

**Central Maine Power Company
and Subsidiaries
Consolidated Financial Statements
For the Years Ended December 31, 2016 and 2015**

**Central Maine Power Company
and Subsidiaries**

Index

Page(s)

Consolidated Financial Statements for the Years Ended December 31, 2016 and 2015

Report of Independent Auditors	
Consolidated Statements of Income	1
Consolidated Statements of Comprehensive Income	1
Consolidated Balance Sheets	2 – 3
Consolidated Statements of Cash Flows	4
Consolidated Statements of Changes in Equity.....	5
Notes to Consolidated Financial Statements	6 – 37



Ernst & Young LLP
5 Times Square
New York, NY 10036-6530

Tel: +1 212 773 3000
Fax: +1 212 773 6350
ey.com

Report of Independent Auditors

To the Shareholders and Board of Directors
Central Maine Power Company

We have audited the accompanying consolidated financial statements of Central Maine Power Company and subsidiaries, which comprise the consolidated balance sheets as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for the years then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in conformity with U.S. generally accepted accounting principles; this includes the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free of material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Central Maine Power Company and subsidiaries at December 31, 2016 and 2015, and the consolidated results of their operations and their cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

Ernst & Young LLP

March 31, 2017

**Central Maine Power Company and Subsidiaries
Consolidated Statements of Income**

Year Ended December 31,	2016	2015
(Thousands)		
Operating Revenues		
Sales and services	\$833,938	\$819,716
Operating Expenses		
Electricity purchased	59,201	57,165
Operations and maintenance	352,244	377,423
Depreciation and amortization	102,786	98,654
Other taxes	54,536	47,482
Total Operating Expenses	568,767	580,724
Operating Income	265,171	238,992
Other Income	6,416	7,629
Other Deductions	(1,711)	(391)
Interest Charges, Net	(52,985)	(54,751)
Income Before Income Tax	216,891	191,479
Income Tax Expense	81,071	77,038
Net Income	135,820	114,441
Less: Net Income Attributable to Noncontrolling Interest	409	353
Net Income Attributable to CMP	135,411	114,088
Preferred Stock Dividends	-	34
Net Income Available for CMP Common Stock	\$135,411	\$114,054

The accompanying notes are an integral part of our consolidated financial statements.

**Central Maine Power Company and Subsidiaries
Consolidated Statements of Comprehensive Income**

Year ended December 31,	2016	2015
(Thousands)		
Net Income	\$135,820	\$ 114,441
Other Comprehensive Income (Loss), Net of Tax		
Amortization of pension cost for nonqualified plans	75	163
Unrealized gain (loss) on derivatives qualified as hedges:		
Unrealized gain (loss) during period on derivatives qualified as hedges	81	(562)
Reclassification adjustment for loss included in net income	388	623
Reclassification adjustment for loss on settled cash flow treasury hedges	1,323	1,315
Net unrealized gain on derivatives qualified as hedges	1,792	1,376
Other Comprehensive Income, Net of Tax	1,867	1,539
Comprehensive Income	137,687	115,980
Less:		
Comprehensive Income Attributable to Noncontrolling Interests	409	353
Comprehensive Income Attributable to CMP	\$137,278	\$115,627

The accompanying notes are an integral part of our consolidated financial statements.

**Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets**

December 31, (Thousands)	2016	2015
Assets		
Current Assets		
Cash and cash equivalents	\$7,968	\$5,360
Accounts receivable and unbilled revenues, net	161,725	149,281
Accounts receivable from affiliates	1,671	1,762
Notes receivable from affiliates	32,100	23,437
Materials and supplies	15,018	15,828
Prepayments and other current assets	79,170	121,095
Regulatory assets	18,198	22,032
Total Current Assets	315,850	338,795
Utility plant, at original cost	3,828,993	3,675,772
Less accumulated depreciation	(893,117)	(826,309)
Net Utility Plant in Service	2,935,876	2,849,463
Construction work in progress	160,459	152,707
Total Utility Plant	3,096,335	3,002,170
Other Property and Investments	1,297	1,506
Regulatory and Other Assets		
Regulatory assets	489,765	521,482
Goodwill	324,938	324,938
Other	19,027	5,304
Total Regulatory and Other Assets	833,730	851,724
Total Assets	\$4,247,212	\$4,194,195

The accompanying notes are an integral part of our consolidated financial statements.

**Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets**

December 31,	2016	2015
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	\$5,154	\$41,312
Accounts payable and accrued liabilities	145,653	123,070
Accounts payable to affiliates	35,844	32,893
Interest accrued	17,851	18,671
Taxes accrued	3,154	7,454
Other current liabilities	54,008	59,781
Regulatory liabilities	36,801	44,799
Total Current Liabilities	298,465	327,980
Regulatory and Other Liabilities		
Regulatory liabilities	109,941	100,228
Deferred income taxes regulatory	149,232	165,119
Other Non-current liabilities		
Deferred income taxes	660,090	626,868
Pension and other postretirement benefits	194,716	226,560
Other	56,096	54,678
Total Regulatory and Other Liabilities	1,170,075	1,173,453
Long-term debt	1,042,310	1,043,512
Total Liabilities	2,510,850	2,544,945
Commitments and Contingencies		
Preferred Stock		
Preferred stock	571	571
CMP Common Stock Equity		
Common stock (\$5 par value, 80,000 shares authorized and 31,211 shares outstanding at December 31, 2016 and 2015)	156,057	156,057
Capital in excess of par value	764,014	713,893
Retained earnings	812,121	777,406
Accumulated other comprehensive loss	(6,647)	(8,514)
Total CMP Common Stock Equity	1,725,545	1,638,842
Noncontrolling Interest	10,246	9,837
Total Equity	1,735,791	1,648,679
Total Liabilities and Equity	\$4,247,212	\$4,194,195

The accompanying notes are an integral part of our consolidated financial statements.

Central Maine Power Company and Subsidiaries
Consolidated Statements of Cash Flows

Year Ended December 31,	2016	2015
(Thousands)		
Cash Flow from Operating Activities		
Net income	\$135,820	\$114,441
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	102,786	98,654
Amortization of regulatory assets and liabilities	(17,548)	(14,835)
Carrying cost of regulatory assets and liabilities	942	1,195
Deferred taxes	14,942	70,198
Other non-cash items	2,925	(673)
Pension expense	22,433	26,274
Changes in operating assets and liabilities		
Accounts receivable and unbilled revenues, net	(14,392)	(134)
Materials and supplies	810	11,648
Accounts payable and accrued liabilities	14,652	30,052
Other assets and other liabilities	15,958	(101,804)
Changes in regulatory assets and liabilities	20,912	19,775
Net Cash Provided by Operating Activities	300,240	254,791
Cash Flow from Investing Activities		
Utility plant additions	(220,257)	(280,224)
Contributions in aid of construction	25,001	16,565
Issuance of notes receivable with affiliates	(8,663)	(22,747)
Proceeds from sale of property, plant and equipment	284	-
Changes in other investments	(20)	166
Net Cash Used in Investing Activities	(203,655)	(286,240)
Cash Flow from Financing Activities		
Capital contributions from parent	50,000	-
Repayment of debts and capital leases	(43,281)	(2,152)
Long-term note issuance	-	150,000
Repayments of notes payable with affiliates	-	(118,192)
Dividends paid on common stock	(100,696)	-
Dividends paid on preferred stock	-	(34)
Capital contribution from noncontrolling interests	-	2,164
Net Cash (Used in) Provided by Financing Activities	(93,977)	31,786
Net Increase in Cash and Cash Equivalents	2,608	337
Cash and Cash Equivalents, Beginning of Year	5,360	5,023
Cash and Cash Equivalents, End of Year	\$7,968	\$5,360

The accompanying notes are an integral part of our consolidated financial statements.

Central Maine Power Company and Subsidiaries
Consolidated Statements of Changes in Equity

CMP Stockholder

(Thousands, except per share amounts)	Shares	Common Stock Outstanding \$5 Par Value Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stock Equity	Noncon- trolling Interest	Total
Balance, January 1, 2015	31,211	\$156,057	\$713,893	\$663,352	\$(10,053)	\$1,523,249	\$7,320	\$1,530,569
Net income				114,088		114,088	353	114,441
Other comprehensive income, net of tax					1,539	1,539		1,539
Comprehensive income								115,980
Capital contribution from noncontrolling interests							2,164	2,164
Dividends paid, preferred stock				(34)		(34)		(34)
Balance, December 31, 2015	31,211	156,057	713,893	777,406	(8,514)	1,638,842	9,837	1,648,679
Net income				135,411		135,411	409	135,820
Other comprehensive income net of tax					1,867	1,867		1,867
Comprehensive income								137,687
Stock-based compensation			121			121		121
Capital contribution from parent			50,000			50,000		50,000
Dividends paid				(100,696)		(100,696)		(100,696)
Balance, December 31, 2016	31,211	\$156,057	\$764,014	\$812,121	\$(6,647)	\$1,725,545	\$10,246	\$1,735,791

The accompanying notes are an integral part of our consolidated financial statements.

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Background: Central Maine Power Company and subsidiaries (CMP, the company, we, our, us) conduct regulated electricity transmission and distribution operations in Maine serving approximately 619,000 customers in a service territory of approximately 11,000 square miles with a population of approximately one million people. The service territory is located in the southern and central areas of Maine and contains most of Maine's industrial and commercial centers, including the city of Portland and the Lewiston-Auburn, Augusta-Waterville, Saco-Biddeford and Bath-Brunswick areas.

CMP is the principal operating utility of CMP Group, Inc. (CMP Group), a wholly-owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc. (AGR), formerly Iberdrola USA, which is a 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation, organized under the law of the Kingdom of Spain.

Networks was formed on November 20, 2013, when AGR was reorganized to become the parent company of Networks. Networks is a public utility sub-holding company operating under the Public Utility Holding Company Act of 2005 with operations in New York, Maine, Connecticut and Massachusetts. The wholly owned subsidiaries and the operating utility companies of Networks include: CMP Group - Central Maine Power Company (CMP), RGS - New York State Electric & Gas Corporation (NYSEG), Rochester Gas and Electric Corporation (RG&E), Maine Natural Gas Company (MNG), The United Illuminating Company (UI), The Southern Connecticut Gas Company (SCG), Connecticut Natural Gas Corporation (CNG) and The Berkshire Gas Company (BGC). UI is also a party to a joint venture with certain affiliates of NRG Energy, Inc. (NRG affiliates) pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly owned subsidiary, GenConn Energy LLC (collectively with GCE Holding LLC, GenConn) operates peaking generation plants in Devon, Connecticut (GenConn Devon) and Middletown, Connecticut (GenConn Middletown).

On December 16, 2015, AGR completed the acquisition of UIL Holdings Corporation (UIL). Immediately following the completion of the acquisition, former UIL shareowners owned 18.5% of the outstanding shares of common stock of AGR, and Iberdrola owned the remaining shares. The acquisition was accounted for as a business combination in AGR's consolidated financial statements. The regulated utility businesses of UIL consist of the electric distribution and transmission operations of UI and the natural gas transportation, distribution and sales operations of SCG, CNG and BGC. Effective as of April 30, 2016, UIL and its subsidiaries were transferred to a wholly-owned subsidiary of Networks.

Accounts receivable: Accounts receivable at December 31 include unbilled revenues of \$27 million for 2016 and \$23 million for 2015, and are shown net of an allowance for doubtful accounts at December 31 of \$3 million for both 2016 and 2015. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was \$4 million in 2016 and \$3 million in 2015.

Unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our existing accounts receivable, determined based on experience. Each month we review our allowance for doubtful accounts and past due accounts by age. When we believe that a receivable will not be recovered, we charge off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently

Notes to Consolidated Financial Statements

uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates.

Our accounts receivable include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the MPUC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments over an extended time by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: pays a reasonable portion of the balance; agrees to pay the balance in installments; and agrees to pay future bills within 30 days until the DPA is paid in full or is otherwise considered to be delinquent. We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses and by establishing specific provisions for known credit issues. Amounts are written off when reasonable collection efforts have been exhausted. The allowance for doubtful accounts for DPAs at December 31 was \$1 million for 2016 and \$2 million in 2015. DPA receivable balances at December 31 were \$9 million in 2016 and \$10 million in 2015.

Asset retirement obligations: We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability periodically to reflect revisions to either the timing or the amount of the original estimated undiscounted cash flows over time. The liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. Our regulated utilities defer any timing differences between rate recovery and depreciation expense and accretion as either a regulatory asset or a regulatory liability.

The term conditional ARO refers to an entity's legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional on a future event that may or may not be within the control of the entity. If an entity has sufficient information to reasonably estimate the fair value of the liability for a conditional ARO, it must recognize that liability at the time the liability is incurred.

Our ARO at December 31, including our conditional ARO, was less than \$1 million for both 2016 and 2015. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of asbestos and PCB-contaminated equipment.

We have AROs for which we have not recognized a liability because the fair value cannot be reasonably estimated due to indeterminate settlement dates, including the removal of property upon termination of an easement, right-of-way or franchise.

Accrued removal obligations: We meet the requirements concerning accounting for regulated operations, and recognize a regulatory liability, for the difference between removal costs collected in rates and actual costs incurred. We classify those amounts as accrued removal obligations.

Consolidated statements of cash flows: We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and those investments are included in cash and cash equivalents. Restricted cash represents cash legally set aside for a specified purpose or as part of an agreement with a third party. As of both December 31, 2016 and 2015, we did not have restricted cash.

Notes to Consolidated Financial Statements

Supplemental Disclosure of Cash Flows Information	2016	2015
(Thousands)		
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	\$50,892	\$48,889
Income taxes paid, net	\$19,018	\$46,696

Interest capitalized was \$1.5 million in 2016 and \$2.1 million in 2015.

Depreciation and amortization: We determine depreciation expense using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Our depreciation accruals were equivalent to 2.5% of average depreciable property for both 2016 and 2015. We amortize our capitalized software cost which is included in other plant, using the straight line method, based on useful lives of 5 to 10 years. Capitalized software costs of approximately \$94 million as of December 31, 2016 and \$87 million as of December 31, 2015. Depreciation expense was \$95 million in 2016 and \$91 million in 2015. Amortization of capitalized software was \$8 million in 2016 and 2015.

We charge repairs and minor replacements to operation and maintenance expense, and capitalize renewals and betterments, including certain indirect costs. We charge the original cost of utility plant retired or otherwise disposed of to accumulated depreciation.

Our balances of major classes of assets and the associated useful lives are shown below.

Plant	Estimated useful life (years)	2016	2015
(thousands)			
Electric			
Transmission	47.2	\$2,192,851	\$2,136,532
Distribution	47.0	1,295,277	1,316,746
Vehicles	7	58,621	52,168
Other	34.8	282,244	170,326
Total Utility Plant		\$3,828,993	\$3,675,772

Electric plant includes capital leases of \$46 million for 2016 and \$40 million for 2015. Accumulated depreciation related to these leases was \$37 million for 2016 and 2015.

Environmental remediation liability: In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. Our environmental liabilities are recorded on an undiscounted basis. Our environmental liability accruals are expected to be paid through the year 2053.

Goodwill: Goodwill represents future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred the fair value of any non-controlling interest and the acquisition date fair value of any previously held equity interest in the acquiree over the fair value of the net identifiable assets acquired and liabilities assumed.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually or more frequently if events occur or circumstances change that will more likely than not reduce the fair value of the reporting unit to which goodwill is assigned below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which goodwill is tested for impairment. In assessing goodwill for impairment we have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary

Notes to Consolidated Financial Statements

(step zero). If it is determined, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass step zero or perform the qualitative assessment, but determine that it is more likely than not that its fair value is less than its carrying amount, a quantitative two step fair value based test is performed. Step one compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, step two is performed. Step two requires an allocation of fair value to the individual assets and liabilities using business combination accounting guidance to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than its carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

Inventory: Inventory comprises materials and supplies that are used for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn at cost and reported on the balance sheet within “Materials and supplies”.

Government grants: We account for government grants related to depreciable assets in the same way as we account for contributions in aid of construction (CIAC), that is, the grant amount is credited to the cost of the related property, plant and equipment. In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as compensation for expenses already incurred in the statements of income in the period in which the expenses are incurred.

Stock-based compensation: Stock-based compensation represents costs related to AGR performance stock units (PSUs) granted to certain officers and employees of CMP under the Avangrid, Inc. Omnibus Incentive Plan in July 2016. The PSUs will vest upon achievement of certain performance and market-based metrics related to the 2016 through 2019 plan and will be payable in three equal installments in 2020, 2021 and 2022. We account for stock-based payment transactions based on the estimated fair value of awards reflecting forfeitures when they occur. The recognition period for these costs begin at either the applicable service inception date or grant date and continues throughout the requisite service period, or until the employee becomes retirement eligible, if earlier.

New Accounting Standards and Interpretations: New accounting standards issued by the Financial Accounting Standards Board (FASB) that we either adopted or have not yet adopted are explained below. Although we are not a public business entity, our parent company became a registrant in December 2015, and in the future we will adopt new accounting standards based on the effective date for public entities.

(a) Revenue from contracts with customers

In May 2014 the FASB issued ASC 606, Revenue from Contracts with Customers (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The core principle is for an entity to recognize revenue to represent the transfer of goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers. The original effective date for public entities was for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. In August 2015 the FASB issued an accounting standards update that defers by one year the original effective date of the revenue standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption as of the original effective date permitted. We do not plan to early adopt. Entities may apply the amendment retrospectively to each prior reporting period presented

Notes to Consolidated Financial Statements

(full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). We will apply the modified retrospective method. We are currently evaluating how our adoption of the amendments will affect our results of operations, financial position, cash flows, and disclosures. We are considering the effects of the amendments on our ability to recognize revenue for certain contracts for our regulated utilities where collectability is in question and our accounting for contributions in aid of construction for our regulated utilities. In addition, the amendments will require us to capitalize, rather than expense, any costs to acquire new contracts. Some revenue arrangements, such as alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on our consolidated financial statements. The FASB has issued various additional accounting standards updates, with the same deferred effective date, as follows: in March 2016 to amend and clarify the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, in April 2016 to address implementation questions on identifying performance obligations and accounting for licenses of intellectual property. We do not expect significant effects as a result of those updates. In May 2016 the FASB issued a final update concerning narrow-scope improvements and practical expedients. We are currently evaluating the effects of that update.

(b) Fair value measurement disclosures for certain investments

In May 2015 the FASB issued amendments that affect reporting entities that elect to estimate the fair value of certain investments within scope using the net asset value (NAV) per share (or its equivalent) practical expedient, as specified. The amendments remove the requirement to categorize within the fair value hierarchy all investments for which the fair value is measured at NAV using the practical expedient. They also remove certain disclosure requirements for eligible investments and limit the required disclosures to investments for which the entity has elected to measure the fair value using the practical expedient. Assets that calculate NAV per share (or its equivalent), but for which the practical expedient is not applied will continue to be included in the fair value hierarchy. The amendments are effective for public entities for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. The amendments permit early application, and require retrospective application to all periods presented. Retrospective application requires investments for which fair value is measured at NAV using the practical expedient to be removed from the fair value hierarchy in all periods presented. Our adoption of the amendments in 2016 did not affect our results of operations, financial position, or cash flows.

Notes to Consolidated Financial Statements

(c) Simplifying the measurement of inventory

In July 2015 the FASB issued amendments that require entities to measure inventory at the lower of cost and net realizable value, rather than the lower of cost or market. The amendments do not apply to inventory measured using last-in, first-out or the retail inventory method but apply to all other inventory, including inventory measured using first-in, first-out or average cost. Prior to this update, market value could be replacement cost, net realizable value, or net realizable value less an approximately normal profit margin. Net realizable value is the “estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation.” The amendments do not change the methods of estimating the cost of inventory under U.S. GAAP. The amendments are effective for public entities for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. The amendments require prospective application and permit earlier application. We expect our adoption of the amendments will not affect our results of operations, financial position, or cash flows.

(d) Classifying and measuring financial instruments

In January 2016 the FASB issued final guidance on the classification and measurement of financial instruments. The new guidance requires that all equity investments in unconsolidated entities (other than those accounted for using the equity method of accounting) to be measured at fair value through earnings. There will no longer be an available-for-sale classification (changes in fair value reported in other comprehensive income) for equity securities with readily determinable fair values. For equity investments without readily determinable fair values, the cost method is also eliminated. However, entities (other than those following “specialized” accounting models, such as investment companies and broker-dealers) are able to elect to record equity investments without readily determinable fair values at cost, less impairment, and plus or minus subsequent adjustments for observable price changes. Changes in the basis of these equity investments will be reported in current earnings. That election only applies to equity investments that do not qualify for the NAV practical expedient. When the fair value option has been elected for financial liabilities, changes in fair value due to instrument-specific credit risk will be recognized separately in other comprehensive income. The accumulated gains and losses due to those changes will be reclassified from accumulated other comprehensive income to earnings if the financial liability is settled before maturity. Public entities are required to use the exit price notion when measuring the fair value of financial instruments measured at amortized cost for disclosure purposes. In addition, the new guidance requires financial assets and financial liabilities to be presented separately in the notes to the financial statements, grouped by measurement category (e.g., fair value, amortized cost, lower of cost or market) and form of financial asset (e.g., loans, securities).

The classification and measurement guidance is effective for public entities in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. An entity will record a cumulative-effect adjustment to beginning retained earnings as of the beginning of the first reporting period in which the guidance is adopted, with two exceptions. The amendments related to equity investments without readily determinable fair values (including disclosure requirements) will be effective prospectively. The requirement to use the exit price notion to measure the fair value of financial instruments for disclosure purposes will also be applied prospectively. We expect our adoption of the guidance will not materially affect our results of operations, financial position, or cash flows.

(e) Leases

In February 2016 the FASB issued new guidance that affects all companies and organizations that lease assets, and requires them to record on their balance sheet assets and liabilities for the rights and obligations created by those leases. A lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Concerning lease expense recognition, after extensive consultation, the FASB has ultimately

Notes to Consolidated Financial Statements

concluded that the economics of leases can vary for a lessee, and those economics should be reflected in the financial statements. As a result, the amendments retain a distinction between finance leases and operating leases, while requiring both types of leases to be recognized on the balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in current GAAP. By retaining a distinction between finance leases and operating leases, the effect of leases on the statement of comprehensive income and the statement of cash flows is largely unchanged from previous GAAP. Lessor accounting will remain substantially the same as current GAAP, but with some targeted improvements to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance issued in 2014. The updated guidance is effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early application is permitted. We are currently reviewing our contracts and are in the process of determining the proper application of the standard to these contracts in order to determine the impact that the adoption will have on our consolidated financial statements. We expect our adoption of the new guidance will materially affect our financial position through the recording of operating leases on the balance sheet as a right-of-use asset.

(f) Derivative contract novations

In March 2016 the FASB issued amendments concerning the effect of derivative contract novations on existing hedge accounting relationships. As it relates to derivative instruments, novation refers to replacing one of the parties to a derivative instrument with a new party, which may occur for a variety of reasons such as: financial institution mergers, intercompany transactions, an entity exiting a particular derivatives business or relationship, or because of laws or regulatory requirements. The amendments clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument under the guidance for Derivatives and Hedging (Topic 815) does not, in and of itself, require dedesignation of that hedge accounting relationship provided that all other hedge accounting criteria continue to be met. The amendments are effective for public entities for financial statements issued for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. The amendments may be applied on either a prospective basis or a modified retrospective basis and early application is permitted. We expect our adoption will not materially affect our results of operations, financial position, and cash flows.

(g) Improvements to employee share-based payment accounting

The FASB issued amendments in March 2016 regarding the simplification of several aspects of accounting for share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities, policy election on accounting for forfeitures and classification on the statement of cash flows. Some areas of simplification apply only to nonpublic entities. The amendments are effective for public entities for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. Early adoption permitted in any interim or annual period, but must adopt all of the amendments in the same period. For the purpose of accounting for the stock-based compensation plans, in the third quarter of 2016 we early adopted all the above amendments and elected to account for forfeitures when they occur. Our adoption of the amendments did not materially affect our results of operations, financial position, or cash flows.

(h) Measurement of credit losses on financial instruments

The FASB issued an accounting standards update in June 2016 that requires more timely recording of credit losses on loans and other financial instruments. The amendments affect entities that hold financial assets and net investment in leases that are not accounted for at fair value through net income (loans, debt securities, trade receivables, net investments in leases, off-

Notes to Consolidated Financial Statements

balance-sheet credit exposures, etc.). They require an entity to present a financial asset (or group of financial assets) that is measured at amortized cost basis at the net amount expected to be collected. The allowance for credit losses is a valuation account that is deducted from the amortized cost basis of the financial asset(s) to present the net carrying value at the amount expected to be collected on the financial asset. The income statement reflects the measurement of credit losses for newly recognized financial assets, as well as the expected increases or decreases of expected credit losses that have taken place during the period. The measurement of expected credit losses is based on relevant information about past events, including historical experience, current conditions, and reasonable and supportable forecasts that affect the collectibility of the reported amount. An entity must use judgment in determining the relevant information and estimation methods appropriate in its circumstances. The amendments are effective for public entities that are SEC filers for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, with early adoption permitted. Entities are to apply the amendments on a modified retrospective basis for most instruments. We expect our adoption will not materially affect our results of operations, financial position, and cash flows.

(i) Certain classifications in the statement of cash flows

The FASB issued the amendments in August 2016 to address existing diversity in practice concerning eight cash flows issues. The guidance addresses classification as operating, investing or financing activities in the statement of cash flows for these issues: 1) Debt prepayment or debt extinguishment costs (financing), 2) Settlement of zero-coupon bonds (interest is operating, principal is financing), 3) Contingent consideration payments made after a business combination (investing or financing based on timing, or operating, as specified), 4) Proceeds from the settlement of insurance claims (based on the nature of the loss), 5) Proceeds from the settlement of corporate-owned life insurance policies (COLI) (investing; with cash payments for COLI premiums as investing, operating or a combination of investing/operating), 6) Distributions received from equity method investees (based on an entity's accounting policy election: either cumulative earnings or nature of distribution), 7) Beneficial interests in securitization transactions (noncash or investing as specified), 8) Separately identifiable cash flows and application of the predominance principle (cash receipts/payments with aspects of more than one classification by applying specific GAAP guidance; or if there is no guidance, based on the nature of the related activity or the activity that is the predominant source or use of the cash flows). The amendments are effective for public entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. The amendments are to be applied retrospectively to each prior period presented, unless impracticable for some issues and then the application would be prospective for those affected issues. We expect our adoption will not materially affect cash flows.

(j) Presentation of restricted cash in the statement of cash flows

The FASB issued the amendment in November 2016 to address existing diversity in the classification and presentation of changes in restricted cash on the statement of cash flows. The amendment requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The amendment does not provide a definition of restricted cash or restricted cash equivalents. The amendment is effective for public entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. The amendment should be applied using a retrospective transition method to each period presented. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2016 and have applied it retrospectively to all periods presented. The adoption of the amendment did not have any impact

Notes to Consolidated Financial Statements

on the consolidated statements of cash flows for the year ended December 31, 2015 as we did not have restricted cash as of the beginning and end of 2015.

Other Income and Other Deductions:

Year Ended December 31, (Thousands)	2016	2015
Gain on sale of property	\$1,409	\$160
Interest and dividends income	139	953
Allowance for funds used during construction	3,759	5,763
Carrying costs on regulatory assets	500	581
Miscellaneous	609	172
Total other income	\$6,416	\$7,629
Donations	(\$500)	(\$390)
Miscellaneous	(1,211)	(1)
Total other deductions	(\$1,711)	(\$391)

Principles of consolidation: These financial statements consolidate our majority-owned subsidiaries after eliminating intercompany transactions.

Regulatory assets and liabilities: We currently meet the requirements concerning accounting for regulated operations for our electric operations in Maine; however, we cannot predict what effect the competitive market or future actions of regulatory entities would have on our ability to continue to do so. If we were to no longer meet the requirements concerning accounting for regulated operations for all or a separable part of our operations, we may have to record certain regulatory assets and regulatory liabilities as an expense or as revenue, or include them in accumulated other comprehensive income.

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric rates. Substantially all regulatory assets for which funds have been expended are either included in rate base or are accruing carrying costs. The primary regulatory assets and liabilities that have not yet been included in rates, and are therefore accruing carrying costs until included in rates, are deferred storm costs and various deferrals, both assets and liabilities, that result from reconciliation mechanisms designed to allow recovery of actual costs. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs (See Note 3).

Related party transactions: Certain Networks subsidiaries, including CMP borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For CMP, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 7 for further detail on the credit facility with AGR.

Avangrid Service Company provides administrative and management services to Networks operating utilities, including CMP, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for operating and capital services provided to CMP by Avangrid Service Company was \$35 million and \$32 million for 2016 and 2015, respectively. Charge for services provided by CMP to AGR and its subsidiaries were approximately \$2.9 million for 2016 and 4 million for 2015. All charges for services are at cost. The balance in accounts payable to affiliates of \$36 million at December 31, 2016 and \$32 million at December 31, 2015 is payable to Avangrid Service Company.

Notes to Consolidated Financial Statements

The balance in notes receivable from affiliates of \$32 million and \$23 million, respectively, at December 31, 2016 and 2015, is mainly receivable from RG&E.

Of the \$19 million paid for income taxes, substantially all was paid to AGR under the tax sharing agreement.

Revenue recognition: We recognize revenues upon delivery of energy and energy-related products and services to our customers.

Pursuant to a Maine state law, CMP earns revenue for the delivery of energy to its retail customers, but is prohibited from selling power to them. CMP generally does not enter into purchase or sales arrangements for power with ISO New England Inc. (ISO-NE), the New England Power Pool, or any other independent system operator or similar entity. CMP generally sells all of its power entitlements under its nonutility generator (NUG) and other purchase power contracts to unrelated third parties under bilateral contracts. If the Maine Public Utilities Commission (MPUC) does not approve the terms of bilateral contracts, it can direct CMP to sell power entitlements that it receives from those contracts on the spot market through ISO-NE.

CMP's electric rates each contain a revenue decoupling mechanism under which their actual energy delivery revenues are compared on a periodic basis with the authorized delivery revenues and the difference accrued, with interest, for refund to or recovery from customers, as applicable (See Note 2).

In addition we accrue revenue pursuant to the various regulatory provisions to record regulatory assets for revenues that will be collected in the future.

Taxes: AGR files consolidated federal and state income tax returns including all of the activities of its subsidiaries. Each subsidiary company is treated as a member of the consolidated group and determines its current and deferred taxes based on the separate return with benefits for loss method. As a member, CMP settles its current tax liability or benefit each year directly with AGR pursuant to a tax allocation agreement between AGR and its members.

The aggregate amount of the intercompany income tax receivable balance due from AGR is \$45.5 million and \$92.5 million at December 31, 2016 and December 31, 2015, respectively.

We use the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities reflect the expected future tax consequences, based on enacted tax laws, of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts. In accordance with generally accepted accounting principles for regulated industries, our regulated subsidiaries have established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. The investment tax credits are deferred when used and amortized over the estimated lives of the related assets.

Deferred tax assets and liabilities are measured at the expected tax rate for the period in which the asset or liability will be realized or settled, based on legislation enacted as of the balance sheet date. Changes in deferred income tax assets and liabilities that are associated with components of OCI are charged or credited directly to OCI. Significant judgment is required in determining income tax provisions and evaluating tax positions. Our tax positions are evaluated under a more-likely-than-not recognition threshold before they are recognized for financial reporting purposes. Valuation allowances are recorded to reduce deferred tax assets when it is not more-likely-than-not that all or a portion of a tax benefit will be realized. Deferred tax assets and liabilities are classified as non-current in the consolidated balance sheets.

Notes to Consolidated Financial Statements

The excess of state franchise tax, computed as the higher of a tax based on income or a tax based on capital, is recorded in other taxes and taxes accrued in the accompanying consolidated financial statements.

Positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, are recognized in the financial statements when it is more likely than not the tax position can be sustained based solely on the technical merits of the position. The amount of a tax return position that is not recognized in the financial statements is disclosed as an unrecognized tax benefit. Changes in assumptions on tax benefits may also impact interest expense or interest income and may result in the recognition of tax penalties. Interest and penalties related to unrecognized tax benefits are recorded within "Interest charges, net" and "Other (income)" of the consolidated statements of income. Uncertain tax positions have been classified as non-current unless expected to be paid within one year.

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognized tax benefits reflect management's best assessment of estimated current and future taxes to be paid. Significant judgments and estimates are required in determining the consolidated income tax components of the financial statements.

We account for sales tax collected from customers and remitted to taxing authorities on a net basis.

Use of estimates and assumptions: The preparation of our consolidated financial statements in conformity with generally accepted accounting principles requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Significant estimates and assumptions are used for, but not limited to: (1) allowance for doubtful accounts and unbilled revenues; (2) asset impairments, including goodwill; (3) depreciable lives of assets; (4) income tax valuation allowances; (5) uncertain tax positions; (6) reserves for professional, workers' compensation, and comprehensive general insurance liability risks; (7) contingency and litigation reserves; (8) environmental remediation liability; (9) pension and Other Postretirement Employee Benefit (OPEB); (10) fair value measurements and (11) AROs. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our consolidated financial statements will change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. We evaluate and update our assumptions and estimates on an ongoing basis and may employ outside experts to assist in our evaluations, as considered necessary. Actual results could differ from those estimates.

Union bargain agreements: The company has approximately 68% of the company's employees are covered by a collective bargaining agreement. CMP has no agreements which will expire within the coming year.

Reclassifications: Certain amounts have been reclassified in the consolidated statements of cash flow to conform to the 2016 presentation.

Note 2. Industry Regulation

Our revenues are regulated, being based on tariffs established in accordance with administrative procedures set by the various regulatory bodies. Distribution rates are established by the Maine Public Utilities Commission (MPUC) and transmission rates are established by the Federal Energy Regulatory Commission (FERC). The tariffs applied based on the cost of providing service and are set to be sufficient to cover all its operating costs, including energy costs, finance costs,

Notes to Consolidated Financial Statements

and the costs of equity, the last of which reflect our capital ratio and a reasonable return on equity (ROE).

Transmission - FERC ROE Proceeding

See Note 9 - Commitments and Contingent Liabilities - for a further discussion.

CMP's transmission rates are determined by a tariff regulated by the FERC and administered by ISO New England, Inc. (ISO-NE). Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, and for a return of and on investment in assets.

On December 28, 2015, the FERC issued an order instituting section 206 proceedings and establishing hearing and settlement judge procedures. Pursuant to section 206 of the Federal Power Act (FPA), the FERC instituted proceedings because it found that ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential. The FERC stated that ISO-NE's Tariff lacks adequate transparency and challenge procedures with regard to the formula rates for ISO-NE Participating Transmission Owners, including Maine Electric Power Company, Inc. (MEPCO) and CMP. The FERC also found that the current Regional Network Service, or RNS and Local Network Service, or LNS, formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful as the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates. A settlement judge has been appointed and a settlement conference has convened. We are unable to predict the outcome of this proceeding at this time.

CMP Distribution Rate Stipulation and New Renewable Source Generation

On May 1, 2013, CMP submitted its required distribution rate request with the Maine Public Utilities Commission (MPUC). On July 3, 2014, after a fourteen month review process, CMP filed a rate stipulation agreement on the majority of the financial matters with the MPUC. The stipulation agreement was approved by the MPUC on August 25, 2014. The stipulation agreement also noted that certain rate design matters would be litigated, which the MPUC ruled on October 14, 2014.

The rate stipulation agreement provided for an annual CMP distribution tariff increase of 10.7% or \$24.3 million. The rate increase was based on a 9.45% ROE and 50% equity capital. CMP was authorized to implement a Rate Decoupling Mechanism (RDM) which protects CMP from variations in sales due to energy efficiency and weather. CMP also adjusted its storm costs recovery mechanism whereby it is allowed to collect in rates a storm allowance and to defer actual storm costs when such storm event costs exceed \$3.5 million. CMP and customers share storm costs that exceed a certain balance on a fifty-fifty basis, with CMP's exposure limited to \$3.0 million annually.

CMP has made a separate regulatory filing for a new customer billing system replacement. In accordance with the stipulation agreement, a new billing system is needed and CMP made its filing on February 27, 2015 to request a separate rate recovery mechanism. On October 20, 2015, the MPUC issued an order approving a stipulation agreement authorizing CMP to proceed with the customer billing system investment. The approved stipulation allows CMP to recover the system costs effective with its implementation, currently expected in mid-2017.

The rate stipulation does not have a predetermined rate term. CMP has the option to file for new distribution rates at its own discretion. The rate stipulation does not contain service quality targets or penalties. The rate stipulation also does not contain any earning sharing requirements.

Under Maine law 35-A M.R.S.A §§ 3210-C, 3210-D, the MPUC is authorized to conduct periodic

Notes to Consolidated Financial Statements

requests for proposals seeking long-term supplies of energy, capacity or Renewable Energy Certificates, or RECs, from qualifying resources. The MPUC is further authorized to order Maine Transmission and Distribution Utilities to enter into contracts with sellers selected from the MPUC's competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, on March 31, 2010, to purchase capacity and energy from Evergreen's 60 MW Rollins wind farm in Penobscot County, Maine. CMP's purchase obligations under the Rollins contract are approximately \$7 million per year. In accordance with subsequent MPUC orders, CMP periodically auctions the purchased Rollins energy to wholesale buyers in the New England regional market. Under applicable law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under M.R.S.A §3210-C and has tentatively accepted long-term proposals from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

Minimum Equity Requirements for Regulated Subsidiaries

CMP is subject to a minimum equity ratio requirement that is tied to the capital structure assumed in establishing revenue requirements. Pursuant to these requirements CMP must maintain a minimum equity ratio equal to the ratio in its currently effective rate plan or decision measured using a trailing 13-month average. On a monthly basis CMP must maintain a minimum equity ratio of no less than 300 basis points below the equity ratio used to set rates. The minimum equity ratio requirement has the effect of limiting the amount of dividends that may be paid and may, under certain circumstances, require that the parent contribute equity capital. CMP is prohibited by regulation from lending to unregulated affiliates. CMP has also agreed to minimum equity ratio requirements in certain short-term borrowing agreements. These requirements are lower than the regulatory requirements.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately \$459 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of other regulatory assets and other regulatory liabilities are shown in the tables below. They result from various regulatory orders that allow for the deferral and/or reconciliation of specific costs. Regulatory assets and regulatory liabilities are classified as current when recovery or refund in the coming year is allowed or required through a specific order or when the rates related to a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

Current and long-term regulatory assets at December 31, 2016 and 2015 consisted of:

December 31, (Thousands)	2016	2015
Current		
Storm costs	\$-	\$7,544

Notes to Consolidated Financial Statements

Transmission revenue reconciliation mechanism	12,049	4,136
Deferred meter replacement costs	2,548	2,216
Merger related	-	1,666
Stranded costs	-	2,808
Environmental remediation costs	1,240	2,616
Other	2,361	1,046
Total current regulatory assets	\$18,198	\$22,032
Long-term		
Federal tax depreciation normalization adjustment	11,920	10,349
Merger related	-	1,000
Storm costs	2,051	4,393
Unamortized losses on reacquired debt	722	1,021
Pension and other postretirement benefit costs	210,394	243,458
Unfunded future income taxes	230,851	225,166
Deferred meter replacement costs	31,543	34,077
Other	2,284	2,018
Total long-term regulatory assets	\$489,765	\$521,482

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs.

Pension and other postretirement benefits represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base.

Storm costs are allowed in rates based on an estimate of the routine costs of service restoration. CMP is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. CMP's total deferral, including carrying costs was \$2 million at December 31, 2016 and \$12 million at December 31, 2015.

Deferred meter replacement costs represent the deferral of the book value of retired meters which were replaced by advanced metering infrastructure meters. This amount is being amortized at the related existing depreciation amounts.

Unamortized losses on reacquired debt represent deferred losses on debt reacquisitions that will be recovered over the remaining original amortization period of the reacquired debt.

Unfunded future income taxes represent unrecovered federal and state income taxes primarily resulting from regulatory flow through accounting treatment. The income tax benefits or charges for certain plant related timing differences, such as removal costs, are immediately flowed through to, or collected from, customers. This amount is being amortized as the amounts related to temporary differences that give rise to the deferrals are recovered in rates.

Notes to Consolidated Financial Statements

Current and long-term regulatory liabilities at December 31, 2016 and 2015 consisted of:

December 31, (Thousands)	2016	2015
Current		
Accrued removal obligations	\$2,251	\$2,251
Transmission revenue reconciliation mechanism	4,764	5,490
Yankee DOE refund	23,938	5,234
Stranded cost	238	7,004
Unfunded future income taxes	-	10,104
Rate refund-FERC ROE proceeding	-	3,092
Revenue decoupling mechanism	4,507	10,143
Other	1,103	1,481
Total current regulatory liabilities	\$36,801	\$44,799
Long-term		
Environmental remediation costs	3,131	4,934
Rate refund-FERC ROE proceeding	21,738	21,039
Accrued removal obligations	78,286	71,188
Other	6,786	3,067
Total non-current regulatory liabilities	109,941	100,228
Deferred income taxes regulatory	149,232	165,119
Total long-term regulatory liabilities	\$259,173	\$265,347

Accrued removal obligations represent the differences between asset removal costs incurred and amounts collected in rates for those costs. The amortization period is dependent upon the asset removal costs of underlying assets and the life of the utility plant.

Other includes the cost of removal being amortized through rates and various items subject to reconciliation including variable rate debt, Medicare subsidy benefits and stray voltage collections.

Note 4. Goodwill

We do not amortize goodwill, but perform a goodwill impairment assessment at least annually as described in Note 1. Our step one impairment testing includes various assumptions, primarily the discount rate, which is based on an estimate of our marginal, weighted-average cost of capital, and forecasted cash flows. We test the reasonableness of the conclusions of our step one impairment testing using a range of discount rates and a range of assumptions for long-term cash flows. Our step zero qualitative assessment involves evaluating key events and circumstances that could affect the fair value of our reporting units, as well as other factors. Events and circumstances evaluated include: macroeconomic conditions, industry, regulatory and market considerations, cost factors and their effect on earnings and cash flows, overall financial performance as compared with projected results and actual results of relevant prior periods, other relevant entity-specific events, and events affecting a reporting unit.

We had no impairment of goodwill in 2016 and in 2015 as a result of our annual impairment assessment, which we performed as of October 1. For 2016 as a result of our step one testing and for 2015 as a result of our step zero qualitative analysis, no impairment was indicated within any of the ranges of assumptions analyzed. There were no events or circumstances subsequent to our annual impairment assessment for 2016 or for 2015 that required us to update the assessment.

The carrying amount of goodwill was \$325 million at both December 31, 2016 and 2015 with no accumulated impairment losses and no changes during 2016 and 2015.

Notes to Consolidated Financial Statements

Note 5. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2016 and 2015 consisted of:

Years Ended December 31,	2016	2015
(Thousands)		
Current		
Federal	\$52,923	\$(15,058)
State	13,206	21,898
Current taxes charged to expense	66,129	6,840
Deferred		
Federal	9,611	75,273
State	5,331	(5,075)
Deferred taxes charged to expense	14,942	70,198
Total Income Tax Expense	\$81,071	\$77,038

The differences between tax expense per the statements of income and tax expense at the 35% statutory federal tax rate for the years ended December 31, 2016 and 2015 consisted of:

Years Ended December 31,	2016	2015
(Thousands)		
Tax expense at federal statutory rate	\$76,033	\$67,018
Depreciation and amortization not normalized	(5,221)	(178)
Tax return and audit adjustments	(597)	(34)
State taxes, net of federal benefit	12,069	10,935
Other, net	(1,213)	(703)
Total Income Tax Expense	\$81,071	\$77,038

Income tax expense for the year ended December 31, 2016 was \$5.2 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, (net of federal benefit), and depreciation and amortization not normalized. This resulted in an effective tax rate of 37.4%. Income tax expense for the year ended December 31, 2015 was \$10 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, (net of federal benefit). This resulted in an effective tax rate of 40.2%.

Deferred tax assets and liabilities as of December 31, 2016 and 2015 consisted of:

December 31,	2016	2015
(Thousands)		
Noncurrent Deferred Income Tax Liabilities (Assets)		
Property related	\$721,444	\$685,724
Unfunded future income taxes	92,946	91,541
Employee benefits	3,768	14,957
Derivative assets	(3,365)	(4,567)
Other	(11,196)	(4,656)
Noncurrent Deferred Income Tax Liabilities	803,597	782,999
Add: Valuation allowance	5,725	8,988
Total Noncurrent Deferred Income Tax Liabilities	809,322	791,987
Less amounts classified as regulatory liabilities		
Noncurrent deferred income taxes	149,232	165,119
Noncurrent Deferred Income Tax Liabilities	\$660,090	\$626,868
Deferred tax assets	\$14,561	\$9,224
Deferred tax liabilities	823,883	801,211
Net Accumulated Deferred Income Tax Liabilities	\$809,322	\$791,987

Notes to Consolidated Financial Statements

CMP has \$8.5 million of federal and state research and development credits offset by \$5.7 million of valuation allowance.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2016, and 2015 consisted of:

Years Ended December 31, (Thousands)	2016	2015
Balance as of January 1	\$20,077	\$20,760
Increases for tax positions related to prior years	19,717	-
Reduction for tax positions related to settlements with taxing authorities	-	(683)
Balance as of December 31	\$39,794	\$20,077

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the consolidated financial statements. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized in the financial statements when it is more likely than not based on the technical merits that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2016 and as of December 31, 2015. If recognized, \$3 million of the total gross unrecognized tax benefits would affect the effective tax rate. Gross unrecognized tax benefits increased \$19.7 million in 2016 due to tax positions related to prior years.

On December 29, 2014, the Joint Committee on Taxation approved the examination of AGR and its subsidiaries, which includes members of the Central Maine Power Group, for the tax years 1998 through 2009. The results of these audits, net of reserves already provided, were immaterial. Maine state returns are closed through 2011.

Note 6. Long-term Debt

At December 31, 2016 and 2015, our long-term debt was:

As of December 31, (Thousands)		2016		2015	
	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds ^(a)	2019-2045	\$ 900,000	3.07%-5.70%	\$ 900,000	3.07%-5.70%
Senior unsecured notes	2025-2037	140,000	5.38%-6.40%	180,000	5.27%-6.40%
Chester: Promissory and Senior Notes ^(b)	2020	4,542	7.05%-10.48%	5,725	7.05%-10.48%
Obligations under capital leases	2017-2036	7,424		4,187	
Unamortized debt issuance costs and discount		(4,502)		(5,088)	
Total Debt		\$1,047,464		\$ 1,084,824	
Less: debt due within one year, included in current liabilities		5,154		41,312	
Total Non-current Debt		\$1,042,310		\$ 1,043,512	

(a) The first mortgages bonds are secured by a first mortgage lien on substantially all of Net Utility Plant In Service.

(b) Chester SVC Partnership notes are secured by the assets of this partnership.

Notes to Consolidated Financial Statements

At December 31, 2016, long-term debt, including sinking fund obligations and capital lease payments (in thousands) that will become due during the next five years are:

2017	2018	2019	2020	2021
\$5,154	\$2,022	\$152,042	\$1,937	\$150,299

We have no debt covenant requirements related to the maintenance of financial ratios in our long term debt agreements at December 31, 2016 and 2015.

Note 7. Bank Loans and Other Borrowings

CMP had no short-term debt outstanding at December 31, 2016 or December 31, 2015. CMP funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the "Virtual Money Pool Agreement"), a bi-lateral intercompany credit agreement with Avangrid (the "Bi-Lateral Intercompany Facility") and a bank provided credit facility to which CMP is a party (the "Avangrid Credit Facility"), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. CMP has a lending/borrowing limit of \$100 million under this agreement. There were no balances outstanding under this agreement as of December 31, 2016.

The Bi-Lateral Intercompany Facility provides for borrowing of up to \$500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There were no balances outstanding under this agreement as of December 31, 2016 and December 31, 2015, respectively.

On April 5, 2016, AGR and its investment-grade rate utility subsidiaries (NYSEG, RG&E, CMP, UI, CNG, SCG and BGC) entered into a revolving credit facility with a syndicate of banks, (the AGR Credit Facility), that provides for maximum borrowings of up to \$1.5 billion in the aggregate. Under the terms of the AGR Credit Facility, each joint borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit established by the banks. AGR's maximum sublimit is \$1 billion, NYSEG, RG&E, CMP and UI have maximum sublimits of \$250 million, CNG, and SCG have maximum sublimits of \$150 million and BGC has a maximum sublimit of \$25 million. Under the AGR Credit Facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 10.0 to 17.5 basis points. The maturity date for the AGR Credit Facility is April 5, 2021. CMP had not borrowed under this agreement as of December 31, 2016.

As a condition of closing on the AGR Credit facility, three existing credit facilities were terminated: i) the AGR revolving credit facility which provided for maximum borrowings of up to \$300 million and had a scheduled termination date in May 2019; ii) a joint utility revolving credit facility, to which NYSEG, RG&E and CMP were parties, which provided for borrowings of up to \$600 million and which had a scheduled termination date in July 2018; iii) the UIL credit facility, to which UIL, UI, SCG, CNG and BGC were parties, which provided for maximum borrowings of \$400 million and which had a scheduled termination date in November 2016.

Notes to Consolidated Financial Statements

Note 8. Redeemable Preferred Stock

We have redeemable preferred stock that contains a feature that could lead to potential redemption-triggering events that are not solely within our control.

At December 31, 2016 and 2015, our redeemable preferred stock was:

Series	Par Value per Share	Redempti on Price per Share	Shares Authorized and Outstanding⁽¹⁾	Amount (Thousands)	
				2016	2015
CMP, 6% Noncallable	\$100	-	5,713	\$571	\$571
Total				\$571	\$571

⁽¹⁾ At December 31, 2016 CMP had 2,300,000 shares of \$100 par value preferred stock authorized but unissued.

CMP Group owns 3,792 shares of the 5,713 shares outstanding.

Note 9. Commitments and Contingencies

CMP Transmission - ROE Complaint

On September 30, 2011, the Massachusetts Attorney General, Massachusetts Department of Public Utilities, Connecticut Public Utilities Regulatory Authority, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Vermont Department of Public Service, numerous New England consumer advocate agencies and transmission tariff customers collectively filed a complaint (Complaint I) with the FERC pursuant to sections 206 and 306 of the Federal Power Act. The filing parties seek an order from the FERC reducing the 11.14% base return on equity used in calculating formula rates for transmission service under the ISO-New England Open Access Transmission Tariff (OATT) to 9.2%. CMP and UI are New England Transmission Owners (NETOs) with assets and service rates that are governed by the OATT and will thereby be affected by any FERC order resulting from the filed complaint.

On June 19, 2014, the FERC issued its decision in Complaint I, establishing a methodology and setting an issue for a paper hearing. On October 16, 2014, FERC issued its final decision in the Complaint I setting the base ROE at 10.57%, and a maximum total ROE of 11.74% (base plus incentive ROE) for the October 2011 – December 2012 period as well as prospectively from October 16, 2014 and ordered the NETOs to file a refund report. On November 17, 2014 the NETOs filed a refund report.

On March 3, 2015, the FERC issued an order on requests for rehearing of its October 16, 2014 decision. The March order upheld the FERC's June 19, 2014 decision and further clarified that the 11.74% ROE cap will be applied on a project specific basis and not on a transmission owner's total average return. In June 2015 the NETOs filed an appeal in the U.S. Court of Appeals for the District of Columbia of the FERC's final order. The appeal is currently pending, and we cannot predict the outcome of this appeal.

On December 26, 2012, a second, ROE complaint (Complaint II) for a subsequent rate period was filed requesting the ROE be reduced to 8.7%. On June 19, 2014, FERC accepted Complaint II, established a 15-month refund effective date of December 27, 2012, and set the matter for hearing using the methodology established in the Complaint I.

On July 31, 2014, a third, ROE complaint (Complaint III) was filed for a subsequent rate period requesting the ROE be reduced to 8.84%. On November 24, 2014, FERC accepted the Complaint III, established a 15-month refund effective date of July 31, 2014, and set this matter consolidated with Complaint II for hearing in June 2015. Hearings were held in June 2015 on Complaints II and

Notes to Consolidated Financial Statements

III before a FERC Administrative Law Judge, relating to the refund periods and going forward period. On July 29, 2015, post-hearing briefs were filed by parties and on August 26, 2015 reply briefs were filed by parties. On July 13, 2015, the NETOs filed a petition for review of FERC's orders establishing hearing and consolidation procedures for Complaints II and III with the U.S. Court of Appeals. The FERC Administrative Law Judge issued an Initial Decision on March 22, 2016. The Initial Decision determined that: (1) for the 15-month refund period in Complaint II, the base ROE should be 9.59% and that the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and (2) for the 15 month refund period in Complaint III and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The Initial Decision is the Administrative Law Judge's recommendation to the FERC Commissioners. The FERC is expected to make its final decision in mid-2017.

CMP reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 final decision in Complaint I. The CMP total reserve associated with Complaints II and III is \$21.7 million as of December 31, 2016. If adopted as final, the impact of the Initial Decision would be an additional aggregate reserve for Complaints II and III of \$17.1 million, which is based upon currently available information for these proceedings. We cannot predict the outcome of the Complaint II and III proceedings.

On April 29, 2016, a fourth ROE complaint (Complaint IV) was filed for a rate period subsequent to prior complaints requesting the base ROE be 8.61% and ROE Cap be 11.24%. The NETOs filed a response to the Complaint IV on June 3, 2016. On September 20, 2016, FERC accepted the Complaint IV, established a 15-month refund effective date of April 29, 2016, and set the matter for hearing and settlement judge procedures. A range of possible outcomes is not able to be determined at this time due to the preliminary state of this matter. We cannot predict the outcome of the Complaint IV proceeding. Hearings will be held later this year with an expected Initial Decision from the Administrative Law Judge in 2017.

Yankee Nuclear Spent Fuel Disposal Claim

CMP has an ownership interest in Maine Yankee Atomic Power Company, Connecticut Yankee Atomic Power Company, and Yankee Atomic Electric Company, (the Yankee Companies), three New England single-unit decommissioned nuclear reactor sites. Every six years, pursuant to the statute of limitations, the Yankee Companies file a lawsuit to recover damages from the Department of Energy (DOE or Government) for breach of the Nuclear Spent Fuel Disposal Contract to remove Spent Nuclear Fuel (SNF) and Greater than Class C Waste (GTCC) as required by contract and the Nuclear Waste Policy Act beginning in 1998. The damages are the incremental costs for the Government's failure to take the spent nuclear fuel.

In 2012, the U.S. Court of Appeals issued a favorable decision in the Yankee Companies' claim for the first six year period (Phase I). Total damages awarded to the Yankee Companies were nearly \$160 million. The Yankee Companies won on all appellate points in the U.S. Court of Appeals for the Federal Circuit's unanimous decision. The Federal Appeals Court affirmed the September 2010 U.S. Court of Federal Claims award of \$39.7 million to Connecticut Yankee Atomic Power Company; affirmed the Court of Federal Claims award of \$81.7 million to Maine Yankee Atomic Power Company; and increased Yankee Atomic Electric Company's damages award from \$21.4 million to \$38.3 million. The Phase I damage award became final on December 4, 2012. The Yankee Companies received payment from DOE in January 2013. CMP's share of the award was approximately \$36.5 million which was credited back to customers.

In November 2013 the U.S. Court of Claims issued its decision in the Phase II case (the second 6 year period). The Trial Court decision awards the Yankee Companies a combined \$235.4 million (Connecticut Yankee \$126.3 million, Maine Yankee \$37.7 million, and Yankee Atomic \$73.3 million). The Phase II period covers January 1, 2002 through December 31, 2008 for Connecticut

Notes to Consolidated Financial Statements

Yankee and Yankee Atomic, and January 1, 2003 through December 31, 2008 for Maine Yankee. Maine Yankee's damage award was lower because it recovered a larger amount in the Phase I case (\$82 million) and its decommissioning was both less expensive and completed sooner than the other Yankee Companies. The damage awards flow through the Yankees to shareholders (including CMP and UI) to reduce retail customer charges. In January 2014 the government informed the Yankee Companies it would not appeal the Trial Court decision, as a result the Yankee Companies received full payment in April 2014. CMP's share of the award was approximately \$28.2 million which was credited back to customers.

In August 2013, the Yankees filed a third round of claims against the government seeking damages for the years 2009-2014 (Phase III). The Phase III trial was completed in July 2015 and the Court has issued its decision on March 25, 2016 awarding the Yankee Companies a combined \$76.8 million (Connecticut Yankee \$32.6 million, Maine Yankee \$24.6 million and Yankee Atomic \$19.6 million). The damage awards will potentially flow through the Yankee Companies to shareholders, including CMP, upon FERC approval, and will reduce retail customer charges or otherwise as specified by law. CMP will receive its proportionate share of the awards that flow through based on percentage ownership. On July 18, 2016, the notice of appeal period expired and the Phase III trial award became final. On October 14, 2016, the Yankee Companies received the Government's payment of the damage award of a combined \$41.6 million (Connecticut Yankee \$18.4 million, Maine Yankee \$3.6 million and Yankee Atomic \$19.6 million). In December 2016 CMP received its proportionate share of \$2.5 million of the Phase III damage awards, based on percentage ownership, and an additional \$21.5 million for SNF trust refund relating to excess funds of Maine Yankee unrelated to Phase III. All amounts will flow through to customers.

Power purchase contracts including nonutility generator

We recognized expense of approximately \$58 million for NUG power in 2016 and \$57 million in 2015. We estimate that our power purchases will total \$12 million in 2017, \$15 million in 2018, \$18 million in 2019, 2020 and 2021 and \$247 million thereafter.

Note 10. Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in our operations and facilities and may increase the cost of electric service.

Waste sites

The EPA and various state environmental agencies, as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at six waste sites. The six sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the six sites, five sites are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and two sites are also included on the National Priorities list. Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of \$1.4 million related to the six sites at December 31, 2016.

We have recorded an estimated liability of \$2.3 million at December 31, 2016, related to four additional sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties or are regulated under State Resource Conservation and Recovery Act (RCRA) program. It is reasonably possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate these sites ranges from \$2.7 million to \$8.9 million as of December 31, 2016. Factors affecting the estimated

Notes to Consolidated Financial Statements

remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Manufactured gas plants

We have a program to investigate and perform necessary remediation at our three sites where gas was manufactured in the past. All three sites are part of Maine's Voluntary Response Action Program and two are on the Maine's Uncontrolled Sites Program.

Our estimate for all costs related to investigation and remediation of the three sites range from \$0.3 million to \$1.2 million at December 31, 2016. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was \$0.7 million at December 31, 2016, and \$2.1, million at December 31, 2015. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis. We have received insurance settlements during the last two years, which we accounted for as reductions in our related regulatory asset.

Note 11. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet. For financial statement presentation, we offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

The financial instruments we hold or issue are not for trading or speculative purposes.

Cash flow hedging: Our fleet fuel hedges are designated as cash flow hedging instruments. We record changes in the fair value of the cash flow hedging instruments in other comprehensive income (OCI), to the extent they are considered effective, and reclassify those gains or losses into earnings in the same period or periods during which the hedged transactions affect earnings.

Our derivatives designated as hedging instruments, which are other commodity contracts (fleet fuel), had a fair value of \$(0.2) million as of December 31, 2016, and \$(0.9) million as of December 31, 2015, and are included in current liabilities.

Notes to Consolidated Financial Statements

The effect of hedging instruments on OCI and income was:

Year Ended December 31,	Gain (Loss) Recognized in OCI on Derivatives	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Gain(Loss) Reclassified from Accumulated OCI into Income
Derivatives in Cash Flow Hedging Relationships (Thousands)	Effective Portion	Effective Portion	
2016			
Interest rate contracts	\$-	Interest expense	\$(2,175)
Commodity contracts:			
Fleet Fuel	\$133	Other operating expenses	(638)
Total	\$133		\$(2,813)
2015			
Interest rate contracts	\$-	Interest expense	\$(2,222)
Commodity contracts:			
Fleet Fuel	\$(950)	Other operating expenses	(1,053)
Total	\$(950)		\$(3,275)

The amount in OCI related to previously settled interest rate hedging contracts, after tax and accumulated amortization, at December 31 is a net loss of \$8.0 million for 2016 and a net loss of \$10.1 million for 2015. For the year ended December 31, 2016, we recorded \$0.2 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately \$2.2 million of discontinued cash flow hedges in 2017.

At December 31, 2016, \$0.2 million in losses are reported in OCI because the forecasted transaction is considered to be probable. We expect that those losses in OCI will be reclassified into earnings within the next 12 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions. There was no ineffective portion of the hedge recognized during the year ended December 31, 2016.

Note 12. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to \$1,144 million and \$1,171 million as of December 31, 2016 and 2015, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2.

Notes to Consolidated Financial Statements

Assets and liabilities measured at fair value on a recurring basis

Description (Thousands)	Total	Fair Value Measurements at December 31, Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
2016				
Assets				
Noncurrent investments available for sale	\$698	\$698	\$-	\$-
Total	\$698	\$698	\$-	\$-
Liabilities				
Derivatives	\$164	\$-	\$-	\$164
Total	\$164	\$-	\$-	\$164
2015				
Assets				
Noncurrent investments available for sale	\$415	\$415	\$-	\$-
Total	\$415	\$415	\$-	\$-
Liabilities				
Derivatives	\$935	\$-	\$-	\$935
Total	\$935	\$-	\$-	\$935

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2016 and 2015. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

Valuation techniques: We measure the fair value of our noncurrent investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments primarily consist of money market funds.

We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in level 3.

Instruments measured at fair value on a recurring basis using significant unobservable inputs

Year ended December 31, (Thousands)	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	
	Derivatives, Net	
	2016	2015
Beginning balance	\$935	\$1,038
Total gain or loss for the period		
Included in earnings	(638)	(1,053)
Included in other comprehensive income	(133)	950
Ending balance	\$164	\$935

The amounts of realized and unrealized gain and loss included in earnings for the period (above) are reported in Operations and maintenance of the consolidated statements of income.

Notes to Consolidated Financial Statements

Note 13. Accumulated Other Comprehensive Loss

	Balance January 1, 2015	2015 Change	Balance December 31, 2015	2016 Change	Balance December 31, 2016
(Thousands)					
Amortization of pension cost for nonqualified plans, net of income tax expense of \$112 for 2015 and \$48 for 2016	\$(2,122)	\$163	\$(1,959)	\$75	\$(1,884)
Unrealized (loss) /gain on derivatives qualified as hedges:					
Unrealized (loss) during period on derivatives qualified as hedges, net of income tax (benefit) expense of (\$388) for 2015 and \$52 for 2016		(562)		81	
Reclassification adjustment for loss included in net income, net of income tax expense of \$430 for 2015 and of \$250 for 2016		623		388	
Reclassification adjustment for loss on settled cash flow treasury hedge, net of income tax expense of \$907 for 2015 and \$852 for 2016		1,315		1,323	
Net unrealized (loss) gain on derivatives qualified as hedges	\$(7,931)	\$1,376	\$(6,555)	\$1,792	\$(4,763)
Accumulated Other Comprehensive Loss	\$(10,053)	\$1,539	\$(8,514)	\$1,867	\$(6,647)

No Accumulated Other Comprehensive Loss is attributable to the noncontrolling interest for the above periods.

Note 14. Retirement Benefits

We have funded noncontributory defined benefit pension plans that cover all eligible employees. For most employees, generally those hired before 2002, the plans provide defined benefits based on years of service and final average salary. Employees hired in 2002 or later are covered under a cash balance plan or formula, where their benefits accumulate based on a percentage of annual salary and credited interest. During 2013 the company announced that we would freeze the benefits for all non-union employees covered under the cash balance plans effective December 31, 2013. CMP union employees covered under the cash balance plans ceased accruals as of December 31, 2014. Their earned balances would continue to accrue interest, but would no longer be increased by a percentage of earnings. In place of the pension benefit for these employees, they will receive a minimum contribution to their account under their respective company's defined contribution plan. There was no change to the defined benefit plans for employees covered under the plans that provide defined benefits based on years of service and final average salary.

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately \$3 million for both 2016 and 2015.

We also have other postretirement health care benefit plans covering substantially all of our employees. The health care plans are contributory with participants' contributions

Notes to Consolidated Financial Statements

adjusted annually.

Obligations and funded status:

	Pension Benefits		Postretirement Benefits	
	2016	2015	2016	2015
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	\$405,281	\$419,710	\$113,861	\$117,567
Service cost	7,846	7,711	712	835
Interest cost	16,267	15,620	4,523	4,331
Plan participants' contributions	-	-	528	399
Actuarial loss (gain)	(12,059)	(20,756)	(5,520)	(3,320)
Special termination benefits	-	824	-	-
Medicare subsidies received	-	-	48	-
Benefits paid	(20,812)	(17,828)	(7,173)	(5,950)
Benefit obligation at December 31	\$396,523	\$405,281	\$106,979	\$113,862
Change in plan assets				
Fair value of plan assets at January 1	\$256,948	\$254,164	\$35,635	\$38,787
Actual return on plan assets	15,773	(4,070)	2,117	(929)
Employer contributions	20,736	24,682	6,597	5,551
Withdrawal from VEBA	-	-	-	(2,223)
Employer and plan participants' contributions	-	-	528	399
Benefits paid	(20,812)	(17,828)	(8,784)	(5,950)
Medicare subsidies received	-	-	48	-
Fair value of plan assets at December 31	\$272,645	\$256,948	\$36,141	\$35,635
Funded status at December 31	\$(123,878)	\$(148,333)	\$(70,838)	\$(78,227)

Amounts recognized in the balance sheet	Pension Benefits		Postretirement Benefits	
December 31,	2016	2015	2016	2015
(Thousands)				
Noncurrent liabilities	\$(123,878)	\$(148,333)	\$(70,838)	\$(78,227)

We have determined that we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans.

Amounts recognized as regulatory assets or regulatory liabilities, consist of:

	Pension Benefits		Postretirement Benefits	
December 31,	2016	2015	2016	2015
(Thousands)				
Net loss	\$179,114	\$205,258	\$41,974	\$50,898
Prior service cost (credit)	\$7	\$16	\$(10,701)	\$(12,713)

Our accumulated benefit obligation for all defined benefit pension plans at December 31 was \$360 million for 2016 and \$363 million for 2015.

Our postretirement benefits were partially funded at December 31, 2016 and 2015.

The projected benefit obligation and accumulated benefit obligation exceeded the fair value of pension plan assets for our plans as of December 31, 2016 and 2015. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the relevant periods.

Notes to Consolidated Financial Statements

December 31,	2016	2015
(Thousands)		
Projected benefit obligation	\$396,523	\$405,281
Accumulated benefit obligation	\$359,747	\$362,643
Fair value of plan assets	\$272,645	\$256,948

Components of net periodic benefit cost and other amounts recognized in regulatory assets and regulatory liabilities:

Years ended December 31,	Pension Benefits 2016	2015	Postretirement Benefits 2016	2015
(Thousands)				
Net periodic benefit cost				
Service cost	\$7,846	\$7,710	\$712	\$835
Interest cost	16,267	15,621	4,523	4,331
Expected return on plan assets	(19,963)	(18,742)	(2,292)	(2,674)
Amortization of prior service cost (credit)	9	117	(2,013)	(2,049)
Special termination benefit charge	-	824	-	-
Amortization of net loss	18,274	20,744	3,579	3,656
Net periodic benefit cost	\$22,433	\$26,274	\$4,509	\$4,099
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss/(gain)	\$(7,870)	\$2,056	\$(5,345)	\$283
Amortization of net (loss)	(18,274)	(20,744)	(3,579)	(3,656)
Amortization of prior service (cost) credit	(9)	(117)	2,013	2,049
Total recognized in regulatory assets and regulatory liabilities	(26,153)	(18,805)	(6,911)	(1,324)
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	\$(3,720)	\$7,469	\$(2,402)	\$2,775

We include the net periodic benefit cost in other operating expenses. The net periodic benefit cost for postretirement benefits represents the amount expensed for providing health care benefits to retirees and their eligible dependents.

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2017

	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	\$15,918	\$2,833
Estimated prior service cost (credit)	\$6	\$(2,013)

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ending December 31, 2017.

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits 2016	2015	Postretirement Benefits 2016	2015
Discount rate	4.12%	4.10%	4.12%	4.10%
Rate of compensation increase	3.80%/4.20%	4.10%	N/A	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate by developing a yield curve derived from a portfolio of high grade non-callable bonds with above median yields that closely matches the duration of the expected cash flows of our benefit obligations.

Notes to Consolidated Financial Statements

Weighted-average assumptions used to determine net periodic benefit cost for Years ended December 31,	Pension Benefits		Postretirement Benefits	
	2016	2015	2016	2015
Discount rate	4.10%	3.80%	4.10%	3.80%
Expected long-term return on plan assets	7.40%	7.50%	-	-
Expected long-term return on plan assets - nontaxable trust	-	-	7.00%	7.50%
Expected long-term return on plan assets - taxable trust	-	-	4.50%	5.00%
Rate of compensation increase (Union/Non-Union)	3.80%/4.20%	4.30%	N/A	N/A

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses using the standard amortization methodology, under which amounts in excess of 10% of the greater of the projected benefit obligation or market-related value are amortized over the plan participants' average remaining service to retirement.

Assumed health care cost trend rates to determine benefit obligations at December 31,

	2016	2015
Health care cost trend rate (pre 65/post 65)	7.00%/9.00%	7.00%/9.00%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	4.50%	4.50%
Year that the rate reaches the ultimate trend rate	2026/2028	2026

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
(Thousands)		
Effect on total of service and interest cost	\$238	\$(199)
Effect on postretirement benefit obligation	\$5,773	\$(4,835)

Contributions: In accordance with our funding policy we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute \$15.7 million to our pension benefit plans in 2017.

Estimated future benefit payments: Our expected benefit payments and expected Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) subsidy receipts, which reflect expected future service, as appropriate, are:

Notes to Consolidated Financial Statements

	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
(Thousands)			
2017	\$17,680	\$7,017	\$151
2018	\$18,266	\$7,037	\$167
2019	\$19,064	\$7,083	\$184
2020	\$19,847	\$7,097	\$203
2021	\$20,656	\$7,040	\$223
2022 - 2026	\$116,582	\$26,869	\$1,426

Plan assets: Our pension benefits plan assets are held in a master trust providing for a single trustee/custodian, a uniform investment manager lineup, and an efficient, cost-effective means of allocating expenses and investment performance to each plan under the master trust. Our primary investment objective is to ensure that current and future benefit obligations are adequately funded and with volatility commensurate with our tolerance for risk. Preservation of capital and achievement of sufficient total return to fund accrued and future benefits obligations are of highest concern. Our primary means for achieving capital preservation is through diversification of the trust's investments while avoiding significant concentrations of risk in any one area of the securities markets. Within each asset group, further diversification is achieved through utilizing multiple asset managers and systematic allocation to various asset classes; providing broad exposure to different segments of the equity, fixed-income and alternative investment markets.

Networks' asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. We have established a target asset allocation policy within allowable ranges for our pension benefits plan assets within broad categories of asset classes made up of Return-Seeking and Liability-Hedging investments. Within the Return-Seeking category, we have targets of 35%-54% in equity securities and 3%-20% in equity alternative investments. The Liability-Hedging asset class has a target allocation percentage of 43%-45%. Return-Seeking investments generally consist of domestic, international, global, and emerging market equities invested in companies across all market capitalization ranges. Return-Seeking assets also include investments in real estate, absolute return, and strategic markets. Liability-Hedging investments generally consist of long-term corporate bonds, annuity contracts, long-term treasury STRIPS, and opportunistic fixed income investments. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair values of Networks' pension benefits plan assets at December 31, 2016 and 2015, by asset category are shown in the following table. CMP's share of the total consolidated assets is approximately 10% for both 2016 and 2015.

Notes to Consolidated Financial Statements

Fair Value Measurements at December 31, Using				
Asset Category (Thousands)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
2016				
Cash and cash equivalents	\$48,645	\$-	\$48,645	\$-
U.S. government securities	171,736	171,736	-	-
Common stocks	120,301	120,301	-	-
Registered investment companies	92,152	92,152	-	-
Corporate bonds	357,773		357,773	-
Preferred stocks	4,078	262	3,816	-
Common/collective trusts	1,193,500		371,831	821,669
Partnership/joint venture interests	-	-	-	-
Real estate investments	60,995	-	-	60,995
Other investments, principally annuity and fixed income	585,233	-	310,785	274,448
Total	\$2,634, 413	\$384,451	\$1,092,850	\$1,157,112
2015				
Cash and cash equivalents	\$57,797	\$3,561	\$54,236	\$-
U.S. government securities	171,024	171,024	-	-
Common stocks	661,639	661,639	-	-
Registered investment companies	81,308	81,308	-	-
Corporate bonds	323,900	-	323,900	-
Preferred stocks	4,926	295	4,631	-
Common/collective trusts	511,504	-	21,476	490,028
Partnership/joint venture interests	78,519	-	-	78,519
Real estate investments	88,865	-	-	88,865
Other investments, principally annuity and fixed income	643,001	324,733	-	318,268
Total	\$2,622,483	\$1,242,560	\$404,243	\$975,680

Valuation techniques: We value our pension benefits plan assets as follows:

- Cash and cash equivalents – Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities, Common stocks and registered investment companies - at the closing price reported in the active market in which the security is traded.
- Corporate bonds – based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks – at the closing price reported in the active market in which the individual investment is traded.
- Common/collective trusts and Partnership/joint ventures – using the Net Asset Value (NAV) provided by the administrator of the fund. The NAV is based on the value of the underlying assets owned by the fund, minus its liabilities, and then divided by the number of shares outstanding. The NAV is classified as Level 2 if the plan has the ability to redeem the investment with the investee at NAV per share at the measurement date. Redemption restrictions or adjustments to NAV based on unobservable inputs result in the fair value measurement being classified as Level 3 if those inputs are significant to the overall fair value measurement.
- Real estate investments – based on a discounted cash flow approach that includes the

Notes to Consolidated Financial Statements

projected future rental receipts, expenses and residual values because the highest and best use of the real estate from a market participant view is as rental property.

- Other investments, principally annuity and fixed income - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: based on yields currently available on comparable securities of issuers with similar credit ratings. Level 3: when quoted prices are not available for identical or similar instruments, under a discounted cash flows approach that maximizes observable inputs such as current yields of similar instruments but includes adjustments for certain risks that may not be observable such as credit and liquidity risks.

The reconciliation of changes in fair value of plan assets based on Level 3 inputs for the years ended December 31, 2016 and 2015, consisted of:

(Thousands)	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)				Total
	Common/ Collective Trusts	Partner- ship/ Joint Venture Interests	Real Estate Invest- ments	Other Invest- ments	
Balance, December 31, 2014	\$450,141	\$79,489	\$74,871	\$341,685	\$946,186
Actual return on plan assets:					
Relating to assets still held at the reporting date	(5,873)	18,518	10,235	(20,169)	2,711
Relating to assets sold during the year	(3,115)	(19,488)	-	904	(21,699)
Purchases, sales and settlements	48,875	-	3,759	(4,152)	48,482
Balance, December 31, 2015	\$490,028	\$78,519	\$88,865	\$318,268	\$975,680
Actual return on plan assets:					
Relating to assets held at the reporting date	50,752	-	1,710	(7,534)	44,928
Relating to assets sold during the year	5,542	(18,519)	478	686	(11,813)
Purchases, sales and settlements	275,347	(60,000)	(30,058)	(36,972)	148,317
Balance, December 31, 2016	\$821,669	\$-	\$60,995	\$274,448	\$1,157,112

Our postretirement benefits plan assets are held with trustees in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately twenty-five-percent of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes with the remainder being invested in arrangements subject to income taxes.

We have established a target asset allocation policy within allowable ranges for postretirement benefits plan assets of 46%-66% for equity securities, 30%-31% for fixed income, and 3%-23% for all other investment types. The target allocations within allowable ranges are further diversified into 27%-66% large cap domestic equities, 5% small cap domestic equities, 8% international developed market, and 6% emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at 24%-31%, global high yield fixed income at 4%, and international developed market debt at 3%. Other alternative investment targets are 6% for real estate, 6% for tangible assets, and 3%-11% for other funds. Systematic rebalancing within target ranges increases the probability that the annualized return on investments will be

Notes to Consolidated Financial Statements

enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The fair value of Networks' other postretirement benefits plan assets, by asset category, as of December 31, 2016 and 2015, by asset category are shown in the following table. CMP's share of the total consolidated assets was approximately 22% for both 2016 and 2015.

		Fair Value Measurements at December 31, Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Asset Category (Thousands)	Total			
2016				
Money market funds	\$5,786	\$3,582	\$2,204	\$-
Mutual funds, fixed	40,856	38,496	2,360	-
Government & corporate bonds	1,651	-	1,651	-
Mutual funds, equity	71,031	41,687	29,344	-
Common stocks	22,896	22,896	-	-
Mutual funds, other	17,868	9,961	7,907	-
Total assets measured at fair value	\$160,088	\$116,622	\$43,466	\$-
2015				
Money market funds	\$4,163	\$4,163	\$-	\$-
Mutual funds, fixed	35,438	35,438	-	-
Government & corporate bonds	1,703	-	1,703	-
Mutual funds, equity	45,679	45,679	-	-
Common stocks	22,939	22,793	-	146
Mutual funds, other	50,518	43,400	7,118	-
Total assets measured at fair value	\$160,440	\$151,473	\$8,821	\$146

Valuation techniques: We value our postretirement benefits plan assets as follows:

- Money market funds and Mutual funds – based upon quoted market prices in active markets, which represent the NAV of the shares held.
- Government bonds, and Common stocks - at the closing price reported in the active market in which the security is traded.
- Corporate bonds – based on yields currently available on comparable securities of issuers with similar credit ratings.

Pension and postretirement benefit plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2016 and 2015.

Note 15. Subsequent events

The company has performed a review of subsequent events through March 31, 2017, which is the date these financial statements were available to be issued, and no subsequent events have occurred from January 1, 2017 through such date.