

Avangrid Networks, Inc.
Consolidated Financial Statements
For the Years Ended December 31, 2015 and 2014

Avangrid Networks, Inc.

Index

Page(s)

Management’s Report on Internal Control Over Financial Reporting

Consolidated Financial Statements for the Years Ended December 31, 2015 and 2014

Reports 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 – 54

Management's Report on Internal Control Over Financial Reporting

Avangrid Networks, Inc.'s (we, us, our) internal control over financial reporting is a process affected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the preparation of reliable financial statements in accordance with accounting principles generally accepted in the United States of America. An entity's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and those charged with governance; and (3) provide reasonable assurance regarding prevention, or timely detection and correction of unauthorized acquisition, use, or disposition of the entity's assets that could have a material effect on the financial statements.

Management is responsible for establishing and maintaining effective internal control over financial reporting. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2015, based on the framework set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework* (1992). Based on that assessment, management concluded that, as of December 31, 2015, our internal control over financial reporting is effective based on the criteria established in *Internal Control—Integrated Framework* (1992). The effectiveness of our internal control over financial reporting as of December 31, 2015, has been audited by Ernst & Young, LLP an independent public accounting firm, as stated in their report which appears herein.

Avangrid Networks, Inc.
May 3, 2016



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Report of Independent Auditors

To the Stockholder and Board of Directors
Avangrid Networks, Inc.

Report on Financial Statements

We have audited the accompanying consolidated financial statements of Avangrid Networks, Inc. which comprise the consolidated balance sheets as of December 31, 2015 and 2014, 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. 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 Avangrid Networks, Inc. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

Report on Internal Control Over Financial Reporting

We also have examined, in accordance with attestation standards established by the American Institute of Certified Public Accountants, Avangrid Networks, Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated May 3, 2016 expressed an unqualified opinion thereon.

Ernst & Young LLP

May 3, 2016



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Independent Auditor's Report on Internal Control Over Financial Reporting

To the Stockholder and Board of Directors
Avangrid Networks, Inc.

We have examined Avangrid Networks, Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). Avangrid Networks, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assertion about the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on Avangrid Networks, Inc.'s internal control over financial reporting based on our examination.

We conducted our examination in accordance with attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the examination to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our examination included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our examination also included performing such other procedures as we considered necessary in the circumstances. We believe that our examination provides a reasonable basis for our opinion.

An entity's internal control over financial reporting is a process effected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the preparation of reliable financial statements in accordance with accounting principles generally accepted in the United States of America. An entity's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and those charged with governance; and (3) provide reasonable assurance regarding prevention, or timely detection and correction of unauthorized acquisition, use, or disposition of the entity's assets that could have a material effect on the financial statements.



Because of its inherent limitations, internal control over financial reporting may not prevent or detect and correct misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Avangrid Networks, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheets as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the years then ended of Avangrid Networks, Inc. and our report dated May 3, 2016 expressed an unqualified opinion thereon.

Ernst & Young LLP

May 3, 2016

Avangrid Networks, Inc.
Consolidated Statements of Income

Year ended December 31,	2015	2014
(Thousands)		
Operating Revenues		
Electricity	\$2,749,142	\$2,730,339
Natural gas	600,678	666,593
Total Operating Revenues	3,349,820	3,396,932
Operating Expenses		
Electricity purchased and fuel used in generation	583,387	772,398
Natural gas purchased	203,422	283,598
Operations and maintenance	1,336,251	1,182,863
Depreciation and amortization	322,189	274,770
Other taxes	306,400	267,537
Total Operating Expenses	2,751,649	2,781,166
Operating Income	598,171	615,766
Other (Income)	(51,596)	(51,164)
Other Deductions	10,345	9,270
Interest Charges, Net	224,373	197,796
Income Before Income Tax	415,049	459,864
Income Tax Expense	172,559	172,378
Net Income	242,490	287,486
Less:		
Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests	34	34
Net Income Attributable to Other Noncontrolling Interests	353	483
Net Income Attributable to Avangrid Networks, Inc.	\$242,103	\$286,969

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

Avangrid Networks, Inc.
Consolidated Statements of Comprehensive Income

Year ended December 31,	2015	2014
(Thousands)		
Net Income	\$242,490	\$287,486
Other Comprehensive Income, Net of Tax		
Net unrealized holding gain on investments	18	17
Amortization of pension for nonqualified plans	3,123	(3,113)
Unrealized loss on derivatives qualified as hedges:		
Unrealized loss during period on derivatives qualified as hedges	(1,617)	(2,170)
Reclassification adjustment for loss included in net income	1,991	505
Reclassification adjustment for loss on settled cash flow treasury hedges	5,178	5,362
Net unrealized gain on derivatives qualified as hedges, Net of Tax	5,552	3,697
Other Comprehensive Income	8,693	601
Comprehensive Income	251,183	288,087
Less:		
Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests	34	34
Comprehensive Income Attributable to Other Noncontrolling Interests	353	483
Comprehensive Income Attributable to Avangrid Networks, Inc.	\$250,796	\$287,570

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

**Avangrid Networks, Inc.
Consolidated Balance Sheets**

December 31,	2015	2014
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	\$9,992	\$13,713
Accounts receivable and unbilled revenues, net	507,428	559,393
Accounts receivable from affiliates	32,474	17,479
Notes receivable from affiliates	4,990	-
Fuel and natural gas in storage	19,375	43,003
Materials and supplies	41,758	52,525
Broker margin accounts	34,766	56,817
Prepaid property taxes	84,739	76,968
Prepayments and other current assets	115,256	73,666
Regulatory assets	125,617	79,629
Total Current Assets	976,395	973,193
Property, plant and equipment	11,702,706	11,001,112
Less accumulated depreciation	3,734,015	3,491,108
Net Property, Plant and Equipment in Service	7,968,691	7,510,004
Construction work in progress	810,836	867,227
Total Property, Plant and Equipment	8,779,527	8,377,231
Other Property and Investments	34,326	52,841
Regulatory and Other Assets		
Regulatory assets	2,304,862	2,399,135
Goodwill	979,603	979,603
Other	8,621	18,278
Total Regulatory and Other Assets	3,293,086	3,397,016
Total Assets	\$13,083,334	\$12,800,281

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

**Avangrid Networks, Inc.
Consolidated Balance Sheets**

December 31,	2015	2014
(Thousands, except shares)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	\$181,602	\$134,415
Notes payable to affiliates	547,126	793,667
Accounts payable and accrued liabilities	414,463	368,793
Accounts payable to affiliates	5,130	17,842
Interest accrued	40,747	38,398
Taxes accrued	9,451	5,036
Derivative liabilities	1,919	27,438
Environmental remediation costs	35,144	35,964
Other current liabilities	171,910	167,633
Regulatory liabilities	110,362	164,560
Total Current Liabilities	1,517,854	1,753,746
Regulatory and Other Liabilities		
Regulatory liabilities	1,314,285	1,228,839
Deferred income taxes regulatory	384,751	433,093
Other Non-current Liabilities		
Deferred income taxes	1,661,669	1,583,648
Nuclear plant obligations	122,258	122,238
Pension and other postretirement benefits	743,962	744,363
Environmental remediation costs	276,969	284,015
Other	212,839	189,618
Total Regulatory and Other Liabilities	4,716,733	4,585,814
Long-term Debt	2,553,486	2,359,623
Total Liabilities	8,788,073	8,699,183
Commitments and Contingencies		
Preferred Stock of Subsidiary		
Redeemable preferred stock, noncontrolling interest	192	192
Avangrid Networks, Inc. Common Stock Equity		
Common stock (\$.01 par value, 100 shares authorized and outstanding at December 31, 2015 and 2014)	-	-
Capital in excess of par value	3,078,759	3,078,759
Retained earnings	1,267,494	1,084,541
Accumulated other comprehensive loss	(61,021)	(69,714)
Total Avangrid Networks, Inc. Common Stock Equity	4,285,232	4,093,586
Other Noncontrolling Interests	9,837	7,320
Total Equity	4,295,069	4,100,906
Total Liabilities and Equity	\$13,083,334	\$12,800,281

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

Avangrid Networks, Inc.
Consolidated Statements of Cash Flows

Year Ended December 31,	2015	2014
(Thousands)		
Cash Flow from Operating Activities		
Net income	\$242,490	\$287,486
Adjustments to reconcile net income to net cash provided by (used in) operating activities		
Depreciation and amortization	322,189	274,770
Impairment of non-current assets	6,000	-
Amortization of regulatory and other assets and liabilities	101,103	(38,054)
Carrying cost of regulatory assets and liabilities	41,109	35,346
Deferred income taxes and investment tax credits, net	53,988	117,302
Pension cost	111,630	46,886
Accretion expenses	1,054	2,046
Changes in current operating assets and liabilities		
Decrease in accounts receivable and unbilled revenues	36,970	26,701
Decrease (increase) in inventories	22,994	(11,472)
Increase in other assets, net	(128,423)	(80,944)
Increase (decrease) in accounts payable	93,383	(11,065)
(Decrease) in other liabilities	(171,382)	(179,612)
Increase (decrease) in accrued taxes	4,415	(43,654)
Changes in regulatory assets/liabilities	46,162	172,875
Net Cash Provided by Operating Activities	783,682	598,611
Cash Flow from Investing Activities		
Capital expenditures	(749,539)	(917,632)
Contribution in aid of construction	38,465	43,034
Government grants	16,479	3,791
Proceeds from sale of subsidiaries	3,047	-
Proceeds from disposals of property, plant and equipment	-	5,303
(Lending)/Proceeds from notes receivable with affiliates	(4,990)	8,198
Other current and noncurrent investments	(2,659)	5,177
Net Cash (Used in) Investing Activities	(699,197)	(852,129)
Cash Flow from Financing Activities		
Long-term note issuances	350,000	-
Long-term note repayments	(131,726)	(33,758)
(Repayments)/proceeds of short-term debt	(246,541)	484,073
Repayment of capital leases	(2,953)	-
Dividends paid on common and preferred stock	(59,150)	(200,034)
Capital contribution from noncontrolling interest	2,164	3,809
Net Cash (Used in)/ Provided by Financing Activities	(88,206)	254,090
Net (Decrease)/Increase in Cash and Cash Equivalents	(3,721)	572
Cash and Cash Equivalents, Beginning of Year	13,713	13,141
Cash and Cash Equivalents, End of Year	\$9,992	\$13,713

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

Avangrid Networks, Inc.
Consolidated Statements of Changes in Equity

	Avangrid Networks, Inc. Stockholder							
	Common Stock Outstanding \$.01 Par Value		Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stock Equity	Other Noncontrolling Interests	Total
(Thousands, except share amounts)	Shares	Amount						
Balance, January 1, 2014	100	-	\$3,078,759	\$997,572	\$(70,315)	\$4,006,016	\$3,028	\$4,009,044
Net income*				286,969		286,969	483	287,452
Other comprehensive income, net of tax					601	601		601
Comprehensive income*								288,053
Capital contribution from noncontrolling interest							3,809	3,809
Cash dividends paid common stock				(200,000)		(200,000)		(200,000)
Balance, December 31, 2014	100	-	3,078,759	1,084,541	(69,714)	4,093,586	7,320	4,100,906
Net income*				242,103		242,103	353	242,456
Other comprehensive income, net of tax					8,693	8,693		8,693
Comprehensive income*								251,149
Capital contribution from noncontrolling interest							2,164	2,164
Cash dividends paid common stock				(59,150)		(59,150)		(59,150)
Balance, December 31, 2015	100	-	\$3,078,759	\$1,267,494	\$(61,021)	\$4,285,232	\$9,837	\$4,295,069

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

*Amounts do not include Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests of \$34 for 2014 and 2015.

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Background: Avangrid Networks, Inc. (Networks, the company, we, our, us) formerly Iberdrola USA Networks, is a public utility holding company operating under the Public Utility Holding Company Act of 2005. Networks is a wholly-owned subsidiary of AVANGRID, Inc. (AGR), formerly Iberdrola USA, Inc. which is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain. We are a super-regional energy services and delivery company with operations in New York and Maine. Our wholly-owned subsidiaries, and their principal operating companies, include: CMP Group, Inc. (CMP Group) – Central Maine Power Company (CMP), and RGS Energy Group, Inc. (RGS) – New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RGE).

Networks was formed on November 20, 2013, when AGR was reorganized to become the parent company of Networks and Avangrid Renewables Holding, Inc. (ARHI), formerly Iberdrola Renewables Holdings, Inc., another subsidiary of AGR. AGR transferred its investments in CMP Group and RGS to Networks at the time of the reorganization, as well as Iberdrola USA Management Corporation, a company providing management services for the utilities. Also transferred to Networks was Iberdrola USA Enterprises, a holding company that owns Maine Natural Gas.

Accounts receivable: Accounts receivable at December 31 include unbilled revenues of \$133 million for 2015 and \$142 million for 2014, and are shown net of an allowance for doubtful accounts at December 31 of \$55 million for 2015 and \$52 million for 2014. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was \$43 million in 2015 and \$41 million in 2014.

Unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, including current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimated amount 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 for each service region. Each month the operating companies review their allowance for doubtful accounts and past due accounts by age. When an operating company believes that a receivable will not be recovered, it charges off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently 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 of a utility company becomes delinquent in making payments, that company's state regulatory commission requires it 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, the utility company 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 \$35 million for 2015 and 2014. DPA receivable balances at December 31 were \$62 million for 2015 and \$78 million for 2014.

Notes to Consolidated Financial Statements

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 and depreciate the capitalized cost 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 \$24 million for 2015 and \$39 million for 2014. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of: asbestos, PCB-contaminated equipment, gas pipeline and cast iron gas mains.

The following table reconciles the beginning and ending aggregate carrying amount of the ARO for the years ended December 31, 2015 and 2014.

Year ended December 31,	2015	2014
(Thousands)		
ARO, beginning of year	\$38,699	\$32,080
Liabilities settled during the year	(15,711)	(1,262)
Accretion expense	1,054	2,046
Revisions in estimated cash flows	-	5,835
ARO, end of year	\$24,042	\$38,699

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 hydroelectric dams due to structural inadequacy or for decommissioning; the removal of property upon termination of an easement, right-of-way or franchise; and costs for abandonment of certain types of gas mains.

Accrued removal obligations: Our regulated utilities 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.

Supplemental Disclosure of Cash Flows Information	2015	2014
(Thousands)		
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	\$126,846	\$121,379
Income taxes paid, net	\$140,682	\$138,691

Interest capitalized was \$12.3 million in 2015 and \$10.5 million in 2014.

Notes to Consolidated Financial Statements

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, in service at each operating company. Our depreciation accruals were equivalent to 2.6% of average depreciable property for 2015 and 2014. We amortize our capitalized software cost, which is included in common plant, using the straight line method, based on useful lives of 5 to 10 years. Depreciation expense was \$299 million in 2015 and \$261 million in 2014. Amortization of capitalized software was \$23 million in 2015 and \$14 million in 2014.

We charge repairs and minor replacements to operations 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.

Plant	Estimated useful life range (years)	December 31, 2015	December 31, 2014
(thousands)			
Electric	37-63	8,910,379	8,624,981
Natural Gas	23-61	1,761,865	1,722,817
Common	9-36	1,030,462	653,314
Total Property, Plant and Equipment		\$11,702,706	\$11,001,112

Electric and Natural gas plant includes capital leases of \$64 million in 2015 and \$42 million in 2014. Accumulated depreciation related to these leases was \$41 million in 2015 and \$38 million in 2014.

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 noncontrolling 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 (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

Notes to Consolidated Financial Statements

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 fuel and gas in storage and materials and supplies. We own natural gas that is stored in third-party owned underground storage facilities. This gas is recorded as inventory. Injections of inventory into storage are priced at the market purchase cost at the time of injection, and withdrawals of working gas from storage are priced at the weighted-average cost in storage.

We continuously monitor the weighted-average cost of gas value to ensure it remains at, or below market value. Inventories to support gas operations are reported on the balance sheet within "Fuel and natural gas in storage."

We also have materials and supplies inventories that are used for construction of new facilities and repairs of existing facilities. These inventories are carried and withdrawn using the weighted average method and reported on the balance sheet within "Materials and supplies."

Inventory items are combined for the cash flow statement presentation purposes.

Government grants: We account for government grants related to depreciable assets in the same way as we account for contributions in aid of construction, 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.

New accounting standards adopted: We have adopted new accounting standards issued by the Financial Accounting Standards Board (FASB) as 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.

Presentation of an Unrecognized Tax Benefit: In July 2013 the FASB issued guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss (NOL) carryforward, a similar tax loss, or a tax credit carryforward exists. An unrecognized tax benefit, or a portion of an unrecognized tax benefit, is to be presented as a reduction to a deferred tax asset for an NOL carryforward, a similar tax loss, or a tax credit carryforward, with certain exceptions. The unrecognized tax benefit is to be presented as a liability and should not be combined with deferred tax assets to the extent that an NOL carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position or the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose. We adopted the amendments effective January 1, 2015. Our adoption of the amendments did not materially affect our results of operation, financial position or cash flows.

Discontinued Operations and Disposals of Components of an Entity: The FASB issued an amendment in April 2014 that changed the requirements for the reporting of discontinued operations. The new definition of discontinued operations limits reporting to disposals of components that represent strategic shifts that have, or will have, a major effect on an entity's operations and financial results. The amendments are effective for public business entities for annual periods beginning on or after December 15, 2014, and interim periods within those years. Our adoption of the amendment did not affect our results of operation, financial position or cash flows.

Notes to Consolidated Financial Statements

Fair Value Measurement Disclosures for Certain Investments: The FASB issued amendments in May 2015 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. We do not expect our adoption of the amendments to affect our results of operation, financial position, or cash flows.

Simplifying the Presentation of Debt Issuance Costs: The FASB issued an amendment in April 2015 that is intended to simplify the presentation of debt issuance costs. Instead of presenting debt issuance costs as a deferred charge (that is, as an asset), the amendments require debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with the presentation for debt discounts. The amendment is effective for public entities for financial statements issued for fiscal years beginning after December 15, 2015, and for interim periods within those fiscal years. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. Accordingly, we reclassified the debt issuance costs from other noncurrent assets to noncurrent debt on our December 31, 2014 consolidated balance sheet, which decreased total assets, noncurrent debt and total liabilities by \$27 million.

Application of the Normal Purchases and Normal Sales Scope Exception: The FASB issued amendments in August 2015 to specify that the use of locational marginal pricing by an independent system operator (ISO) does not constitute net settlement of a contract for the purchase or sale of electricity on a forward basis that necessitates transmission through, or delivery to a location within, a nodal energy market, even when legal title to the associated electricity is conveyed to the ISO during transmission. As a result, the use of locational marginal pricing by the ISO does not cause that contract to fail to meet the physical delivery criterion of the normal purchases and normal sales (NPNS) scope exception. If the physical delivery criterion is met, along with all of the other criteria of the NPNS scope exception, an entity may elect to designate that contract as a normal purchase or normal sale. The amendments were effective upon issuance of the accounting standards update, which was August 10, 2015, and require prospective application. Our adoption of the amendments did not materially affect our results of operation, financial position or cash flows.

Balance Sheet Classification of Deferred Taxes: The FASB issued an amendment in November 2015 that is intended to simplify the presentation of deferred income taxes by requiring entities that present a classified statement of financial position to classify deferred tax liabilities and assets as noncurrent in their balance sheet. This aligns the presentation of deferred income tax liabilities and assets with International Financial Reporting Standards. The amendments do not affect the current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount. The amendments are effective for public entities for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. As permitted, we have early adopted the amendments as of the beginning of the fourth quarter of 2015, and have elected retrospective

Notes to Consolidated Financial Statements

application to all periods presented in order to simplify the presentation in our balance sheet. Accordingly, we reclassified the current deferred taxes to noncurrent on our December 31, 2014 consolidated balance sheet, which decreased current assets and noncurrent deferred tax liabilities by \$76 million due to right of offset.

New accounting standards issued but not yet adopted: New accounting standards issued by the FASB that we have not yet adopted in these financial statements are as explained below.

Revenue from Contracts with Customers: In May 2014 the FASB issued an amendment related to the recognition of revenue from contracts with customers and required disclosures. 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 standard is effective for public entities 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 effective date of the 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. In March 2016 the FASB issued an accounting standards update that amends and clarifies the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, with the same deferred effective date. We are currently evaluating how our adoption of the amendment will affect our results of operation, financial position, and cash flows.

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, and thus many stakeholders considered that the guidance was unnecessarily complex. 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 do not expect our adoption of the amendments to affect our results of operation, financial position or cash flows.

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 those 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

Notes to Consolidated Financial Statements

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. The new guidance can be early adopted for financial statements of annual or interim periods that have not yet been issued or made available for issuance. We do not expect our adoption of the guidance to materially affect our results of operation, financial position or cash flows.

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 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 current GAAP. Lessor accounting will remain substantially the same as current GAAP, but with some targeted improvements intended 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 expect our adoption of the new guidance will materially affect our results of operation and financial position.

Derivative contract novations: The FASB issued amendments in March 2016 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 do not expect our adoption will materially affect our results of operation, financial position, and cash flows.

Notes to Consolidated Financial Statements

Other (Income) and Other Deductions:

Year Ended December 31,	2015	2014
(Thousands)		
Interest and dividend income	\$(542)	\$(1,458)
Allowance for funds used during construction	(20,596)	(17,495)
Carrying costs on regulatory assets	(28,088)	(28,787)
Gain on sale of property	(2,014)	(3,204)
Miscellaneous	(356)	(220)
Total other (income)	\$(51,596)	\$(51,164)
Losses from equity investments	-	\$5,699
Asset Impairment	\$6,000	-
Civic donations	1,939	2,011
Miscellaneous	2,406	1,560
Total other deductions	\$10,345	\$9,270

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

Reclassifications: Certain amounts have been reclassified in our consolidated statements of cash flows to conform to the 2015 presentation which have not affected the operating, investing, and financing activity sections. Additionally, certain amounts have been reclassified in the consolidated statement of income and consolidated balance sheet to conform to the 2015 presentation as follows:

- Operations and maintenance expenses have been combined into Operations and maintenance in the consolidated statement of income for the year ended December 31, 2014.
- Non-current regulatory assets and liabilities items have been combined into Regulatory assets and Regulatory liabilities, respectively, in the consolidated balance sheet as of December 31, 2014.
- Accounts payable for electricity and natural gas purchased have been combined into Accounts payable and accrued liabilities in the consolidated balance sheet as of December 31, 2014.
- Current and non-current liabilities amounting pertaining to the Rate refund – FERC ROE proceeding of \$12 million and \$23 million, respectively, have been reclassified to current and non-current regulatory liabilities in the consolidated balance sheet as of December 31, 2014.
- Prepaid property taxes were reclassified out of Prepayments and other current assets in the consolidated balance sheet as of December 31, 2014.
- Utility plant line items for Electricity, Natural gas and Common have been combined into Property, plant and equipment in the consolidated balance sheet as of December 31, 2014.

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

Notes to Consolidated Financial Statements

Pursuant to the requirements concerning accounting for regulated operations our utilities capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas 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. Our operating utilities 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 borrow from AGR, through intercompany revolving credit agreements. For NYSEG, RGE and CMP, the intercompany revolving credit agreements provide access to supplemental liquidity. Other Networks subsidiaries do not have third party borrowing arrangements and rely on AGR as their primary source of financing. Networks incurred financing costs from AGR of \$3 million in 2015 and \$4 million in 2014 recorded as interest expense. See Note 7 for further detail on the credit facility with AGR.

Networks, including its subsidiaries, provides various administrative and other services to AGR. The costs charged to the affiliates are based upon service agreements which include allocation methodologies and vary depending on the type of service provided. Management believes such allocations are reasonable. The cost for services provided by Networks to AGR was less than \$1 million for 2015 and 2014. Networks received charges from Iberdrola for work on the unified SAP project of \$1.4 million in 2015 and \$4.7 million in 2014. Networks' subsidiaries received services from Iberdrola Engineering Products (IEP) related to capital projects of \$2.5 million for 2015 and \$13.6 million for 2014. Networks contributed amounts to fund IEP's direct costs associated with these engineering projects.

The balance in accounts payable to affiliates of \$5 million at December 31, 2015 and \$18 million at December 31, 2014 is mostly associated to IEP for capital projects and other miscellaneous affiliate costs, as described above.

Networks incurs a corporate overhead charge from its ultimate parent, Iberdrola. The total amount charged to Networks for management services provided by Iberdrola was approximately \$16.6 million for 2015 and \$11.2 million for 2014. In 2015, the process was changed whereby Networks receives the charge for all of AGR and passes through ARHI's share on to them. The total amount charged to ARHI in 2015 for these management services was approximately \$31 million (netted against expense for a zero impact to the statement of net income).

The balance in accounts receivable from affiliates of \$32 million at December 31, 2015 is mostly associated to ARHI and \$17 million at December 31, 2014 is mostly associated to IEP related to payroll services and the funding of their payroll during the year.

AGR has reciprocal current account agreements with many of its unregulated subsidiaries, including the nonregulated subsidiaries of Networks, which do not have their own bank accounts. This arrangement creates a net receivable or payable position for Networks, with the underlying balance in the form of a note, subject to an interest rate charge for the borrower. The Networks balance in notes receivable from affiliates at December 31, 2015 is of approximately \$5 million. The lending rate as of December 31, 2015 is 1.30%.

Included in the income taxes paid, \$133 million was paid to AGR under the tax sharing agreement.

Notes to Consolidated Financial Statements

AGR has provided a guarantee on behalf of RGE in the amount of \$123 million related to RGE's nuclear plant obligation on the balance sheet. This is a liability that RGE may have to ultimately pay to the DOE related to spent nuclear fuel from the Ginna Nuclear Power Plant (formerly owned by RGE). AGR on behalf of Maine Natural Gas, a 100% owned subsidiary of Networks, also guarantees approximately \$20 million toward natural gas purchases.

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.

NYSEG and RGE enter into power purchase and sales transactions with the New York Independent System Operator (NYISO). When NYSEG and RGE sell electricity from owned generation to the NYISO, and subsequently repurchase electricity from the NYISO to serve their customers, they record the transactions on a net basis in their statements of income. NYSEG and RGE net their purchase and sale transactions with the NYISO on an hourly basis.

NYSEG's and RGE's electric and natural gas rate plans and 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, our regulated utilities 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. Networks is treated as a separate member and calculates its consolidated income tax expense or benefit by combining the current and deferred income tax expense or benefit of each of its subsidiaries and of Networks holding company, which is treated as a separate member. Each member settles its current tax liability or benefit each year directly with AGR pursuant to a tax sharing agreement between AGR and its members.

The aggregate amount of the intercompany income tax receivable balance due from AGR is \$90.7 million and \$69.0 million at December 31, 2015 and December 31, 2014, 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.

Notes to Consolidated Financial Statements

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.

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. Uncertain tax positions have been classified as non-current unless expected to be paid within one year. 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 operations.

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 U.S. GAAP 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) fair value measurement; and (9) earnings sharing mechanism (ESM); (10) environmental remediation liabilities; (11) pension and Other Postretirement Employee Benefit (OPEB) and (12) 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 54% of the company's employees are covered by a collective bargaining agreement. None of the union contract agreements will expire within the coming year.

Notes to Consolidated Financial Statements

Note 2. Industry Regulation

Electricity and Natural Gas Distribution

The Maine distribution rate stipulation, the Maine transmission Federal Energy Regulatory Commission (FERC) Return on Equity (ROE) case, the New York rate plans, Reforming Energy Vision (REV), and the New York Transmission Company (New York Transco) filings are some of the most important specific regulatory processes that affect Networks.

The revenues of Networks companies are essentially regulated, being based on tariffs established in accordance with administrative procedures set by the various regulatory bodies. The tariffs applied to regulated activities in the U.S. are approved by the regulatory commissions of the different states and are based on the cost of providing service. The revenues of each regulated utility are set to be sufficient to cover all its operating costs, including energy costs, finance costs, and the costs of equity, the last of which reflect our capital ratio and a reasonable ROE.

Energy costs that are set on the New York and New England wholesale markets are passed on to consumers. The difference between energy costs that are budgeted and those that are actually incurred by the utilities is offset by applying compensation procedures that result in either immediate or deferred tariff adjustments. These procedures apply to other costs, which are in most cases exceptional, such as the effects of extreme weather conditions, environmental factors, regulatory and accounting changes, and treatment of vulnerable customers, that are offset in the tariff process. Any New York revenues that allow a utility to exceed target returns, usually the result of better than expected cost efficiency, are generally shared between the utility and its customers, resulting in future tariff reductions.

Each of the four Networks' New York and Maine supply companies must comply with regulatory procedures that differ in form but in all cases conform to the basic framework outlined above. Generally, tariff reviews cover various years and provide for a reasonable ROE, protection, and automatic adjustments for exceptional costs incurred and efficiency incentives.

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 ratio. 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,

Notes to Consolidated Financial Statements

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 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.

Transmission - FERC ROE Proceeding

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. The FERC currently provides a base ROE of 10.57% and additional ROE incentive adders applicable to assets based upon vintage, voltage and other factors.

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 finds 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. The FERC also found that the current Regional Network Service (RNS) and Local Network Service (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.

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

NYSEG and RGE Rate Plans

On September 16, 2010, the New York Public Service Commission (NYPSC) approved a new rate plan for electric and natural gas service provided by NYSEG and RGE effective from August 26, 2010 through December 31, 2013. The rate plans contain continuation provisions beyond 2013 if NYSEG and RGE do not request new rates to go into effect and the current base rates will stay in place.

Notes to Consolidated Financial Statements

The revenue requirements were based on a 10% allowed ROE applied to an equity ratio of 48%. If annual earnings exceed the allowed return, a tiered Earnings Sharing Mechanism (ESM) will capture a portion of the excess for the ratepayers' benefit. The ESM is subject to specified downward adjustments if NYSEG and RGE fail to meet certain reliability and customer service measures. Key components of the rate plan include electric reliability performance mechanisms, natural gas safety performance measures, customer service quality metrics and targets, and electric distribution vegetation management programs that establish threshold performance targets. There will be downward revenue adjustments if NYSEG and RGE fail to meet the targets.

The 2010 rate plans established Revenue Decoupling Mechanism (RDM), intended to remove company disincentives to promote increased energy efficiency. Under RDM, electric revenues are based on revenue per customer class rather than billed revenue, while natural gas revenues are based on revenue per customer. Any shortfalls or excesses between billed revenues and allowed revenues will be accrued for future recovery or refund.

In August 2010, NYSEG began amortizing \$15.2 million per year of its \$303.9 million theoretical excess depreciation reserve. On September 1, 2012, RGE began amortizing \$5.3 million per year of its \$105 million theoretical excess depreciation reserve. Both amortization amounts reflect a twenty year amortization period. Theoretical excess depreciation is the difference between actual accumulated depreciation taken to date and a theoretical reserve. The actual accumulated depreciation is the result of depreciation rates allowed in prior rate orders based on estimates of useful lives and net salvage values as determined in those cases. The theoretical reserve is the amount that would have accumulated if the depreciation rates in the new rate plan had been in place for the entire useful lives of the affected assets. Differences between the actual reserve and the theoretical reserve are normal aspects of utility ratemaking. The usual treatment is to flow any excess or deficiency back as an adjustment to depreciation expense over the remaining life of the property. However, in accordance with the new rate plan, NYSEG and RGE will moderate electric rates by recording the theoretical reserve amortization as a debit to accumulated depreciation and a credit to other revenues, and normalize a portion of the amortization from a tax perspective.

On May 20, 2015, NYSEG and RGE filed electric and gas rate cases with the NYPSC. The companies requested rate increases for NYSEG electric, NYSEG gas and RGE gas. RGE electric proposed a rate decrease.

On February 19, 2016, the NYSEG, RGE and other signatory parties filed a Joint Proposal (Proposal) with the NYPSC for a three-year rate plan for electric and gas service at NYSEG and RGE commencing May 1, 2016. The Proposal balances the varied interests of the signatory parties including but not limited to maintaining the companies' credit quality and mitigating the rate impacts to customers. The Proposal reflects many customer attributes including: acceleration of the companies' natural gas leak prone main replacement programs and enhanced electric vegetation management to provide continued safe and reliable service. The delivery rate increase in the Proposal can be summarized as follows:

	May 1, 2016		May 1, 2017		May 1, 2018	
	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %
NYSEG Electric	\$29.6	4.10%	\$29.9	4.10%	\$30.3	4.10%
NYSEG Gas	13.1	7.30%	13.9	7.30%	14.8	7.30%
RGE Electric	3.0	0.70%	21.6	5.00%	25.9	5.70%
RGE Gas	8.8	5.20%	7.7	4.40%	9.5	5.20%

Notes to Consolidated Financial Statements

The allowed rate of return on common equity for NYSEG Electric, NYSEG Gas, RGE Electric and RGE Gas is 9.00%. The equity ratio for each company is 48%. The Proposal includes an Earnings Sharing Mechanism (ESM) applicable to each company. The customer share of earnings would increase at higher earnings levels, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first year. Earnings thresholds would increase in subsequent years. The Proposal reflects the recovery of deferred NYSEG Electric storm costs of approximately \$ 262 million, of which \$123 million will be amortized over ten years and the remaining \$139 million will be amortized over five years. The Proposal also continues reserve accounting for qualifying Major Storms (\$21.4 million annually for NYSEG Electric and \$2.5 million annually for RGE Electric). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds.

The Proposal maintains NYSEG's and RGE's current electric reliability performance measures (and associated potential negative revenue adjustments for failing to meet established performance levels) which include the system average interruption frequency index and the customer average interruption duration index. The Proposal also modifies certain gas safety performance measures at the companies, including those relating to the replacement of leak prone main, leak backlog management, emergency response, and damage prevention. The Proposal establishes threshold performance levels for designated aspects of customer service quality and continues and expands NYSEG's and RGE's bill reduction and arrears forgiveness Low Income Programs at increased funding levels. The Proposal provides for the implementation of NYSEG's Energy Smart Community ("ESC") Project in the Ithaca region which will serve as a test-bed for implementation and deployment of Reforming the Energy Vision (REV) initiatives. The ESC Project will be supported by NYSEG's planned rollout of Distribution Automation and Advanced Metering Infrastructure (AMI) to customers on circuits in the Ithaca region. The Companies will also pursue Non-Wires Alternative projects as described in the Proposal. REV-related incremental costs and fees will be included in the Rate Adjustment Mechanism (RAM) to the extent cost recovery is not provided for elsewhere. Under the Proposal, each company will implement a RAM, which will be applicable to all customers, to return or collect RAM Eligible Deferrals and Costs, including: (1) property taxes; (2) Major Storm deferral balances; (3) gas leak prone pipe replacement; (4) REV costs and fees which are not covered by other recovery mechanisms; and (5) NYSEG Electric Pole Attachment revenues.

The Proposal provides for partial or full reconciliation of certain expenses including, but not limited to: pensions, other postretirement benefits; property taxes; variable rate debt and new fixed rate debt; gas research and development; environmental remediation costs; Major Storms; nuclear electric insurance limited credits; economic development; and Low Income Programs. The Proposal also includes a downward-only Net Plant reconciliation. In addition, the Proposal includes downward-only reconciliations for the costs of: electric distribution and gas vegetation management; pipeline integrity; and incremental maintenance. The Proposal provides that NYSEG and RGE continue their electric RDMs on a total revenue per class basis and their gas RDMs on a revenue per customer basis.

The Administrative Law Judges assigned to the New York rate case will issue a procedural schedule establishing the remaining procedure for review and decision on the Proposal. We expect hearings on the Proposal to be held in April 2016 and a NYPSC decision to be made in May 2016.

Reforming the Energy Vision (REV)

In April 2014, the NYPSC commenced a proceeding entitled REV which is a wide ranging

Notes to Consolidated Financial Statements

initiative to reform New York state's energy industry and regulatory practices. REV has been divided into two tracks, Track 1 for Market Design and Technology, and Track 2 for Regulatory Reform. REV proposes regulatory changes that are intended to promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar, and wider deployment of distributed energy resources, such as micro grids, on-site power supplies and storage.

REV is also intended to promote greater use of advanced energy management products to enhance demand elasticity and efficiencies. Track 1 of this initiative involves a collaborative process to examine the role of distribution utilities in enabling market based deployment of distributed energy resources to promote load management and greater system efficiency, including peak load reductions. NYSEG and RGE are participating in the initiative with other New York utilities and are providing their unique perspective. NYPSC staff is currently conducting public statement hearings regarding REV across New York state. The NYPSC has issued a 2015 order in Track 1, which acknowledges the utilities' role as a Distribution System Platform (DSP) provider, and requires the utilities to file an initial Distribution System Implementation Plan (DSIP) by June 30, 2016. The DSIP will also include information regarding the potential deployment of Automated Metering Infrastructure (AMI). Various proceedings have also been initiated by the NYPSC which are REV related, and each proceeding has its own schedule. These proceedings include the Clean Energy Fund, Demand Response Tariffs, and Community Choice Aggregation.

Track 2 of the REV initiative is also underway, and through a NYPSC Staff Whitepaper review process, is examining potential changes in current regulatory, tariff, market design and incentive structures which could better align utility interests with achieving New York state and NYPSC's policy objectives. New York utilities will also be addressing related regulatory issues in their individual rate cases. We expect an Order by the end of the second quarter of 2016.

Ginna Reliability Support Service Agreement

Ginna Nuclear Power Plant, LLC (GNPP), which is a subsidiary of Constellation Energy Nuclear Group, LLC (CENG), owns and operates the R.E. Ginna Nuclear Power Plant (Ginna Facility and together with GNPP, Ginna), a 581 MW single-unit pressurized water reactor located in Ontario, New York. In May 2014, the New York Independent System Operator (NYISO) produced a Reliability Study, confirming that the Ginna Facility needs to remain in operation to avoid bulk transmission and non-bulk local distribution system reliability violations from 2015 through 2018.

On July 11, 2014, GNPP filed a petition requesting that the NYPSC initiate a proceeding to examine a proposal for the continued operation of the Ginna Facility. Ginna asserted that "in the two preceding calendar years, 2012 and 2013, it had sustained cumulative losses at the Facility of nearly \$100 million (including the allocation of CENG corporate overhead)" and that "CENG has not been compensated for any operational risk or an appropriate return on its investment over this period." Based on the results of the 2014 Reliability Study, GNPP requested that: 1) the NYPSC determine that the continued operation of the Ginna Facility is required to preserve system reliability; and 2) the NYPSC issue an Order directing RGE to negotiate and file a Reliability Support Services Agreement (RSSA) for the continued operation of the Ginna Facility.

In November 2014, the NYPSC ruled that GNPP had demonstrated that the Ginna Facility is required to maintain system reliability and that its actions with respect to meeting the relevant retirement notice requirements were satisfactory. The NYPSC also accepted the findings of the 2014 Reliability Study and stated that it established "the reliability need for continued operation of the Ginna Facility that is the essential prerequisite to negotiating an RSSA." As such, the NYPSC ordered RGE and GNPP to negotiate an RSSA.

Notes to Consolidated Financial Statements

On February 13, 2015, RGE submitted to the NYPSC an executed RSSA between RGE and GNPP. RGE requested that the NYPSC accept the RSSA and approve cost recovery by RGE from its customers of all amounts payable to GNPP under the RSSA utilizing the cost recovery surcharge mechanism.

On October 21, 2015, RGE, GNPP, New York Department of Public Service, Utility Intervention Unit and Multiple Interveners filed a Joint Proposal with the NYPSC for approval of the RSSA, as modified. The Joint Proposal provides a term of the RSSA from April 1, 2015 through March 31, 2017. RGE shall make monthly payments to Ginna in the amount of \$15.4 million. RGE will be entitled to 70% of revenues from Ginna's sales into the NYISO energy and capacity markets, while Ginna will be entitled to 30% of such revenues. The signatory parties recommend that the NYPSC authorize RGE to implement a rate surcharge effective January 1, 2016 to recover amounts paid to Ginna pursuant to the RSSA. RGE's payment obligation to Ginna shall not begin until the rate surcharge is in effect and FERC has issued an order authorizing the FERC Settlement agreement in the Settlement Docket. RGE will use deferred rate credit amounts (regulatory liabilities) to offset the full amount of the Deferred Collection Amount (including carrying costs), plus credit amounts to offset all RSSA costs that exceed \$2.3 million per month, not to exceed a total use of credits in the amount of \$110 million, applicable through June 30, 2017. To the extent that the available credits are insufficient to satisfy the final payment from RGE to Ginna then the RSSA surcharge may continue past March 31, 2017 to recover up to \$2.3 million per month until the final payment has been recovered by RGE from ratepayers. In the month following the expiration of the term on March 31, 2017, Ginna shall prepare and issue an invoice to RGE for, and RGE shall pay to Ginna, a one-time payment in the amount of \$11.5 million, which will be recovered from ratepayers. On February 23, 2016, the NYPSC unanimously adopted the Joint Proposal in the Ginna RSSA proceeding as in the public interest. On March 1, 2016, FERC issued an order approving the contested settlement agreement, subject to conditions.

New York Transco

Affiliates of National Grid, Central Hudson, Networks, together with an affiliate of Consolidated Edison and Orange and Rockland Utilities, are part of a new organization, New York Transco. New York Transco is focused on developing electric transmission to meet future electricity needs of all New Yorkers and will develop New York transmission projects upon receipt of all necessary regulatory approvals.

New York Transco members (Applicants) are requesting regulatory approval for a group of transmission projects expected to cost \$1.7 billion, funded through debt and equity. Networks allocated twenty-percent equity contribution amounts to approximately \$183 million over the period 2015 through 2018. Additional projects may be developed in the future. Equity investments will be expressly contingent on receiving necessary regulatory approvals and acceptable economic returns. The investment will be made through a Networks affiliate, Networks New York Transco, LLC, formed on November 3, 2014.

New York Transco filed with FERC in early December 2014. The filing requests a formula base ROE of 10.6%, plus one-hundred fifty basis points ROE incentives. The filing also requests recognition of construction work in process, abandoned plant, regulatory asset for pre-commercial costs, and sixty-percent equity for five years. Various parties, including the NYPSC, have protested the filing with FERC.

On April 2, 2015, the FERC issued an order granting, inter alia, Applicants' request for a 50 basis point adder for NY Transco's membership in the NYISO regional transmission organization (RTO), subject to the adder being capped within the zone of reasonableness after a determination of where within that zone its base level ROE should be set. The FERC also set the formula rate

Notes to Consolidated Financial Statements

and base ROE issue for hearing and settlement judge procedures. In addition, the FERC rejected the Applicants' cost allocation method for the Transmission Owner Transmission Solutions (TOTS) Projects because it would allocate costs to Power Supply Long Island (LIPA) and New York Power Authority (NYPA) that they did not voluntarily agree to pay.

On November 5, 2015, Applicants, filed the Settlement with the FERC to resolve all outstanding issues associated with the TOTS Projects, including issues related to the TOTS Projects that were set for hearing and issues pending on rehearing. The issues regarding certain other projects remain pending.

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations our utilities capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas 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 \$1.9 billion 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.

The regulatory asset for pension and postretirement benefits represents the actuarial losses that will be reflected in customer rates when they are amortized and recognized in future expenses. The regulatory asset for environmental remediation costs represents spending that has occurred and is eligible for future recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism, whereby projected spending is included in rates, with any variance recorded as a regulatory asset or a regulatory liability. It also includes the anticipated future rate recovery of costs that are recorded as our environmental liability since these will be recovered when incurred. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs.

Our electric utilities are allowed in rates an estimate of the routine costs of service restoration. They are also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. Since the approval of the 2010 rate plan in New York, NYSEG has experienced unusually high levels of restoration costs resulting from various storms including Hurricane Sandy, Hurricane Irene and tropical storm Lee. NYSEG's deferred storm costs, reflecting the over (under) spending of actual costs compared with amounts currently allowed in rates, was \$(9) million and \$5 million for the years ended December 31, 2015 and 2014, respectively. NYSEG's total deferral, including carrying costs was \$247 million at December 31, 2015 and \$241 million at December 31, 2014. Pursuant to the Proposal, if approved, NYSEG would recover a portion of the balance over five years and the remainder over ten years. The method and timing of recovery of the costs will be determined in the future rate cases.

CMP's deferred service restoration costs, primarily as a result of an ice storm in late December 2014, reflecting over (under) spending of actual costs compared with amounts allowed in rates, was \$(6) million and \$15 million for the years ended December 31, 2015 and 2014, respectively. CMP's total deferral, including carrying costs was \$12 million at December 31, 2015 and \$32 million at December 31, 2014.

Notes to Consolidated Financial Statements

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.

Most of the items related to NYSEG for which the amortization period has been characterized as to be determined in a future proceeding have been addressed in the Joint Proposal. If the Joint Proposal is approved, most of these items would be amortized over a five year period, except the portion of storm costs to be recovered over ten years and plant related tax items which will be amortized over the life of associated plant. Annual amortization expense for NYSEG would be approximately \$16.5 million. The RGE items that would begin being amortized are plant related tax items. A majority of the other items related to RGE, which net to a regulatory liability, will not be amortized until future proceedings or will be used to recover costs of the Ginna RSSA agreement.

Current and long-term regulatory assets at December 31, 2015 and 2014 consisted of:

December 31, (Thousands)	2015	2014
Current		
Environmental remediation costs	\$36,203	\$-
Pension and other postretirement benefits cost deferrals	7,530	-
Hedges losses	36,730	33,502
Storm costs	7,544	14,198
Transmission revenue reconciliation mechanism	4,809	5,061
Non by-passable charges	6,686	1,779
Revenue decoupling mechanism	6,493	5,775
Temporary supplemental assessment surcharge	6,545	11,664
Other	13,077	7,650
Total current regulatory assets	\$125,617	\$79,629
Other long-term		
Deferred meter replacement costs	\$34,077	\$35,960
Federal tax depreciation normalization adjustment	157,783	128,226
Asset retirement obligation	23,705	32,013
Pension and other postretirement benefits cost deferrals	151,001	124,632
Deferred property tax	45,044	30,163
Unamortized loss on debt reacquisitions	22,526	25,435
Merger capital expense	14,533	10,486
Low Income Programs	18,549	14,140
Pension and other postretirement benefits	1,030,076	1,101,415
Unfunded future income taxes	351,837	366,491
Environmental remediation costs	167,650	246,073
Storm costs	251,326	258,869
Other	36,755	25,232
Total long-term regulatory assets	\$2,304,862	\$2,399,135

Environmental remediation costs includes spending that has occurred and is eligible for future recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. It also includes the anticipated future rate recovery of costs

Notes to Consolidated Financial Statements

that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base. 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. Pension and other postretirement benefits cost deferrals" include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. The recovery of these amounts will be determined in future proceedings.

Storm costs for Central Maine Power (CMP), New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RGE) are allowed in rates based on an estimate of the routine costs of service restoration. The companies are also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration.

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.

Asset Retirement Obligations represent the differences in timing of the recognition of costs associated with our AROs and the collection of such amounts through rates. This amount is being amortized at the related depreciation and accretion amounts of the underlying liability.

Deferred property taxes represents the customer portion of the difference between actual expense for property taxes and the amount provided for in rates. The amortization period is awaiting a future NYPSC rate proceeding.

Notes to Consolidated Financial Statements

Current and long-term regulatory liabilities at December 31, 2015 and 2014 consisted of:

December 31, (Thousands)	2015	2014
Current		
Plant decommissioning	-	\$12,539
Gas supply charge and deferred natural gas cost	\$6,204	6,485
Revenue decoupling mechanism	13,948	7,831
Transmission revenue reconciliation mechanisms	5,490	6,795
Reliability support services (Cayuga)	15,968	18,135
Yankee DOE Phase I	5,234	23,475
Non by-passable charges	7,004	18,428
Energy supply reconciliation	7,895	2,240
Energy efficiency portfolio standard	32,914	34,094
Unfunded deferred income tax adjustment	10,104	16,423
Rate refund-FERC ROE proceeding	3,092	12,322
Other	2,509	5,793
Total current regulatory liabilities	\$110,362	\$164,560
Other long-term		
Asset sale gain account	\$8,365	\$19,180
Other taxes	67,763	26,484
Carrying costs on deferred income tax bonus depreciation	115,743	80,540
Economic development	35,939	32,765
Merger capital expense target customer credit	16,800	16,800
Pension and other postretirement benefits	76,739	49,873
Positive benefit adjustment	50,928	50,928
Deferred property tax	14,605	51,481
New York State tax rate change	16,925	16,090
Unfunded future income taxes	-	13,469
Rate refund-FERC ROE proceeding	21,039	23,259
Post term amortization	25,332	20,382
Spent nuclear fuel	14,155	11,536
Theoretical reserve flow thru impact	31,067	23,807
Variable rate debt	17,794	13,318
Accrued removal obligations	740,206	720,866
Other	60,885	58,061
Total noncurrent regulatory liabilities	1,314,285	1,228,839
Deferred income taxes regulatory	384,751	433,093
Total long-term regulatory liabilities	\$1,699,036	\$1,661,932

Reliability support services (Cayuga) represent the difference between actual expenses for reliability support services and the amount provided for in rates.

Non by-passable charges represent the non by-passable fixed charge paid by all customers. An asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered. This will be refunded to customers within the next year.

Energy efficiency portfolio standard represents the difference between revenue billed to customers through an energy efficiency charge and the costs of our energy efficiency programs as approved by the state authorities.

Notes to Consolidated Financial Statements

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.

Asset sale gain account represents the gain on NYSEG's 2001 sale of its interest in Nine Mile Point 2 nuclear generating station. The net proceeds from the Nine Mile Point 2 nuclear generating station were placed in this account and will be used to benefit customers. The amortization period is awaiting a future NYPSC rate proceeding.

Carrying costs on deferred income tax bonus depreciation represent the carrying costs benefit of increased accumulated deferred income taxes created by the change in tax law allowing bonus depreciation. The amortization period is awaiting a future NYPSC rate proceeding.

Economic development represents the economic development program which enables NYSEG and RGE to foster economic development through attraction, expansion, and retention of businesses within its service territory. If the level of actual expenditures for economic development allocated to NYSEG and RGE varies in any rate year from the level provided for in rates, the difference is refunded to ratepayers. The amortization period is awaiting a future NYPSC rate proceeding.

Merger capital expense target customer credit account was created as a result of NYSEG and RGE not meeting certain capital expenditure requirements established in the order approving the purchase of Energy East by Iberdrola. The amortization period is awaiting a future NYPSC rate proceeding.

Pension and other postretirement benefits represent the actuarial gains on other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future expenses. Because no funds have yet been received for this a regulatory liability is not reflected within rate base. It also represents the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. Recovery of these amounts will be determined in future proceedings.

Positive benefit adjustment resulted from Iberdrola's 2008 acquisition of Energy East. This will be used to moderate increases in rates. The remaining amortization period is awaiting a future NYPSC rate proceeding.

New York State tax rate change represents the excess funded accumulated deferred income tax balance caused by the 2014 New York State tax rate change from 7.5% to 7.1% and then from 7.1% to 6.5%. The amortization period is awaiting a future NYPSC rate proceeding.

Post term amortization represents the revenue requirement associated with certain expired joint proposal amortization items. Further amortization is awaiting a future NYPSC rate proceeding.

Theoretical reserve flow thru impact represent the differences from the rate allowance for applicable federal and state flow through tax impacts related to the excess depreciation reserve amortization. It also represents the carrying cost on the differences. The amortization period is awaiting a future NYPSC rate proceeding.

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

Notes to Consolidated Financial Statements

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 2015 or in 2014 as a result of our annual impairment assessment, which we performed as of October 1. For 2015, as a result of our step zero qualitative analysis and for 2014, as a result of our step one testing, no impairment was indicated within any of the ranges of assumptions analyzed for our New York or Maine reporting units. There were no events or circumstances subsequent to our annual impairment assessment for 2015 or for 2014 that required us to update the assessment.

As of December 31, 2015 and 2014 the carrying amount of goodwill was \$979.6 million, with no accumulated impairment losses and no changes during 2015 and 2014.

Note 5. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2015 and 2014 consisted of:

Years Ended December 31, (Thousands)	2015	2014
Current		
Federal	\$81,483	\$42,057
State	37,088	22,176
Current taxes charged to expense	118,571	64,233
Deferred		
Federal	54,717	122,073
State	(219)	(12,204)
Deferred taxes charged to expense	54,498	109,869
Investment tax credit adjustments	(510)	(1,724)
Total Income Tax expense	\$172,559	\$172,378

Notes to Consolidated Financial Statements

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, 2015 and 2014 consisted of:

Years Ended December 31,	2015	2014
(Thousands)		
Tax expense at Federal statutory rate	\$145,267	\$160,952
Depreciation and amortization not normalized	13,358	15,456
Allowance for funds used during construction	(10,901)	(9,341)
Investment tax credit amortization	(510)	(1,724)
Medicare subsidy	-	579
Tax return related adjustments	137	(2,863)
State taxes, net of federal benefit	23,965	6,484
Other, net	1,243	2,835
Total Income Tax expense	\$172,559	\$172,378

Income tax expense for the year ended December 31, 2015 was \$27.3 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 not normalized, partially offset by allowance for funds used during construction. This resulted in an effective tax rate of 41.6%. Income tax expense for the year ended December 31, 2014 was \$11.4 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 not normalized, partially offset by allowance for funds used during construction. This resulted in an effective tax rate of 37.5%. State taxes, net of federal benefit, are higher in 2015 than in 2014 due to the benefit in 2014 for a rate reduction in New York from 7.1% to 6.5%

Deferred tax assets and liabilities as of December 31, 2015 and 2014 consisted of:

	2015	2014
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	\$1,889,907	\$1,885,860
Unfunded future income taxes	143,853	149,524
Employee Benefits	161,571	99,271
Accumulated deferred investment tax credits	15,168	15,678
Federal and State NOL's	(829)	(19)
Positive benefits adjustments merger order	(24,789)	(20,175)
Storm cost deferral	102,693	101,210
Other	(250,142)	(223,907)
Non-current Deferred Income Tax Liabilities	2,037,432	2,007,442
Add: Valuation allowance	8,988	9,299
Total Non-current Deferred Income Tax Liabilities	2,046,420	2,016,741
Less amounts classified as regulatory liabilities		
Non-current deferred income taxes	384,751	433,093
Non-current Deferred Income Tax Liabilities	\$1,661,669	\$1,583,648
Deferred tax assets	\$275,760	\$244,101
Deferred tax liabilities	2,322,180	2,260,842
Net Accumulated Deferred Income Tax Liabilities	\$2,046,420	\$2,016,741

Valuation allowances are recorded to reduce deferred tax assets when it is not more likely than not that some portion or the entire deferred income tax asset will be realized. A valuation allowance for the entire \$9 million (net of federal benefit) carryforward of Maine Research and Development Super credits generated in tax years 2007 to 2012 was established as of December 31, 2012. There was a small change in the balance in 2015 to true-up to the filed return.

Notes to Consolidated Financial Statements

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2015 and 2014 consisted of:

Years ended December 31,	2015	2014
(Thousands)		
Balance as of January 1	\$31,598	\$36,014
Increases for tax positions related to prior years	-	19,022
Reduction for tax position related to settlements with taxing authorities	(5,092)	(23,438)
Balance as of December 31	\$26,506	\$31,598

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.

The total amount of unrecognized tax benefits anticipated to result in a net decrease to unrecognized tax benefits within 12 months of December 31, 2015 is estimated to be \$9 million primarily relating to anticipation of additional guidance to be released by the IRS.

Accruals for interest and penalties on tax reserves were \$1.7 million as of December 31, 2015 and \$3.6 million as of December 31, 2014. If recognized, \$1 million of the total gross unrecognized tax benefits would affect the effective tax rate. Gross unrecognized tax benefits decreased \$5.1 million in 2015 due to settlements with taxing authorities.

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

Notes to Consolidated Financial Statements

Note 6. Long-term Debt

At December 31, 2015 and 2014, our consolidated long-term debt was:

(Thousands)	Maturity Dates	2015		2014	
		Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds ⁽¹⁾					
CMP	2019-2045	\$900,000	3.07%-5.70%	\$750,000	3.07%-5.70%
RGE	2016-2033	639,850	4.10%-8.00%	639,850	4.10%-8.00%
Subtotal first mortgage bonds		\$1,539,850		\$1,389,850	
Unsecured PCNs ⁽²⁾ - fixed					
NYSEG	2020	\$200,000	2.00%-2.375%	\$132,000	2.125%-2.25%
Subtotal unsecured PCNs - fixed		\$200,000		\$132,000	
Unsecured PCNs – variable					
NYSEG	2034	\$96,850	1.18%	\$96,875	0.030%-0.461%
RGE	2032	62,150	0.195%	62,150	0.104%
Subtotal unsecured PCNs - variables		\$159,000		\$159,025	
Senior unsecured debt					
NYSEG	2016-2042	\$650,000	3.24%-6.15%	\$650,000	3.24%-6.15%
CMP	2016-2037	180,000	5.27-6.40%	180,000	5.27-6.40%
Subtotal senior unsecured debt		\$830,000		\$830,000	
Chester: Promissory and Senior Notes ⁽⁴⁾	2020	5,725	7.05%-10.48%	6,908	7.05%-10.48%
Total Debt		\$2,734,575		\$2,517,783	
Obligations under capital leases	2020-2023	\$24,451		\$5,545	
Unamortized debt (costs) premium, net		(23,939)		(29,290)	
Less: debt due within one year, included in current liabilities		181,602		134,415	
Total Non-current Debt		\$2,553,486		\$2,359,623	

- (1) RGE and CMP first mortgage bonds are secured by liens on substantially all of the Net Utility Plant In Service at each respective utility, \$2,811 in the case of CMP and \$2,050 in the case of RGE.
- (2) PCNs = pollution control notes.
- (3) RGE's Unsecured PCNs – fixed of \$39,850 are secured by the first mortgage lien at RGE.
- (4) Chester SVC Partnership notes are secured by the assets of this partnership.

Notes to Consolidated Financial Statements

In January 2015, CMP issued \$150 million of first mortgage bonds in three tranches: \$65 million maturing in 2025 bearing a coupon of 3.15%, \$20 million maturing in 2030 bearing a coupon of 3.37%, and \$65 million maturing in 2045 bearing a coupon of 4.07%.

In April 2015, NYSEG issued \$200 million of fixed rate pollution control notes in four separate series. The notes have mandatory redemption dates in 2020. \$99 million of the notes bear an interest rate of 2.375% and \$101 million bear an interest rate of 2.00%.

In March, October and December 2015, NYSEG redeemed at maturity three separate series of fixed rate unsecured pollution control notes totaling \$132 million.

At December 31, 2015, long-term debt, including sinking fund obligations and capital lease payments (in thousands) that will become due during the next five years is:

2016	2017	2018	2019	2020
\$181,602	\$204,569	\$4,649	\$304,733	\$204,633

We are in compliance with all debt covenants as of December 31, 2015.

Note 7. Bank Loans and Other Borrowings

Each of the Networks' subsidiaries has the ability to borrow from AGR under intercompany credit facilities that take the form of demand notes. Under the agreements, we had a total of \$547 million of Notes payable to affiliates at December 31, 2015 and \$794 million outstanding at December 31, 2014, all of which was provided by AGR. As of December 31, 2015, borrowing rates ranges from 0.40% to 1.29%.

In July 2011, NYSEG, RGE and CMP jointly entered into a bank provided revolving credit facility (the "Joint Facility") that allows maximum borrowings of up to \$600 million in aggregate and expires in 2018. Each company is currently subject to a \$200 million credit limit. Each borrower pays a facility fee ranging from 15 to 20 basis points annually depending on the rating of its unsecured debt. CMP and NYSEG established commercial paper programs with limits of \$200 million and \$200 million, respectively. The Joint Facility serves as the backstop to these programs. The companies intend to use commercial paper as an alternative to revolving credit facilities as a source of short-term credit. There were no Notes payable under the Joint Facility or commercial paper programs at December 31, 2015 or December 31, 2014.

In the Joint Facility each joint borrower covenants not to permit, without the consent of the lender, its ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to total capitalization, the facility excludes from consolidated net worth the balance of Accumulated other comprehensive loss as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness each borrower may maintain. Continued unremedied failure to comply with those covenants for five business days after written notice of such failure from the lender constitutes an event of default and would result in acceleration of maturity for the party in default. We are not in default as of December 31, 2015.

Note 8. Redeemable Preferred Stock of Subsidiary, Noncontrolling Interest

The redeemable preferred stock of CMP is a noncontrolling interest because it contains a feature that allows the holders to elect a majority of CMP's board of directors if preferred stock dividends are in default in an amount equivalent to four full quarterly dividends. Such a potential redemption-triggering event is not solely within the control of CMP.

Notes to Consolidated Financial Statements

At December 31, 2015 and 2014, our consolidated redeemable preferred stock, noncontrolling interest was:

Subsidiary and Series	Par Value per Share	Redemption Price per Share	Shares Authorized and Outstanding⁽¹⁾	Amount (Thousands)	
				2015	2014
CMP, 6% Noncallable	\$100	-	1,921	\$192	\$192
Total				\$192	\$192

⁽¹⁾At December 31, 2015 and 2014, Network's subsidiaries had 6,755,000 shares of \$100 par value preferred stock, 14,800,000 shares of \$25 par value preferred stock, 1,000,000 shares of \$100 par value preference stock and 5,000,000 shares of \$1 par value preference stock authorized but unissued.

Note 9. Commitments and Contingencies

NYPSC Staff Review of Earnings Sharing Calculations and Other Regulatory Deferrals

In December 2012, the NYPSC Staff (Staff) informed NYSEG and RGE that the Staff had conducted an audit of the companies' annual compliance filings (ACF) for 2009 through August 31, 2010, and the first rate year of the current rate plan, September 1, 2010 through August 31, 2011. The Staff's preliminary findings indicated adjustments to deferred balances primarily associated with storm costs and the treatment of certain incentive compensation costs for purposes of the 2011 ACF. The Staff's findings approximate \$9.8 million of adjustments to deferral balances and customer earnings sharing accruals. NYSEG and RGE reviewed the Staff's adjustments and work papers and provided a response in 2013. NYSEG and RGE disagreed with certain staff conclusions and as a result recorded a \$3.4 million reserve in December 2012 in anticipation of settling the Staff issues. In the Joint Proposal the parties agreed that \$2.4 million would be added to customer share of Earnings Sharing.

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 a just and reasonable level of 9.2%. CMP is one of the 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 initial decision in the first complaint, establishing a methodology and setting the issues for a paper hearing. On October 16, 2014, FERC issued its final decision in the first complaint (Complaint I) setting the base ROE at 10.57%, and a maximum total ROE of 11.74% for the October 2011 – December 2012 period 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 initial 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. We cannot predict the outcome of this appeal.

On December 26, 2012, a second, related, complaint (Complaint II) for a subsequent rate period was filed requesting the ROE be reduced to 8.7%. On June 19, 2014, FERC accepted the second

Notes to Consolidated Financial Statements

complaint, established a refund effective date of December 27, 2012, and set the matter for hearing using the methodology established in the first complaint.

On July 31, 2014, the Complainants filed a third, related, complaint (Complaint III) for a subsequent rate period requesting the ROE be reduced to 8.84%. On November 24, 2014, FERC accepted the third complaint, established a refund effective date of July 31, 2014, and set for consolidated hearing with Complaint II in June 2015. Hearings were held in June 2015 on the Complaints II and III before a FERC Administrative Law Judge, relating to the refund periods and going forward. 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 New England transmission owners filed a petition for review of FERC's orders establishing hearing and consolidation procedures for the Complaints II and III with the U.S. Court of Appeals. The 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 late 2016 or early 2017.

CMP reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 final Complaint I decision. The CMP total reserve associated with Complaints I, II and III is \$23.9 million as of December 31, 2015. If adopted as final, the impact of the initial decision would be an additional reserve for Complaints II and III of \$7.7 million, net of tax, which is based upon currently available information for these proceedings. We cannot predict the outcome of Complaint II and III proceedings.

On April 29, 2016, the Complainants filed a fourth, related, complaint (Complaint IV) for a subsequent rate period requesting the base ROE be 8.61% and ROE Cap be 11.24%. We cannot predict the outcome of the Complaint IV proceeding.

MNG rate case

On March 5, 2015, MNG filed a rate case in order to further recover future investments and provide safe and adequate service. MNG requested a 10.0% ROE and 50% equity ratio. The MPUC Staff has recommended a separate revenue requirement for MNG's Augusta customers and MNG's non-Augusta customers. Staff also recommended a \$19.95 million disallowance of the Augusta Expansion investment based upon the Staff's conclusion that MNG's management of the Augusta Expansion Project was imprudent.

On November 6, 2015, a stipulation was filed with the MPUC, which was executed by MNG, the Office of Public Advocate and the City of Augusta. The stipulation contained a combined revenue requirement for Augusta and Non-Augusta based on a 9.55% ROE and 50% equity ratio. The stipulation also provided for an initial Augusta investment disallowance of \$6 million and an investment phase-in of \$10 million. On December 22, 2015, MPUC rejected the proposed Stipulation as not in the public interest. In January 2016, the Administrative Law Judge established a new litigation schedule. The litigation was suspended at the end of January 2016 for settlement discussions. We cannot predict the outcome of the proceeding. We reserved \$6 million for this case in 2015.

Minimum Equity Requirements for Regulated Subsidiaries:

Our regulated utility subsidiaries (NYSEG, RGE, CMP and Maine Natural Gas) of Maine and New York are each subject to a minimum equity ratio requirement that is tied to the capital structure

Notes to Consolidated Financial Statements

assumed in establishing revenue requirements. 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. The regulated utility subsidiaries are prohibited by regulation from lending to unregulated affiliates. The regulated utility subsidiaries have also agreed to minimum equity ratio requirements in certain borrowing agreements. These requirements are lower than the regulatory requirements. Movement of capital from our wholly owned unregulated subsidiaries is unrestricted.

Yankee Nuclear Spent Fuel Disposal Claim

CMP has an ownership interest in Maine Yankee, Connecticut Yankee, and Yankee Atomic, (the Yankee Companies), three New England single-unit decommissioned nuclear reactor sites. Every six years, pursuant to the statute of limitations, the Yankee companies need to 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 \$40.3 million to Connecticut Yankee Atomic Power Company; affirmed the Court of Federal Claims award of \$65 million to Maine Yankee Atomic Power Company; and increased Yankee Atomic Electric Company's damages award from \$21.4 million to \$37.8 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 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 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. .

Notes to Consolidated Financial Statements

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 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 based on percentage ownership. We cannot predict the timing or amount of damage awards that may ultimately flow through to shareholders.

Leases

On January 16, 2014, as required by its regulator, NYSEG renewed a Reliability Support Services Agreement (RSS Agreement) with Cayuga Operating Company, LLC (Cayuga) for Cayuga to provide reliability support services to maintain necessary system reliability through June 2017. Cayuga owns and operates the Cayuga Generating Facility (Facility), a coal-fired generating station that includes two generating units. Cayuga will operate and maintain the RSS units and manage and comply with scheduling deadlines and requirements for maintaining the Facility and the RSS units as eligible energy and capacity providers and will comply with dispatch instructions. NYSEG will pay Cayuga a monthly fixed price and will also pay for capital expenditures for specified capital projects. NYSEG will be entitled to a share of any capacity and energy revenues earned by Cayuga. We account for this arrangement as an operating lease. The net expense incurred under this operating lease was \$25.5 million and \$19.8 million for the years ended December 31, 2015 and 2014. We estimate our expenses will be approximately \$42 million in 2016 and \$13 million in 2017.

On October 21, 2015, RGE, GNPP and multiple interveners filed a Joint Proposal with the regulator for approval of the modified RSS Agreement for the continued operation of the Ginna Facility through March 2017. RGE shall make monthly payments to GNPP in the amount of \$15.4 million. RGE will be entitled to 70% of revenues from GNPP's sales into the energy and capacity markets, while GNPP will be entitled to 30% of such revenues. We account for this arrangement as an operating lease. We estimate our expenses will be approximately \$147 million in 2016 and \$51 million in 2017.

Other operating leases: We recognized expenses of approximately \$5 million related to our operating leases in 2015 and \$8 million in 2014. We estimate our expenses will be approximately \$3 million in 2016, 2017 and 2018, and \$2 million per year in 2019 and 2020 and \$8 million thereafter.

Purchase power and gas contracts, including nonutility generators: NYSEG and RGE are the providers of last resort for customers. As a result, the companies buy physical energy and capacity from the NYISO. In accordance with the NYPSC's February 26, 2008 Order, NYSEG and RGE are required to hedge on behalf of non-demand billed customers. The physical electric capacity purchases we make from parties other than the NYISO are to comply with the hedge requirement for electric capacity. The companies enter into financial swaps to comply with the hedge requirement for physical electric energy purchases. Other purchases, from some Independent Power Producers (IPPs) and NYPA are from contracts entered into many years ago when the companies made purchases under contract as part of their supply portfolio to meet their load requirement. More recent IPP purchases are required to comply with the companies' Public Utility Regulatory Policies Act (PURPA) purchase obligation.

NYSEG and RGE satisfy their natural gas supply requirements through purchases from various producers and suppliers, withdrawals from natural gas storage, capacity contracts and winter

Notes to Consolidated Financial Statements

peaking supplies and resources. The companies operate diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual reasonable gas costs incurred by each of the companies are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

The companies purchase the majority of their natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. The companies acquire firm transportation capacity on interstate pipelines under long-term contracts and utilize that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. The companies acquire firm underground natural gas storage capacity using long-term contracts and fill the storage facilities with gas in the summer months for subsequent withdrawal in the winter months.

We recognized expenses of approximately \$197 million for these contracts including NUG power in 2015 and \$170 million in 2014. We estimate that our power purchases will total \$211 million in 2016, \$117 million in 2017, \$76 million per year in 2018 and 2019, \$42 million in 2020 and \$340 million thereafter.

Property, Plant and Equipment: We have made future commitments to purchase property, plant, and equipment in order to continue to develop and grow our business. The amount of such future commitments was \$308 million as of December 31, 2015.

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 and natural gas service.

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 24 waste sites. The 24 sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the 24 sites, 14 sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites, six are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and nine 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 \$6 million related to nine of the 24 sites. We have paid remediation costs related to the remaining 15 sites, and do not expect to incur any additional liability. We have recorded an estimated liability of \$8 million related to another 13 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) programs. It is possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us.

We have a program to investigate and perform necessary remediation at our 53 sites where gas was manufactured in the past. Eight sites are included in the New York State Registry, 11 sites are included in the New York Voluntary Cleanup Program, three sites are part of Maine's Voluntary Response Action Program and of those, two sites are part of Maine's Uncontrolled Sites Program. We have entered into consent orders with various environmental agencies to investigate and, where necessary, remediate 47 of the 53 sites.

Notes to Consolidated Financial Statements

Our estimate for all costs related to investigation and remediation of the 53 sites ranges from a minimum of \$235 million to \$468 million at December 31, 2015. Our 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 \$298 million at December 31, 2015 and \$312 million at December 31, 2014. We recorded a corresponding regulatory asset, net of insurance recoveries and the amount collected from FirstEnergy described below, because we expect to recover the net costs in rates. Our environmental liability accruals are recorded on an undiscounted basis and are expected to be paid through the year 2053.

FirstEnergy: NYSEG sued FirstEnergy under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) to recover environmental clean-up costs at 16 former manufactured gas sites. (Liability was based upon FirstEnergy's status as successor to Associated Gas & Electric Company (AGECO), a utility holding conglomerate that unlawfully dominated operations at the plants from approximately 1906-1942.) In July 2011, the Court issued a decision and order in NYSEG's favor. Based upon past and future clean-up costs at the 16 sites in dispute, FirstEnergy will be required to pay NYSEG approximately \$60 million if the decision is upheld on appeal. FirstEnergy appealed the decision to the Second Circuit Court of Appeals. On September 9, 2011, FirstEnergy paid NYSEG \$30 million, representing their share of past costs of \$27 million and pre-judgment interest of \$3 million.

On September 11, 2014 the Second Circuit Court of Appeals affirmed the District Court's decision in NYSEG's favor, but modified it for nine sites, reducing NYSEG's damages for incurred costs from \$27 million to \$22 million (excluding interest) and reducing FirstEnergy's allocable share of future costs at these sites. NYSEG refunded FirstEnergy the excess \$5 million in November 2014.

FirstEnergy remains liable for a substantial share of clean up expenses at nine MPG Energy sites. In January 2015, NYSEG sent FirstEnergy a demand for \$16 million representing FirstEnergy's share of clean-up expenses incurred by NYSEG at the nine sites from January 2010 to November 2014 while the District Court appeal was pending. This amount has been paid by FirstEnergy. FirstEnergy would also be liable for a share of post 2014 costs, which, based on current projections, would be \$26 million. This amount is being treated as a contingent asset and has not been recorded as either a receivable or a decrease to the environmental provision.

Century Indemnity and OneBeacon: On August 14, 2013, NYSEG filed suit in federal court against two excess insurers, Century Indemnity and OneBeacon, who provided excess liability coverage to NYSEG. NYSEG seeks payment for clean-up costs associated with contamination at twenty-two former manufactured gas plants. Based on estimated clean-up costs of \$282 million, the carriers' allocable share is approximately \$89 million, excluding pre-judgment interest. Any recovery will be flowed through to NYSEG ratepayers. Century and One Beacon have answered admitting issuance of the excess policies, but contesting coverage and providing documentation proving they received notice of the claims in the 1990s. We cannot predict the outcome of this matter.

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.

Notes to Consolidated Financial Statements

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

Commodity price risk: Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas utility industries. We manage this risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Owned electric generation and long-term supply contracts reduce our exposure to market fluctuations.

We have electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that have been designated and qualify for the normal purchases and normal sales exception in accordance with the accounting requirements concerning derivative instruments and hedging activities.

We currently have a non by-passable wires charge adjustment that allows us to pass through rates any changes in the market price of electricity. We use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations. At December 31, 2015, the loss recognized in regulatory assets was \$34 million for electricity derivatives. Also is a gain of \$0.2 million in regulatory liabilities. At December 31, 2014, the loss recognized in regulatory assets was \$28.8 million for electricity derivatives. For the year ended December 31, the amount reclassified from regulatory liabilities into income, which is included in electricity purchased, was a loss of \$46.9 million for 2015 and a gain of \$21.3 million for 2014.

We have a purchased gas adjustment clause that allows us to recover through rates any changes in the market price of purchased natural gas, substantially eliminating our exposure to natural gas price risk. We use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations. At December 31, 2015, the loss recognized in regulatory assets was \$3.1 million for natural gas hedges. At December 31, 2014, the loss recognized in regulatory assets was \$4.7 million for natural gas hedges. For the years ended December 31, the loss reclassified from regulatory assets into income, which is included in natural gas purchased, was \$6.3 million for 2015 and a gain of \$2.2 million for 2014.

Notes to Consolidated Financial Statements

Our derivative volumes by commodity type that are expected to settle each year are:

	Electricity Contracts	Natural Gas Contracts	Fleet Fuel Contracts
Year to settle	Mwhs	Dths	Gals
As of December 31, 2015			
2016	4,507,500	3,850,000	2,500,100
2017	2,158,400	920,000	1,260,000
As of December 31, 2014			
2015	4,277,800	3,180,000	2,778,200
2016	2,364,000	610,000	-

The location and amounts of derivative fair values in the balance sheet are:

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
As of December 31, (Thousands)				
Derivatives designated as hedging instruments				
2015				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	-	Current liabilities	-
Long-term	Other assets	\$180	Other liabilities	-
Natural gas derivatives				
Current	Current assets	-	Current liabilities	-
Long-term	Other assets	-	Other liabilities	-
Fleet fuel contracts				
Current	Current assets	-	Current liabilities	\$1,919
Long-term	Other assets	-	Other liabilities	779
Total		\$180		\$2,698
2014				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	-	Current liabilities	\$20,002
Long-term	Other assets	-	Other liabilities	8,758
Natural gas derivatives				
Current	Current assets	-	Current liabilities	4,116
Long-term	Other assets	-	Other liabilities	625
Fleet fuel contracts	Current assets	-	Current liabilities	3,320
Total		-		\$36,821

Notes to Consolidated Financial Statements

The effect of hedging instruments on other comprehensive income (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	Effective Portion	Effective Portion	
(Thousands)			
2015			
Interest rate contracts	-	Interest expense	\$(8,618)
Commodity contracts:	\$(2,696)	Other operating expenses	(3,318)
Total	\$(2,696)		\$(11,936)
2014			
Interest rate contracts	-	Interest expense	\$(8,923)
Commodity contracts:	\$(3,616)	Other operating expenses	(843)
Total	\$(3,616)		\$(9,766)

The amounts in AOCI related to previously settled forward starting swaps, and accumulated amortization, as of December 31, 2015, is a net loss of \$84.9 million as compared to a net loss of \$93.5 million for 2014. For the year ended December 31, 2015, we recorded \$8.6 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately \$8.1 million of discontinued cash flow hedges in 2016. There was no ineffective portion of hedge during the years ended December 31, 2015 and 2014.

As of December 31, 2015, \$2.7 million in losses are reported in AOCI because the forecasted transaction is considered to be probable. We expect that those losses will be reclassified into earnings within the next 24 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions.

Notes to Consolidated Financial Statements

Offsetting Assets and Liabilities

Offsetting of Derivative Assets

				<u>Gross Amounts Not Offset in the Balance Sheet</u>		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet	Financial Instruments	Cash Collateral Pledged	Net Amount
Description						
(Thousands)						
As of December 31, 2015						
Derivatives	\$9,665	\$(9,485)	\$180	-	-	\$180
As of December 31, 2014						
Derivatives	\$11,382	\$(11,382)	-	-	-	-

Offsetting of Derivative Liabilities

<u>Sheeting of Derivative Liabilities</u>				<u>Gross Amounts Not Offset in the Balance Sheet</u>		
Description	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Liabilities Presented in the Balance Sheet	Financial Instruments	Cash Collateral Pledged	Net Amount
(Thousands)						
As of December 31, 2015						
Derivatives	\$(49,184)	\$46,486	\$(2,698)	-	-	\$(2,698)
As of December 31, 2014						
Derivatives	\$(48,203)	\$11,382	\$(36,821)	-	\$36,821	-

We face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's or the counterparty guarantor's applicable credit rating (normally Moody's or Standard & Poor's). When our exposure to risk for a counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or we will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of default on or termination of any one contract.

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 amount of cash collateral used to offset against net derivative

Notes to Consolidated Financial Statements

positions was \$37 million as of December 31, 2015. Under the master netting arrangements our obligation to return cash collateral was \$0.1 million at December 31, 2015 and \$0.2 million at 2014.

Certain of our derivative instruments contain provisions that require us to maintain an investment grade credit rating on our debt from each of the major credit rating agencies. If our debt were to fall below investment grade, it would be in violation of those provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2015, is \$39.7 million for which we have posted collateral of \$68.6 million in the normal course of business

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

The estimated fair value of debt amounted to \$3,023 million and \$2,894 million as of December 31, 2015 and 2014, 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, except for unsecured pollution control notes-variable with a fair value of \$145 million both as of December 31, 2015 and 2014, which are considered Level 3. The fair value of these unsecured pollution control notes-variable are determined using unobservable interest rates as the market for these notes is inactive.

Notes to Consolidated Financial Statements

Assets and liabilities measured at fair value on a recurring basis

The financial instruments measured at fair value as of December 31, consist of :

Description (Thousands)	(Level 1)	(Level 2)	(Level 3)	Netting	Total
2015					
Assets					
Noncurrent investments available for sale, primarily money market funds	\$24,860	-	-		\$24,860
Derivatives					
Commodity contracts:					
Electricity	9,665	-	-	\$(9,485)	180
Total	\$34,525	-	-	\$(9,485)	\$25,040
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	\$(43,326)			\$43,326	-
Natural gas	(3,160)			3,160	-
Other	-	-	\$(2,698)		\$(2,698)
Total	\$(46,486)	-	\$(2,698)	\$46,486	\$(2,698)
2014					
Assets					
Noncurrent investments available for sale, primarily money market funds	\$33,326	-	-		\$33,326
Derivatives					
Commodity contracts:					
Electricity	11,382	-	-	\$(11,382)	
Total	\$44,708	-	-	\$(11,382)	\$33,326
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	\$(39,800)	\$(340)	-	\$11,381	\$(28,759)
Natural gas	(4,743)	-	-	1	(4,742)
Other	-	-	\$(3,320)		(3,320)
Total	\$(44,543)	\$(340)	\$(3,320)	\$11,382	\$(36,821)

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 which are Rabbi Trusts for deferred compensation plans primarily consist of money market funds.

We determine the fair value of our derivative assets and liabilities utilizing market approach valuation techniques:

- We enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. We hedge their electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. We have a combination of Level 1 and Level 2 fair values for our electric

Notes to Consolidated Financial Statements

energy derivative contracts. A portion of its electric load obligations are exchange traded contracts in a NYISO location where an active market exists. The forward market prices used to value these open electric energy derivative contracts are based on quoted prices in active markets for identical assets or liabilities, with no adjustment required and therefore we include the fair value in Level 1. A portion of our electric energy derivative contracts, are non-exchange traded contracts that are valued using inputs that are directly observable for the asset or liability, or indirectly observable through corroboration with observable market data and therefore, we include the fair value in Level 2.

- We enter into natural gas derivative contracts to hedge the forecasted purchases required to serve our natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.
- 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	
	2015	2014
Beginning balance	\$3,320	\$547
Total gains (losses) (realized/unrealized)		
Included in earnings	(3,318)	(843)
Included in other comprehensive income	2,696	3,616
Ending balance	\$2,698	\$3,320

The gains and losses included in earnings for the periods (above), which are reported in other operating expense are:

(Thousands)	
Total gains (losses) included in earnings for year ended	
December 31,	
2015	\$(3,318)
2014	\$(843)

Notes to Consolidated Financial Statements

Note 13. Accumulated Other Comprehensive Income (Loss)

	Balance January 1, 2014	2014 Change	Balance December 31, 2014	2015 Change	Balance December 31, 2015
(Thousands)					
Net unrealized holding gain (loss) on investments, net of income tax benefit (expense) of \$(11) for 2014 and 2015	-	\$17	\$17	\$18	\$35
Amortization of pension cost for nonqualified plans, net of income tax (expense) benefit of \$1,956 for 2014 and \$1,577 for 2015	\$(8,292)	(3,113)	(11,405)	3,123	(8,282)
Unrealized (loss) gain on derivatives qualified as hedges:					
Unrealized (loss) during period on derivatives qualified as hedges, net of income tax benefit of \$1,446 for 2014 and \$1,079 for 2015	-	(2,170)	-	(1,617)	
Reclassification adjustment for loss included in net income, net of income tax (benefit) of \$(338) for 2014 and \$(1,327) for 2015	-	505	-	1,991	
Reclassification adjustment for losses on settled cash flow treasury hedges, net of income tax (benefits) of \$(3,561) for 2014 and \$(3,441) for 2015	-	5,362	-	5,178	
Net unrealized (loss) gain on derivatives qualified as hedges	\$(62,023)	\$3,697	\$(58,326)	\$5,552	\$(52,774)
Accumulated Other Comprehensive (Loss) Income	\$(70,315)	\$601	\$(69,714)	\$8,693	\$(61,021)

No Accumulated Other Comprehensive Income (Loss) is attributable to the noncontrolling interests for the above periods.

Note 14. Retirement Benefits

We have funded noncontributory defined benefit pension plans that cover substantially all of our 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 benefit accumulates based on a percentage of annual salary and credited interest. During 2013 we announced that we would stop the cash balance accruals 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. NYSEG's union employees covered under the cash balance plans ceased to receive accruals as of December 31, 2015. 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 those 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.

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

Notes to Consolidated Financial Statements

Obligations and funded status:

	Pension Benefits		Postretirement Benefits	
	2015	2014	2015	2014
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	\$2,564,092	\$2,265,395	\$411,456	\$359,443
Service cost	34,689	30,154	4,176	3,504
Interest cost	94,657	107,321	15,137	16,905
Plan participants' contributions	-	-	3,398	3,935
Plan amendments	-	-	(914)	-
Actuarial (gain) loss	(104,564)	431,769	(23,671)	68,585
Special termination benefits	1,602	-	-	-
Benefits paid	(154,537)	(270,547)	(23,993)	(40,962)
Federal subsidy on benefits paid	-	-	4	46
Benefit obligation at December 31	\$2,435,939	\$2,564,092	\$385,593	\$411,456
Change in plan assets				
Fair value of plan assets at January 1	\$2,097,242	\$2,177,504	\$127,865	\$128,031
Actual return on plan assets	(19,626)	158,979	(4,201)	3,905
Employer contributions	26,651	31,306	20,595	37,028
Plan participants' contributions	-	-	3,398	3,934
Benefits paid	(154,537)	(270,547)	(23,993)	(40,962)
Withdrawal from VEBA	-	-	(2,223)	(4,071)
Fair value of plan assets at December 31	\$1,949,730	\$2,097,242	\$121,441	\$127,865
Funded status at December 31	\$(486,209)	\$(466,850)	\$(264,152)	\$(283,591)

Amounts recognized in the balance sheet	Pension Benefits		Postretirement Benefits	
December 31,	2015	2014	2015	2014
(Thousands)				
Current liabilities	-	-	\$(5,274)	\$(5,424)
Noncurrent liabilities	\$(486,209)	\$(466,850)	(258,878)	(278,167)
	\$(486,209)	\$(466,850)	\$(264,152)	\$(283,591)

During 2014, we offered retired employees who are currently receiving benefits an option to receive their future pension benefit as a lump sum. Approximately \$118.5 million of payments were made in 2014 as a result of retirees exercising the lump sum option. Settlement account was not triggered by these payments.

We have determined that all of our operating companies 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,	2015	2014	2015	2014
(Thousands)				
Net loss	\$982,073	\$1,044,786	\$76,365	\$95,618
Prior service cost (credit)	\$9,122	\$12,028	\$(48,880)	\$(56,818)

Our accumulated benefit obligation for all defined benefit pension plans was \$2.3 billion at December 31, 2015, and \$2.4 billion at December 31, 2014.

CMP's and NYSEG's postretirement benefits were partially funded at December 31, 2015 and 2014. CMP had withdrawals of \$2.2 million 2015 and \$4.1 million in 2014 to reimburse it for a portion of benefits they paid.

Notes to Consolidated Financial Statements

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for all plans as of December 31, 2015 and for all plans as of December 31, 2014. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for the companies' plans for the relevant periods.

December 31, (Thousands)	Projected Benefit Obligation Exceeds Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds Fair Value of Plan Assets	
	2015	2014	2015	2014
Projected benefit obligation	\$2,435,939	\$2,564,092	\$2,435,939	\$2,564,092
Accumulated benefit obligation	\$2,279,859	\$2,380,679	\$2,279,859	\$2,380,679
Fair value of plan assets	\$1,949,729	\$2,097,242	\$1,949,729	\$2,097,242

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

Year ended December 31, (Thousands)	Pension Benefits		Postretirement Benefits	
	2015	2014	2015	2014
Net periodic benefit cost				
Service cost	\$34,689	\$30,154	\$4,176	\$3,504
Interest cost	94,656	107,321	15,137	16,905
Expected return on plan assets	(154,141)	(161,420)	(7,128)	(7,185)
Amortization of prior service cost (benefit)	2,907	4,063	(8,851)	(10,678)
Amortization of net loss	129,987	93,597	6,911	(86)
Special termination benefit charge	1,602	-	-	-
Settlement charge	1,930	35	-	-
Net periodic benefit cost	\$111,630	\$73,750	\$10,245	\$2,460
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss/(gain)	\$69,204	\$434,211	\$(12,342)	\$71,866
Settlement	(1,930)	(35)	-	-
Amortization of net (loss)	(129,987)	(93,597)	(6,911)	86
Current year prior service cost	-	-	(914)	-
Amortization of prior service (cost)	(2,907)	(4,063)	8,851	10,678
Total recognized in regulatory assets and regulatory liabilities	(65,620)	336,516	(11,316)	82,630
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	\$46,010	\$410,266	\$(1,071)	\$85,090

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

Notes to Consolidated Financial Statements

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2016

	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	\$123,423	\$6,888
Estimated prior service cost (benefit)	\$1,767	\$(9,018)

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ended December 31, 2015.

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits 2015	2014	Postretirement Benefits 2015	2014
Discount rate	4.10%	3.80%	4.10%	3.80%
Rate of compensation increase	4.00%	4.10%	NA	NA

As of December 31, 2015, we increased our discount rate from 3.80% to 4.10%. 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 noncallable bonds with yields that closely matches the duration of the expected cash flows of our benefit obligations.

Weighted-average assumptions used to determine net periodic benefit cost for year ended December 31,	Pension Benefits 2015	2014	Postretirement Benefits 2015	2014
Discount rate	3.80%	4.90%	3.80%	4.90%
Expected long-term return on plan assets	7.50%	7.50%	-	-
Expected long-term return on plan assets - nontaxable trust	-	-	7.50%	7.50%
Expected long-term return on plan assets - taxable trust	-	-	5.00%	5.00%
Rate of compensation increase	4.10%	4.20%	NA	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. The operating companies amortize unrecognized actuarial gains and losses either over 10 years from the time they are incurred or 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,	2015	2014
Health care cost trend rate assumed for next year	7.00%/9.00%	7.50%/7.00%
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	2027	2027

Notes to Consolidated Financial Statements

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. 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	\$302	\$(256)
Effect on postretirement benefit obligation	\$6,884	\$(5,793)

Cash Flows

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 \$21 million to our pension benefit plans in 2016.

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:

	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
(Thousands)			
2016	\$148,014	\$25,813	\$133
2017	\$152,489	\$25,945	\$153
2018	\$155,121	\$25,988	\$171
2019	\$157,206	\$26,155	\$189
2020	\$159,550	\$26,163	\$208
2021 – 2025	\$808,873	\$129,542	\$1,344

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.

Our 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% in equity securities and 20% in equity alternative investments. The Liability-Hedging asset class has a target allocation percentage of 45%. Return-Seeking investments generally consist of domestic, international, global and emerging market equities, invested in companies across all market capitalizations. Return-Seeking assets also include investments in strategies such as 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. Systematic rebalancing within the target ranges, should any asset categories drift outside their specified ranges, increases the

Notes to Consolidated Financial Statements

probability that the annualized return on the investments will be enhanced, while realizing lower overall risk.

Networks 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 Networks totaled approximately \$12 million for 2015 and \$10 million for 2014.

The fair values of our pension benefits plan assets at December 31, 2015 and 2014, by asset category are:

		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	Total			
(Thousands)				
2015				
Cash and cash equivalents	\$57,526	\$3,290	\$54,236	-
U.S. government securities	171,024	171,024	-	-
Common stocks	313,911	313,911	-	-
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	318,247	(21)	-	318,268
Total	\$1,949,730	\$569,807	\$404,243	\$975,680
2014				
Cash and cash equivalents	\$47,941	\$3,795	\$44,146	-
U.S. government securities	177,379	177,379	-	-
Common stocks	430,900	343,757	87,143	-
Registered investment companies	115,930	115,930	-	-
Corporate bonds	344,216	-	344,216	-
Preferred stocks	4,050	281	3,769	-
Common/collective trusts	476,581	-	26,440	\$450,141
Partnership/joint venture interests	79,489	-	-	79,489
Real estate investments	74,871	-	-	74,871
Other investments, principally annuity and fixed income	345,885	-	4,200	341,685
Total	\$2,097,242	\$641,142	\$509,914	\$946,186

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.

Notes to Consolidated Financial Statements

- 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 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.

(Thousands)	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)				
	Common/ Collective Trusts	Partner- ship/ Joint Venture Interests	Real Estate Invest- ments	Other Invest- ments	Total
Balance, December 31, 2013	\$458,313	\$56,880	\$67,266	\$336,595	\$919,054
Actual return on plan assets:					
Relating to assets still held at the reporting date	60,324	2,609	4,670	(834)	66,769
Relating to assets sold during the year	(48,286)	-		6,251	(42,035)
Purchases, sales and settlements	(20,210)	20,000	2,935	(327)	2,398
Balance, December 31, 2014	\$450,141	\$79,489	\$74,871	\$341,685	\$946,186
Actual return on plan assets:					
Relating to assets 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

Our postretirement benefits plan assets are held with a trustee in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes in order 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 100% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes. The remainder is invested in arrangements subject to income taxes.

We have established a target asset allocation policy within allowable ranges for our postretirement benefits plan assets of 47% equity securities, 38% fixed income and 15% for all other types of investments. The target allocations within allowable ranges are further diversified into 20% large cap domestic equities, 12% medium and small cap domestic equities, 10%

Notes to Consolidated Financial Statements

international developed market and 5% emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at 38%. Other, alternative investment targets are 5% for real estate, 5% absolute return and 5% tangible assets. Systematic rebalancing within target ranges, should any asset categories drift outside their specified ranges, increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk.

The fair values of Networks' other postretirement benefits plan assets at December 31, 2015 and 2014, by asset category are:

and 2014, by asset category are:

		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	Total			
(Thousands)				
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	11,519	11,519	-	-
Total assets measured at fair value	\$121,441	\$119,592	\$1,703	\$146
2014				
Money market funds	\$4,478	\$4,478	-	-
Mutual funds, fixed	35,914	35,914	-	-
Government & corporate bonds	2,126	-	\$2,126	-
Mutual funds, equity	44,877	44,877	-	-
Common stocks	28,459	28,459	-	-
Mutual funds, other	12,011	12,011	-	-
Total assets measured at fair value	\$127,865	\$125,739	\$2,126	-

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.

Diversified equity securities did not include any Iberdrola or AGR common stock at December 31, 2015.

Note 15. Subsequent events

The company has performed a review of subsequent events through May 3, 2016, which is the date these financial statements were available to be issued, and the financial statements reflect events occurring from January 1, 2016 through such date.

See also Note 9 relating to ROE Complaint proceeding update on April 29, 2016.

Notes to Consolidated Financial Statements

New Credit Facility

On April 5, 2016, AGR, NYSEG, RGE, CMP, The United Illuminating Company (“UI”), Connecticut Natural Gas Corporation (“CNG”), The Southern Connecticut Gas Company (“SCG”) and The Berkshire Gas Company (“BGC”) entered into a revolving credit facility with a syndicate of banks (the “Credit Facility”), that provides for maximum borrowings of up to \$1.5 billion in the aggregate.

Under the terms of the 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, RGE, 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 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 Credit Facility is April 5, 2021.

As a condition of closing on the new Credit Facility, the Joint Facility was terminated and all amounts outstanding, accrued or payable under the Joint Facility were repaid in full.

Transfer of UIL Holdings Corporation under Networks

Effective as of April 30, 2016, and in compliance with a regulatory commitment, the ownership of UIL Holdings Corporation and its subsidiaries, collectively UIL, a heretofore wholly owned by AGR, has been transferred to a newly created special purpose entity named UIL Group, LLC, which is a wholly-owned subsidiary of Networks. Total consolidated assets for UIL were \$7,048 million at December 31, 2015. The company is still evaluating the accounting implications of the transaction and during 2016 will be applying ASC 805, Business Combinations, for common control transactions.