

Iberdrola USA Networks, Inc.
Consolidated Financial Statements
For the Years Ended December 31, 2014 and 2013

Iberdrola USA Networks, Inc.

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Management's Report on Internal Control Over Financial Reporting

Iberdrola USA 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, 2014, 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, 2014, 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, 2014, has been audited by Ernst & Young, LLP an independent public accounting firm, as stated in their report which appears herein.

Iberdrola USA Networks, Inc.
March 9, 2015



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

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Report of Independent Auditors on Financial Statements

To the Stockholder and Board of Directors of Iberdrola USA Networks, Inc.:

We have audited the accompanying consolidated financial statements of Iberdrola USA Networks, Inc., which comprise the consolidated balance sheet as of December 31, 2014, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for the year 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 audit. We conducted our audit 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 Iberdrola USA Networks, Inc. at December 31, 2014, and the consolidated results of its operations and its cash flows for the year then ended in conformity with U.S. generally accepted accounting principles.



Report of Other Auditors on December 31, 2013 Financial Statements

The financial statements of Iberdrola USA Networks, Inc. as of and for the year ended December 31, 2013 were audited by other auditors whose report dated February 7, 2014, except as to Note 2., as to which the date is March 9, 2015, expressed an unqualified opinion thereon.

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, Iberdrola USA Networks, Inc.'s internal control over financial reporting as of December 31, 2014, 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 March 9, 2015 expressed an unqualified opinion thereon.

Ernst & Young LLP

March 9, 2015



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Independent Auditors Report on Internal Control Over Financial Reporting

To the Stockholder and Board of Directors of Iberdrola USA Networks, Inc.:

We have examined Iberdrola USA Networks, Inc.'s internal control over financial reporting as of December 31, 2014, 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). Iberdrola USA 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 Iberdrola USA 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, Iberdrola USA Networks, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, 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 sheet as of December 31, 2014, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for the year then ended of Iberdrola USA Networks, Inc. and our report dated March 9, 2015 expressed an unqualified opinion thereon.

Ernst & Young LLP

March 9, 2015

**Iberdrola USA Networks, Inc.
Consolidated Statements of Income**

Year ended December 31, (Thousands)	2014	2013
Operating Revenues		
Electricity	\$2,730,339	\$2,667,904
Natural gas	666,593	651,170
Total Operating Revenues	3,396,932	3,319,074
Operating Expenses		
Electricity purchased and fuel used in generation	772,398	707,377
Natural gas purchased	283,598	249,871
Other operating expenses	927,332	889,750
Maintenance	255,531	246,649
Depreciation and amortization	274,770	256,514
Other taxes	267,537	265,761
Total Operating Expenses	2,781,166	2,615,922
Operating Income	615,766	703,152
Other (Income)	(51,164)	(43,999)
Other Deductions	9,270	2,690
Interest Charges, Net	197,796	202,061
Income Before Income Tax	459,864	542,400
Income Tax Expense	172,378	235,167
Net Income	287,486	307,233
Less:		
Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests	34	34
Net Income/(Loss) Attributable to Other Noncontrolling Interests	483	(39)
Net Income Attributable to Iberdrola USA Networks, Inc.	\$286,969	\$307,238

**Iberdrola USA Networks, Inc.
Consolidated Statements of Comprehensive Income**

Year ended December 31, (Thousands)	2014	2013
Net Income	\$287,486	\$307,233
Other Comprehensive Income, Net of Tax		
Net unrealized holding gain (loss) on investments	17	(135)
Amortization of pension cost for nonqualified plans	(3,113)	(959)
Unrealized loss on derivatives qualified as hedges:		
Unrealized loss during period on derivatives qualified as hedges	(1,802)	(79)
Reclassification adjustment for loss included in net income	137	212
Reclassification adjustment for loss on settled cash flow treasury hedges	5,362	6,765
Net unrealized gain on derivatives qualified as hedges	3,697	6,898
Other Comprehensive Income	601	5,804
Comprehensive Income	288,087	313,037
Less:		
Preferred Stock Dividends of Subsidiaries, Noncontrolling Interests	34	34
Comprehensive Income (Loss) Attributable to Other Noncontrolling Interests	483	(39)
Comprehensive Income Attributable to Iberdrola USA Networks, Inc.	\$287,570	\$313,042

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

**Iberdrola USA Networks, Inc.
Consolidated Balance Sheets**

December 31, (Thousands)	2014	2013
Assets		
Current Assets		
Cash and cash equivalents	\$13,713	\$13,141
Accounts receivable and unbilled revenues, net	559,393	592,576
Accounts receivable from affiliates	17,479	10,997
Notes receivable from affiliates	-	8,198
Fuel and natural gas in storage, at average cost	43,003	42,016
Materials and supplies, at average cost	52,525	42,040
Derivative assets	-	8,024
Deferred income taxes	46,514	35,497
Broker margin accounts	56,817	7,756
Prepayments and other current assets	150,634	113,253
Regulatory assets	79,629	35,665
Deferred income taxes regulatory	29,251	19,578
Total Current Assets	1,048,958	928,741
Utility Plant, at Original Cost		
Electric	8,624,981	8,087,241
Natural gas	1,722,817	1,652,341
Common	653,314	627,759
	11,001,112	10,367,341
Less accumulated depreciation	3,491,108	3,421,299
Net Utility Plant in Service	7,510,004	6,946,042
Construction work in progress	867,227	940,982
Total Utility Plant	8,377,231	7,887,024
Other Property and Investments	52,841	63,320
Regulatory and Other Assets		
Regulatory assets		
Pension and other postretirement benefits	1,101,415	729,368
Unfunded future income taxes	366,491	357,220
Environmental remediation costs	246,073	219,689
Storm costs	258,869	245,434
Other	426,287	373,566
Total regulatory assets	2,399,135	1,925,277
Other assets		
Goodwill	979,603	979,603
Pension	-	52,650
Other	45,427	52,432
Total other assets	1,025,030	1,084,685
Total Regulatory and Other Assets	3,424,165	3,009,962
Total Assets	\$12,903,195	\$11,889,047

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

**Iberdrola USA Networks, Inc.
Consolidated Balance Sheets**

December 31,	2014	2013
(Thousands, except shares)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	\$134,415	\$22,759
Notes payable	-	13,800
Notes payable to affiliates	793,667	295,794
Accounts payable and accrued liabilities	297,606	433,362
Accounts payable to affiliates	17,842	12,065
Accounts payable, electricity purchased	49,766	52,681
Accounts payable, natural gas purchased	21,421	27,304
Interest accrued	38,398	44,261
Taxes accrued	5,036	55,287
Derivative liabilities	27,438	547
Environmental remediation costs	35,964	30,327
Other current liabilities	179,955	260,186
Regulatory liabilities	152,238	84,409
Total Current Liabilities	1,753,746	1,332,782
Regulatory and Other Liabilities		
Regulatory liabilities		
Accrued removal obligations	720,866	714,037
Deferred income taxes	462,344	312,567
Other	484,714	437,289
Total regulatory liabilities	1,667,924	1,463,893
Other liabilities		
Deferred income taxes	1,630,162	1,636,064
Nuclear plant obligations	122,238	122,192
Pension and other postretirement benefits	744,363	364,577
Environmental remediation costs	284,015	259,604
Other	212,877	168,786
Total other liabilities	2,993,655	2,551,223
Total Regulatory and Other Liabilities	4,661,579	4,015,116
Long-term Debt	2,386,772	2,531,913
Total Liabilities	8,802,097	7,879,811
Commitments and Contingencies		
Preferred Stock of Subsidiary		
Redeemable preferred stock, noncontrolling interest	192	192
Iberdrola USA Networks, Inc. Common Stock Equity		
Common stock (\$.01 par value, 100 shares authorized and outstanding at December 31, 2014 and 2013)	-	-
Capital in excess of par value	3,078,759	3,078,759
Retained earnings	1,084,541	997,572
Accumulated other comprehensive loss	(69,714)	(70,315)
Total Iberdrola USA Networks, Inc. Common Stock Equity	4,093,586	4,006,016
Other Noncontrolling Interests	7,320	3,028
Total Equity	4,100,906	4,009,044
Total Liabilities and Equity	\$12,903,195	\$11,889,047

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

Iberdrola USA Networks, Inc.
Consolidated Statements of Cash Flows

Year Ended December 31, (Thousands)	2014	2013
Cash Flow from Operating Activities		
Net income	\$287,486	\$307,233
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	271,860	254,221
Amortization of regulatory and other assets and liabilities	(38,054)	24,751
Carrying cost of regulatory assets and liabilities	35,346	21,342
Deferred income taxes and investment tax credits, net	117,302	189,797
Pension expense	46,886	67,076
Amortization of positive benefit adjustments	-	(26,504)
Changes in current operating assets and liabilities		
Accounts receivable and unbilled revenues, net	26,701	(48,598)
Broker margin accounts	(49,061)	748
Inventory	(11,472)	2,731
Prepayments and other current assets	(39,233)	23,938
Accounts payable and accrued liabilities	2,052	(8,614)
Interest accrued	(5,863)	3,023
Taxes accrued	(43,654)	(33,317)
Other current liabilities	(102,219)	33,215
Pension and other postretirement benefits contributions	(31,306)	(8,052)
VEBA withdrawal	4,071	3,450
Changes in other assets		
Department of Energy – Yankee settlement received	10,260	12,903
Payment to Efficiency Maine	(13,117)	(5,787)
Changes in regulatory assets and regulatory liabilities	183,941	(25,196)
Environmental remediation costs	8,984	11,821
Deferred storm costs	(20,051)	(34,864)
Other	(42,248)	(4,367)
Net Cash Provided by Operating Activities	598,611	760,950
Cash Flow from Investing Activities		
Utility plant additions, net of contributions in aid of construction	(874,598)	(789,075)
Grants received from governmental entities	3,791	4,250
Proceeds from sale	5,303	1,898
Notes receivable	8,198	(3,095)
Investments	5,177	1,931
Net Cash (Used in) Investing Activities	(852,129)	(784,091)
Cash Flow from Financing Activities		
Long-term note issuances	-	225,000
Long-term note repayments	(33,758)	(271,930)
Notes payable three months or less, net	(13,800)	31,050
Notes payable affiliates	497,873	-
Capital infusion	-	145,000
Dividends paid on common and preferred stock	(200,034)	(110,034)
Other noncontrolling interests	3,809	1,070
Net Cash Provided by Financing Activities	254,090	20,156
Net Increase/(Decrease) in Cash and Cash Equivalents	572	(2,985)
Cash and Cash Equivalents, Beginning of Year	13,141	16,126
Cash and Cash Equivalents, End of Year	\$13,713	\$13,141

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

**Iberdrola USA Networks, Inc.
Consolidated Statements of Changes in Equity**

(Thousands, except share amounts)	Iberdrola USA Networks, Inc. Stockholder						Comprehensive Income	Total
	Common Stock Outstanding \$.01 Par Value Shares	Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Other Noncontrolling Interests		
Balance, January 1, 2013	100	-	\$2,933,759	\$800,334	\$(76,119)	\$1,997		\$3,659,971
Net income*				307,238		(39)	\$307,199	307,199
Other comprehensive income, net of tax					5,804		5,804	5,804
Comprehensive income*							313,003	313,003
Additional paid in capital			145,000			1,086		146,086
Dividends to other noncontrolling interests						(16)		(16)
Cash dividends paid common stock				(110,000)				(110,000)
Balance, December 31, 2013	100	-	3,078,759	997,572	(70,315)	3,028		4,009,044
Net income*				286,969		483	287,452	287,452
Other comprehensive income, net of tax					601		601	601
Comprehensive income*							288,053	288,053
Additional paid in capital				-		3,809		3,809
Cash dividends paid common stock				(200,000)				(200,000)
Balance, December 31, 2014	100	-	\$3,078,759	\$1,084,541	\$(69,714)	\$7,320		\$4,100,906

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 2013 and 2014.

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Background: Iberdrola USA Networks, Inc. (Networks, the company, we, our, us) is a public utility holding company operating under the Public Utility Holding Company Act of 2005. Networks is a wholly-owned subsidiary of Iberdrola USA, Inc. (IUSA), which is a wholly-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 (RG&E).

Networks was formed on November 20, 2013, when IUSA was reorganized to become the parent company of Networks and Iberdrola Renewables Holding, Inc. (IRHI), another subsidiary of Iberdrola. IUSA 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. IUSA retained other assets and liabilities it held directly including goodwill, tax assets and liabilities attributable to IUSA according to the tax sharing agreement, and debt obligations.

These financial statements reflect the operations and financial position of the businesses consolidated by Networks as if Networks had been in existence since January 1, 2012. Beginning balances reflect the historical cost of IUSA for Networks as of January 1, 2012, in the various subsidiaries and investments transferred to Networks, as described above. Equity was allocated to retained earnings based on the Retained Earnings of RGS, CMP Group and IUSA Enterprises, with the remainder being allocated to Capital in Excess of Par Value after adjustments for Noncontrolling Interests and Accumulated Other Comprehensive Loss.

Accounts receivable: Accounts receivable at December 31 include unbilled revenues of \$142 million for 2014 and \$134 million for 2013, and are shown net of an allowance for doubtful accounts at December 31 of \$52 million for 2014 and \$59 million for 2013. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was \$41 million in 2014 and \$38 million in 2013.

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:

Notes to Consolidated Financial Statements

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 2014 and \$41 million for 2013. DPA receivable balances, net of the applicable reserve, at December 31 were: \$40 million for 2014 and \$51 million for 2013.

Asset retirement obligations: We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability periodically to reflect revisions to either the timing or the amount of the original estimated undiscounted cash flows over time, 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 \$39 million for 2014 and \$32 million for 2013. 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, 2014 and 2013.

Year ended December 31, (Thousands)	2014	2013
ARO, beginning of year	\$32,080	\$35,459
Liabilities settled during the year	(1,262)	(1,444)
Accretion expense	2,046	2,237
Revisions in estimated cash flows	5,835	(4,172)
ARO, end of year	\$38,699	\$32,080

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.

Notes to Consolidated Financial Statements

Supplemental Disclosure of Cash Flows Information	2014	2013
(Thousands)		
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	\$121,379	\$123,999
Income taxes paid, net	\$138,691	\$68,895

Interest capitalized was \$10.5 million in 2014 and \$8.5 million in 2013.

Preliminary survey costs: Consolidated preliminary survey costs included in Other assets at December 31 totaled approximately \$14 million for 2014 and \$13 million for 2013. Preliminary survey costs represent expenditures incurred for the purpose of determining the feasibility of utility projects under contemplation. When construction begins on such projects, the amounts are moved to Construction work in progress (CWIP), and then eventually to Utility plant when construction is completed and the asset is placed in service. If a project is abandoned, the costs incurred for that project are charged to expense.

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 2014 and 2013. 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 \$261 million in 2014 and \$239 million in 2013. Amortization of capitalized software was \$14 million in 2014 and \$18 million in 2013.

We charge repairs and minor replacements to operating 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 (years)	December 31, 2014	December 31, 2013
(thousands)			
Electric			
Transmission	52	\$3,230,591	\$2,812,182
Distribution	51	4,576,638	4,416,524
Generating	62	306,530	305,007
Other	31	511,222	553,528
Total electric		8,624,981	8,087,241
Natural Gas			
Transportation	41	766	32,013
Distribution	61	1,677,097	1,574,445
Other	23	44,954	45,883
Total Gas		1,722,817	1,652,341
Other common	38	653,314	627,759
Total plant		\$11,001,112	\$10,367,341

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 2048.

Notes to Consolidated Financial Statements

Goodwill: We are required to perform an annual goodwill impairment assessment at the same time each year and, accordingly, we perform our annual impairment assessment of goodwill as of August 31st. We update our goodwill assessment during interim periods if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value.

An entity is allowed to first assess qualitative factors – also referred to as step zero – to determine if there are events or circumstances that indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount, including goodwill. If it is not more likely than not that the fair value is less than the carrying amount, then it is not necessary to perform the two-step quantitative goodwill impairment test. An entity has the option to bypass step zero for any reporting unit in any period and proceed directly to performing step one of the goodwill impairment test, and may resume performing the step zero qualitative assessment in any subsequent period.

If step zero indicates that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the entity would perform step one of the two-step impairment test. Step one of the impairment test involves comparing the fair value of a reporting unit with its carrying value, including goodwill. If the carrying value of a reporting unit exceeds the reporting unit's fair value, step two must be performed to determine the amount, if any, of goodwill impairment charge. If the carrying amount is less than fair value, further testing for goodwill impairment is not performed.

Step two of the goodwill impairment test involves comparing the implied fair value of the reporting unit's goodwill against the carrying value of the goodwill. In step two, determining the implied fair value of goodwill requires the valuation of a reporting unit's identifiable tangible and intangible assets and liabilities as if the reporting unit had been acquired in a business combination on the testing date. The difference between the fair value of the entire reporting unit as determined in step one and the net fair value of all identifiable assets and liabilities represents the implied fair value of goodwill. A goodwill impairment charge, if any, would be the difference between the carrying amount of goodwill and the implied fair value of goodwill upon the completion of step two.

We may be required to recognize an impairment of goodwill in the future due to market conditions or other factors related to our performance. Those market events could include a decline in the forecasted results in our business plan, significant adverse rate case results, changes in capital investment budgets or changes in interest rates that could permanently impair the fair value of a reporting unit. Recognition of impairments of a significant portion of goodwill would negatively affect our reported results of operations and total capitalization, the effect of which could be material and could make it more difficult to maintain our credit ratings, secure financing on attractive terms, maintain compliance with debt covenants and meet expectations of our regulators.

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 profit or loss 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.

Technical Corrections and Improvements: In October 2012 the FASB issued amendments to make certain technical corrections to a wide variety of Topics in its Accounting Standards Codification® (ASC). The amendments are generally not substantive, and include amendments that identify when the use of *fair value* should be linked to the definition of fair value in Topic 820,

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Fair Value Measurement, as well as conforming amendments to reflect the measurement and disclosure requirements of Topic 820. The amendments are not expected to significantly affect current accounting practice. The amendments not subject to transition guidance were effective upon issuance for both public entities and nonpublic entities. For nonpublic entities, the amendments that are subject to transition guidance are effective for fiscal periods beginning after December 15, 2013. Our adoption of the amendments, including those subject to the transition guidance, did not affect our results of operation, financial position or cash flows.

Comprehensive Income: In February 2013 the FASB issued its final update for the amendments concerning improving the reporting of amounts reclassified out of accumulated other comprehensive income (AOCI), including information an entity is to provide and present parenthetically on the face of the financial statements or in a single note. The amendments are effective for nonpublic entities prospectively for reporting periods beginning after December 15, 2013. Our adoption of the amendments did not affect our results of operation, financial position or cash flows.

Pushdown Accounting: In November 2014 the FASB issued guidance on when and how an acquired entity that is a business or nonprofit activity (public or nonpublic) can apply pushdown accounting in its separate financial statements upon the occurrence of an event in which an acquirer (individual or entity) obtains control of the acquired entity. It provides an acquired entity with an option to apply pushdown accounting in its separate financial statements. An acquired entity would determine whether to elect to apply pushdown accounting for each individual change-in-control event in which an acquirer obtains control of the acquired entity. If pushdown accounting is not applied in the reporting period in which the change-in-control event occurs, an acquired entity will have the option to elect to apply pushdown accounting in a subsequent reporting period to the acquired entity's most recent change-in-control event, but such an election would be considered a change in accounting principle. An election to apply pushdown accounting to an individual change-in-control event is irrevocable. Disclosures are required if the option is elected. The change was effective November 18, 2014. After the effective date, an acquired entity can make an election to apply the guidance to future change-in-control events or to its most recent change-in-control event. Our adoption of the pronouncement did not affect our results of operation, financial position or cash flows. We have not made an election to apply pushdown accounting since the effective date for the new guidance.

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.

Presentation of an Unrecognized Tax Benefit: In July 2013 the FASB issued amendments intended to eliminate diversity in practice 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. No new recurring disclosures are required. The amendments are effective for nonpublic entities for fiscal years beginning after December 15, 2014, with early adoption allowed. We have not elected early adoption. The amendments are to be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is allowed. Our

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adoption of the amendments is not expected to materially affect our results of operation, financial position or cash flows.

Discontinued Operations and Disposals of Components of an Entity: The FASB issued amendments in April 2014 that change the requirements for reporting 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 require additional disclosures about the financial effects of discontinued operations and disclosure of the pretax profit or loss of an individually significant component of an entity that does not qualify for discontinued operations reporting. The amendments are effective for public business entities and certain not-for-profit entities for annual periods beginning on or after December 15, 2014, and interim periods within those years, and are effective for all other entities for annual periods beginning on or after December 15, 2014, and interim periods within annual periods beginning on or after December 15, 2015. Prospective application is required, and early adoption is permitted as specified. Our adoption of the amendments is not expected to materially affect our results of operation, financial position or cash flows.

Revenue from Contracts with Customers: In May 2014 the FASB and the International Accounting Standards Board jointly issued their converged standard that creates common revenue recognition guidance. The primarily principles-based guidance provides a framework intended to improve financial reporting of revenue and improve comparability of revenue reporting in financial statements of companies using U.S. GAAP and IFRS. 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. An entity is required to apply the following five steps to achieve that core principle: 1) Identify the contract(s) with a customer. 2) Identify the performance obligations in the contract. 3) Determine the transaction price. 4) Allocate the transaction price to the performance obligations in the contract. 5) Recognize revenue when (or as) the entity satisfies a performance obligation. The standard also enhances disclosures about revenue, provides guidance for transactions not previously addressed comprehensively and improves guidance for multiple-element arrangements. The standard is effective for public entities for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early application is not permitted. It is effective for nonpublic entities for annual reporting periods beginning after December 15, 2017, and interim periods within annual periods beginning after December 15, 2018. Nonpublic entities may elect earlier application as specified, but not earlier than the public entity effective date. All entities are required to apply the standard retrospectively, choosing one of two specified transition methods. We have yet to determine how our adoption of the standard will affect our results of operation, financial position or cash flows.

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Other (Income) and Other Deductions:

Year Ended December 31, (Thousands)	2014	2013
Interest and dividend income	\$(1,458)	\$(813)
Allowance for funds used during construction	(17,495)	(14,327)
Earnings from equity investments	-	(185)
Carrying costs on regulatory assets	(28,787)	(28,665)
Gain on sale of property	(3,204)	-
Miscellaneous	(220)	(9)
Total other (income)	\$(51,164)	\$(43,999)
Earnings from equity investments	\$5,699	-
Civic donations	2,011	\$1,910
Miscellaneous	1,560	780
Total other deductions	\$9,270	\$2,690

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

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.

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 16).

Related party transactions: Certain Networks subsidiaries borrow from IUSA, the parent of Networks, through intercompany revolving credit agreements. For NYSEG, RG&E 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 IUSA as their primary source of financing. Networks incurred financing costs from IUSA of \$4 million in 2014 and 2013 recorded as interest expense. See Note 5 for further detail on the credit facility with IUSA.

Networks, including its subsidiaries, provides various administrative and other services to IUSA and IUSA Group. 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 IUSA was less than \$1 million for 2014 and \$8 million for 2013. Networks received charges from Iberdrola for work on the unified SAP project of \$4.7 million in 2014 and \$3.5 million in 2013. Networks' subsidiaries received services from Iberdrola Engineering Products (IEP)

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related to capital projects of \$13.6 million for 2014 and \$9.1 million for 2013. Networks contributed amounts to fund IEP's direct costs associated with these engineering projects.

Since the reorganization that created Networks on November 20, 2013, the cost for management services provided to Networks by Iberdrola and its subsidiaries was approximately \$11.2 million for 2014 and \$3.1 million for 2013. Prior to the reorganization these costs were charged to IUSA and not allocated to any of the subsidiaries. All of the costs for services provided are recorded to other operating expenses on the financial statements.

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 RG&E enter into power purchase and sales transactions with the New York Independent System Operator (NYISO). When NYSEG and RG&E 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 RG&E net their purchase and sale transactions with the NYISO on an hourly basis.

NYSEG's and RG&E'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 13.)

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: Iberdrola USA, the parent company of Networks, 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 Iberdrola USA pursuant to a tax sharing agreement between Iberdrola USA and its members.

Deferred income taxes are recorded for the temporary differences between the financial statement and tax bases of assets and liabilities using currently enacted tax rates. Valuation allowances are established against deferred tax assets whenever circumstances indicate that it is more likely than not that such assets will not be realized in future periods. We amortize investment tax credits over the estimated lives of the related assets.

The state of New York imposes on corporations a franchise tax that is computed as the higher of a tax based on income or a tax based on capital. To the extent our state tax based on capital is in

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excess of the state tax based on income, we report such excess in other taxes and taxes accrued in the accompanying consolidated financial statements.

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

We classify all interest and penalties related to uncertain tax positions as interest expense. The gross interest accrued was \$3.6 million as of December 31, 2014, and \$10.5 million as of December 31, 2013.

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), nonbypassable wires charges and environmental remediation liability. 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 57% of the company's employees are covered by a collective bargaining agreement. Agreements which will expire within the coming year apply to approximately 35% of our employees.

Note 2. 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 2014 or in 2013 as a result of our annual impairment assessment, which we performed as of August 31. 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. For 2013, as a result of our step zero qualitative assessment, it was not more likely than not that the fair value of each reporting unit was less than its carrying amount, and it was not necessary to perform the two-step goodwill impairment test. There were no events

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or circumstances subsequent to our annual impairment assessment for 2014 or for 2013 that required us to update the assessment.

As of December 31, 2014 and 2013, the carrying amount of goodwill was \$979.6 million, with no accumulated impairment losses and no changes during 2014 and 2013.

Note 3. Income Taxes

Year Ended December 31, (Thousands)	2014	2013
Current		
Federal	\$42,057	\$28,358
State	22,176	21,553
Current taxes charged to expense	64,233	49,911
Deferred		
Federal	122,073	174,686
State	(12,204)	12,669
Deferred taxes charged to expense	109,869	187,355
Investment tax credit adjustments	(1,724)	(2,099)
Total	\$172,378	\$235,167

Our tax expense differed from the expense at the federal statutory rate of 35% due to the following:

Year Ended December 31, (Thousands)	2014	2013
Tax expense at Federal statutory rate	\$160,952	\$189,840
Depreciation and amortization not normalized	15,456	11,061
Investment tax credit amortization	(1,724)	(2,099)
Medicare subsidy	579	4,029
Impairment of unfunded deferred tax regulatory assets		11,339
Tax return and audit adjustments	(2,863)	4,222
State taxes, net of federal benefit	6,484	22,246
Other, net	(6,506)	(5,471)
Total	\$172,378	\$235,167

Income taxes were \$11.4 million more in 2014 than they would have been at the federal statutory rate of 35% and \$45.3 million more in 2013. The 2014 effective tax rate was higher than the statutory rate primarily due to an increase in depreciation not normalized. There was a decrease in state taxes due in large part to the reduction of the New York tax rate, from 7.1% to 6.5%, (2013 New York Senate Bill No. 6359). The 2013 effective tax rate was higher than the statutory rate primarily due to state taxes and the impairment of certain unfunded deferred tax regulatory assets related to deferred income taxes that we determined it would not seek rate recovery of as well as an increase in depreciation not normalized resulting from a more accurate determination of the tax vs. book depreciation temporary difference subject to normalization.

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Our consolidated deferred tax assets and liabilities consisted of:

December 31, (Thousands)	2014	2013
Current Deferred Income Tax Assets		
Regulatory	\$29,251	\$19,578
Other	46,514	35,497
Total Current Deferred Income Tax Assets	\$75,765	\$55,075
Noncurrent Deferred Income Tax Liabilities (Assets)		
Property related	\$1,895,159	\$1,756,207
Employee Benefits	99,271	100,637
Accumulated deferred investment tax credits	15,678	17,402
Federal and State NOL's	(19)	-
Positive benefits adjustments merger order	(20,175)	(20,175)
Storm cost deferral	101,210	75,519
Other	1,382	19,041
Total Noncurrent Deferred Income Tax Liabilities	2,092,506	1,948,631
Less amounts classified as regulatory liabilities		
Current deferred income taxes		-
Long-term deferred income taxes	462,344	312,567
Noncurrent Deferred Income Tax Liabilities	\$1,630,162	\$1,636,064
Deferred tax assets	\$95,959	\$75,250
Deferred tax liabilities	2,112,700	1,968,806
Net Accumulated Deferred Income Tax Liabilities	\$2,016,741	\$1,893,556

Deferred tax assets are reduced by a valuation allowance when it is more likely than not that some portion or the entire deferred income tax asset will not be realized. A valuation allowance for the entire \$14.3 million carryforward of Maine Research and Development Super credits generated in tax years 2007 to 2012 was established as of December 31, 2013 with no change of this balance in 2014.

Reconciliation of Gross Income Tax Reserves (Thousands)	2014	2013
Balance as of January 1	\$36,014	\$33,793
Increases for tax positions related to prior years	19,022	3,479
Reduction for tax position related to settlements with taxing authorities	(23,438)	(1,258)
Balance as of December 31	\$31,598	\$36,014

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.

Unrecognized income tax benefits represent income tax positions taken on income tax returns but not yet recognized in the consolidated financial statements. We have unrecognized income tax benefits of \$31.6 million as of December 31, 2014, and \$36.0 million as of December 31, 2013. Accruals for interest and penalties on tax reserves were \$3.6 million as of December 31, 2014 and \$10.5 million as of December 31, 2013 and \$7.3 million as of December 31, 2012. If recognized, \$0.4 million of the total gross unrecognized tax benefits would affect the effective tax rate. Gross income tax reserves decreased \$4.4 million in 2014 primarily due to increases for additional positions reserved in 2014 of \$19.0 million offset by settlements with taxing authorities of \$23.4 million.

On December 29, 2014, the Joint Committee on Taxation approved the examination of Iberdrola IUSA and its subsidiaries, which includes members of the Networks consolidated group, for the

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1998-2009 tax years. The results of these audits, net of reserves already provided, were immaterial. All New York and Maine state returns are closed through 2011.

Note 4. Long-term Debt

At December 31, 2014 and 2013, our consolidated long-term debt was:

Company		Interest Rates	Maturity	Amount (Thousands)	
				2014	2013
First mortgage bonds ⁽¹⁾					
RG&E	Series WW, VV, XX, YY & AAA	4.10% - 8.00%	2019 - 2033	\$600,000	\$600,000
RG&E	PCN 2004 Series A	4.75%	2016	10,500	10,500
RG&E	PCN Series C	5.00%	2016	29,350	29,350
CMP	Series A, B, C, D & E	3.07% - 5.70%	2019 - 2043	750,000	750,000
Total first mortgage bonds				1,389,850	1,389,850
Unsecured pollution control notes (PCNs), fixed					
NYSEG	2011 Series A, B & D	2.125% -2.250%	2015	132,000	132,000
CMP	Industrial Development Authority of the state of New Hampshire Notes	5.375%	2014	-	19,500
Total unsecured pollution control notes, fixed				132,000	151,500
Unsecured PCNs, variable					
NYSEG	2005 Series A	0.03%	2026	25	25
NYSEG	2004 Series C	0.461%	2034	96,850	100,000
RG&E	1997 Series A & B	0.104%	2032	62,150	68,000
Total unsecured pollution control notes, variable				159,025	168,025
Various long-term debt, fixed rate					
NYSEG	Unsecured Notes	3.24% - 6.15%	2016 - 2023	650,000	650,000
CMP	Series F Medium Term Notes	5.27% - 6.40%	2016 - 2037	180,000	180,000
Chester	Promissory and Senior Notes	7.05% - 10.48%	2020	6,908	8,091
Total various long-term debt				836,908	838,091
Obligations under capital leases				5,545	9,619
Unamortized premium on debt, net				(2,141)	(2,413)
				2,521,187	2,554,672
Less debt due within one year, included in current liabilities				134,415	22,759
Total Long-Term Debt				\$2,386,772	\$2,531,913

⁽¹⁾ The first mortgage bonds are secured by liens on substantially all of the respective utility's properties of approximately \$5 billion.

In July 2014 NYSEG executed a tender offer for its 2004 Series C pollution control notes and purchased \$3.15 million par value at 92% of par.

In November 2014 RG&E executed a tender offer for its 1997 Series A and B pollution control notes and purchased \$5.85 million par value at 90% of par.

As of December 31, 2014, NYSEG and RG&E had outstanding \$331 million of tax-exempt PCNs, including \$132 million with coupons fixed to maturity, \$40 million of notes with a mandatory redemption date in 2016, \$97 million of 7-day auction rate notes and \$62 million of 35-day auction rate notes.

In April 2013 NYSEG issued a notice to call \$70 million of 5.35% pollution control notes. The notes were redeemed at par in May of 2013. In June of 2013, NYSEG redeemed \$113 million pollution control notes at par subject to a mandatory redemption requirement.

In April 2013 RG&E issued a notice to call \$50 million of 5.375% pollution control notes. The notes were redeemed at par in May of 2013.

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As of December 31, 2013, NYSEG and RG&E had outstanding \$340 million of tax-exempt PCNs, including \$132 million with coupons fixed to maturity, \$40 million of notes with a mandatory redemption date in 2016, \$100 million of 7-day auction rate notes and \$68 million of 35-day auction rate notes.

At December 31, 2014, long-term debt, including sinking fund obligations and capital lease payments (in thousands) that will become due during the next five years is:

2015	2016	2017	2018	2019
\$134,415	\$182,270	\$201,836	\$1,901	\$301,973

We are in compliance with all debt covenants as of December 31, 2014.

Note 5. Bank Loans and Other Borrowings

NYSEG, RG&E and CMP rely on bank provided revolving credit facilities and on inter-company revolving credit facilities with IUSA, the parent of Networks, to fund short-term liquidity needs. In July 2011 NYSEG, RG&E and CMP jointly entered into a bank provided revolving credit facility (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. 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.

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 income (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, 2014.

The restatement of 2013 results at CMP created an Event of Default for CMP under the Joint Facility. This Event of Default has been waived by agreement of all the lending banks, subject to the requirements that CMP deliver audited statements including the restatement by March 31, 2015.

There was \$793.7 million of short-term debt outstanding at December 31, 2014, all of which was provided by IUSA, and \$309.6 million outstanding at December 31, 2013, of which \$295.8 million was provided by IUSA. The weighted-average interest rate on short-term debt was 0.39% at December 31, 2014, and 0.40% at December 31, 2013.

Note 6. Redeemable Preferred Stock of Subsidiary, Noncontrolling Interest

The redeemable preferred stock of subsidiary is a noncontrolling interest because it contains a feature that allows the holders to elect a majority of the subsidiary'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 the subsidiary.

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At December 31, 2014 and 2013, 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)	
				2014	2013
CMP, 6% Noncallable	\$100	-	1,921	\$192	\$192
Total				\$192	\$192

⁽¹⁾At December 31, 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 7. Commitments and Contingencies

CMP customer charge-offs: Under Maine electric restructuring law, Maine electric delivery utilities are required to bill customers for delivery and supply service. This includes managing delivery and supply accounts receivable and uncollectibles. In October 2010 the MPUC initiated a proceeding to investigate CMP's credit and collection practices, and, in particular, whether CMP complies with the MPUC's new credit and collection rules, including the treatment of unpaid customer balances for delivery charges and supply charges.

In August 2012 the Hearing Examiner issued a report and recommended decision in the case, recommending that the MPUC order CMP to retroactively reallocate \$2.6 million of customer deposits, previously applied to CMP's delivery service receivables during the period 2008 through 2010 as a credit to Standard Offer Service receivables. The Examiner's Report also recommended that the MPUC find CMP's collections practices during the period 2005 through 2010 were imprudent, resulting in an additional recommended disallowance of \$3.7 million. In total, the Examiner's Report recommended that the MPUC order CMP to credit the Standard Offer Service retainage account by \$6.3 million at CMP's expense. In September 2012 CMP filed its exceptions to the Examiner's Report, arguing that the Examiner's recommendations constitute illegal, retroactive, single-issue ratemaking and that the Examiner has failed to meet the burden of proof necessary to support a finding of imprudent utility behavior. In October 2012 the MPUC deliberated the matter and agreed with the Hearing Examiner's recommendation to require CMP to retroactively reallocate \$2.6 million of customer deposits. The MPUC also agreed with the Hearing Examiner's finding of imprudent behavior with respect to appropriately pursuing customer collections during the period of 2008 through 2010. The MPUC determined that this imprudent behavior resulted in additional harm of \$1.5 million and CMP should therefore credit a total of \$4.1 million to Standard Offer Service receivables. On January 25, 2013, the MPUC issued its written Order confirming the \$4.1 million credit to the standard offer retainage account. In December 2012 CMP reallocated \$5.1 million in customer receivables with an associated charge to operating expense.

On February 14, 2013, CMP filed a motion requesting that the MPUC reconsider its January 25 order with respect to the allocation of customer deposits. On May 14, 2013, the MPUC issued an order denying CMP's motion. On June 4, 2013, CMP filed an appeal of the MPUC's January 25 and May 14 orders with the Maine Supreme Judicial Court. On August 22, 2013, CMP submitted its initial brief to the Court, disputing the MPUC's order with regard to the retroactive reallocation of customer deposits, but not seeking review of the MPUC's finding of imprudence.

The Law Court issued its decision on April 8, 2014, denying CMP's appeal and upholding the MPUC's decision.

Notes to Consolidated Financial Statements

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, as well as return of and on investment in assets. The FERC provided a base ROE of 11.14% and additional incentive adders applicable to assets based upon vintage, voltage and other factors.

Complaint I - In September 2011 the Massachusetts Attorney general filed a complaint with the FERC that the ROE was too high and should be lowered by 1.94%, to a value of 9.2%. CMP is a member of the New England Transmission Owners and is therefore subject to the outcome of the complaint proceeding. On October 16, 2014, the FERC issued an order in the ROE case which concluded:

- The base ROE is set at 10.57% effective October 16, 2014.
- There is an ROE cap on incentive returns of 11.74%, also effective October 16, 2014.
- The long-term growth rate used in the two-step DCF analysis should be GDP and is 4.39% in this proceeding. This aspect of their decision results from the paper hearing that FERC initiated in its June 2014 decision in this case.
- CMP must provide refunds for the period October 2011 through December 2012 with a base ROE of 10.57% and an ROE cap on incentives of 11.74%.

On March 3, 2015, the FERC issued an order on requests for rehearing of its October 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.

Complaint II – Filed December 27, 2012. On June 19, 2014 the Commission issued an order setting this case for settlement and hearing and set a refund effective date of December 27, 2012.

- The parties entered settlement negotiations which ended in late October 2014 when the parties where unable to reach agreement
- FERC has set a schedule for this case that calls for hearings in June 2015. The order estimates a decision by April 30, 2016 (subsequently revised to September 2016).

Complaint III – Filed August 2014 by the initial complainants, reiterates the same position in Complaint II. On November 24, 2014, the FERC issued an order setting the complaint for hearing, consolidating Complaints II and III, and establishing a refund effective date of July 31, 2014.

CMP reserved for refunds in 2013 and 2014. The 2013 reserve was \$6.6 million associated with Complaint I. In 2014, CMP recorded an additional reserve of \$29.9 million associated with Complaints I, II, and III. CMP's reserved amounts reflect projected refund obligations that are consistent with the FERC's March 3, 2015 final Complaint I decision.

Decision in Yankee Litigation vs. DOE: CMP has an ownership interest in three nuclear generating companies (the Yankee companies) that have been decommissioned and currently store spent nuclear fuel (SNF) on their sites. In May 2012 the U.S. Court of Appeals issued a favorable decision in the Yankee companies' Phase I litigation over the U.S. Department of Energy (DOE)'s failure to remove SNF from the three New England single-unit decommissioned nuclear reactor sites as required by contract and the Nuclear Waste Policy Act beginning in 1998. Damages awarded to the three companies totaled nearly \$160 million. CMP's share of the award is approximately \$37 million.

Notes to Consolidated Financial Statements

The Yankee companies received the proceeds in early 2013. The proceeds will be used to offset future costs of spent fuel storage which are borne by the owners, with any excess being credited to the owners. Each of the Yankee companies have established a schedule to refund any excess to its owners, including CMP. Any refund ultimately distributed to CMP will ultimately be passed on to customers through lower rates. During 2013 CMP recorded a receivable of \$30.6 million with an offsetting regulatory liability. CMP is obligated, as required by a Maine law enacted in 2013, to transfer to Efficiency Maine approximately \$13.1 million, of its Phase I proceeds from Maine Yankee Atomic Power Company which will reduce the amount ultimately credited to customers. As a result, CMP established a liability to Efficiency Maine with an offsetting decrease in the regulatory liability.

On November 14, 2013, the Court of Federal Claims in Washington, D.C. issued a ruling in favor of the Yankee companies in Phase II of their litigation with the DOE, awarding a total of about \$235 million in damages. CMP's share of the award is approximately \$28 million. There was a 60-day appeal period that ended on January 14, 2014, and the U.S. Department of Justice, representing the DOE, did not appeal the decision. As a result, the decision is final and non-appealable and the Yankee Companies received full payment in April 2014.

In August 2013, the Yankees filed a third round of claims against the government seeking damages for the years 2009-2014 (Phase III). The Respondent cannot predict the timing or amount of damages that may ultimately be awarded.

The trial court decisions, the appeals court decisions in this case (Phase I and Phase II), and legal precedents, provide strong support that the Yankee Companies will continue to recover future costs caused by the DOE's breach. The Respondent cannot predict the exact outcome or the timing of these proceedings.

Operating leases: We expensed approximately \$8 million related to our operating leases in 2014 and \$26 million in 2013. We estimate our expenses will be approximately \$6 million per year over the next five years and \$9 million thereafter.

Purchase power contracts, including nonutility generators: We expensed approximately \$73 million for NUG power in 2014 and \$70 million in 2013. We estimate that our power purchases will total \$76 million in 2015, \$73 million in 2016, \$17 million in 2017, \$17 million in 2018 and \$198 million thereafter.

Nuclear entitlement power purchase contracts: In connection with our sale of nuclear generating assets in 2004, we entered into entitlement contracts under which we purchase electricity at a fixed contract price. We expensed approximately \$86 million for nuclear entitlement power in 2014 and \$200 million in 2013.

NYPSC Staff Review of Earnings Sharing Calculations and other Regulatory Deferrals: In December 2012 the NYPSC Staff informed NYSEG and RG&E 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 to August 31, 2011). The NYPSC Staff's preliminary findings indicated adjustments to deferred balances, primarily associated with storm costs, as well as 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 RG&E have reviewed the Staff's adjustments and workpapers and provided a response to the Staff in 2013. Staff has not yet replied to NYSEG and RG&E's response. As a result of the Staff report NYSEG and RG&E recorded a \$3.4 million reserve in December 2012 in anticipation of settling the issues. We cannot predict the ultimate outcome of this proceeding.

Notes to Consolidated Financial Statements

Note 8. 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 23 waste sites. The 23 sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the 23 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 \$1 million related to nine of the 23 sites. We have paid remediation costs related to the remaining 14 sites, and do not expect to incur any additional liability. We have recorded an estimated liability of \$6 million related to another 10 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.

Our estimate for all costs related to investigation and remediation of the 53 sites ranges from a minimum of \$312 million to \$480 million at December 31, 2014. 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 \$312 million at December 31, 2014, and \$280 million at December 31, 2013. 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 liabilities are recorded on an undiscounted basis. Our environmental liability accruals are expected to be paid through the year 2048.

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

Notes to Consolidated Financial Statements

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 expense at nine MPG sites. Because the District Court's original damage award for incurred costs was based upon 2009 figures, FirstEnergy now owes NYSEG an additional damages payment of approximately \$16 million for clean-up costs incurred while the appeal was pending.

In addition to the \$16 million, excluding interest, in damages incurred through 2014, FirstEnergy would be liable for a share of future costs. Based on current projections, the future costs would be \$27 million. At the present time both of these amounts are being treated as contingent assets and have not been recorded as either a receivable or a decrease to the environmental provision.

Note 9. 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 consolidated balance sheet.

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 that 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.

NYSEG and RG&E have a nonbypassable wires charge adjustment that allows them to pass through rates any changes in the market price of electricity. They 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, 2014, the loss recognized in regulatory assets was \$28.8 million for electricity derivatives. For the year ended December 31, the loss reclassified from regulatory assets into income, which is included in electricity purchased, was \$21.3 million for 2014 and \$2.2 million for 2013.

Notes to Consolidated Financial Statements

NYSEG and RGE have purchased gas adjustment clauses that allow them to recover through rates any changes in the market price of purchased natural gas, substantially eliminating their exposure to natural gas price risk. NYSEG and RG&E 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, 2014, the loss recognized in regulatory assets was \$4.7 million for natural gas hedges. For the year ended December 31, the loss reclassified from regulatory assets into income, which is included in natural gas purchased, was \$2.2 million for 2014 and \$1.8 million for 2013.

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

	Electricity Contracts	Natural Gas Contracts	Other Fuel Contracts
Year to settle	Financial MwHs	Financial Dths	Financial Gals
As of December 31, 2014			
2015	4,277,800	3,180,000	2,778,200
2016	2,364,000	610,000	-
As of December 31, 2013			
2014	2,605,300	3,810,000	2,913,800
2015	1,920,000	660,000	-

Notes to Consolidated Financial Statements

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

As of December 31, (Thousands)	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments				
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
Other contracts:	Current assets	-	Current liabilities	3,320
Total		-		\$36,821
2013				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	\$7,315	Current liabilities	-
Long-term	Other assets	-	Other liabilities	\$1,337
Natural gas derivatives:				
Current	Current assets	709	Current liabilities	-
Long-term	Other assets	139	Other liabilities	-
Other contracts:	Current assets	-	Current liabilities	547
Total		\$8,163		\$1,884

Notes to Consolidated Financial Statements

The effect of hedging instruments on OCI and income was:

Year Ended December 31, Derivatives in Cash Flow Hedging Relationships (Thousands)	(Loss) Recognized in OCI on Derivatives Effective Portion ⁽¹⁾	Location of (Loss) Reclassified from Accumulated OCI into Income Effective Portion ⁽¹⁾	(Loss) Reclassified from Accumulated OCI into Income
2014			
Interest rate contracts	-	Interest expense	\$(8,923)
Commodity contracts:			
Other	\$(3,616)	Other operating expenses	(843)
Total	\$(3,616)		\$(9,766)
2013			
Interest rate contracts	-	Interest expense	\$(11,246)
Commodity contracts:			
Other	\$(393)	Other operating expenses	(615)
Total	\$(393)		\$(11,861)

⁽¹⁾ Changes in OCI are reported in pre-tax dollars.

The amount in AOCI related to previously settled forward starting swaps, and accumulated amortization, as of December 31, 2014, is a net loss of \$93.5 million as compared to a net loss of \$102.5 million for 2013. For the year ended December 31, 2014, we recorded \$8.9 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately \$8.9 million of discontinued cash flow hedges in 2015.

At December 31, 2014, \$3.3 million in losses are reported in OCI because the forecasted transaction is considered to be probable. We expect that those losses will be reclassified into earnings within the next 12 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions.

Offsetting Assets and Liabilities

Offsetting of Derivative Assets

Description (Thousands)	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Gross Net Amounts of Assets Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet		
				Financial Instruments	Cash Collateral Pledged	Net Amount
As of December 31, 2014						
Derivatives	\$11,382	\$(11,382)	-	-	-	-
As of December 31, 2013						
Derivatives	\$14,269	\$(6,106)	\$8,163	-	-	\$8,163

Notes to Consolidated Financial Statements

Offsetting of Derivative Liabilities

Description	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Liabilities Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet		
				Financial Instruments	Cash Collateral Pledged	Net Amount
(Thousands)						
As of December 31, 2014						
Derivatives	\$(48,203)	\$11,382	\$(36,821)	-	\$36,821	-
As of December 31, 2013						
Derivatives	\$(7,990)	\$6,106	\$(1,884)	-	\$(1,884)	-

NYSEG and RG&E 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 S&P). 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 do not 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. Under the master netting arrangements our obligation to return cash collateral was \$0.2 million at December 31, 2014 and, 2013.

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, 2014, is \$36.8 million for which we have posted collateral of \$56.8 million in the normal course of business. If the credit-risk-related contingent features underlying those agreements were triggered on December 31, 2014, we would receive a refund of \$20 million of collateral from our counterparties.

Notes to Consolidated Financial Statements

Note 10. Fair Value of Financial Instruments and Fair Value Measurements

The carrying amounts and estimated fair values of our financial instruments are shown in the following table. Carrying amounts include related debt premiums and discounts.

December 31,	2014		2013	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
(Thousands)				
First mortgage bonds	\$1,389,162	\$1,660,938	\$1,389,110	\$1,569,336
Pollution control notes, fixed	\$132,000	\$133,251	\$151,500	\$153,820
Pollution control notes, variable	\$159,025	\$145,060	\$168,025	\$146,055
Various long-term debt	\$835,455	\$954,735	\$836,419	\$924,469

The carrying amounts for cash and cash equivalents, accounts receivable, accounts payable, notes payable and interest accrued approximate their estimated fair values.

We value all fixed rate long-term debt, whether unsecured or secured by a first mortgage lien, taxable or tax-exempt, by assigning a market-based yield for each security and then deriving the price from the yield. Market-based yields are determined by observing secondary market trading levels for debt of similar maturity, rating, tax and structural characteristics. All of our variable rate debt instruments are auction rate securities. The auction function for these securities has not properly functioned since the financial crisis in 2008 and, as a result under the agreements, the variable rate is set in reference to various short-term indices that provide for competitive short-term returns. These securities lack secondary market liquidity and as a result the auction rate securities were valued using a discounted cash flow model based on the underlying terms of the agreement including the variable rate used, if the auction fails, available market information, and consideration of historical activity for benchmark interest rates. These financial debt instruments are considered as Level 2, except for the auction rate securities which are considered Level 3.

Notes to Consolidated Financial Statements

Assets and liabilities measured at fair value on a recurring basis

Description (Thousands)	Total	Fair Value Measurements at December 31, Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
2014				
Assets				
Noncurrent investments available for sale, other	\$33,326	\$33,326	-	-
Total	\$33,326	\$33,326	-	-
Liabilities				
Derivatives				
Commodity contracts:				
Electric	\$28,760	\$28,420	\$340	-
Natural gas	4,741	4,741	-	-
Other	3,320	-	-	\$3,320
Total	\$36,821	\$33,161	\$340	\$3,320
2013				
Assets				
Noncurrent investments available for sale, other	\$35,244	\$35,244	-	-
Derivatives				
Commodity contracts:				
Electricity	7,315	3,126	\$4,189	-
Natural gas	848	848	-	-
Total	\$43,407	\$39,218	\$4,189	-
Liabilities				
Derivatives				
Commodity contracts:				
Electric	\$1,337	\$1,184	\$153	-
Other	547	-	-	\$547
Total	\$1,884	\$1,184	\$153	\$547

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

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

- NYSEG and RG&E enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. They hedge their electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. RG&E hedges all of its electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value RG&E's 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. NYSEG has a combination of Level 1 and Level 2 fair values for its electric 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 NYSEG's open electric energy derivative contracts are based on

Notes to Consolidated Financial Statements

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 NYSEG's 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.

- NYSEG and RG&E enter into natural gas derivative contracts to hedge the forecasted purchases required to serve their 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.
- NYSEG, RG&E and CMP enter into fuel derivative contracts to hedge their unleaded and diesel fuel requirements for their 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

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3) Liabilities Derivatives, Net
Balance, January 1, 2013	\$769
Total (losses) gains (realized/unrealized)	
Included in earnings	(615)
Included in other comprehensive income	393
Balance, December 31, 2013	547
Total (losses) gains (realized/unrealized)	
Included in earnings	(843)
Included in other comprehensive income	3,616
Balance, December 31, 2014	\$3,320

The gains and losses included in earnings for the period (above), which are reported in the various categories indicated are:

	Other operating expense
(Thousands)	
Total gains (losses) included in earnings for the year ended December 31,	
2013	\$(615)
2014	\$(843)

Notes to Consolidated Financial Statements

Note 11. Accumulated Other Comprehensive Income (Loss)

	Balance January 1, 2013	2013 Change	Balance December 31, 2013	2014 Change	Balance December 31, 2014
(Thousands)					
Net unrealized holding gain (loss) on investments, net of income tax benefit (expense) of \$88 for 2013 and \$(11) for 2014	\$135	\$(135)	-	\$17	\$17
Amortization of pension cost for nonqualified plans, net of income tax (expense) benefit of \$(1,076) for 2013 and \$1,956 for 2014	(7,333)	(959)	(8,292)	(3,113)	(11,405)
Unrealized (loss) gain on derivatives qualified as hedges:					
Unrealized (loss) during period on derivatives qualified as hedges, net of income tax benefit of \$52 for 2013 and \$1,446 for 2014		(79)		(2,170)	
Reclassification adjustment for loss included in net income, net of income tax (benefit) of \$(141) for 2013 and \$(338) for 2014		212		505	
Reclassification adjustment for losses on settled cash flow treasury hedges, net of income tax (benefits) of \$(4,481) for 2013 and \$(3,561) for 2014		6,765		5,362	
Net unrealized (loss) gain on derivatives qualified as hedges	\$(68,921)	6,898	(62,023)	3,697	(58,326)
Accumulated Other Comprehensive (Loss) Income	\$(76,119)	\$5,804	\$(70,315)	\$601	\$(69,714)

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

Note 12. 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. 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	
	2014	2013	2014	2013
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	\$2,265,395	\$2,564,264	\$359,443	\$415,543
Service cost	30,154	36,240	3,504	4,716
Interest cost	107,321	102,059	16,905	16,324
Plan participants' contributions	-	-	3,935	4,170
Plan amendments	-	-	-	(2,473)
Actuarial loss	431,769	(227,253)	68,585	(44,184)
Benefits paid	(270,547)	(209,915)	(40,962)	(35,274)
Federal subsidy on benefits paid	-	-	46	621
Benefit obligation at December 31	\$2,564,092	\$2,265,395	\$411,456	\$359,443
Change in plan assets				
Fair value of plan assets at January 1	\$2,177,504	\$2,196,573	\$128,031	\$118,449
Actual return on plan assets	158,979	182,794	3,905	12,582
Employer contributions	31,306	8,052	37,028	31,104
Plan participants' contributions	-	-	3,934	4,170
Benefits paid	(270,547)	(209,915)	(40,962)	(35,274)
Withdrawal from VEBA	-	-	(4,071)	(3,000)
Fair value of plan assets at December 31	\$2,097,242	\$2,177,504	\$127,865	\$128,031
Funded status at December 31	\$(466,850)	\$(87,891)	\$(283,591)	\$(231,412)
Amounts recognized in the balance sheet				
December 31,				
(Thousands)				
Noncurrent assets	-	\$52,650	-	-
Current liabilities	-	-	\$(5,424)	\$(6,079)
Noncurrent liabilities	\$(466,850)	(140,541)	(278,167)	(225,333)
	\$(466,850)	\$(87,891)	\$(283,591)	\$(231,412)

During 2013 we offered terminated vested employees an option to receive their future pension benefit as a lump sum. Approximately \$59.9 million of payments were made in 2013 as a result of terminated employees exercising that option. The lump sums paid did not trigger settlement accounting. Another \$5.8 million was paid out in 2014.

During 2014 we made a similar offer to retired employees who are currently receiving benefits. 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	
	2014	2013	2014	2013
(Thousands)				
Net loss	\$1,044,786	\$704,206	\$95,618	\$23,665
Prior service cost (credit)	\$12,028	\$16,091	\$(56,818)	\$(67,495)

Our accumulated benefit obligation for all defined benefit pension plans was \$2.4 billion at December 31, 2014, and \$2.1 billion at December 31, 2013.

Notes to Consolidated Financial Statements

CMP's and NYSEG's postretirement benefits were partially funded at December 31, 2014 and 2013. NYSEG had no withdrawal for 2014 and 2013 from its postretirement benefit fund. CMP withdrew \$4.1 million in 2014 and withdrew \$3 million in 2013 to reimburse it for a portion of benefits paid.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for all plans as of December 31, 2014 and for all plans except NYSEG's as of December 31, 2013. 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	
	2014	2013	2014	2013
Projected benefit obligation	\$2,564,092	\$784,447	\$2,564,092	\$784,447
Accumulated benefit obligation	\$2,380,679	\$724,629	\$2,380,679	\$724,629
Fair value of plan assets	\$2,097,242	\$643,905	\$2,097,242	\$643,905

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	
	2014	2013	2014	2013
Net periodic benefit cost				
Service cost	\$30,154	\$36,240	\$3,504	\$4,716
Interest cost	107,321	102,059	16,905	16,324
Expected return on plan assets	(161,420)	(165,866)	(7,185)	(6,696)
Amortization of prior service cost (benefit)	4,063	4,279	(10,678)	(14,441)
Amortization of net loss	93,597	120,407	(86)	3,302
Settlement charge	35	-	-	-
Net periodic benefit cost	\$73,750	\$97,119	\$2,460	\$3,205
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss/(gain)	\$434,211	\$(244,181)	\$71,866	\$(50,070)
Settlement	(35)	-	-	-
Amortization of net (loss)	(93,597)	(120,407)	86	(3,302)
Current year prior service cost	-	-	-	(2,473)
Amortization of prior service (cost)	(4,063)	(4,279)	10,678	14,441
Total recognized in regulatory assets and regulatory liabilities	336,516	(368,867)	82,630	(41,404)
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	\$410,266	\$(271,748)	\$85,090	\$(38,199)

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, 2015	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	\$129,987	\$6,912
Estimated prior service cost (benefit)	\$2,907	\$(8,851)

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 2014	Pension Benefits 2013	Postretirement Benefits 2014	Postretirement Benefits 2013
Discount rate	3.80%	4.90%	3.80%	4.90%
Rate of compensation increase	4.10%	4.20%	NA	NA

As of December 31, 2014, we decreased our discount rate from 4.90% to 3.80%. 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 2014	Pension Benefits 2013	Postretirement Benefits 2014	Postretirement Benefits 2013
Discount rate	4.90%	4.10%	4.90%	4.10%
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	4.20%	4.00%	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. 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,

	2014	2013
Health care cost trend rate assumed for next year	7.75%/7.25%	8.0%/7.5%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	4.5%	4.5%
Year that the rate reaches the ultimate trend rate	2027	2027

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	\$267	\$(223)
Effect on postretirement benefit obligation	\$6,671	\$(5,514)

Notes to Consolidated Financial Statements

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 \$1 million to our pension benefit plans in 2015.

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)			
2015	\$147,631	\$26,624	\$135
2016	\$151,193	\$25,899	\$162
2017	\$155,312	\$26,170	\$200
2018	\$157,829	\$26,299	\$243
2019	\$159,525	\$26,511	\$288
2020 - 2024	\$814,678	\$132,153	\$2,392

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

Notes to Consolidated Financial Statements

The fair values of our pension benefits plan assets at December 31, 2014 and 2013, by asset category are:

Fair Value Measurements at December 31, Using				
Asset Category (Thousands)	Total	Quoted Prices	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		in Active Markets for Identical Assets (Level 1)		
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
2013				
Cash and cash equivalents	\$43,170	\$1,665	\$41,505	-
U.S. government securities	187,556	187,556	-	-
Common stocks	607,549	426,311	181,238	-
Registered investment companies	115,008	115,008	-	-
Corporate bonds	224,709	-	224,709	-
Preferred stocks	2,383	2,383	-	-
Common/collective trusts	513,293	-	54,980	\$458,313
Partnership/joint venture interests	56,880	-	-	56,880
Real estate investments	67,266	-	-	67,266
Other investments, principally annuity and fixed income	359,690	21,625	1,470	336,595
Total	\$2,177,504	\$754,548	\$503,902	\$919,054

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

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

Notes to Consolidated Financial Statements

- 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.

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)				
(Thousands)	Common/ Collective Trusts	Partner- ship/ Joint Venture Interests	Real Estate Invest- ments	Other Invest- ments	Total
Balance, December 31, 2012	\$249,550	\$50,040	\$59,119	\$319,037	\$677,746
Actual return on plan assets:					
Relating to assets still held at the reporting date	357	-	-	(1,899)	(1,542)
Relating to assets sold during the year	49,424	6,840	4,819	(7,409)	53,674
Purchases, sales and settlements	158,982	-	3,328	26,866	189,176
	-	-	-	-	-
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	-	-	(834)	59,490
Relating to assets sold during the year	(48,286)	2,609	4,670	6,251	(34,756)
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

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 25% 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% international developed market and 5% emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at 31%, global high yield fixed income 4% and international developed market debt 3%. 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

Notes to Consolidated Financial Statements

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, 2014 and 2013, by asset category are:

Asset Category (Thousands)	Total	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)
2014				
Money market funds	\$4,478	\$4,478	-	-
Mutual funds, fixed	16,032	16,032	-	-
Government & corporate bonds	23,517	21,391	\$2,126	-
Mutual funds, equity	42,156	42,156	-	-
Common stocks	33,723	33,723	-	-
Mutual funds, other	7,959	7,959	-	-
Total assets measured at fair value	\$127,865	\$125,739	\$2,126	-
2013				
Money market funds	\$6,495	\$6,495	-	-
Mutual funds, fixed	19,672	19,672	-	-
Government & corporate bonds	18,049	8,819	\$9,230	-
Mutual funds, equity	41,522	41,522	-	-
Common stocks	36,960	36,960	-	-
Mutual funds, other	5,333	5,333	-	-
Total assets measured at fair value	\$128,031	\$118,801	\$9,230	-

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 common stock at December 31, 2014.

Note 13. NYSEG and RG&E Rate Proceedings

On September 16, 2010, the NYPSC approved a new rate plan for electric and natural gas service provided by the companies effective August 26, 2010, through December 31, 2013. The companies have not requested new rates to go into effect and 2013 base rates have stayed in place.

The revenue requirements were based on a 10% allowed ROE applied to an equity ratio of 48 percent. If annual earnings exceed the allowed return, a tiered earnings sharing mechanism (ESM) will capture a portion of the excess for the benefit of ratepayers. The ESM is subject to specified downward adjustments if the companies fail to meet certain reliability and customer service measures. Key components of the rate plan include electric reliability performance

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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 the companies fail to meet the targets. To date the companies have met all of the service quality targets.

The 2010 rate plans established revenue decoupling mechanisms (RDMs), which are intended to remove company disincentives to promote increased energy efficiency. Under the RDMs, 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 (excesses) between billed revenues and allowed revenues will be accrued for future recovery (refund).

In August 2010, NYSEG began amortizing \$15.2 million per year of a theoretical excess depreciation reserve of \$303.9 million; and on September 1, 2012, RG&E began amortizing \$5.25 million per year of its theoretical excess depreciation reserve of \$105 million. Both amortization amounts reflect a 20-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 RG&E will moderate electric rates by recording the theoretical reserve amortization as a debit to accumulated depreciation and a credit to other revenues, and normalize the amortization from a tax perspective.

Note 14. Reforming Energy Vision (REV)

In April 2014, the NYPSC commenced a proceeding entitled REV which is an initiative to reform New York State's energy industry and regulatory practices. The 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. The 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 RG&E are participating in the initiative with other New York utilities as well as providing their unique perspective. NYPSC Staff is currently conducting public statement hearings across the state of New York regarding REV.

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.

The Track 2 (Regulatory reform) undertaken in parallel with the first track, examines changes in current regulatory, tariff, and market designs and incentive structures to better align utility interests with achieving the Commission's policy objectives. The NYPSC Staff straw proposal is anticipated in the second quarter 2015. New York utilities will also be addressing related regulatory issues in their individual rate cases.

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Note 15. CMP Rate Setting Process

CMP Distribution rate stipulation

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

The rate stipulation agreement provided for an annual CMP distribution tariff increase of 10.7% or \$24.3 million. The rate increase was based on a 9.45% ROE and 50% equity capital. CMP was authorized to implement a revenue 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 events exceed \$3.5 million. CMP and customers share storm costs that exceed a certain balance on a 50/50 basis, with CMP's exposure limited to \$3.0 million annually. The stipulation also required changes to depreciation lives creating lower depreciation expense of approximately \$2 million annually.

CMP will make a separate regulatory filing for a new customer billing system replacement. In accordance with the stipulation agreement, a new billing system is needed. CMP has filed a request for a separate rate recovery mechanism.

The rate stipulation does not have a pre-determined 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.

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, as well as return of and on investment in assets. The FERC provided a base ROE of 11.14% and additional incentive adders applicable to assets based upon vintage, voltage and other factors. For a description of proceedings related to ROE's on transmission assets, see Note 7.

Note 16. 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. Our operating utilities 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 \$2.1 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

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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 three operating 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 (see Note 13), NYSEG has experienced unusually high levels of restoration costs resulting from various storms including Hurricane Sandy, Hurricane Irene and tropical storm Lee. NYSEG deferred storm costs, reflecting the excess of actual spending over amounts currently allowed in rates, were \$5 million for 2014 and \$9 million for 2013. NYSEG's total deferral, including carrying costs was \$241 million at December 31, 2014 and \$221 million at December 31, 2013. The method and timing of recovery of the costs will be determined in the future rate cases.

CMP deferred \$15 million in 2014 for service restoration costs, primarily as a result of an ice storm in late December 2014. We have determined that the storm meets the criteria for deferral and future recovery. CMP's total deferral, including carrying costs was \$32 million at December 31, 2014 and \$31 million at December 31, 2013. CMP will seek to include the cost of the 2013 storm in customer rates in its annual ARP filing.

We amortize unfunded future income taxes and deferred income taxes as the amounts related to temporary differences that gave rise to deferrals are recovered in rates.

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 a specific regulatory asset or regulatory liability are subject to automatic annual adjustment.

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Current and long-term regulatory assets at December 31, 2014 and 2013 consisted of:

December 31, (Thousands)	2014	2013
Current		
Environmental remediation costs	-	\$41
Pension and other postretirement benefits cost deferrals	-	9,445
Hedges losses	\$33,502	171
Storm costs	14,198	7,177
Nuclear plant obligations	-	288
Deferred meter replacement costs	2,216	2,246
Legacy meter retirement deferral	1,563	2,861
Nonbypassable charges	1,779	2,366
Unamortized loss on reacquired debt	2,911	3,510
Revenue decoupling mechanism	5,775	4,511
Rate reconciliation mechanism	2,854	2,345
Deferred income taxes regulatory	29,251	19,578
Temporary supplemental assessment surcharge	11,664	-
Other	3,167	704
Total current regulatory assets	\$108,880	\$55,243
Other long-term		
Deferred meter replacement costs	\$35,960	\$39,225
Deferred income taxes	128,226	98,328
Asset retirement obligation	32,013	30,161
Pension and other postretirement benefits cost deferrals	124,632	87,970
Deferred property tax	30,163	51,382
Unamortized loss on debt reacquisitions	25,435	28,380
Merger capital expense target customer credit	10,486	10,486
Other	39,372	27,634
Total other long-term regulatory assets	426,287	373,566
Pension and other postretirement benefits	1,101,415	729,368
Unfunded future income taxes	366,491	357,220
Environmental remediation costs	246,073	219,689
Storm costs	258,869	245,434
Total long-term regulatory assets	\$2,399,135	\$1,925,277

Notes to Consolidated Financial Statements

Current and long-term regulatory liabilities at December 31, 2014 and 2013 consisted of:

December 31, (Thousands)	2014	2013
Current		
Plant decommissioning	\$12,539	-
Gas supply charge and deferred natural gas cost	6,485	\$6,334
Revenue decoupling mechanism	7,831	12,388
Revenue reconciliation mechanism transmission revenue true up	6,795	9,956
Seneca Lake asset sale gain account	-	6,079
Reliability support service (Cayuga)	18,135	7,231
Yankee DOE Phase I	23,475	17,557
Nonbypassable charges	18,428	10,342
Hedges losses	-	6,909
Energy efficiency portfolio standard	34,094	-
Unfunded deferred income tax adjustment	16,423	-
Other	8,033	7,613
Total current regulatory liabilities	\$152,238	\$84,409
Other long-term		
Asset sale gain account	\$19,180	\$19,833
Plant decommissioning	-	13,412
Carrying costs on deferred income tax bonus depreciation	80,540	54,001
Economic development	32,765	27,635
Merger capital expense target customer credit	16,800	16,800
Pension and other postretirement benefits	49,873	77,491
Positive benefit adjustment	50,928	50,928
Deferred property tax	51,481	56,639
New York State tax rate change	16,090	-
Unfunded future income taxes	13,469	26,217
Post term amortization	20,382	-
Spent nuclear fuel	11,536	9,114
Theoretical reserve flow thru impact	23,807	16,995
Other	97,863	68,224
Total other long-term regulatory liabilities	484,714	437,289
Accrued removal obligations	720,866	714,037
Deferred income taxes	462,344	312,567
Total long-term regulatory liabilities	\$1,667,924	\$1,463,893

Note 17. New York Transco

Affiliates of National Grid, Central Hudson, NYSEG and RG&E, together with an affiliate of Consolidated Edison and Orange and Rockland Utilities, are part of a new organization, New York Transco LLC. 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 are requesting regulatory approval for a group of transmission projects expected to cost \$1.7 billion funded through debt and equity. NYSEG and RG&E allocated equity contribution (20%) 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.

Notes to Consolidated Financial Statements

The New York Transco filed with FERC in early December 2014. The filing requests a formula base ROE of 10.6%, plus 150 basis points ROE incentives. The filing also requests recognition of construction work in process, abandoned plant, regulatory asset for pre-commercial costs and 60% equity for five years. Various parties, including the NYPSC, have protested the filing with FERC. The company anticipates a FERC decision in 2015.

Note 18. Subsequent events

The company has performed a review of subsequent events through March 9, 2015, which is the date these financial statements were available to be issued, and the financial statements reflect events occurring from January 1, 2015 through such date.

On February 25, 2015, Iberdrola USA and UIL Holdings Corporation (UIL) announced that they have entered into a definitive agreement under which Iberdrola USA will acquire UIL and create a newly listed U.S. publicly-traded company. This combination creates a larger, more diversified power and utility company with seven highly-regulated electric and gas utilities in complementary geographies. The acquisition is subject to various regulatory and UIL shareholder approvals and is expected to close by the end of 2015.

In January of 2015, CMP issued first mortgage bonds that were priced in October of 2014 for \$150 million with interest rates ranging from 3.15% to 4.07%.