sensitivity analysis to currency risk on equity was performed based on all financial instruments qualified as net investment hedges at the reporting date.

For currency risk, sensitivity corresponds to a 10% rise or fall in exchange rates of foreign currencies against the euro compared to closing rates.

In millions of euros	Dec. 31, 2020			
	Impact on income		Impact on equity	
	+10% ⁽¹⁾	-10% ⁽¹⁾	+10% ⁽¹⁾	-10% ⁽¹⁾
Exposures denominated in a currency other than the functional currency of companies carrying the liabilities on their statements of financial position ⁽²⁾	4	(4)	NA	NA
Financial instruments (debt and derivatives) qualified as net investment hedges ⁽³⁾	NA	NA	155	(155)

(1) +(-)10%: depreciation (appreciation) of 10% of all foreign currencies against the euro.

(2) Excluding derivatives qualified as net investment hedges.

(3) This impact is countered by the offsetting change in the net investment hedged.

17.1.4 Interest rate risk

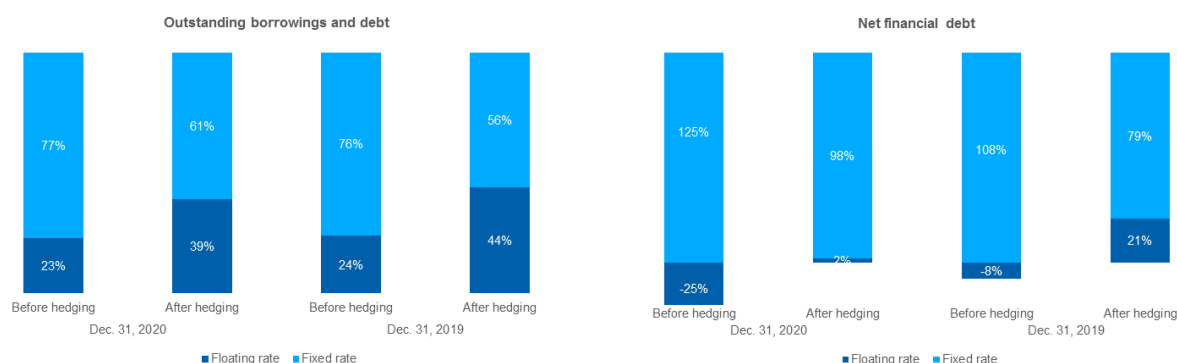
The Group seeks to manage its borrowing costs by limiting the impact of interest rate fluctuations on its income statement. The Group's policy is therefore to arbitrate between fixed rates, floating rates and capped floating rates for its net debt. The interest rate mix may shift within a range defined by Group Management in line with market trends.

In order to manage the interest rate structure for its net debt, the Group uses hedging instruments, particularly interest rate swaps and options. At December 31, 2020, the Group had a portfolio of interest rate options (caps) protecting it from a rise in short-term interest rates for the euro.

The Group has a portfolio of 2021, 2023, 2024 and 2025 forward interest rate pre-hedges with respective 20/21-year and 10 year maturities on each of the volumes initiated in 2020 to protect the refinancing interest rate on a portion of its debt.

17.1.4.1 Analysis of financial instruments by type of interest rate

The following tables present a breakdown by type of interest rate of outstanding borrowings and debt and net financial debt before and after hedging:



17.1.4.2 Interest rate risk sensitivity analysis

Sensitivity was analyzed based on the Group's net debt position (including the impact of interest rate and foreign currency derivatives relating to net debt) at the reporting date.

For interest rate risk, sensitivity corresponds to a 100-basis-point rise or fall in the yield curve compared to year-end interest rates.

In millions of euros	Dec. 31, 2020			
	Impact on income		Impact on equity	
	+100 basis points	-100 basis points	+100 basis points	-100 basis points
Net interest expense on floating-rate net debt (nominal amount) and on floating-rate leg of derivatives	(3)	2	NA	NA
Change in fair value of derivatives not qualifying as hedges	70	(139)	NA	NA
Change in fair value of derivatives qualifying as cash flow hedges	NA	NA	549	(711)

17.1.5 Currency and interest rate hedges

The COVID-19 crisis has not prompted the Group to review its foreign exchange and interest rate risk management policy described below

17.1.5.1 Currency risk management

Foreign currency exchange risk (or "FX" risk) is reported and managed based on a Group-wide approach, reflected in a dedicated Group policy that is approved by Group Management. The policy distinguishes between the three following main sources of currency risk:

- Regular transaction risk**

Regular transaction risk corresponds to the potential negative financial impact of currency fluctuations on business and financial operations denominated in a currency other than the functional currency.

The management of regular transaction risk is fully delegated to the subsidiaries for their scope of activities, while the risks related to central activities are managed at corporate level.

FX risks related to operational activities are systematically hedged when the related cash flows are certain, with a hedging horizon that corresponds at least to the medium-term plan horizon. For cash flows that are not certain, in their entirety, the hedge is initially based on a “no regret” volume. Exposures are monitored and managed based on the sum of nominal cash flows in FX, including highly probable amounts and related hedges.

For FX risks related to financial activities, all significant exposures related to cash, financial debt, etc. are systematically hedged. Exposures are monitored based on the net sum of balance sheet items in FX.

- **Project transaction risk**

Specific project transaction risk corresponds to the potential negative financial impact of FX fluctuations on specific major operations such as investment projects, acquisitions, disposals and restructuring projects, involving multiple currencies.

The management of these FX risks includes the definition and implementation of hedging transactions, taking into account the likelihood of the risk (including probability of project completion) and its evolution, the availability of hedging instruments and their associated cost. Management’s aim is to ensure the viability and the profitability of the transactions.

- **Translation risk**

Translation risk corresponds to the potential negative financial impact of FX fluctuations concerning consolidated entities with a functional currency other than the euro. It relates to the translation of their income and expenses and their net assets.

Translation risk is managed centrally, with a focus on securing the net asset value.

The pertinence of hedging this translation risk is assessed regularly for each currency (as a minimum) or set of assets in the same currency, taking into account notably the value of the assets and the hedging costs.

Hedging instruments and sources of hedge ineffectiveness

The Group principally uses the following risk management levers for mitigating currency risk:

- derivative instruments: these mostly correspond to over-the-counter contracts and include FX forward transactions, FX swaps, currency swaps, cross currency swaps, plain vanilla FX options or combinations (calls, puts or collars);
- monetary items such as debt, cash and loans.

Sources of hedge ineffectiveness are mainly related to uncertainty regarding the timing and in some cases the amount of the future cash flows in foreign currency that are being hedged.

17.1.5.2 Interest rate risk management

The Group is exposed to interest rate risk through its financing and investing activities. Interest rate risk is defined as a financial risk resulting from fluctuations in base interest rates that may increase the cost of debt and affect the viability of investments. Base interest rates are market interest rates, such as EURIBOR, LIBOR, etc., that do not include the borrower’s credit spread.

As part of the interest rate benchmark reform, since 2019 the Group has applied, the transition reliefs permitted by the IASB which allow the uncertainties caused by the reform not to be taken into account in the “highly probable” requirement. In 2020, the Group decided to apply the “IBOR phase 2” amendments, which provide for the clarification of the accounting treatment of financial instruments concerned by the reform, in advance. These amendments, which mainly aim to address the issues relating to the valuation of financial instruments and hedging relationships, only apply to the changes required by the reform.

The approach adopted by the ENGIE Group, through an ad hoc working group, makes it possible to address the issue both at the level of central financing vehicles and external financing issued directly by the Business Units.

A Group-wide approach to interest rate risk management is reflected in a dedicated Group policy that is approved by Group Management. This policy distinguishes between the two following main sources of interest rate risk:

- **Interest rate risk relating to Group net debt**

Interest rate risk relating to Group net debt designates the financial impact of base rate movements on the debt and cash portfolio from recurring financing activities. This risk is mainly managed centrally.

Risk management objectives are, by order of importance:

- to protect the long term viability of assets;
- to optimize financing costs and ensure competitiveness; and
- to minimize uncertainty on the cost of debt.

Interest rate risk is managed actively by monitoring changes in market rates and their impact on the Group's gross and net debt.

- **Project interest rate risk**

Specific project interest rate risk corresponds to the potential negative financial impact of base rate movements on specific major operations such as investment projects, acquisitions, disposals and restructuring projects. Interest rate risk after the closing of an operation is considered as regular (see "Interest rate risk" above).

Interest rate risk is managed for specific project transactions in order to protect the economic viability of projects, acquisitions, disposals and restructuring initiatives against adverse changes in interest rates. It may include the implementation of hedging transactions, depending on a number of factors including the likeliness of completion, the availability of hedging instruments and their associated cost.

Hedging instruments and sources of hedge ineffectiveness

The Group principally uses the following risk management levers for mitigating interest rate risk:

- derivative instruments: these mostly correspond to over-the-counter contracts that are used to manage base interest rates. Such instruments include:
 - swaps, to change the nature of interest payments on debts, typically from fixed to floating rates or vice versa, and
 - plain vanilla interest rate options;
- caps, floors and collars that allow the impact of interest rate fluctuations to be limited by setting minimum and/or maximum limits on floating interest rates.

Sources of hedge ineffectiveness are mainly related to changes in the credit quality of the counterparties and related charges, as well as potential gaps in settlement dates and in indices between the derivative instruments and the related underlying exposures.

17.1.5.3 Currency and interest rate hedges

The Group has elected to apply hedge accounting whenever possible and suitable for currency risk and interest rate risk management purposes and also manages a portfolio of undesignated derivative instruments, corresponding to economic hedges relating to net debt and foreign currency exposures.

The Group uses the three hedge accounting methods: cash flow hedging, fair value hedging and net investment hedging.

In general, the Group does not frequently reset hedging relationships, designate specific risk components as a hedged item or designate credit exposures as measured at fair value through income.

The Group qualifies interest rate or cross currency swaps transforming fixed-rate debt into floating-rate debt as fair value hedges.

Cash flow hedges are mainly used to hedge future cash flows in foreign currency, floating-rate debt as well as future refinancing requirements.

Net investment hedging instruments are mainly FX swaps and forwards.

The fair values of derivatives (excluding commodity instruments) are indicated in the table below:

	Dec. 31, 2020				Dec. 31, 2019			
	Assets		Liabilities		Assets		Liabilities	
	Non-current	Current	Non-current	Current	Non-current	Current	Non-current	Current
<i>In millions of euros</i>								
Derivatives hedging borrowings	619	147	(313)	(39)	705	124	(183)	(41)
<i>Fair value hedges</i>	526	14	(48)	(3)	530	81	(54)	(1)
<i>Cash flow hedges</i>	8	7	(220)	(8)	55	-	(93)	(7)
<i>Derivative instruments not qualifying for hedge accounting</i>	85	126	(46)	(28)	120	43	(36)	(34)
Derivatives hedging other items	1,214	43	(2,530)	(45)	949	17	(1,934)	(45)
<i>Cash flow hedges</i>	30	3	(768)	(11)	25	-	(571)	(4)
<i>Net investment hedges</i>	55	-	(4)	-	33	-	(6)	-
<i>Derivative instruments not qualifying for hedge accounting</i>	1,130	40	(1,758)	(33)	891	17	(1,357)	(41)
TOTAL	1,833	189	(2,844)	(84)	1,654	142	(2,118)	(86)

The fair values shown in the table above reflect the amounts relating to the price that would be received for the sale of an asset or paid for the transfer of a liability between market participants in the normal course of business. They are not representative of expected future cash flows insofar as the positions (i) are sensitive to changes in prices or to changes in credit ratings, (ii) can be modified by subsequent transactions, and (iii) can be offset by future cash flows arising on the underlying transactions.

Amount, timing and uncertainty of future cash flows

The following tables provide a profile of the timing at December 31, 2020 of the nominal amount of hedging instruments:

<i>In millions of euros</i>										
Buy/Sell	Interest rate type	Derivative instrument type	Currency	Total	2021	2022	2023	2024	2025	Beyond 5 years
Buy	Fixed	CCS	EUR	(486)	(303)	(32)	(30)	(29)	(26)	(67)
			USD	(2,205)	(982)	(937)	(41)	(41)	(41)	(163)
			GBP	(15,712)	(2,031)	(1,780)	(1,780)	(1,780)	(1,780)	(6,563)
			HKD	(1,987)	(242)	(242)	(242)	(242)	(242)	(778)
			JPY	(1,146)	(356)	(356)	(277)	(158)	-	-
			PEN	(1,334)	(220)	(220)	(220)	(183)	(165)	(326)
			Other	(1,682)	(336)	(336)	(336)	(336)	(126)	(214)
Sell	Fixed	CCS	EUR	21,194	2,865	2,568	2,568	2,568	2,352	8,273
			USD	1,472	243	243	243	202	182	360
			GBP	255	255	-	-	-	-	-
			Other	221	36	32	31	29	26	67
	Floating	CCS	EUR	2,323	953	953	273	144	-	-
		CCS	BRL	390	195	195	-	-	-	-

In millions
of euros

Buy/Sell	Interest rate type	Derivative instrument type	Currency	Total	2021	2022	2023	2024	2025	Beyond 5 years
Buy	Fixed	CAP	EUR	1,000	1,000	-	-	-	-	-
			Other	-	-	-	-	-	-	-
		IRS	EUR	70,376	6,506	9,971	9,009	8,382	8,818	27,689
			USD	4,180	1,368	1,367	1,366	16	15	47
	Floating	IRS	BRL	186	93	93	-	-	-	-
			Other	41	8	7	6	5	5	10
			EUR	72,713	14,979	11,236	9,078	7,978	7,978	21,464
			BRL	739	308	308	123	-	-	-

The tables presented above exclude currency derivatives (except for cross currency swaps - CCS). Their maturity dates are aligned with those of the hedged items.

Pursuant to the FX and interest rate risk management policy, FX sensitivity is presented in Note 17.1.3.2 "Currency risk sensitivity analysis" and the average cost of debt is 2.38% as presented in Note 10 "Net financial income/(loss)".

Effects of hedge accounting on the Group's financial position and performance

Currency derivatives

In millions of euros	Dec. 31, 2020			Dec. 31, 2019		
	Fair value		Nominal amount	Fair value		Nominal amount
	Assets	Liabilities	Total	Total	Total	Total
Cash flow hedges	30	(657)	(628)	3,779	(305)	3,814
Net investment hedges	55	(4)	50	1,999	27	3,027
Derivative instruments not qualifying for hedge accounting	149	(76)	73	6,907	(6)	8,985
TOTAL	233	(737)	(504)	12,686	(284)	15,827

Interest rate derivatives

In millions of euros	Dec. 31, 2020			Dec. 31, 2019		
	Fair value		Nominal amount	Fair value		Nominal amount
	Assets	Liabilities	Total	Total	Total	Total
Fair value hedges	546	(51)	495	4,622	556	6,089
Cash flow hedges	1	(332)	(331)	2,497	(290)	3,649
Derivative instruments not qualifying for hedge accounting	1,232	(1,802)	(569)	17,910	(393)	21,487
TOTAL	1,779	(2,184)	(405)	25,029	(126)	31,224

The fair values presented in the above table are positive for an assets and negative for a liabilities.

In millions of euros		Nominal and outstanding amount	Fair value ⁽¹⁾	Change in fair value used for calculating hedge ineffectiveness	Change in the value of the hedging instrument recognized in equity ⁽²⁾	Ineffective portion recognized in profit or loss ⁽²⁾	Amount reclassified from the hedge reserve to profit or loss ⁽²⁾	Line item of the income statement
Fair value hedges	Hedging instruments	4,622	495	495	NA	-	NA	Cost of net debt
	Hedged items ^{(3) (4)}	4,302	396	(1,698)	NA		NA	
Cash flow hedges	Hedging instruments	7,463	(958)	(860)	207	(5)	47	Other financial income and expenses / Current operating income including operating MtM
	Hedged items			854				
Net investment hedges	Hedging instruments	3,027	27	56	(119)	NA	(9)	Other financial income and expenses / Current operating income including operating MtM
	Hedged items			(56)				

(1) The adjustment of the fair value of hedged items is presented as long term and short-term borrowings and debt for an amount of €396 million.

(2) Gains/(losses)

(3) The difference between the fair value used to determine the ineffective portion relating to hedging instruments and that relating to the hedged items corresponds to the amortized cost of borrowings and debt that are part of a fair value hedge relationship.

(4) Of which €98 million relating to hedging items that are no longer adjusted as a result of disqualification as a fair value hedge.

Hedge inefficiency is calculated based on the change in the fair value of the hedging instrument compared to the change in the fair value of the hedged items since inception of the hedge. The fair value of the hedging instruments at December 31, 2020 reflects the cumulative change in the fair value of the hedging instruments since inception of the hedges. For fair value hedges, the same principle applies to the hedged items.

No significant impact in terms of ineffectiveness or disqualification of certain hedges was recognized at December 31, 2020.

Foreign currency and interest rate derivatives designated as cash flow hedges can be analyzed as follows by maturity

In millions of euros	2021	2022	2023	2024	2025	Beyond 5 years	Total at Dec. 31, 2020	Total at Dec. 31, 2019
Fair value of derivatives by maturity	(44)	(38)	(41)	(34)	(29)	(774)	(958)	(594)

Amounts presented in the statement of changes in equity and the statement of comprehensive income

The following table provides a reconciliation of each component of equity and an analysis of other comprehensive income:

	Cash flow hedge			Net investment hedge
	Derivatives hedging borrowings - currency risk hedging ^{(1) (3)}	Derivatives hedging other items - interest rate risk hedging ^{(1) (3)}	Derivatives hedging other items - currency risk hedging ^{(2) (3)}	Derivatives hedging other items - currency risk hedging ^{(2) (4)}
<i>In millions of euros</i>				
AT DECEMBER 31, 2019	45	(1,010)	14	(284)
Effective portion recognized in equity	(202)		(6)	119
Amount reclassified from the hedge reserve to profit or loss	(47)		-	9
Translation differences	-	-	-	-
Changes in scope of consolidation and other	-	56	-	-
AT DECEMBER 31, 2020	46	(1,203)	9	(156)

(1) Cash flow hedges for given periods.

(2) Cash flow hedges for given transactions.

(3) Of which a negative €487 million of cash flow hedge reserves for which hedge accounting is no longer applied.

(4) All of the reserves relate to continuing hedging relationships.

17.2 Counterparty risk

Due to its financial and operational activities, the Group is exposed to the risk of default of its counterparties (customers, suppliers, EPC contractors, partners, intermediaries, and banks). Default could affect payments, goods delivery and/or asset performance.

The principles of counterparty risk management are set out in the Group counterparty risk policy, which:

- assigns roles and responsibilities for managing and controlling counterparty risk at different levels (Corporate, BU or entity), and ensures operational procedures are in place and consistent across the Group;
- characterizes counterparty risk and the mechanisms by which it impacts the economic performance and financial statements of the Group;
- defines indicators, reporting and control mechanisms to ensure visibility and to provide tools for financial performance management; and
- provides guidelines on the use of mitigating mechanisms such as collateral and guarantees, which are widely used by some businesses.

Depending on the nature of the business, the Group is exposed to different types of counterparty risk. As a result some businesses use collateral instruments – particularly the Energy Management business, where the use of margin calls and other types of financial collateral (standardized legal framework) is a market standard. In addition, other businesses may request guarantees from their counterparties in certain cases (parent company guarantees, bank guarantees, etc.).

Under the new standard IFRS 9, the Group has defined and applied a Group-wide methodology including the two different approaches:

- a portfolio approach, whereby the Group determines that:
 - coherent customer portfolios and sub-portfolios have to be considered (i.e., portfolios that have comparable credit risk and/or comparable payment behavior), taking into account different aspects:
 - public or private counterparties,
 - residential or BtoB counterparties,
 - geography,
 - type of activity,
 - size of the counterparty, and
 - any other aspects the Group may consider relevant,
 - impairment rates must be determined based on historical aging balances and, when correlation is proven and documentation possible, historical data must be adjusted by forward-looking elements; and

- an individualized approach for significant counterparties, for which the Group has set rules for defining the stage of the concerned asset for Expected Credit Loss (ECL) calculations:
 - stage 1 covers financial assets that have not deteriorated significantly since initial recognition. The ECL for stage 1 is calculated on a 12-month basis,
 - stage 2 covers financial assets for which the credit risk has significantly increased. The ECL for stage 2 is calculated on a lifetime basis. The decision to move an asset from stage 1 to stage 2 is based on certain criteria such as:
 - a significant downgrade in the creditworthiness of a counterparty and/or its parent company and/or its guarantor (if any),
 - significant adverse change in the regulatory environment,
 - changes in political or country-related risk, and
 - any other aspect the Group may consider relevant.

Regarding financial assets that are more than 30 days past due, the move to stage 2 is not systematically applied as long as the Group has reasonable and supportable information that demonstrates that, even if payments become more than 30 days past due, this does not represent a significant increase in the credit risk since initial recognition.

- stage 3 covers assets for which default has already been observed, such as:
 - when there is evidence of significant and ongoing financial difficulty of the counterparty,
 - when there is evidence of failure in credit support from a parent company to its subsidiary (in this case the subsidiary is the Group's counterparty at risk),
 - when a Group entity has initiated legal proceedings against the counterparty for non-payment.

Regarding financial assets that are more than 90 days past due, the presumption can be rebutted if the Group has reasonable and supportable information that demonstrates that even if payments become more than 90 days past due, this does not indicate counterparty default.

The ECL formula applicable in stages 1 and 2 is $ECL = EAD \times PD \times LGD$, where:

- for 12-month ECL, Exposure At Default (EAD) equals the carrying amount of the financial asset, to which the relevant Probability of Default (PD) and the Loss Given Default (LGD) are applied;
- for lifetime ECL, the calculation method consists in identifying changes in exposure for each year, especially the expected timing and amount of the contractual repayments, and then applying to each repayment the relevant PD and the LGD, and discounting the figures obtained. ECL is then the sum of the discounted figures; and
- probability of default is the likelihood of default over a particular time horizon (in stage 1, this time horizon is 12 months after the reporting period; in stage 2 this time horizon is the entire lifetime of the financial asset). This information is based on external data from a well-known rating agency. The PD depends on the time horizon and of the rating of the counterparty. The Group uses external ratings if they are available; ENGIE's credit risk experts determine an internal rating for major counterparties with no external rating.

LGD levels are notably based on Basel standards:

- 75% for subordinated assets; and
- 45% for standard assets.

For assets considered to be of strategic importance for the counterparty, such as essential public services or goods, LGD is set at 30%.

The Group has decided that write-offs apply in the following situations:

- assets for which a legal recovery procedure is pending: should not be written off as long as the procedure is ongoing; and

- assets for which no legal recovery procedure is pending: should be written off once the trade receivable is 3 years overdue (5 years overdue for public counterparties).

As a result of the COVID-19 crisis, the Group has implemented a specific management system to secure its counterparty risk. It is based in particular on:

- an increased monitoring of exposures and cash inflow delays for individually monitored counterparties; and
- an enhanced monitoring of aging balances of the Group's various activities for counterparties monitored using a portfolio approach.

Since the beginning of the crisis, the Group has taken immediate action to limit its exposures such as:

- the closure of customer lines in the most affected sectors within the Energy Management activity;
- the reassignment, during the lockdown in the first half of 2020, of commercial resources to sales administration missions, within the supply and marketing activities, in order to limit the deterioration of aging balances. This increased monitoring of collection procedures throughout 2020 led to no significant change in outstandings (trade receivables, contract assets or receivables recognized at amortized cost) and a general improvement in the cash position of the business units concerned.

Furthermore, the Group has also implemented measures to support the most vulnerable households and microenterprises such as:

- the reimbursement of 2 months of electricity standing charges (April and May) for beneficiaries of an energy voucher or of the Housing Solidarity Fund (*Fonds de Solidarité Logement*);
- the implementation of a payment facility over 6 months with a postponement of the first due date until the end of the health crisis for companies with less than 10 employees.

From an accounting point of view, these various measures were accompanied by an adjustment of the provisioning rate in the customer segments most at risk, particularly in the aeronautical and hotel & catering sectors. These effects led to an increase in expected credit loss, the impact of which on the Group's net income amounted to €230 million at December 31, 2020.

17.2.1 Operating activities

Counterparty risk arising on operating activities is managed via standard mechanisms such as third-party guarantees, netting agreements and margin calls, using dedicated hedging instruments or special prepayment and debt recovery procedures, particularly for retail customers.

Under the Group's policy, each business unit is responsible for managing counterparty risk, although the Group continues to manage the biggest counterparty exposures centrally.

The credit rating of large- and mid-sized counterparties with which the Group has exposures above a certain threshold is measured based on a specific rating process, while a simplified credit scoring process is used for commercial customers with which the Group has fairly low exposures. These processes are based on formally documented, consistent methods across the Group. Consolidated exposures are monitored by counterparty and by segment (credit rating, sector, etc.) using standard indicators (payment risk, mark-to-market exposure).

The Group's Energy Market Risk Committee (CRME) consolidates and monitors the Group's exposure to its main energy counterparties on a quarterly basis and ensures that the exposure limits set for these counterparties are respected.

17.2.1.1 Trade and other receivables, assets from contracts with customers

Total outstanding exposures presented in the tables below do not include impacts relating to VAT or to any other item not subject to credit risk, which amounted to €2,431 million at December 31, 2020 (compared to €2,898 million at December 31, 2019).

Individual approach

		Dec. 31, 2020							
<i>In millions of euros</i>		Individual approach	Level 1: low credit risk	Level 2: increased credit risk	Level 3: impaired assets	Total by risk level	Investment Grade ⁽¹⁾	Other	Total by counterparty type
Trade and other receivables, net	Gross	9,530	8,329	893	308	9,530	7,854	1,676	9,530
	Expected credit losses	(391)	(103)	(46)	(242)	(391)	(188)	(203)	(391)
TOTAL		9,139	8,226	846	66	9,139	7,666	1,473	9,139
Assets from contracts with customers	Gross	3,039	2,714	318	8	3,039	2,076	963	3,039
	Expected credit losses	(19)	(18)	-	-	(19)	(14)	(5)	(19)
TOTAL		3,021	2,696	318	7	3,021	2,062	959	3,021

		Dec. 31, 2019							
<i>In millions of euros</i>		Individual approach	Level 1: low credit risk	Level 2: increased credit risk	Level 3: impaired assets	Total by risk level	Investment Grade ⁽¹⁾	Other	Total by counterparty type
Trade and other receivables, net	Gross	9,395	8,300	802	294	9,395	7,814	1,581	9,395
	Expected credit losses	(318)	(64)	(66)	(187)	(318)	(172)	(146)	(318)
TOTAL		9,077	8,235	735	107	9,077	7,642	1,436	9,077
Assets from contracts with customers	Gross	2,896	2,672	196	28	2,896	1,782	1,115	2,896
	Expected credit losses	(15)	(13)	(1)	(1)	(15)	(10)	(6)	(15)
TOTAL		2,881	2,659	195	27	2,881	1,772	1,109	2,881

(1) Investment Grade corresponds to counterparties that are rated at least BBB- by Standard & Poor's.

Collective approach

		Dec. 31, 2020				Total past due assets at Dec. 31, 2020
<i>In millions of euros</i>		Collective approach	0 to 6 months	6 to 12 months	Beyond	
Trade and other receivables, net	Gross	3,625	593	235	300	1,128
	Expected credit losses	(865)	(20)	(22)	(211)	(253)
TOTAL		2,761	574	213	88	875
Assets from contracts with customers	Gross	4,748	487	1	3	491
	Expected credit losses	(1)	-	-	-	-
TOTAL		4,747	487	1	3	491

		Dec. 31, 2019				Total past due assets at Dec. 31, 2019
<i>In millions of euros</i>		Collective approach	0 to 6 months	6 to 12 months	Beyond	
Trade and other receivables, net	Gross	4,019	875	113	293	1,281
	Expected credit losses	(754)	(24)	(29)	(159)	(213)
TOTAL		3,265	851	83	134	1,068
Assets from contracts with customers	Gross	4,953	486	4	2	492
	Expected credit losses	(2)	-	-	-	-
TOTAL		4,951	485	4	2	492

17.2.1.2 Commodity derivatives

In the case of commodity derivatives, counterparty risk arises from positive fair value. Counterparty risk is taken into account when calculating the fair value of these derivative instruments.

In millions of euros	Dec. 31, 2020		Dec. 31, 2019	
	Investment Grade ⁽¹⁾	Total	Investment Grade ⁽¹⁾	Total
Gross exposure ⁽²⁾	6,633	9,031	9,849	12,466
Net exposure ⁽³⁾	2,817	3,750	3,501	4,422
% of credit exposure to "Investment Grade" counterparties	75.1%		79.2%	

- (1) Investment Grade corresponds to transactions with counterparties that are rated at least BBB- by Standard & Poor's, Baa3 by Moody's, or equivalent by Dun & Bradstreet. "Investment Grade" is also determined based on an internal rating tool that has been rolled out within the Group, and covers its main counterparties.
- (2) Corresponds to the maximum exposure, i.e., the value of the derivatives shown under assets (positive fair value).
- (3) After taking into account the liability positions with the same counterparties (negative fair value), collateral, netting agreements and other credit enhancement techniques.

The COVID-19 crisis has not affected the Group's exposure due to the credit quality of its counterparties, which has been maintained to date.

17.2.2 Financing activities

For its financing activities, the Group has put in place procedures for managing and monitoring risk based on (i) the accreditation of counterparties according to external credit ratings, objective market data (credit default swaps, market capitalization) and financial structure, and (ii) counterparty risk exposure limits.

To reduce its counterparty risk exposure, the Group has drawn increasingly on a structured legal framework based on master agreements (including netting clauses) and collateralization contracts (margin calls).

The oversight procedure for managing counterparty risk arising from financing activities is managed by a Middle Office that operates independently of the Group's Treasury department and reports to the Finance division.

17.2.2.1 Loans and receivables at amortized cost

The total outstanding exposures presented in the tables below do not include impacts relating to VAT or to any other item not subject to credit risk, which amounted to €1,424 million at December 31, 2020 (compared to €899 million at December 31, 2019).

In millions of euros	Dec. 31, 2020						
	Level 1: low credit risk	Level 2: increased credit risk	Level 3: impaired assets	Total by risk level	Investment Grade ⁽¹⁾	Other	Total by counterparty type
Gross	4,144	415	67	4,626	2,582	2,045	4,626
Expected credit losses	(57)	(34)	(110)	(201)	(127)	(74)	(201)
TOTAL	4,087	381	(43)	4,425	2,455	1,970	4,425

In millions of euros	Dec. 31, 2019						
	Level 1: low credit risk	Level 2: increased credit risk	Level 3: impaired assets	Total by risk level	Investment Grade ⁽¹⁾	Other	Total by counterparty type
Gross	4,257	564	49	4,870	2,772	2,098	4,870
Expected credit losses	(53)	(56)	(30)	(139)	(36)	(104)	(139)
TOTAL	4,204	508	19	4,731	2,736	1,995	4,731

- (1) Investment Grade corresponds to counterparties that are rated at least BBB- by Standard & Poor's.

17.2.2.2 Counterparty risk arising from investing activities and the use of derivative financial instruments

The Group is exposed to counterparty risk arising from investments of surplus cash and from the use of derivative financial instruments. In the case of financial instruments at fair value through income, counterparty risk arises on instruments with a positive fair value. Counterparty risk is taken into account when calculating the fair value of these derivative instruments.

In millions of euros	Dec. 31, 2020				Dec. 31, 2019			
	Total	Investment Grade ⁽¹⁾	Unrated ⁽²⁾	Non Investment-Grade ⁽²⁾	Total	Investment Grade ⁽¹⁾	Unrated ⁽²⁾	Non-Investment Grade ⁽²⁾
Exposure	13,174	84.4%	8.7%	6.9%	10,686	85.7%	4.7%	9.6%

(1) Investment Grade corresponds to counterparties that are rated at least BBB- by Standard & Poor's or Baa3 by Moody's.

(2) Most of these two exposures is carried by consolidated companies that include non-controlling interests, or by Group companies that operate in emerging countries, where cash cannot be pooled and is therefore invested locally.

Furthermore, at December 31, 2020, Crédit Agricole Corporate and Investment Bank (CACIB) is the main Group counterparty and represents 20% of cash surpluses. This relates mainly to a depositary risk.

17.3 Liquidity risk

In the context of its operating activities, the Group is exposed to a risk of having insufficient liquidity to meet its contractual obligations. As well as the risks inherent in managing working capital requirements (WCR), margin calls are required in certain market activities.

The Group has set up a weekly committee tasked with managing and monitoring liquidity risk throughout the Group, by maintaining a broad range of investments and sources of financing, preparing forecasts of cash investments and divestments. Stress tests are also performed on the margin calls put in place when commodity, interest rate and currency derivatives are negotiated to assess the Group's resilience in terms of liquidity.

The Group centralizes virtually all the financing needs and cash flow surpluses of the companies it controls, as well as most of their medium- and long-term external financing requirements. Centralization is provided by financing vehicles (long-term and short-term) and by dedicated Group cash pooling vehicles based in France, Belgium and Luxembourg.

Surpluses held by these structures are managed in accordance with a uniform policy. In accordance with this policy, unpooled cash surpluses are invested in instruments selected on a case-by-case basis in light of local financial market imperatives and the financial strength of the counterparties concerned.

The onslaught of successive financial crises since 2008 and the ensuing rise in counterparty risk prompted the Group to tighten its investment policy with the aim of keeping an extremely high level of liquidity and protecting invested capital and a daily monitoring of performance and counterparty, allowing the Group to take immediate action where required in response to market developments. Consequently, 77% of the cash pooled at December 31, 2020 was invested in overnight bank deposits and standard money market funds with daily liquidity.

The Group's financing policy is based on:

- centralizing external financing;
- diversifying sources of financing between credit institutions and capital markets;
- achieving a balanced debt repayment profile.

The Group seeks to diversify its sources of financing by carrying out public or private bond issues within the scope of its Euro Medium Term Notes program. It also issues negotiable commercial paper in France (Negotiable European Commercial Paper) and in the United States (U.S. Commercial Paper). As negotiable commercial paper is relatively inexpensive and highly liquid, it is used by the Group in a cyclical or structural fashion to finance its short-term cash requirements. However, the refinancing of all outstanding negotiable commercial paper remains secured by confirmed bank lines of credit – mainly centralized – allowing the Group to continue to finance its activities if access to this financing

source were to dry up. These facilities are appropriate for the scale of its operations and for the timing of contractual debt repayments.

As a result of the COVID-19 crisis, the Group implemented specific management measures to secure its liquidity. These measures are based on, (i) increased monitoring of centralized cash management and central liquidity, which is regularly communicated to General Management and the Board of Directors, and (ii) stress tests to assess the Group's liquidity.

In this context, the Group has also taken several actions including:

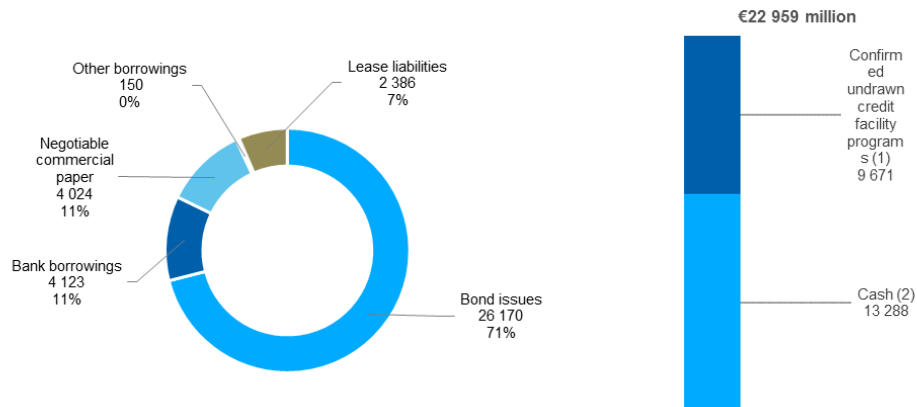
- maintaining an outstanding amount of negotiable commercial papers in France and the United States of €4 billion on average over the year, benefiting from the measures offered by the ECB to combat the pandemic (PEPP ⁽¹⁾ CSPP ⁽²⁾) for €900 million in the first half of 2020;
- the drawdown on bilateral credit lines of €885 million in March for a period of one month to cover the decline in liquidity in the negotiable commercial papers market;
- a bond issue for a total amount of €2.5 billion on March 27, 2020;
- the signature on May 11, 2020 of a syndicated credit line for an amount of €2.5 billion with a 12-month term and renewable for two 6-month periods. At the end of 2020 and given the changes in the Group's liquidity, in particular following the sale of its stake in SUEZ, this line was cancelled entirely.

In addition to these actions, the Group decided to (i) propose the cancellation of the payment of the 2019 dividend – this resolution was approved by the Shareholders' Meeting on May 14, 2020, and (ii) revise the timetable of certain investment projects (adjustments, postponements, etc.).

The various actions carried out by the Group ensure a high and reinforced level of liquidity.

Diversifying sources of financing and liquidity

In millions of euros



(1) Net amount of negotiable commercial paper.

(2) Cash corresponds to cash and cash equivalents, other financial assets deducted from net financial debt, net of bank overdrafts and current accounts, of which 78% was invested in the Eurozone.

At December 31, 2020, all the entities of the Group whose debt is consolidated complied with the covenants and declarations included in their financial documentation, except for some non-significant entities for which compliance actions are being implemented. None of the available centralized credit lines contain a default clause linked to financial ratios or rating level.

(1) Pandemic emergency purchase programme.

(2) Corporate sector purchase programme.

17.3.1 Undiscounted contractual payments relating to financial activities

Undiscounted contractual payments on outstanding borrowings and debt by maturity

<i>In millions of euros</i>	2021	2022	2023	2024	2025	Beyond 5 years	Total at Dec. 31, 2020	Total at Dec. 31, 2019
Bond issues	1,446	2,623	2,546	1,183	2,015	16,356	26,170	26,015
Bank borrowings	986	537	371	265	371	1,594	4,123	5,292
Negotiable commercial paper	4,024	-	-	-	-	-	4,024	3,233
Lease liabilities	513	460	284	258	231	921	2,386	2,512
Other borrowings	34	38	15	13	7	43	150	261
Bank overdrafts and current accounts	301	-	-	-	-	-	301	247

Other financial assets and cash and cash equivalents deducted from net financial debt have a liquidity of less than one year.

Undiscounted contractual interest payments on outstanding borrowings and debt by maturity

<i>In millions of euros</i>	2021	2022	2023	2024	2025	Beyond 5 years	Total at Dec. 31, 2020	Total at Dec. 31, 2019
Undiscounted contractual interest flows on outstanding borrowings and debt	959	731	658	554	553	6,398	9,853	9,872

Undiscounted contractual payments on outstanding derivatives (excluding commodity instruments) by maturity

<i>In millions of euros</i>	2021	2022	2023	2024	2025	Beyond 5 years	Total at Dec. 31, 2020	Total at Dec. 31, 2019
Derivatives (excluding commodity instruments)	(213)	(107)	55	19	31	532	317	(237)

To better reflect the economic substance of these transactions, the cash flows linked to the derivatives recognized in assets and liabilities shown in the table above relate to net positions.

Group's undrawn credit facility programs

<i>In millions of euros</i>	2021	2022	2023	2024	2025	Beyond 5 years	Total at Dec. 31, 2020	Total at Dec. 31, 2019
Confirmed undrawn credit facility programs	1,002	6,463	560	4,991	-	678	13,695	13,019

Of these undrawn programs, an amount of €4,024 million is allocated to covering commercial paper issues.

At December 31, 2020, no single counterparty represented more than 5% of the Group's confirmed undrawn credit lines.

17.3.2 Undiscounted contractual payments relating to operating activities

The table below provides an analysis of undiscounted fair values due and receivable in respect of commodity derivatives recorded in assets and liabilities at the statement of financial position date.

The Group provides an analysis of residual contractual maturities for commodity derivative instruments included in its portfolio management activities. Derivative instruments relating to trading activities are considered to be liquid in less than one year, and are presented under current items in the statement of financial position.

<i>In millions of euros</i>	2021	2022	2023	2024	2025	Beyond 5 years	Total at Dec. 31, 2020	Total at Dec. 31, 2019
Derivative instruments carried in liabilities								
<i>relating to portfolio management activities</i>	(744)	(509)	(181)	(76)	(40)	(149)	(1,699)	(4,428)
<i>relating to trading activities</i>	(8,483)	-	-	-	-	-	(8,483)	(9,238)
Derivative instruments carried in assets								
<i>relating to portfolio management activities</i>	802	671	204	101	29	166	1,975	3,363
<i>relating to trading activities</i>	7,059	-	-	-	-	-	7,059	8,954
TOTAL	(1,367)	162	23	25	(11)	18	(1,149)	(1,349)

17.3.3 Commitments relating to commodity purchase and sale contracts entered into within the ordinary course of business

Some Group operating companies have entered into long-term contracts, some of which include “take-or-pay” clauses. These consist of firm commitments to purchase or sell specified quantities of gas, electricity or steam as well as related services, in exchange for a firm commitment from the other party to deliver or purchase said quantities and services. These contracts were documented as falling outside the scope of IFRS 9. The table below shows the main future commitments arising from contracts entered into by Others (GEM BU) and Latin America (expressed in TWh).

<i>In TWh</i>	2021	2022-2025	Beyond 5 years	Total at Dec. 31, 2020	Total at Dec. 31, 2019
Firm purchases	(309)	(586)	(934)	(1,829)	(2,498)
Firm sales	498	608	465	1,571	1,573

NOTE 18 EQUITY

18.1 Share capital

	Number of shares			Value <i>(in millions of euros)</i>		
	Total	Treasury stock	Outstanding	Share capital	Additional paid-in capital	Treasury stock
AT DECEMBER 31, 2019	2,435,285,011	(22,153,694)	2,413,131,317	2,435	31,470	(303)
Dividend paid in cash	-	-	-	-	-	-
Allocation of prior-year income	-	-	-	-	(178)	-
Purchase/disposal of treasury stock	-	-	-	-	-	47
Delivery of treasury stock (bonus)	-	3,689,060	3,689,060	-	-	-
Revaluation	-	-	-	-	-	-
AT DECEMBER 31, 2020	2,435,285,011	(18,464,634)	2,416,820,377	2,435	31,291	(256)

Changes in the number of outstanding shares in 2020 result solely from the disposal of 3.7 million treasury shares, as part of bonus share plans.

18.1.1 Potential share capital and instruments providing a right to subscribe for new ENGIE SA shares

Since 2017, the Group no longer has any stock purchase or subscription option plans.

Shares to be allocated under the performance share award plans described in Note 21 "Share-based payments" are covered by existing ENGIE SA shares.

18.1.2 Treasury stock

Accounting standards

Treasury shares are recognized at acquisition cost and deducted from equity. Gains and losses on disposals of treasury shares are recorded directly in equity and do not, therefore, impact income for the period.

The Group has a stock repurchase program as a result of the authorization granted to the Board of Directors by the Ordinary and Extraordinary Shareholders' Meeting of May 17, 2020. This program provides for the repurchase of up to 10% of the shares comprising the share capital of ENGIE SA at the date of the said Shareholders' Meeting. The aggregate amount of acquisitions net of expenses under the program may not exceed €7.3 billion, and the purchase price must be less than €30 per share excluding acquisition costs.

At December 31, 2020, the Group held 18.5 million treasury shares. To date, all of the shares have been allocated to cover the Group's share commitments to employees and corporate officers.

The liquidity agreement signed with an investment service provider assigns to the latter the role of operating on the market on a daily basis, to buy or sell ENGIE SA shares, in order to ensure liquidity and an active market for the shares on the Paris and Brussels stock exchanges. To date, the resources allocated to the implementation of this agreement amount to €50 million.

18.2 Other disclosures concerning additional paid-in capital, consolidated reserves and issuance of deeply-subordinated perpetual notes (Group share)

Total additional paid-in capital, consolidated reserves and issuance of deeply-subordinated perpetual notes (including net income for the year), amounted to €33,830 million at December 31, 2020, including €31,291 million in additional paid-in capital. Additional paid-in capital includes the allocation of ENGIE SA's net income for an amount of €178 million.

Consolidated reserves include the cumulative income of the Group, the legal and statutory reserves of ENGIE SA, cumulative actuarial gains and losses, net of tax and the change in fair value of equity instruments at fair value through OCI.

Under French law, 5% of the net income of French companies must be allocated to the legal reserve until the latter reaches 10% of share capital. This reserve can only be distributed to shareholders in the event of liquidation. The ENGIE SA legal reserve amounts to €244 million.

18.2.1 Issuance of deeply-subordinated perpetual notes

On November 19, 2020, ENGIE SA carried out an early refinancing of deeply-subordinated perpetual notes, resulting in:

- an issue of green deeply-subordinated perpetual notes for an amount of €850 million offering a coupon of 1.5% with an annual reimbursement option from November 2028, accounted for in equity for a net amount of €844 million;
- a partial early redemption of three tranches of deeply-subordinated perpetual notes for an amount of €850 million, broken down as follows :
 - A redemption of €50 million (4.750% coupon) on a residual nominal amount of €413 million. The first reimbursement option for this hybrid debt was planned for July 2021,
 - A redemption of green deeply-subordinated perpetual notes for €342 million (1.375% coupon) out of a nominal amount of €1 billion. The first reimbursement option for this hybrid debt was planned for April 2023,
 - A redemption of €458 million (3.875% coupon) on a residual nominal amount of €1 billion. The first reimbursement option for this hybrid debt was planned for June 2024.

In accordance with the provisions of IAS 32 – *Financial Instruments – Presentation*, and given their characteristics, these new instruments were accounted for in equity in the Group's consolidated financial statements.

At December 31, 2020 the nominal value of the deeply-subordinated notes amounted to €3,913 million.

In 2020, the Group paid €187 million to the owners of these notes, including €128 million relating to coupons and €59 million for early repayment compensation. This amount is accounted for as a deduction from equity in the Group's consolidated financial statements; the relating tax saving is accounted for in the income statement.

18.2.2 Distributable capacity of ENGIE SA

ENGIE SA's distributable capacity totaled €27,363 million at December 31, 2020 (compared with €31,290 million at December 31, 2019), including €31,291 million of additional paid-in capital.

18.2.3 Dividends

It was proposed, at the Shareholders' Meeting convened to approve the ENGIE Group financial statements for the year ended December 31, 2019, to pay a dividend of €0.80 per share, representing a total payout of €1,931 million based on the number of shares outstanding at December 31, 2019. It will be increased by 10% for all shares held for at least two

years on December 31, 2019 and up to the 2019 dividend payment date. Based on the number of outstanding shares on December 31, 2019, this increase is valued at €17 million.

At the Shareholders' Meeting of May 14, 2020, the shareholders approved the Board's decision not to pay a dividend for the 2019 fiscal year in a spirit of responsibility and prudence in the exceptional context of the COVID-19 pandemic.

Proposed dividend in respect of 2020

At the Shareholders' Meeting convened to approve the ENGIE Group financial statements for the year ended December 31, 2020, the shareholders will be asked to approve a dividend of €0.53 per share, representing a total payout of €1,281 million based on the number of shares outstanding at December 31, 2020. It will be increased by 10% for all shares held for at least two years on December 31, 2020 and up to the 2020 dividend payment date. Based on the number of outstanding shares on December 31, 2020, this increase is valued at €10 million.

Subject to approval by the Shareholders' Meeting of May 20 2021, this dividend, net of the interim dividend paid will be detached on Monday May 24, 2021 and paid on Wednesday May 26, 2021. It is not recognized as a liability in the financial statements at December 31, 2020, since the financial statements at the end of 2020 were presented before the appropriation of earnings.

18.2.4 Other transactions

On February 5, 2020, Elengy acquired 27,5% of Total's shares in Fosmax LNG via its subsidiary Total Gaz Electricité Holding France (TGEHF). The acquisition of the shares excluding fees, amounting to €212 million, was financed mainly by an increase in Elengy's capital reserved for "Société d'Infrastructures Gazières (SIG)" in the amount of €185 million.

On July 2, 2020, ENGIE signed an agreement to sell a 49% stake in a 2.3 GW renewable energy portfolio in the United States to the American group Hannon Armstrong, a leader in investing in environmentally friendly solutions. This transaction resulted in the immediate sale of a 49% stake in 663 MW of wind projects in service, with the remaining projects (1.6 GW including 0.5 GW of solar projects), currently under construction, being transferred only upon commissioning. ENGIE will continue fully to consolidate, operate and manage these assets. This transaction resulted in a cash inflow of €406 million.

18.3 Gains and losses recognized in equity (Group share)

All items shown in the table below correspond to cumulative gains and losses (Group share) at December 31, 2020 and December 31, 2019, which are recyclable to income in subsequent periods.

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Debt instruments	30	76
Net investment hedges ⁽¹⁾	(156)	(284)
Cash flow hedges (excl. commodity instruments) ⁽¹⁾	(1,214)	(958)
Commodity cash flow hedges ⁽¹⁾	76	(837)
Deferred taxes on the items above	358	505
Share of equity method entities accounted in recyclable items, net of tax ⁽²⁾	(813)	(462)
TOTAL RECYCLABLE ITEMS BEFORE TRANSLATION ADJUSTMENTS	(1,719)	(1,961)
Translation adjustments ⁽³⁾	(2,850)	(1,098)
TOTAL RECYCLABLE ITEMS	(4,570)	(3,059)

(1) See Note 17 "Risks arising from financial instruments".

(2) See Note 3 "Investments in equity method entities".

(3) The change in translation adjustments is mainly due to the strong depreciation of the Brazilian real (negative €1,038 million) and the change in the US dollar (negative €677 million).

18.4 Capital management

ENGIE SA seeks to optimize its financial structure at all times by pursuing an optimal balance between its economic net debt and its EBITDA. The Group's key objective in managing its financial structure is to maximize value for shareholders

and reduce the cost of capital, while ensuring that the Group has the financial flexibility required to continue its expansion. The Group manages its financial structure and makes any necessary adjustments in light of prevailing economic conditions. In this context, it may choose to adjust the amount of dividends paid to shareholders, reimburse a portion of capital, carry out share buybacks (see Note 18.1.2 “*Treasury stock*”), issue new shares or deeply-subordinated notes, launch share-based payment plans, recalibrate its investment budget, or sell assets in order to scale back its net debt.

The Group's policy is to maintain an “strong investment grade” rating from the rating agencies. To achieve this, it manages its financial structure in line with the indicators usually monitored by these agencies, namely the Group's operating profile, financial policy and a series of financial ratios. One of the most commonly used ratios is the ratio where the numerator includes operating cash flows less net financial expense and taxes paid, and the denominator includes adjusted net financial debt. Net financial debt is mainly adjusted for nuclear provisions, provisions for pensions and deeply-subordinated notes.

The Group's objectives and processes for managing capital have remained unchanged over the past few years.

ENGIE SA is not obliged to comply with any external minimum capital requirements except those provided for by law.

NOTE 19 PROVISIONS

Accounting standards

General principles related to the recognition of a provision

The Group recognizes a provision where it has a present obligation (legal or constructive) towards a third party arising from past events and where it is probable that an outflow of resources will be necessary to settle the obligation with no expected consideration in return.

A provision for restructuring costs is recognized when the general criteria for setting up a provision are met, i.e. when the Group has a detailed formal plan relating to the restructuring and has raised a valid expectation in those affected that it will carry out the restructuring by starting to implement that plan or announcing its main features to those affected by it.

Provisions with a maturity of over 12 months are discounted when the effect of discounting is material. The Group's main long-term provisions are provisions for the back-end of the nuclear fuel cycle, provisions for dismantling facilities and provisions for site restoration costs. The discount rates used reflect current market assessments of the time value of money and the risks specific to the liability concerned. Expenses with respect to unwinding the discount on the provision are recognized as other financial income and expenses.

Estimates of provisions

Factors having a significant influence on the amount of provisions, and particularly, but not solely, those relating to the back-end of the nuclear fuel cycle, to the dismantling of nuclear facilities and of gas infrastructures in France, include:

- cost estimates (notably the retained scenario for managing radioactive nuclear fuel consumed) (*see Note 19.2*);
- the timing of expenditure (notably, for nuclear power generation activities, the timetable for reprocessing radioactive nuclear fuel consumed and for dismantling facilities as well as the timetable for the end of gas operations regarding the main gas infrastructure businesses in France) (*see Notes 19.2 and 19.3*); and
- the discount rate applied to cash flows.

These factors are based on information and estimates deemed by the Group to be the most appropriate as of today.

Modifications to certain factors could lead to a significant adjustment in these provisions.

<i>In millions of euros</i>	Post-employment and other long-term benefits	Back-end of the nuclear fuel cycle	Dismantling of plant and equipment ⁽¹⁾ and Site rehabilitation	Other contingencies	Total
AT DECEMBER 31, 2019	7,481	7,611	7,566	2,458	25,115
Additions	313	194	84	531	1,122
Utilizations	(412)	(107)	(86)	(626)	(1,232)
Reversals	(2)	-	(1)	(18)	(20)
Changes in scope of consolidation	6	-	(1)	5	10
Impact of unwinding discount adjustments	90	251	187	17	544
Translation adjustments	(31)	-	(23)	(24)	(78)
Other	1,497	-	116	-	1,613
AT DECEMBER 31, 2020	8,941	7,948	7,841	2,343	27,073
Non-current	8,810	7,849	7,816	400	24,876
Current	131	99	25	1,942	2,197

(1) Of which €6,207 million in provisions for dismantling nuclear facilities, managed by Synatom, compared to €6,060 million at December 31, 2019.

The impact of unwinding discount adjustments in respect of post-employment and other long-term benefits relates to the interest expense on the benefit obligation, net of the interest income on plan assets.

The “Other” line mainly comprises actuarial gains and losses arising on post-employment benefit obligations in 2020, which are recorded in “Other comprehensive income” as well as provisions recorded against a dismantling or site rehabilitation asset.

Additions, utilizations, reversals and the impact of unwinding discount adjustments are presented as follows in the consolidated income statement:

<i>In millions of euros</i>	Dec. 31, 2020
Income/(loss) from operating activities	130
Other financial income and expenses	(544)
TOTAL	(414)

The different types of provisions and the calculation principles applied are described below.

19.1 Post-employment benefits and other long-term benefits

See Note 20 “Post-employment benefits and other long-term benefits”.

19.2 Obligations relating to nuclear power generation activities

In the context of its nuclear power generation activities, the Group assumes obligations relating to the management of the back-end nuclear fuel cycle and the dismantling of nuclear facilities.

19.2.1 Legal framework

The Belgian law of April 11, 2003 granted Group subsidiary Synatom responsibility for managing provisions set aside to cover the costs of dismantling nuclear power plants and managing spent nuclear fuel in those plants. The tasks of the Commission for Nuclear Provisions (CNP) set up pursuant to the above-mentioned law is to oversee the process of computing and managing these provisions.

To enable the Commission for Nuclear Provisions to carry out its work in accordance with the above-mentioned law, Synatom is required to submit a report every three years describing the core inputs used to measure these provisions. If any changes are observed from one triennial report to another that could materially impact the financial inputs used, i.e., the industrial scenario, estimated costs and timing, the Commission may revise its opinion, and the Group makes the necessary adjustments, if any, in the income statement.

Synatom submitted its triennial report to the Commission on September 12, 2019 and the Commission issued its opinion on December 12, 2019, which was taken into account in preparing the financial statements for the year ended December 31, 2019. The provisions recognized by the Group were determined taking into account the prevailing contractual and legal framework, which sets the operating life of the Tihange 1 reactor and the Doel 1 and 2 reactors at 50 years, and the other reactors at 40 years. These provisions have not changed significantly since that date, besides the impact of recurring factors such as the passage of time (unwinding) and utilizations of and additions to provisions for fuel spent during the year.

The provisions include in their assumptions all existing or planned environmental regulatory requirements on a European, national and regional level. If new legislation were to be introduced in the future, the cost estimates used as a basis for the calculations could vary. The Group does not believe that it is aware of any developments that could materially impact the amount of the provisions with the exception of the ongoing studies conducted by ONDRAF to define a technical solution for the storage of category A, low- or medium- activity and short-lived waste.

The estimated provision amounts include margins for contingencies and other risks that may arise in connection with dismantling and radioactive spent fuel management procedures. The contingency margins relating to the disposal of waste are determined by ONDRAF and built into its fees. The Group also estimates appropriate margins for each cost category.

The Group considers that, to the best of its knowledge, the provisions approved by the Commission take into account all currently available information to manage the contingencies and other risks associated with processes such as dismantling nuclear facilities and managing radioactive spent fuel.

19.2.2 Provisions for the back-end of the nuclear fuel cycle

Accounting standards

Allocations to provisions for the back-end of the nuclear fuel cycle are computed based on the average unit cost of the quantities expected to be used up to the end of the operating life of the plants, applied to quantities used at the closing date. An annual allocation is also recognized with respect to unwinding the discount on the provisions.

When spent nuclear fuel is removed from a reactor and temporarily stored on-site, it requires conditioning and potentially reprocessing to separate the most active radionuclides, before being consigned to long-term storage.

ONDRAF proposed on February 9, 2018 that geological storage be adopted as the national policy for managing high-level and/or long-lived radioactive waste. The proposal is subject to the approval of the Belgian government after obtaining the opinion of the Federal Agency for Nuclear Control (*Agence Fédérale de Contrôle Nucléaire – AFCN*).

In addition, ENGIE considers that the “mixed” scenario adopted by the Commission for Nuclear Provisions continues to apply, whereby the fuel containing the most active radionuclides is reprocessed, and the rest disposed of directly without reprocessing.

The provisions booked by the Group for nuclear fuel processing and storage cover all of the costs linked to the “mixed” scenario, including on-site storage, transportation, reprocessing, conditioning, storage and geological disposal. They are calculated based on the following principles and inputs:

- storage costs primarily comprise the costs of building and operating additional dry storage facilities and operating existing facilities, along with the costs of purchasing containers;
- part of the radioactive spent fuel is transferred for reprocessing. The resulting plutonium and uranium is sold to a third party;
- radioactive spent fuel that has not been reprocessed is to be conditioned, which requires conditioning facilities to be built according to ONDRAF's approved criteria. ONDRAF's recommendations as regards the cost of these facilities have been fully taken into account;
- the reprocessing residues and conditioned spent fuel are transferred to ONDRAF;

- the cost of burying fuel in deep geological repositories is estimated using the royalty rate established by ONDRAF based on a total disposal facility cost of €10.7 billion²⁰¹⁷. The estimated cost of the AFCN's preliminary recommendation as regards an additional well has also been included based on ONDRAF's recommendations.
- the long-term obligation is calculated using estimated internal costs and external costs assessed based on offers received from third parties;
- the baseline scenario includes ONDRAF's latest scenario, with geological storage starting in around 2070 and ending in around 2135;
- the discount rate used is 3.25%. It takes into account (i) an analysis of trends in long-term benchmark rates and their historical and forecast averages, as well as (ii) the long life of the liabilities based on ONDRAF's scenario;
- an inflation rate assumption of 2.0% (actual rate of 1.25%).

The costs effectively incurred in the future may differ from the estimates in terms of their nature and timing of payment. In its opinion to the Commission for Nuclear Provisions, ONDRAF pointed out the uncertainty over some costs, which in principle are covered by the contingency margins, but for which the Commission set up a work and further analysis program as of 2020. The provisions may be subsequently adjusted in line with changes in the above-mentioned inputs and related cost estimates. Belgium's current legal framework does not permit partial reprocessing and has not yet confirmed the adoption of geological storage as the policy for managing medium and high level nuclear waste.

As regards the partial reprocessing scenario, following a resolution adopted by the House of Representatives in 1993, reprocessing contracts that had not already begun were suspended and then terminated in 1998. The scenario adopted is based on the assumption that the Belgian government will allow Synatom to reprocess spent fuel and that an agreement will be reached between Belgium and France designating Orano (formerly Areva) as responsible for these reprocessing operations. A scenario assuming the direct disposal of waste without reprocessing would lead to a decrease in the provision compared to the provision resulting from the "mixed" scenario currently used and approved by the Commission for Nuclear Provisions.

The Belgian government has not yet taken a decision as to whether the waste should be buried in a deep geological repository or stored over the long term. On November 27, 2019, the European Commission sent a reasoned opinion to Belgium under the breach procedure provided for in Article 258 of the Treaty on the Functioning of the European Union, on the grounds that Belgium had not adopted a national program for managing radioactive waste in compliance with various requirements set out in the directive on spent fuel and radioactive waste (Council Directive 2011/70/Euratom). Therefore, at this stage, there is only one national program for the safe storage of spent fuel pending reprocessing or long-term storage. The scenario adopted by the Commission for Nuclear Provisions is based on the assumption that the waste will be buried in a deep geological repository at a site yet to be identified and classified in Belgium.

Sensitivity

Provisions for the back-end of the nuclear fuel cycle remain sensitive to assumptions regarding costs, the timing of operations and expenditure, as well as to discount rates:

- a 10% increase in ONDRAF's fees above the royalty rate for the removal of high-level and/or long-lived waste would lead to an increase in provisions of approximately €175 million based on unchanged contingency margins;
- a five-year advance in ONDRAF's expenditure on temporary storage, conditioning and long-term storage for high-level and/or long-lived radioactive waste would lead to an increase in provisions of approximately €170 million. A five-year delay in the payment schedule for these various expenses would lead to a decrease of less than that amount;
- a change of 10 basis points in the discount rate used could lead to an adjustment of approximately €260 million in provisions for the back-end of the nuclear fuel cycle. A fall in discount rates would lead to an increase in outstanding provisions, while a rise in discount rates would reduce the provision amount.

These sensitivities are calculated on a purely financial basis and should therefore be interpreted with appropriate caution in view of the variety of other inputs – some of which may be interdependent – included in the evaluation.

19.2.3 Provisions for dismantling nuclear facilities

Accounting standards

A provision is recognized when the Group has a present legal or constructive obligation to dismantle facilities or to restore a site. The present value of the obligation at the time of commissioning represents the initial amount of the provision for dismantling with, as the counterpart, an asset for the same amount, which is included in the carrying amount of the facilities concerned. This asset is depreciated over the operating life of the facilities and is included in the scope of assets subject to impairment tests. Adjustments to the provision due to subsequent changes in (i) the expected outflow of resources, (ii) the timing of dismantling expenses or (iii) the discount rate, are deducted from or, subject to specific conditions, added to the cost of the corresponding asset. The impacts of unwinding the discount are recognized in expenses for the period.

A provision is also recorded for nuclear units for which the Group holds a capacity right up to its share of the expected decommissioning costs to be borne by the Group.

Nuclear power plants have to be dismantled at the end of their operating life. Provisions are set aside in the Group's financial statements to cover all costs relating to (i) the shutdown phase, which involves removing radioactive spent fuel from the site and (ii) the dismantling phase, which consists of decommissioning and cleaning up the site.

The dismantling strategy is based on the facilities being dismantled (i) immediately after the reactor is shut down, (ii) on a mass basis rather than on a site-by-site basis, and (iii) completely, the land being subsequently returned to greenfield status.

Provisions for dismantling nuclear facilities are calculated based on the following principles and inputs:

- costs payable over the long term are calculated by reference to the estimated costs for each nuclear facility, based on a study conducted by independent experts under the assumption that the facilities will be dismantled on a mass basis;
- fees for handling Class A – low or medium activity and short-lived - and B – low or medium activity and long-lived dismantling waste are determined using the royalty rate established by ONDRAF and include the margins recommended by ONDRAF for waste reclassification risk given the uncertainty over the definition of the criteria for classification in those classes;
- for the various phases, margins for usual contingencies, reviewed by ONDRAF and the Commission for Nuclear Provisions, are included;
- an inflation rate of 2.0% is applied until the dismantling obligations expire in order to determine the value of the future obligation;
- a discount rate of 2.5% (including inflation of 2.0%) is applied to determine the present value (NPV) of the obligation. It is different from the rate used to calculate the provision for processing spent nuclear fuel due to the major differences in horizon of the two liabilities after taking into account ONDRAF's new scenario;
- the operating life is 50 years for Tihange 1 and Doel 1 and 2, and 40 years for the other facilities;
- the start of the technical shutdown procedures depends on the facility concerned and on the timing of operations for the nuclear reactor as a whole. The shutdown procedures are immediately followed by dismantling operations.

The costs effectively incurred in the future may differ from the estimates in terms of their nature and timing of payment. In its opinion to the Commission for Nuclear Provisions, ONDRAF pointed out the uncertainty over some costs, which in principle are covered by the contingency margins, but for which the Commission set up a work and further analysis program in 2020. The provisions may be subsequently adjusted in line with changes in the above-mentioned inputs. However, these inputs and assumptions are based on information and estimates which the Group deems reasonable to date and which have been approved by the Commission for Nuclear Provisions.

The scenario adopted is based on a dismantling program and on timetables that have to be approved by the nuclear safety authorities.

Sensitivity

Based on currently applied inputs for estimating costs and the timing of payments, a change of 10 basis points in the discount rate used could lead to an adjustment of approximately €62 million in dismantling provisions. A fall in discount rates would lead to an increase in outstanding provisions, while a rise in discount rates would reduce the provision amount.

This sensitivity is calculated on a purely financial basis and should therefore be interpreted with appropriate caution in view of the variety of other inputs – some of which may be interdependent – included in the evaluation.

19.3 Dismantling of non-nuclear plant and equipment and site rehabilitation

19.3.1 Dismantling obligations arising on non-nuclear plant and equipment

Certain plant and equipment, including conventional power stations, transmission and distribution pipelines, storage facilities and LNG terminals, have to be dismantled at the end of their operational lives. This obligation is the result of prevailing environmental regulations in the countries concerned, contractual agreements, or an implicit Group commitment.

Based on estimates of proven and probable gas reserves through 2260 using current production levels, dismantling provisions for gas infrastructures in France have a present value near zero.

19.3.2 Hazelwood Power Station & Mine (Australia)

The Group and its partner Mitsui announced in November 2016 their decision to close the coal-fired Hazelwood Power Station, and cease coal extraction operations from the adjoining mine from late March 2017. The Group holds a 72% interest in the former 1,600 MW power station and adjoining mine, which was previously fully consolidated and has been consolidated as a joint operation since September 2018.

At December 31, 2020, the Group's share (72%) of the provision covering the obligation to dismantle and rehabilitate the mine amounted to €277 million.

Dismantling and site rehabilitation work commenced in 2017 and focused on: managing site contamination; planning site-wide environmental clean-up; the demolition and dismantling of all of the site's industrial facilities, including the former power station; and ongoing aquifer pumping and designated earthworks within the mine to ensure mine floor and batter stability with a view to long-term rehabilitation into a pit lake.

Several policies and laws that have a direct or indirect impact on mine rehabilitation and on the agencies that administer them have recently been reformed. Consequently, the ultimate regulatory obligations are likely to be revised during the life of the project and could therefore have an impact on provisions.

The average discount rate used to determine the amount of the provisions is 4.03%.

The amount of the provision recognized is based on the Group's best current estimate of the demolition and rehabilitation costs that Hazelwood is expected to incur. However, the amount of this provision may be adjusted in the future to take into account any changes in the key inputs.

19.4 Other contingencies

This caption essentially includes provisions for commercial litigation, tax claims and disputes (except income tax, pursuant to IFRIC 23) as well as provisions for onerous contracts relating to storage and transport capacity reservation contracts.

NOTE 20 POST-EMPLOYMENT BENEFITS AND OTHER LONG-TERM BENEFITS

Accounting standards

Depending on the laws and practices in force in the countries where the Group operates, Group companies have obligations in terms of pensions, early retirement payments, retirement bonuses and other benefit plans. Such obligations generally apply to all employees within the companies concerned.

The Group's obligations in relation to pensions and other employee benefits are recognized and measured in compliance with IAS 19. Accordingly:

- the cost of defined contribution plans is expensed based on the amount of contributions payable in the period;
- the Group's obligations concerning pensions and other employee benefits payable under defined benefit plans are assessed on an actuarial basis using the projected unit credit method. These calculations are based on assumptions relating to mortality, staff turnover and estimated future salary increases, as well as the economic conditions specific to each country or entity of the Group. Discount rates are determined by reference to the yield, at the measurement date, on investment grade corporate bonds in the related geographical area (or on government bonds in countries where no representative market for such corporate bonds exists).

Pension commitments are measured on the basis of actuarial assumptions. The Group considers that the assumptions used to measure its obligations are relevant and documented. However, any change in these assumptions could have a significant impact on the resulting calculations.

Provisions are recorded when commitments under these plans exceed the fair value of plan assets. Where the value of plan assets (capped where appropriate) is greater than the related commitments, the surplus is recorded as an asset under "Other assets" (current or non-current).

As regards post-employment benefit obligations, actuarial gains and losses are recognized in other comprehensive income. Where appropriate, adjustments resulting from applying the asset ceiling to net assets relating to overfunded plans are treated in a similar way. However, actuarial gains and losses on other long-term benefits such as long-service awards, are recognized immediately in income.

Net interest on the net defined benefit liability (asset) is presented in net financial income/(loss).

20.1 Description of the main pension plans

20.1.1 Companies belonging to the Electricity and Gas Industries sector in France

Since January 1, 2005, the CNIEG (*Caisse Nationale des Industries Électriques et Gazières*) has operated the pension, disability, death, occupational accident and occupational illness benefit plans for electricity and gas industry (hereinafter "EGI") companies in France. The CNIEG is a social security legal entity under private law placed under the joint responsibility of the ministries in charge of social security and the budget.

Employees and retirees of EGI sector companies have been fully affiliated to the CNIEG since January 1, 2005. The main affiliated Group entities are ENGIE SA, GRDF, GRTgaz, Elengy, Storengy, ENGIE Thermique France, CPCU, CNR and SHEM.

Following the funding reform of the special EGI pension plan introduced by Law No. 2004-803 of August 9, 2004 and its implementing decrees, specific benefits (pension benefits on top of the standard benefits payable under ordinary law) already vested at December 31, 2004 ("past specific benefits") were allocated between the various EGI entities. Past

specific benefits (benefits vested at December 31, 2004) relating to regulated transmission and distribution businesses ("regulated past specific benefits") are funded by the levy on gas and electricity transmission and distribution services (*Contribution Tarifaire d'Acheminement*) and therefore no longer represent an obligation for the ENGIE Group. Unregulated past specific benefits (benefits vested at December 31, 2004) are funded by EGI sector companies to the extent defined by Decree No. 2005-322 of April 5, 2005.

The special EGI pension plan is a legal pension plan available to new entrants.

The specific benefits vested under the plan since January 1, 2005 are wholly financed by EGI sector companies in proportion to their respective weight in terms of payroll costs within the EGI sector.

As this plan represents a defined benefit plan, the Group has set aside a pension provision in respect of specific benefits payable to employees of unregulated activities and specific benefits vested by employees of regulated activities since January 1, 2005. This provision also covers the Group's early retirement obligations. The provision amount may be subject to fluctuations based on the weight of the Group's companies within the EGI sector.

Pension benefit obligations and other "mutualized" obligations are assessed by the CNIEG.

At December 31, 2020, the projected benefit obligation in respect of the special pension plan for EGI sector companies amounted to €4.3 billion.

The duration of the pension benefit obligation of the EGI pension plan is 24 years.

20.1.2 Companies belonging to the electricity and gas sector in Belgium

In Belgium, the rights of employees in electricity and gas sector companies, principally Electrabel, Laborelec and some ENGIE Energy Management Trading and ENGIE CC employee categories, are governed by collective bargaining agreements.

These agreements, applicable to "wage-rated" employees recruited prior to June 1, 2002 and managerial staff recruited prior to May 1, 1999, specify the benefits entitling employees to a supplementary pension equivalent to 75% of their most recent annual income, for a full career and in addition to the statutory pension. These top-up pension payments provided under defined benefit plans are partly reversionary. In practice, the benefits are paid in the form of a lump sum for the majority of plan participants. Most of the obligations resulting from these pension plans are financed through pension funds set up for the electricity and gas sector and by certain insurance companies. Pre-funded pension plans are financed by employer and employee contributions. Employer contributions are calculated annually based on actuarial assessments.

The projected benefit obligation relating to these plans represented around 16% of total pension obligations and related liabilities at December 31, 2020. The average duration is 9 years.

"Wage-rated" employees recruited after June 1, 2002 and managerial staff (i) recruited after May 1, 1999 or (ii) having opted for the transfer through defined contribution plans, are covered under defined contribution plans. Prior to January 1, 2017, the law specified a minimum average annual return (3.75% on wage contributions and 3.25% on employer contributions) when savings are liquidated.

The law on supplementary pensions, approved on December 18, 2016 and enforced on January 1, 2017 henceforth specifies a minimum rate of return, depending on the actual rate of return of Belgian government bonds, within a range of 1.75%-3.25% (the rates are now identical for employee and employer contributions). In 2020, the minimum rate of return stood at 1.75%.

An expense of €37 million was recognized in 2020 in respect of these defined contribution plans (€36 million in 2019).

20.1.3 Multi-employer plans

Employees of some Group companies are affiliated to multi-employer pension plans.

Under multi-employer plans, risks are pooled to the extent that the plan is funded by a single contribution rate determined for all affiliated companies and applicable to all employees.

Multi-employer plans are particularly common in the Netherlands, where employees are normally required to participate in a compulsory industry-wide plan. These plans cover a significant number of employers, thereby limiting the impact of potential default by an affiliated company. In the event of default, the vested rights are maintained in a special compartment and are not transferred to the other members. Refinancing plans may be set up to ensure the funds are balanced.

The ENGIE Group accounts for multi-employer plans as defined contribution plans.

The expense recognized in 2020 in respect of multi-employer pension plans was stable as compared to 2019 at €73 million.

20.1.4 Other pension plans

Most other Group companies also grant their employees retirement benefits. In terms of financing, pension plans within the Group are almost equally split between defined benefit and defined contribution plans.

The Group's main pension plans outside France, Belgium and the Netherlands concern:

- the United Kingdom: the large majority of defined benefit pension plans is now closed to new entrants and future benefits no longer vest under these plans. All entities run a defined contribution scheme. The pension obligations of International Power's subsidiaries in the United Kingdom are covered by the special Electricity Supply Pension Scheme (ESPS). The assets of this defined benefit scheme are invested in separate funds. Since June 1, 2008, the scheme has been closed and a defined contribution plan has been set up for new entrants;
- Germany: the Group's German subsidiaries have closed their defined benefit plans to new entrants and now offer defined contribution plans;
- Brazil: ENGIE Brasil Energia operates its own pension scheme. This scheme has been split into two parts, one for the (closed) defined benefit plan, and the other for the defined contribution plan that has been available to new entrants since the beginning of 2005.

20.2 Description of other post-employment benefit obligations and other long-term benefits

20.2.1 Other benefits granted to current and former EGI sector employees

Other benefits granted to EGI sector employees are:

Post-employment benefits:

- reduced energy prices;
- end-of-career indemnities;
- bonus leave;
- death capital benefits.

Long-term benefits:

- allowances for occupational accidents and illnesses;
- temporary and permanent disability allowances;
- long-service awards.

The Group's main obligations are described below.

20.2.1.1 Reduced energy prices

Under Article 28 of the national statute for electricity and gas industry personnel, all employees (current and former employees, provided they meet certain length-of-service conditions) are entitled to benefits in kind, which take the form of reduced energy prices known as “employee rates”.

This benefit entitles employees to electricity and gas supplies at a reduced price. For retired employees, this provision represents a post-employment defined benefit. Retired employees are only entitled to the reduced rate if they have completed at least 15 years’ service within EGI sector companies.

In accordance with the agreements signed with EDF in 1951, ENGIE provides gas to all current and former employees of ENGIE and EDF, while EDF supplies electricity to these same beneficiaries. ENGIE pays (or benefits from) the balancing contribution payable in respect of its employees as a result of energy exchanges between the two utilities.

The obligation to provide energy at a reduced price to current and former employees is measured as the difference between the energy sale price and the preferential rate granted.

The provision set aside in respect of reduced energy prices stood at €4.2 billion at December 31, 2020. The duration of the obligation is 25 years.

20.2.1.2 End-of-career indemnities

Retiring employees (or their dependents in the event of death during active service) are entitled to end-of-career indemnities, which increase in line with the length of service within the EGI sector.

20.2.1.3 Compensation for occupational accidents and illnesses

EGI sector employees are entitled to compensation for accidents at work and occupational illnesses. These benefits cover all employees or the dependents of employees who die as a result of occupational accidents or illnesses, or injuries suffered on the way to work.

The amount of the obligation corresponds to the likely present value of the benefits to be paid to current beneficiaries, taking into account any reversionary annuities.

20.2.2 Other benefits granted to employees of the gas and electricity sector in Belgium

Electricity and gas sector companies also grant other employee benefits such as the reimbursement of medical expenses, electricity and gas price reductions, as well as length-of-service awards and early retirement schemes. These benefits are not prefunded, with the exception of the special “*allocation transitoire*” termination indemnity, considered as an end-of-career indemnity.

20.2.3 Other collective agreements

Most other Group companies also grant their staff post-employment benefits (early retirement plans, medical coverage, benefits in kind, etc.) and other long-term benefits such as jubilee and length-of-service awards.

20.3 Defined benefit plans

20.3.1 Amounts presented in the statement of financial position and statement of comprehensive income

In accordance with IAS 19, the information presented in the statement of financial position relating to post-employment benefit obligations and other long-term benefits results from the difference between the gross projected benefit obligation and the fair value of plan assets. A provision is recognized if this difference is positive (net obligation), while a prepaid benefit cost is recorded in the statement of financial position when the difference is negative, provided that the conditions for recognizing the prepaid benefit cost are met.

Changes in provisions for pension plans, post-employment benefits and other long-term benefits, plan assets and reimbursement rights recognized in the statement of financial position are as follows:

<i>In millions of euros</i>	Provisions	Plan assets	Reimbursement rights
At December 31, 2019	(7,481)	53	161
Exchange rate differences	35	-	-
Changes in scope of consolidation and other	-	-	-
Actuarial gains and losses	(1,488)	(31)	(7)
Periodic pension cost	(438)	(3)	25
Asset ceiling	-	-	-
Contributions/benefits paid	431	17	9
AT December 31, 2020	(8,941)	36	188

Plan assets and reimbursement rights are presented in the statement of financial position under "Other non-current assets" or "Other current assets".

The cost recognized for the period amounted to €441 million in 2020 (€492 million in 2019). The components of this defined benefit cost in the period are set out in Note 20.3.3 "Components of the net periodic pension cost".

The Eurozone represented 98% of the Group's net obligation at December 31, 2020, 97% at December 31, 2019).

Cumulative actuarial gains and losses recognized in equity amounted to €6,037 million at December 31, 2020, compared to €-4,594 million at December 31, 2019.

Net actuarial differences arising in the period and presented on a separate line in the statement of comprehensive income represented a net actuarial loss of €1,519 million in 2020 and of €-1,149 million in 2019.

20.3.2 Change in benefit obligations and plan assets

The table below shows the amount of the Group's projected benefit obligations and plan assets, changes in these items during the periods presented, and their reconciliation with the amounts reported in the statement of financial position:

	Dec. 31, 2020				Dec. 31, 2019			
	Pension benefit obligations (1)	Other post-employment benefit obligations (2)	Long-term benefit obligations (3)	Total	Pension benefit obligations (1)	Other post-employment benefit obligations (2)	Long-term benefit obligations (3)	Total
In millions of euros								
A - CHANGE IN PROJECTED BENEFIT OBLIGATION								
Projected benefit obligation at January 1	(8,570)	(4,470)	(531)	(13,572)	(7,712)	(3,794)	(499)	(12,006)
Service cost	(303)	(79)	(50)	(432)	(291)	(63)	(43)	(397)
Interest expense	(115)	(57)	(5)	(177)	(173)	(76)	(9)	(258)
Contributions paid	(16)	-	-	(16)	(16)	-	-	(16)
Amendments	(19)	4	(1)	(16)	(1)	-	-	(1)
Changes in scope of consolidation	-	-	-	-	172	(5)	(1)	166
Curtailments/settlements	125	1	1	127	75	-	1	76
Non-recurring items	-	-	-	-	-	-	-	-
Financial actuarial gains and losses	(789)	(678)	(31)	(1,498)	(887)	(698)	(5)	(1,590)
Demographic actuarial gains and losses	(56)	8	(6)	(55)	(120)	57	(14)	(76)
Benefits paid	405	104	57	566	373	108	39	521
Other (of which translation adjustments)	152	-	2	154	10	-	-	10
Projected benefit obligation at December 31	A (9,186)	(5,167)	(565)	(14,919)	(8,570)	(4,470)	(531)	(13,572)
B - CHANGE IN FAIR VALUE OF PLAN ASSETS								
Fair value of plan assets at January 1	6,169	-	-	6,169	5,767	-	-	5,767
Interest income on plan assets	86	-	-	86	133	-	-	133
Financial actuarial gains and losses	(4)	-	-	(4)	497	-	-	497
Contributions received	206	-	-	206	197	-	-	197
Changes in scope of consolidation	-	-	-	-	(109)	-	-	(109)
Settlements	9	-	-	9	(28)	-	-	(28)
Benefits paid	(308)	-	-	(308)	(282)	-	-	(282)
Other (of which translation adjustments)	(124)	-	-	(124)	(7)	-	-	(7)
Fair value of plan assets at December 31	B 6,034	-	-	6,034	6,169	-	-	6,169
C - FUNDED STATUS	A+B (3,153)	(5,167)	(565)	(8,885)	(2,402)	(4,470)	(531)	(7,403)
Asset ceiling	(21)	-	-	(21)	(25)	-	-	(25)
NET BENEFIT OBLIGATION	(3,174)	(5,167)	(565)	(8,906)	(2,427)	(4,470)	(531)	(7,428)
ACCRUED BENEFIT LIABILITY	(3,210)	(5,137)	(595)	(8,941)	(2,480)	(4,470)	(531)	(7,481)
PREPAID BENEFIT	36	-	-	36	53	-	-	53

(1) Pensions and retirement bonuses.

(2) Reduced energy prices, healthcare, gratuities and other post-employment benefits.

(3) Length-of-service awards and other long-term benefits.

20.3.3 Components of the net periodic pension cost

The net periodic cost recognized in respect of defined benefit obligations for the years ended December 31, 2020 and 2019 breaks down as follows:

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Current service cost	432	397
Actuarial gains and losses ⁽¹⁾	37	19
Plan amendments	-	-
Gains or losses on pension plan curtailments, terminations and settlements	(120)	(48)
Non-recurring items	-	-
Total accounted for under current operating income including operating MtM and share in net income of equity method entities	350	368
Net interest expense	91	125
Total accounted for under net financial income/(loss)	91	125
TOTAL	441	493

(1) On the long-term benefit obligation.

20.3.4 Funding policy and strategy

When defined benefit plans are funded, the related plan assets are invested in pension funds and/or with insurance companies, depending on the investment practices specific to the country concerned. The investment strategies underlying these defined benefit plans are aimed at striking the right balance between return on investment and acceptable levels of risk.

The objectives of these strategies are twofold: to maintain sufficient liquidity to cover pension and other benefit payments; and as part of risk management, to achieve a long-term rate of return higher than the discount rate or, where appropriate, at least equal to future required returns.

When plan assets are invested in pension funds, investment decisions are the responsibility of the fund management concerned. For French companies, where plan assets are invested with an insurance company, the latter manages the investment portfolio for unit-linked policies or euro-denominated policies, in a manner adapted to the risk and long-term profile of the liabilities.

The funding of these obligations at December 31 for each of the periods presented can be analyzed as follows:

<i>In millions of euros</i>	Projected benefit obligation	Fair value of plan assets	Asset ceiling	Total net obligation
Underfunded plans	(7,671)	5,192	(21)	(2,500)
Overfunded plans	(606)	842	-	236
Unfunded plans	(6,641)	-	-	(6,641)
AT DECEMBER 31, 2020	(14,918)	6,034	(21)	(8,905)
Underfunded plans	(7,399)	5,616	(25)	(1,809)
Overfunded plans	(517)	553	-	36
Unfunded plans	(5,655)	-	-	(5,655)
AT DECEMBER 31, 2019	(13,571)	6,169	(25)	(7,428)

The allocation of plan assets by principal asset category can be analyzed as follows:

<i>In %</i>	Dec. 31, 2020	Dec. 31, 2019
Equity investments	26	27
Sovereign bond investments	23	26
Corporate bond investments	29	27
Money market securities	3	3
Real estate	2	2
Other assets	16	15
TOTAL	100	100

All plan assets were quoted on an active market at December 31, 2020.

The actual return on assets of EGI sector companies stood at a positive 1.4% in 2020.

In 2020, the actual return on plan assets of Belgian entities amounted to approximately 2.8% in Group insurance and a positive 0.8% in pension funds.

The allocation of plan asset categories by geographic area of investment can be analyzed as follows:

In %	Europe	North America	Latin America	Asia - Oceania	Rest of the World	Total
Equity investments	60	23	3	10	4	100
Sovereign bond investments	82	1	16	-	-	100
Corporate bond investments	74	20	1	4	2	100
Money market securities	96	-	3	1	-	100
Real estate	92	1	5	1	1	100
Other assets	46	23	3	4	24	100

20.3.5 Actuarial assumptions

Actuarial assumptions are determined individually by country and company in conjunction with independent actuaries. Weighted discount rates for the main actuarial assumptions are presented below:

		Pension benefit obligations		Other post-employment benefit obligations		Long-term benefit obligations		Total benefit obligations	
		2020	2019	2020	2019	2020	2019	2020	2019
Discount rate	Eurozone	0.6%	1.2%	0.6%	1.2%	0.6%	1.0%	0.6%	1.2%
	UK Zone	1.6%	1.7%	-	-	-	-	-	-
Inflation rate	Eurozone	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%
	UK Zone	3.2%	3.4%	-	-	-	-	-	-

20.3.5.1 Discount and inflation rate

The discount rate applied is determined based on the yield, at the date of the calculation, of investment grade corporate bonds with maturities mirroring the term of the plan.

The rates were determined for each monetary area based on data for AA corporate bond yields. For the Eurozone, data (from Bloomberg) are extrapolated on the basis of government bond yields for long maturities.

According to the Group's estimates, a 100-basis-point increase or decrease in the discount rate would result in a change of approximately 18% in the projected benefit obligation.

The inflation rates were determined for each monetary area. A 100-basis-point increase or decrease in the inflation rate (with an unchanged discount rate) would result in a change of approximately 17% in the projected benefit obligation.

20.3.5.2 Other assumptions

The increase in the rate of medical costs (including inflation) was estimated at 1%.

A 100-basis-point change in the assumed increase in medical costs would have the following impacts:

In millions of euros	100 basis point increase	100 basis point decrease
Impact on expenses	-	-
Impact on pension obligations	5	(5)

20.3.6 Estimated employer contributions payable in 2021 under defined benefit plans

The Group expects to pay around €214 million in contributions into its defined benefit plans in 2021, including €133 million for EGI sector companies. Annual contributions in respect of EGI sector companies will be made by reference to rights vested during the year, taking into account the funding level for each entity in order to even out contributions over the medium term.

20.4 Defined contribution plans

In 2020, the Group recorded a €248 million expense in respect of amounts paid into Group defined contribution plans (€121 million in 2019). These contributions are recorded under “Personnel costs” in the consolidated income statement.

NOTE 21 SHARE-BASED PAYMENTS

Accounting standards

Under IFRS 2, share-based payments made in consideration for services provided are recognized as personnel costs. These services are measured at the fair value of the instruments awarded.

The fair value of bonus share plans is estimated by reference to the share price at the grant date, taking into account the fact that no dividend is payable over the vesting period, and based on the estimated turnover rate for the employees concerned and the probability that the Group will meet its performance targets. The fair value measurement also takes into account the non-transferability period associated with these instruments. The cost of shares granted to employees is expensed over the vesting period of the rights and offset against equity.

A Monte Carlo pricing model is used for performance shares granted on a discretionary basis and subject to external performance criteria.

Expenses recognized in respect of share-based payments break down as follows:

In millions of euros	Expense for the year	
	Dec. 31, 2020	Dec. 31, 2019
Employee share issues ⁽¹⁾	(2)	(1)
Bonus/performance share plans ⁽²⁾⁽³⁾	(45)	(48)
Other Group companies' plans	(3)	(2)
TOTAL	(50)	(51)

(1) Including Share Appreciation Rights set up within the scope of employee share issues in certain countries.

(2) Of which a reversal of €6 million in 2020 for failure to meet the performance conditions.

(3) Of which a reversal of €5 million in 2020 for failure to meet the condition of continuing employment within the Group (€2 million in 2019).

21.1 Performance shares

21.1.1 New awards in 2020

ENGIE Performance Share plan of December 17, 2020

On December 17, 2020, the Board of Directors approved the award of 4.9 million performance shares to members of the Group's executive and senior management, breaking down into three tranches:

- performance shares vesting on March 14, 2024, subject to a one-year lock-up period;
- performance shares vesting on March 14, 2024, without a lock-up period; and
- performance shares vesting on March 14, 2025, without a lock-up period.

In addition to a condition requiring employees to be employed with the Group at the vesting date, each tranche is made up of instruments subject to three different conditions, excluding the first 150 performance shares granted to beneficiaries (excluding top management), which are exempt from performance conditions. The performance conditions, each of which accounts for one-third of the total grant, are as follows:

- a market performance condition relating to ENGIE's Total Shareholder Return compared to that of a reference panel of nine companies, as assessed between November 2020 and January 2024;
- two internal performance conditions relating to net recurring income Group share and to Return On Capital Employed (ROCE) in 2022 and 2023.

Under this plan, performance shares without conditions were also awarded to the winners of the Innovation and Incubation programs (21,150 shares awarded).

21.1.2 Fair value of bonus share plans with or without performance conditions

The following assumptions were used to calculate the fair value of the new plans awarded by ENGIE in 2020:

Award date	Vesting date	End of the lock-up period	Price at the award date	Expected dividend	Financing cost for the employee	Non-transferability cost	Market-related performance condition	Fair value per unit
December 17, 2020	March 14, 2024	March 14, 2025	12.7	0,75	3.9%	0,36	yes	9,44
December 17, 2020	March 14, 2024	March 14, 2024	12.7	0,75	3.9%	0,36	yes	9,87
December 17, 2020	March 14, 2024	March 14, 2024	12.7	0,75	3.9%	0,47	no	10,67
December 17, 2020	March 14, 2025	March 14, 2025	12.7	0,75	3.9%	0,36	yes	9,16
Weighted average fair value of the December 17, 2020 plan								9,93

21.1.3 Review of internal performance conditions applicable to the plans

In addition to the condition of continuing employment within the Group, eligibility for certain bonus share and performance share plans is subject to an internal performance condition. When this condition is not fully met, the number of bonus shares granted to employees is reduced in accordance with the plans' regulations, leading to a decrease in the total expense recognized in relation to the plans in accordance with IFRS 2. Performance conditions are reviewed at each reporting date.

The Group decided to adjust the effect of the COVID-19 crisis on the achievement of the internal performance conditions for the performance share plans awarded in December 2017 and December 2018 including 2020 as the year of reference. After applying the adjusted achievement rates, the Group recognized income of €6 million.

NOTE 22 RELATED PARTY TRANSACTIONS

This note describes material transactions between the Group and its related parties.

Compensation payable to key management personnel is disclosed in Note 23 "Executive compensation".

Transactions with joint ventures and associates are described in Note 3 "Investments in equity method entities".

Only material transactions are described below.

22.1 Relations with the French State and with entities owned or partly owned by the French State

22.1.1 Relations with the French State

The French State's interest in the Group at December 31, 2020 was unchanged from the previous year at 23.64%. This entitles it to three seats of the 13 seats on the Board of Directors (one director representing the State appointed by decree, and directors appointed by the Shareholders' Meeting at the proposal of the State).

The French State holds 33.19% of the theoretical voting rights (33.39% of exercisable voting rights) compared with 33.67% at end-2019.

On May 22, 2019, the PACTE act ("Action plan for business growth and transformation") was enacted, enabling the French State to dispose of its ENGIE shares without restriction.

In addition, the French State holds a golden share aimed at protecting France's critical interests and ensuring the continuity and safeguarding of supplies in the energy sector. The golden share is granted to the French State indefinitely and confers the right to oppose ENGIE's decision if it considers them contrary to the interest of France.

entitles it to veto decisions taken by ENGIE if it considers they could harm France's interests.

Public service engagements in the energy sector are defined by the law of January 3, 2003.

Transmission rates on the GRTgaz transportation network and the gas distribution network in France, as well as rates for accessing the French LNG terminals and revenues from storage capacities are all regulated.

The Law on Energy and Climate enacted on November 8, 2019 will put an end to regulated gas tariffs and will restrict regulated electricity tariffs for consumers and small businesses. The final date for the discontinuation of regulated gas tariffs is July 1, 2023.

22.1.2 Relations with EDF

Following the creation on July 1, 2004 of the French gas and electricity distribution network operator (EDF Gaz de France Distribution), Gaz de France SA and EDF entered into an agreement on April 18, 2005 setting out their relationship as regards the distribution business. The December 7, 2006 law on the energy sector reorganized the natural gas and electricity distribution networks. Enedis SA (previously ERDF SA), a subsidiary of EDF SA, and GRDF SA, a subsidiary of ENGIE SA, were created on January 1, 2007 and January 1, 2008, respectively, and act in accordance with the agreement previously signed by the two incumbent operators.

22.2 Relations with the CNIEG (*Caisse Nationale des Industries Électriques et Gazières*)

The Group's relations with the CNIEG, which manages all old-age, death and disability benefits for active and retired employees of the Group who belong to the special EGI pension plan, employees of EDF and Non-Nationalized Companies (*Entreprises Non Nationalisées* – ENN), are described in Note 20 "Post-employment benefits and other long-term benefits".

NOTE 23 EXECUTIVE COMPENSATION

The executive compensation presented below includes the compensation of the members of the Group's Executive Committee and Board of Directors.

The Executive Committee had ten members at December 31, 2020 (14 members at December 31, 2019).

Their compensation breaks down as follows:

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Short-term benefits	29	21
Post-employment benefits	-	10
Share-based payments	2	5
Termination benefits	7	-
TOTAL	38	36

Pursuant to the European Directive of April 16, 2014, French ordinance no. 2019-697 relating to supplementary pensions, published on July 4, 2019, terminated the existing L137-11 pension plan (referred to as "Article 39") and prohibited the accrual of further rights and the entry of any new members as of that date.

Following the closure of the plan and the freezing of the random rights in 2019, in 2020 the Group transformed the random rights of beneficiaries, including the members of the Group's Executive Committee, under a defined contribution plan referred to as "Article 82".

NOTE 24 WORKING CAPITAL REQUIREMENTS, INVENTORIES, OTHER ASSETS AND OTHER LIABILITIES

Accounting standards

In accordance with IAS 1, the Group's current and non-current assets and liabilities are shown separately in the consolidated statement of financial position. For most of the Group's activities, the breakdown into current and non-current items is based on when assets are expected to be realized, or liabilities extinguished. Assets expected to be realized or liabilities extinguished within 12 months of the reporting date are classified as current, while all other items are classified as non-current.

Inventories

Inventories are measured at the lower of cost and net realizable value. Net realizable value corresponds to the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale.

The cost of inventories is determined based on the first-in, first-out method or the weighted average cost formula.

Nuclear fuel purchased is consumed in the process of producing electricity over a number of years. The consumption of this nuclear fuel inventory is recorded based on estimates of the quantity of electricity produced per unit of fuel.

Gas inventories

Gas injected into underground storage facilities includes working gas, which can be withdrawn without adversely affecting the subsequent operation of the reservoirs, and cushion gas, which is inseparable from the reservoirs and essential for their operation (see Note 15 "*Property, plant and equipment*").

Working gas is classified in inventories and measured at weighted average purchase cost upon entering the transportation network regardless of its source, including any regasification costs.

Group inventory outflows are valued using the weighted average unit cost method.

Tax equity

The ENGIE Group finances its renewables projects in the United States through tax equity structures, in which part of the necessary funds is provided by a tax partner. The tax partner obtains, up to a pre-determined level, a preferential right essentially to the project's tax credits, which it can deduct from its own tax base.

The tax partner's investments meet the definition of a liability under IFRS. Since the tax equity liability corresponding to these tax benefits does not give rise to any cash outflow for the project entity, it does not represent a financial debt and is accounted for in "Other liabilities".

Besides the unwinding effect, the liability changes mainly as a function of the tax credits allocated to the tax partner recognized in profit or loss.

24.1 Composition of change in working capital requirements

<i>In millions of euros</i>	Change in working capital requirements at Dec. 31, 2020	Change in working capital requirements at Dec. 31, 2019
Inventories	(492)	465
Trade and other receivables, net	107	802
Trade and other payables, net	(586)	(1,107)
Tax and employee-related receivables/payables	(58)	(36)
Margin calls and derivative instruments hedging commodities relating to trading activities	(109)	(981)
Other	539	(253)
TOTAL	(600)	(1,110)

24.2 Inventories

<i>In millions of euros</i>	Dec. 31, 2020	Dec. 31, 2019
Inventories of natural gas, net	1,146	1,104
Inventories of uranium ⁽¹⁾	530	538
CO ₂ emissions allowances, green certificates and energy saving certificates, net	1,070	682
Inventories of commodities other than gas and other inventories, net	1,395	1,294
TOTAL	4,140	3,617

(1) Financial hedging instruments are backed by these uranium inventories and represented an amount of €18 million at December 31, 2020

24.3 Other assets and other liabilities

<i>In millions of euros</i>	Dec. 31, 2020				Dec. 31, 2019			
	Assets		Liabilities		Assets		Liabilities	
	Non-current	Current	Non-current	Current	Non-current	Current	Non-current	Current
Other assets and liabilities	396	8,990	(2,004)	(12,545)	384	10,216	(1,222)	(13,101)
Tax receivables/payables	-	6,274	-	(6,960)	-	6,986	-	(7,750)
Employee receivables/payables	222	51	(6)	(2,667)	214	39	(6)	(2,594)
Dividend receivables/payables	-	17	-	(76)	-	21	-	(104)
Other	174	2,649	(1,998)	(2,841)	171	3,170	(1,215)	(2,653)

At December 31, 2020, other non-current assets also included a receivable towards EDF Belgium in respect of nuclear provisions amounting to €94 million (€92 million at December 31, 2019).

Other liabilities include €1,123 million in investments made by tax partners as part of the financing of renewable projects in the United States by tax equity (€228 million at December 31, 2019).

NOTE 25 LEGAL AND ANTI-TRUST PROCEEDINGS

The Group is party to a number of legal and anti-trust proceedings with third parties or with legal and/or administrative authorities (including tax authorities) in the normal course of its business.

The main disputes and investigations presented hereafter are recognized as liabilities or give rise to contingent assets or liabilities.

In the normal course of its business, the Group is involved in a number of disputes and investigations before state courts, arbitral tribunals or regulatory authorities. The disputes and investigations that could have a material impact on the Group are presented below.

25.1 France excluding Infrastructures

25.1.1 Canvassing

EDF brought an action against ENGIE before the Nanterre Commercial Court on July 20, 2017, seeking €13.5 million in damages for alleged losses due to unfair competitive practices pursued by ENGIE mainly in its door-to-door canvassing campaigns. In its judgment of December 14, 2017, the court ordered ENGIE to pay EDF the sum of €150,000, concluding that ENGIE was guilty of unfair competition but acknowledging that there had been no disparagement of EDF and that ENGIE had set up training and control arrangements for its partners.

ENGIE appealed the judgment and EDF brought a cross-appeal seeking €94.7 million in damages for its alleged loss. The Versailles Court of Appeal delivered its judgment on March 12, 2019, ordering ENGIE to pay EDF €1 million. It also ordered ENGIE to cease and desist from all parasitic business practices and disparagement to the detriment of EDF, subject to a penalty of €10,000 for each infringement.

On July 6, 2020, EDF asked the enforcement judge at the Nanterre Court to assess the penalty ordered by the Versailles Court of Appeal, seeking payment from ENGIE of the sum of €106.89 million and a final penalty of €50,000 per infringement for a period of one year. On December 11, 2020, the enforcement judge ordered ENGIE to pay EDF the sum of €230,000 and ordered a new provisional penalty of €15,000 per new infringement for a period of one year as of notification of the judgment by EDF.

On December 22, 2020, EDF appealed the enforcement judge's decision before the Versailles Court of Appeal.

25.2 France Infrastructures

25.2.1 Commissioning

Regarding the customer management services carried out on behalf of the grid manager in the gas sector, on June 30, 2020, two memorandums of understanding were signed by GRDF with Total Direct Energie and ENI respectively with a view to ending all ongoing disputes between GRDF, Total Direct Energie and ENI. The financial impact of these memorandums of understanding was fully taken into account in the financial statements for the six months ended June 30, 2020.

Regarding the customer management services carried out on behalf of the grid manager in the electricity sector (in this case ERDF, now ENEDIS), following proceedings brought by ENGIE, in a decision of July 13, 2016, the *Conseil d'État* ruled that the principle whereby the grid manager pays compensation to the supplier should apply. In the same decision, the *Conseil d'État* denied the CRE the right to set a customer threshold beyond which the compensation would not be payable, which hitherto prevented ENGIE from receiving any compensation. In light of this decision, ENGIE brought an action against ENEDIS with the purpose of obtaining payment for these customer management services. The legislature has adopted a decision that retroactively validates the agreements entered into with ENEDIS and precludes

any request for compensation for unpaid customer management services. In a decision handed down on April 19, 2019, the Constitutional Court ruled that this provision was constitutional. The proceedings against ENEDIS are still underway.

25.2.2 Investigation into the regulation mechanism for natural gas storage in France

On February 29, 2020, the European Commission announced that it had launched an in-depth investigation into the regulation mechanism for the storage of natural gas introduced on January 1, 2018 to secure France's natural gas supply. Storengy and Géométhane provided the Commission with all the necessary information to substantiate their analyses for the purposes of the Commission's investigation aimed at reaching a final decision. The initiation of these proceedings provides no guarantee as to the outcome of the investigation.

25.3 Rest of Europe

25.3.1 Resumption and extension of operations at the nuclear power plants

Various associations have brought actions before the Constitutional Court, the *Conseil d'État* and the ordinary courts against the laws and administrative decisions authorizing the extension of operations at the Doel 1 and 2 and Tihange 1 reactors. The Brussels Court of Appeal dismissed Greenpeace's claims in a decision dated June 12, 2018. Greenpeace appealed this decision before the Court of Cassation. This appeal was rejected by a ruling of the Court of Cassation dated January 9, 2020, such that the decision by the Brussels Court of Appeal dated June 12, 2018 is now final. As for the action brought before the Constitutional Court, on June 22, 2017 the Court referred the case to the Court of Justice of the European Union (CJEU) for a preliminary ruling. In its judgment of July 29, 2019, the CJEU ruled that the Belgian law extending the operating lives of the Doel 1 and Doel 2 reactors (Law extending Doel 1 and Doel 2) was adopted without the required environmental assessments being carried out first, but that the effects of the law on extension may provisionally be maintained where there is a genuine and serious threat of an interruption to electricity supply, and then only for the length of time that is strictly necessary to eliminate this threat. In its decision of March 5, 2020, the Constitutional Court overturned the Law extending Doel 1 and Doel 2, while maintaining its effects until the legislator adopts a new law after having carried out the required environmental assessments, including a cross-border public consultation process, by December 31, 2022 at the latest. The appeal before the *Conseil d'État* is still ongoing.

In addition, some local authorities and various organizations have challenged the authorization to restart operations at the Tihange 2 reactor. On November 9, 2018, the *Conseil d'État* rejected the action brought by some local German authorities seeking the annulment of this decision. Civil proceedings are still ongoing before the Brussels Court of First Instance. On September 3, 2020, the Court ruled that the case was admissible, but unfounded.

25.3.2 Claim by the Dutch tax authorities related to interest deductibility

Based on a disputable interpretation of a statutory modification that came into force in 2007, the Dutch tax authorities refuse the deductibility of a portion (€1.1 billion) of the interest paid on financing contracted for the acquisition of investments made in the Netherlands since 2000. Following the Dutch tax authorities' rejection of the administrative claim against the 2007 tax assessment, action was brought before the Arnhem Court of First Instance in June 2016. On October 4, 2018, the court ruled in favor of the tax authorities. On October 26, 2020, the ruling was confirmed by the Arnhem Court of Appeal. ENGIE Energie Nederland Holding BV considers that the Court committed errors in law and that its decision was not well-founded, either under Dutch or European law. It has therefore appealed the decision before the Court of Cassation.

25.3.3 Claim by the Dutch tax authorities related to power plant impairment losses

The Dutch tax authorities have disallowed the tax deduction of asset impairment losses reported by ENGIE Energie Nederland NV on its 2010-2013 tax returns. The authorities challenged both the period of coverage of the impairment losses and the amount. Accordingly, they added back the full amount of the accumulated asset impairment losses over the abovementioned period, i.e., an amount of €1.9 billion. ENGIE has contested the tax authorities position as regards

both the period and the amount and filed an administrative appeal in November 2018, which was rejected in February 2019. ENGIE is considering whether to launch legal proceedings.

25.3.4 Transfer price of gas

The Belgian tax authorities' Special Tax Inspectorate has issued two tax deficiency notices in respect of taxable income for fiscal years 2012 and 2013 for an aggregate amount of €706 million, considering that the price applied for the supply of gas by ENGIE (then GDF SUEZ) to Electrabel S.A. was excessive. ENGIE and Electrabel S.A. are challenging this adjustment. Belgium and France have begun conciliation proceedings to settle the dispute.

25.3.5 Spain - Punica

In the Punica case (investigation into the awarding of contracts), 12 Cofely España employees, as well as the company itself, were placed under investigation by the examining judge in charge of the case. The criminal proceedings are still ongoing and will probably continue through 2021.

25.3.6 Italy - Vado Ligure

On March 11, 2014, the Court of Savona seized and closed down the VL3 and VL4 coal-fired production units at the Vado Ligure thermal power plant belonging to Tirreno Power S.p.A. (TP), a company which is 50%-owned by the ENGIE Group. This decision was taken as part of a criminal investigation against the present and former executive managers of TP into environmental infringements and public health risks. The investigation was closed on July 20, 2016. The case was referred to the Savone Court to be tried on the merits. The proceedings began on December 11, 2018 and will continue through 2021.

25.3.7 Italy - Tax dispute relating to excise duties and ENGIE Italia VAT (formerly GDF SUEZ Energie)

In 2017, the Italian tax authorities challenged the excise duty waiver for gas transfers carried out by ENGIE Italia SpA (ENGIE Italia) for industrial customers in Italy on the grounds that it did not have a certificate for these customers. The authorities plan to issue a tax reassessment for a total amount of €126 million (excise duties, VAT, late payment penalties and interest). ENGIE Italia has challenged the legality of this procedure both in light of Italian and European law and in any event deems the sanction to be disproportionate compared to a formal requirement.

In 2018, ENGIE Italia launched an appeal with the Perugia Court of First Instance requesting the cancellation of the tax reassessment notice.

In October 2018, the Court of First Instance dismissed the cancellation request, simply applying an outdated ministerial decree and ignoring ENGIE Italia's legal arguments.

ENGIE Italia appealed the ruling in November 2018 and the Court of Appeal ruled in its favor in November 2019 on the grounds that the documents requested by the Italian tax authorities were not legal and that the authorities needed to take into account the factual situation of the taxpayer to determine its requirement to pay excise duties. In 2020, the tax authorities referred the case to the Court of Cassation.

25.3.8 Italy - Competition procedure

On May 9, 2019, a fine of €38 million was jointly and severally imposed on ENGIE Servizi SpA and ENGIE Energy Services International S.A. by the Italian Competition Authority (the Authority) for certain alleged anti-competitive practices relating to the award of the Consip FM4 2014 contract. An appeal was lodged with the Lazio Regional Administrative Court (Lazio RAC). On July 18, 2019, the Lazio RAC suspended the payment of the fine, and on July 27, 2020, it overturned the Authority's decision as regards both ENGIE Servizi SpA and ENGIE Energy Services International SA. On November 17, 2020, the Authority appealed the Lazio RAC's decision before Italy's highest administrative court.

25.4 Latin America

25.4.1 Concessions in Buenos Aires and Santa Fe

In 2003, ENGIE and its joint shareholders, water distribution concession operators in Buenos Aires and Santa Fe, initiated two arbitration proceedings against the Argentinean State before the International Center for Settlement of Investment Disputes (ICSID). The purpose of these proceedings was to obtain compensation for the loss in value of investments made since the start of the concession, in accordance with bilateral investment protection treaties.

As a reminder, prior to the stock market listing of SUEZ Environnement Company, ENGIE and SUEZ (formerly SUEZ Environnement) entered into an agreement providing for the economic transfer to SUEZ of the rights and obligations relating to the ownership interests held by ENGIE in Aguas Argentinas and Aguas Provinciales de Santa Fe, including the rights and obligations resulting from the arbitration proceedings.

On April 9, 2015, the ICSID ordered the Argentinean State to pay USD 405 million in respect of the termination of the Buenos Aires water distribution and treatment concession contracts (including USD 367 million to ENGIE and its subsidiaries), and on December 4, 2015, to pay USD 225 million in respect of the termination of the Santa Fe concession contracts. The Argentinean State sought the annulment of these awards. By decision dated May 5, 2017, the claim for the annulment of the Buenos Aires award was rejected. The claim to annul the award in the Santa Fe case was rejected by a decision dated December 14, 2018. Consequently, the two ICSID awards, which are a step in the settlement of the dispute, are now final.

The Argentinean government and the various shareholders of Aguas Argentinas entered into and implemented a settlement agreement in accordance with the arbitral award of April 9, 2015, handed down in respect of the water distribution and treatment concession contracts in Buenos Aires. In accordance with the above-mentioned agreement concerning the economic transfer to SUEZ of ENGIE's rights and obligations, SUEZ and its subsidiaries received €224.1 million in cash. Furthermore, the December 14, 2018 ruling pertaining to the water distribution and wastewater treatment concessions granted to Aguas Provinciales de Santa Fe has yet to be applied.

25.4.2 Planned construction of an LNG terminal in Uruguay

GNLS SA, a joint subsidiary of Marubeni and ENGIE, was selected in 2013 to build an offshore LNG terminal in Uruguay. On November 20, 2013, GNLS contracted out the design and construction of the terminal to Construtora OAS SA. Following a number of problems and defects, GNLS terminated the contract in March 2015 and made use of its guarantees. OAS challenged the termination of the contract but did not take action against GNLS. OAS went bankrupt in Uruguay on April 8, 2015. In September 2015, GNLS and the authorities agreed to cancel the planned construction.

On May 24, 2017, OAS and GNLS appeared before the Uruguayan courts in a conciliation process at the request of OAS. The conciliation process was unsuccessful. OAS then threatened to call GNLS before the Uruguayan courts to claim damages.

Since GNLS had incurred significant losses as a result of the termination of the contract, it filed a request for arbitration on August 22, 2017 in accordance with the terms of the contract providing for dispute resolution in Madrid by the ICC International Court of Arbitration, claiming a principal amount of USD 373 million. OAS responded by summoning GNLS before the Montevideo Commercial Court, claiming USD 311 million in damages. ENGIE was officially named as a party to the proceedings on December 5, 2018. Both proceedings are still pending.

25.4.3 Claim against sales tax adjustments in Brazil

On December 14, 2018, the Brazilian tax authorities sent ENGIE Brasil Energia S.A. tax assessment notices for the 2014, 2015 and 2016 fiscal years considering that the company was liable for the PIS and COFINS taxes (federal value added taxes) on the reimbursement of certain fuels used in the production of energy by thermoelectric plants. The adjustments amounted to a total of 492 million Brazilian reais, including 229 million Brazilian reais in taxes to which are added fines and interest.

ENGIE Brasil Energia disputes these notices of tax assessment and introduced tax claims in 2019, which the tax authorities have rejected, however. A final claim at administrative level (prior to possible appeals before tax courts at judicial level) was filed by ENGIE Brasil Energia in January 2020.

25.4.4 Mexico – Renewable energy

In the past few months, the Mexican government and public authorities have taken positions and regulatory measures that directly affect private players in the energy sector (in particular renewable energy producers) and go against the letter and spirit of the latest energy sector reforms introduced in 2013 and 2014. The constitutionality and legality of some of these measures have been contested in legal proceedings launched by non-government bodies and private investors, in particular by ENGIE subsidiaries that develop or implement renewable energy projects in the country. These proceedings are currently ongoing. In most cases, including in proceedings initiated by ENGIE subsidiaries, the competent courts ordered the suspension of the disputed measures pending a decision on the merits.

25.5 Other

25.5.1 Withholding tax

In their tax deficiency notice dated December 22, 2008, the French tax authorities questioned the tax treatment of the non-recourse sale by SUEZ (now ENGIE) of a withholding tax (*précompte*) receivable in 2005 for an amount of €995 million (receivable relating to the *précompte* paid in respect of the 1999-2003 fiscal years). The Montreuil Administrative Court handed down a judgment in ENGIE's favor in April 2019, which led to the French tax authorities appealing the decision before the Versailles Court of Appeal in May 2019. The submissions have been exchanged and the parties are awaiting a date for the hearing.

Regarding the dispute over the *précompte* itself, on February 1, 2016, the *Conseil d'État* dismissed the appeal before the Court of Cassation seeking the repayment of the *précompte* in respect of the 1999, 2000 and 2001 fiscal years. On June 23, 2020, the Versailles Administrative Court of Appeal found in favor of ENGIE as regards the cases seeking repayment of the *précompte* in respect of the 2002 and 2003 fiscal years but rejected the case in respect of the 2004 fiscal year. As the *précompte* receivables for 2002/2003 have been assigned, the relevant amounts will be repaid to the assignee banks. The case has been referred to the *Conseil d'État* by the two parties. Pursuant to an application for a priority preliminary ruling on the issue of constitutionality, on October 23, 2020, the *Conseil d'État* decided to seek a preliminary ruling from the Court of Justice of the European Union to ascertain whether Directive 90/435/EC of 1990 precludes the withholding of the *précompte* upon the redistribution by a parent company of dividends received from subsidiaries established in the European Union.

Furthermore, after ENGIE and several French groups lodged a complaint, on April 28, 2016, the European Commission issued a reasoned opinion to the French State as part of infringement proceedings, setting out its view that the *Conseil d'État* did not comply with European Union law when handing down decisions in disputes regarding the *précompte*, such as those involving ENGIE. On July 10, 2017, the European Commission referred the matter to the Court of Justice of the European Union (CJEU) on the grounds of France's failure to comply. On October 4, 2018, the Court of Justice of the European Union ruled partially in favor of the European Commission. Following this decision, France must revisit its methodology in order to determine the *précompte* repayment amounts in closed and pending court cases.

25.5.2 Luxembourg - State aid investigation

On September 19, 2016, the European Commission announced its decision to open an investigation into whether or not two private rulings granted by the Luxembourg State in 2008 and 2010 covering two similar transactions between several of the Group's Luxembourg subsidiaries constituted State aid. On June 20, 2018, the European Commission adopted a final, unfavorable decision deeming that Luxembourg had provided ENGIE with State aid. On September 4, 2018, ENGIE requested the annulment of the decision before the European Courts, thereby challenging the existence of a selective advantage. As these proceedings do not have a suspensive effect, ENGIE paid a sum of €123 million into an escrow account on October 22, 2018 in respect of one of the two transactions in question, since no aid was actually received for

the other. Following the proceedings before the European Courts, this sum will be returned to ENGIE or paid to the Luxembourg State depending on whether or not the Commission's decision is annulled. On September 15, 2020, the hearing was held in the presence of the parties and the Court's decision is currently pending.

25.5.3 Poland - Competition procedure

On November 7, 2019, a fine of 172 million Polish zloty (€40 million) was imposed on ENGIE Energy Management Holding Switzerland AG (EEMHS) for failing to respond to a request for disclosure of documents from the Polish Competition Authority (UOKiK) in a proceeding initiated by the UOKiK which suspected a potential failure to notify by EEMHS and other financial investors involved in the financing of the Nord Stream 2 pipeline (main proceeding). EEMHS filed an appeal with the Competition Protection Court. The appeal proceedings are pending.

In the context of the main proceedings, on October 6, 2020, the UOKiK ordered EEMHS to pay a fine of 55.5 million Polish zlotys (approximately €12.3 million). The UOKiK also ordered the termination of the financing agreements for the Nord Stream 2 project. On November 5, 2020, EEMHS appealed this decision with the Competition Protection Court. The appeal automatically suspends the execution of all of the penalties ordered by the UOKiK.

25.5.4 Sale of 29.9% of the capital of SUEZ to Veolia

In the context of the sale by ENGIE of 29.9% of the capital of SUEZ to Veolia, on October 6, 2020, ENGIE was summonsed to various proceedings, both in summary hearings or hearings on the merits, and both in labor law and commercial law matters. The main proceedings involved Veolia and SUEZ and were initiated by SUEZ, acting alone or jointly with its staff representation bodies. ENGIE has acted within its rights in all circumstances, has not violated any of its obligations and there is no irregularity in the form or substance of the sale to Veolia, which is now final, that is likely to affect the validity thereof.

NOTE 26 SUBSEQUENT EVENTS

No significant event occurred after the closing of the financial statements at December 31, 2020.

NOTE 27 FEES PAID TO THE STATUTORY AUDITORS AND TO MEMBERS OF THEIR NETWORKS

Pursuant to Article 222-8 of the General Regulations of the French Financial Markets Authority (AMF), the following table presents information on the fees paid by ENGIE SA, its fully consolidated subsidiaries and joint operations to each of the auditors in charge of auditing the annual and consolidated financial statements of the ENGIE Group.

The Shareholders' Meeting of ENGIE SA of May 14, 2020 decided to renew the terms of office of Deloitte and EY as Statutory Auditors for a six-year period from 2020 to 2025.

	Deloitte			EY			Total
	Deloitte & Associés	Network	Total	EY & others	Network	Total	
<i>In millions of euros</i>							
Statutory audit and review of consolidated and parent company financial statements	5.6	7.1	12.7	6.0	8.9	14.9	27.6
ENGIE SA	2.4	-	2.4	2.6	-	2.6	5.0
Controlled entities	3.2	7.1	10.3	3.3	8.9	12.2	22.6
Non-audit services	0.7	1.6	2.3	1.3	1.2	2.5	4.8
ENGIE SA	0.6	-	0.6	1.1	0.0	1.1	1.7
<i>Of which services related to legal and regulatory requirements</i>	0.3	-	0.3	0.3	-	0.3	0.6
<i>Of which other audit services</i>	0.3	-	0.3	0.7	-	0.7	0.9
<i>Of which reviews of internal control</i>	-	-	-	0.1	-	0.1	0.1
<i>Of which due diligence services</i>	-	-	-	-	-	-	-
<i>Of which tax services</i>	-	-	-	-	0.0	0.0	0.0
Controlled entities	0.2	1.6	1.7	0.3	1.2	1.4	3.1
<i>Of which services related to legal and regulatory requirements</i>	-	0.4	0.4	0.2	0.2	0.4	0.8
<i>Of which other audit services</i>	0.1	0.2	0.3	0.1	0.3	0.4	0.7
<i>Of which reviews of internal control</i>	-	0.1	0.1	-	-	-	0.1
<i>Of which due diligence services</i>	0.1	0.2	0.3	0.0	-	0.0	0.4
<i>Of which tax services</i>	-	0.7	0.7	-	0.6	0.6	1.3
Total	6.4	8.7	15.0	7.3	10.1	17.3	32.4

NOTE 28 INFORMATION REGARDING LUXEMBOURG AND DUTCH COMPANIES EXEMPTED FROM THE REQUIREMENTS TO PUBLISH ANNUAL FINANCIAL STATEMENTS

Some companies in the Rest of Europe and Others reportable segments do not publish annual financial statements pursuant to domestic provisions under Luxembourg law (Article 70 of the Law of December 19, 2002) and Dutch law (Article 403 of the Civil Code) relating to the exemption from the requirement to publish audited annual financial statements.

The companies exempted are notably: ENGIE Energie Nederland NV, ENGIE Energie Nederland Holding BV, ENGIE Nederland Retail BV, ENGIE United Consumers Energie BV, Epon Eemscentrale III BV, Epon Eemscentrale IV BV, Epon Eemscentrale V BV, Epon Eemscentrale VI BV, Epon Eemscentrale VII BV, Epon Eemscentrale VIII BV, Epon International BV, Epon Power Engineering BV, IPM Energy Services BV, Electrabel Invest Luxembourg, ENGIE Corp Luxembourg SARL, ENGIE Treasury Management SARL and ENGIE Invest International SA.



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[engie.com](https://www.engie.com)



Attachment 5-5

Redacted

Attachment 5-6

Redacted

Attachment 5-7

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