THE UNITED ILLUMINATING COMPANY

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2015 AND 2014

TABLE OF CONTENTS

pwc

Independent Auditor's Report

To the Board of Directors
of The United Illuminating Company:

We have audited the accompanying financial statements of The United Illuminating Company (the "Company"), which comprise the balance sheets as of December 31, 2015 and December 31, 2014, and the related statements of income, comprehensive income, shareholders' equity and cash flows for the years then ended.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

Our responsibility is to express an opinion on the financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from 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 our 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, we consider internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of The United Illuminating Company at December 31, 2015 and December 31, 2014, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP, 101 Seaport Boulevard, Suite 500, Boston, MA 02210
T: (617) 530 5000, F: (617) 530 5001, www.pwc.com/us

Emphasis of Matter

As discussed in Note (A) to the financial statements, the Company changed the manner in which it classifies deferred taxes in 2015. Our opinion is not modified with respect to this matter.

PricewaterhouseCoopers LLP

April 4, 2016

THE UNITED ILLUMINATING COMPANY
STATEMENT OF INCOME
For the Years Ended December 31, 2015 and 2014
(In Thousands)

	2015	2014
Operating Revenues	$ 887,811	$ 796,549
Operating Expenses		
Operation		
Purchased power	226,973	173,059
Operation and maintenance	308,435	238,593
Transmission wholesale	93,078	88,370
Depreciation and amortization	68,870	65,489
Taxes - other than income taxes	92,220	86,009
Total Operating Expenses	789,576	651,520
Operating Income	98,235	145,029
Other Income and (Deductions), net (Note H), (Note A)		
Other income	10,338	16,112
Other (deductions)	(659)	(310)
Total Other Income and (Deductions), net	9,679	15,802
Interest Charges, net		
Interest on long-term debt	42,819	42,236
Other interest, net	(1,217)	2,479
	41,602	44,715
Amortization of debt expense and redemption premiums	1,441	1,483
Total Interest Charges, net	43,043	46,198
Income from Equity Investments	14,246	13,893
Income Before Income Taxes	79,117	128,526
Income Taxes (Note E)	21,853	44,158
Net Income	$ 57,264	$ 84,368

The accompanying Notes to Financial
Statements are an integral part of the financial statements.

THE UNITED ILLUMINATING COMPANY
STATEMENT OF CASH FLOWS
For the Years Ended December 31, 2015 and 2014
(In Thousands)

		2015		2014
Cash Flows From Operating Activities				
Net income	$	57,264	$	84,368
Adjustments to reconcile net income				
to net cash provided by operating activities:				
Depreciation and amortization		70,313		66,972
Deferred income taxes		13,738		39,775
Pension expense		22,980		16,932
Allowance for funds used during construction (AFUDC) - equity		(6,500)		(7,053)
Undistributed (earnings) losses in equity investments		(14,246)		(13,891)
Environmental liabilities		30,000		-
Other regulatory activity, net		(4,976)		30,303
Other non-cash items, net		(346)		(4,092)
Changes in:				
Accounts receivable, net		(3,074)		2,341
Unbilled revenues		6,708		1,195
Accounts payable		(7,253)		30,414
Cash distribution received from GenConn		14,100		14,004
Taxes accrued and refundable		(9,915)		(1,624)
Accrued liabilities		7,307		1,099
Accrued pension		(7,270)		(18,364)
Accrued post-employment benefits		(834)		(805)
Other assets		(1,028)		(543)
Other liabilities		(495)		2,851
Total Adjustments		109,209		159,514
Net Cash provided by Operating Activities		166,473		243,882
Cash Flows from Investing Activities				
Plant expenditures including AFUDC debt		(187,086)		(142,179)
Cash distribution from GenConn		4,029		3,928
Deposits in New England West Solution (NEEWS) (Note C)		(1,451)		(8,437)
Changes in restricted cash		(676)		995
Intercompany receivable		(39,000)		(11,000)
Net Cash (used in) Investing Activities		(224,184)		(156,693)
Cash Flows from Financing Activities				
Issuances of long-term debt		50,000		-
Payments on long-term debt		(27,500)		-
Payment of common stock dividend		(59,700)		(82,700)
Equity infusion from parent		4,500		75,000
Other		(295)		-
Net Cash (used in) Financing Activities		(32,995)		(7,700)
Unrestricted Cash and Temporary Cash Investments:				
Net change for the period		(90,706)		79,489
Balance at beginning of period		96,363		16,874
Balance at end of period	$	5,657	$	96,363
Cash paid during the period for:				
Interest (net of amount capitalized)	$	40,130	$	38,117
Income taxes	$	1,600	$	5,344
Non-cash investing activity:				
Plant expenditures included in ending accounts payable	$	22,940	$	21,521
Plant expenditures funded by deposits in NEEWS	$	(20,012)	$	-
Investment in NEEWS	$	20,012	$	-

The accompanying Notes to Financial
Statements are an integral part of the financial statements.

THE UNITED ILLUMINATING COMPANY
BALANCE SHEET
December 31, 2015 and 2014

ASSETS
(In Thousands)

	2015	2014
Current Assets		
Unrestricted cash and temporary cash investments	$ 5,657	$ 96,363
Restricted cash	1,727	1,051
Utility accounts receivable less allowance of $3,500 and $2,800, respectively	106,186	103,812
Unbilled revenues	39,880	46,588
Current regulatory assets (Note A)	44,469	52,419
Materials and supplies, at average cost	7,619	5,263
Refundable taxes	11,741	3,345
Prepayments	2,242	3,751
Current portion of derivative assets (Note A), (Note J)	10,507	6,849
Intercompany receivable	54,000	15,000
Other current assets	107	70
Total Current Assets	284,135	334,511
Other Investments		
Equity investment in GenConn (Note A)	110,306	114,195
Other	9,702	8,650
Total Other Investments	120,008	122,845
Total Property, Plant and Equipment	2,441,295	2,253,467
Less accumulated depreciation	539,289	505,313
	1,902,006	1,748,154
Construction work in progress	187,212	194,900
Net Property, Plant and Equipment	2,089,218	1,943,054
Regulatory Assets (Note A)	431,923	430,263
Deferred Charges and Other Assets		
Unamortized debt issuance expenses	210	419
Other long-term receivable	1,484	1,490
Derivative assets (Note A), (Note J)	18,757	20,421
Other	380	18,792
Total Deferred Charges and Other Assets	20,831	41,122
Total Assets	$ 2,946,115	$ 2,871,795

The accompanying Notes to Financial
Statements are an integral part of the financial statements.

THE UNITED ILLUMINATING COMPANY
BALANCE SHEET
December 31, 2015 and 2014

LIABILITIES AND CAPITALIZATION
(In Thousands)

	2015	2014
Current Liabilities		
Accounts payable	$ 110,955	$ 117,886
Accrued liabilities	23,524	15,120
Current regulatory liabilities (Note A)	10,079	11,459
Interest accrued	10,888	11,485
Taxes accrued	12,280	13,799
Current portion of derivative liabilities (Note A), (Note K)	28,466	23,308
Total Current Liabilities	196,192	193,057
Deferred Income Taxes (Note E)	585,324	559,108
Regulatory Liabilities	130,220	133,542
Other Noncurrent Liabilities		
Pension accrued (Note F)	153,636	152,456
Other post-retirement benefits accrued (Note F)	42,487	55,644
Derivative liabilities (Note A), (Note J)	67,764	61,766
Environmental liabilities	33,011	3,011
Other	5,800	6,296
Total Other Noncurrent Liabilities	302,698	279,173
Commitments and Contingencies (Note I)		
Capitalization (Note B)		
Long-term debt, net of unamortized discount and premium	862,737	840,035
Common Stock Equity		
Common stock	1	1
Paid-in capital	709,230	704,730
Retained earnings	159,713	162,149
Net Common Stock Equity	868,944	866,880
Total Capitalization	1,731,681	1,706,915
Total Liabilities and Capitalization	$ 2,946,115	$ 2,871,795

The accompanying Notes to Financial
Statements are an integral part of the financial statements.

THE UNITED ILLUMINATING COMPANY
Statement of Changes in Shareholder's Equity
December 31, 2015 and 2014
(Thousands of Dollars)

	Common Stock		Paid-in	Retained	
	Shares	Amount	Capital	Earnings	Total
Balance as of December 31, 2013	100	$ 1	$ 629,730	$ 160,481	$ 790,212
Net income				84,368	84,368
Cash dividends				(82,700)	(82,700)
Equity infusion from parent			75,000		75,000
Balance as of December 31, 2014	100	$ 1	$ 704,730	$ 162,149	$ 866,880
Net income				57,264	57,264
Cash dividends				(59,700)	(59,700)
Equity infusion from parent			4,500		4,500
Balance as of December 31, 2015	100	$ 1	$ 709,230	$ 159,713	$ 868,944

The accompanying Notes to Financial
Statements are an integral part of the financial statements.

THE UNITED ILLUMINATING COMPANY

NOTES TO FINANCIAL STATEMENTS

(A) BUSINESS ORGANIZATION AND STATEMENT OF ACCOUNTING POLICIES

The United Illuminating Company (UI), a wholly owned subsidiary of UIL Holdings Corporation, formerly Green Merger Sub, Inc., and a wholly-owned subsidiary of Avangrid, Inc., is a regulated operating electric public utility established in 1899. On December 16, 2015, UIL Holdings Corporation, a Connecticut corporation (Predecessor UIL) merged with and into Green Merger Sub, Inc., after which Green Merger Sub, Inc. changed its name to UIL Holdings Corporation (UIL Holdings). Throughout this document "UIL Holdings" shall refer to UIL Holdings and Predecessor UIL unless the context otherwise indicates. See Note (C) "Regulatory Proceedings" for further information regarding the merger. UI is engaged principally in the purchase, transmission, distribution and sale of electricity for residential, commercial and industrial purposes in a service area of about 335 square miles in the southwestern part of the State of Connecticut. The population of this area is approximately 754,000, which represents approximately 21% of the population of Connecticut. The service area, largely urban and suburban, includes the principal cities of Bridgeport (population of approximately 145,000) and New Haven (population of approximately 130,000) and their surrounding areas. The service territory is home to a diverse array of business sectors including aerospace manufacturing, healthcare, biotech, financial services, precision manufacturing, retail and education. At December 31, 2015, UI had approximately 331,000 customers. Of UI's 2015 retail revenues, 58.8% were derived from residential sales, 34.6% from commercial sales, 4.9% from industrial sales and 1.6% from street lighting and other sales. UI's retail electric revenues vary by season, with the highest revenues typically in the third quarter of the year reflecting seasonal rates, hotter weather and air conditioning use. UI is regulated as an electric distribution company by the Connecticut Public Utilities Regulatory Authority (PURA) and is also subject to regulation by the Federal Energy Regulatory Commission (FERC).

UI is also a party to a joint venture with certain affiliates of NRG Energy, Inc. (NRG affiliates) pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly owned subsidiary, GenConn Energy LLC (together with GCE Holding LLC, GenConn) operates peaking generation plants in Devon, Connecticut (GenConn Devon) and Middletown, Connecticut (GenConn Middletown).

Accounting Records

The accounting records of UI are maintained in conformity with accounting principles generally accepted in the United States of America (GAAP) and in accordance with the uniform systems of accounts prescribed by the FERC and the PURA.

Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to use estimates and assumptions that affect (1) the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and (2) the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Certain amounts related to deferred tax liabilities, regulatory liabilities, operation and maintenance expense, depreciation and amortization expense, taxes other than income taxes, and other income and (deductions) that were reported as such in the Financial Statements in previous periods have been reclassified to conform to the current presentation as a result of UIL Holdings presenting such information consistent with its parent Avangrid, Inc. due to the merger. See further discussion regarding the merger in Note (A) "Statement of Accounting Policies – Merger with Avangrid, Inc." and Note (C) "Regulatory Proceedings".

The following table summarizes (1) the impact to the prior period Financial Statements of the adjustments noted above (2) the impacts to the prior period financials of the adjustments made as a result of the early adoption of certain new accounting standards (See Note (A) "Statement of Accounting Policies – New Accounting Standards"), and (3) certain immaterial amounts that have been reclassified to conform to the current presentation.

December 31, 2014 (in thousands)	As previously filed	Reclassifications	As currently reported
Statement of Income			
Operation and maintenance	235,448	3,145	238,593
Depreciation and amortization	67,410	(1,921)	65,489
Taxes - other than income taxes	87,233	(1,224)	86,009
Other income	-	16,112	16,112
Other income and (deductions)	15,802	(16,112)	(310)
Statement of Cash Flows			
Depreciation and amortization	68,893	(1,921)	66,972
Other regulatory activity, net	23,265	7,038	30,303
Accrued liabilities	7,160	(6,061)	1,099
Other assets	(1,487)	944	(543)
Balance Sheet			
Accrued liabilities	26,768	(11,648)	15,120
Current regulatory liabilities	5,039	6,420	11,459
Deferred income taxes (current)	24,903	(24,903)	-
Total Current Liabilities	223,188	(30,131)	193,057
Environmental remediation costs	-	3,011	3,011
Total Other Noncurrent Liabilities	276,162	3,011	279,173
Deferred income taxes	534,205	24,903	559,108
Regulatory liabilities	131,325	2,217	133,542
Unamortized debt issuance expenses	5,844	(5,425)	419
Total deferred charges and other assets	46,547	(5,425)	41,122
Total assets	2,877,220	(5,425)	2,871,795
Long-term debt	845,460	(5,425)	840,035
Total capitalization	1,712,340	(5,425)	1,706,915
Total liabilities and capitalization	2,877,220	(5,425)	2,871,795

UI has evaluated subsequent events through the date its financial statements were available to be issued, April 4, 2016.

Allowance for Funds Used During Construction

In accordance with the uniform systems of accounts, the UI capitalizes allowance for funds used during construction (AFUDC), which represents the approximate cost of debt and equity capital devoted to plant under construction. The portion of the allowance applicable to borrowed funds is presented as other interest and the portion of the allowance applicable to equity funds is presented as other income in the Statement of Income. Although the allowance does not represent current cash income, it has been recoverable under the ratemaking process over the service lives of the related properties. Weighted-average AFUDC rates for 2015 and 2014 were 7.67% and 7.66%, respectively.

Asset Retirement Obligations

The fair value of the liability for an asset retirement obligation (ARO) and/or a conditional ARO is recorded in the period in which it is incurred and the cost is capitalized by increasing the carrying amount of the related long-lived asset. The liability is adjusted to its present value periodically over time, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement, the obligation is settled either at its recorded amount or a gain or a loss is incurred. Any timing differences between rate recovery and depreciation expense are deferred 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 and/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.

UI's ARO, including estimated conditional AROs, consists primarily of obligations related to the removal or retirement of asbestos and polychlorinated biphenyl (PCB)-contaminated equipment. The long-lived assets associated with the AROs are distribution property and other property. UI's ARO is carried on the balance sheet as other long-term liabilities.

ARO activity for 2015 and 2014 is as follows:

	2015	2014
	(In Thousands)	
Balance as of January 1	$ 303	$ 289
Accretion	11	14
Liabilities settled during the year	(314)	-
Balance as of December 31	$ -	$ 303

Cash and Temporary Cash Investments

UI considers all of its highly liquid debt instruments with an original maturity of three months or less at the date of purchase to be cash and temporary cash investments.

Depreciation

Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis, using estimated service lives. For utility plant other than software, service lives are determined by independent engineers and subject to review and approval by PURA. Software service life is based upon management's estimate of useful life and subject to review and approval by PURA. The aggregate annual provisions for depreciation for 2015 and 2014 were approximately 2.9% and 3.0% respectively, of the original cost of depreciable property.

Derivatives

UI is party to contracts, and involved in transactions, that are derivatives.

<u>Contracts for Differences (CfDs)</u>

Pursuant to Connecticut's 2005 Energy Independence Act, the Connecticut Public Utilities Regulatory Authority (PURA) solicited bids to create new or incremental capacity resources in order to reduce federally mandated congestion charges, and selected four new capacity resources. To facilitate the transactions between the selected capacity resources and Connecticut electric customers, and provide the commitment necessary for owners of these resources to obtain necessary financing, PURA required that UI and The Connecticut Light and Power Company (CL&P) execute long-term contracts with the selected resources. In August 2007, PURA approved four CfDs, each of which specifies a capacity quantity and a monthly settlement that reflects the difference between a forward market price and the contract price. UI executed two of the contracts and CL&P executed the other two contracts. The costs or benefits of each contract will be paid by or allocated to customers and will be subject to a cost-sharing agreement between UI and CL&P pursuant to which approximately 20% of the cost or benefit is borne by or allocated to UI customers and approximately 80% is borne by or allocated to CL&P customers.

PURA has determined that costs associated with these CfDs will be fully recoverable by UI and CL&P through electric rates, and in accordance with ASC 980 "Regulated Operations," UI has deferred recognition of costs (a regulatory asset) or obligations (a regulatory liability). The CfDs are marked-to-market in accordance with ASC 815 "Derivatives and Hedging." For those CfDs signed by CL&P, UI records its approximate 20% portion pursuant to the cost-sharing agreement noted above. As of December 31, 2015, UI has recorded a gross derivative asset of $29.3 million ($1.4 million of which is related to UI's portion of the CfD signed by

CL&P), a regulatory asset of $67.7 million, a gross derivative liability of $96.2 million ($61.4 million of which is related to UI's portion of the CfD signed by CL&P) and a regulatory liability of $0.7 million. See Note (J) "Fair Value of Financial Instruments" for additional CfD information.

The gross derivative assets and liabilities as of December 31, 2015 and 2014 were as follows:

	December 31, 2015		December 31, 2014	
	(In Thousands)			
Gross derivative assets:				
Current Assets	$	10,507	$	6,849
Deferred Charges and Other Assets	$	18,757	$	20,421
Gross derivative liabilities:				
Current Liabilities	$	28,466	$	23,308
Noncurrent Liabilities	$	67,764	$	61,766

The unrealized gains and losses from fair value adjustments to these derivatives, which are recorded in regulatory assets or regulatory liabilities, for years ended December 31, 2015 and 2014 were as follows:

	Year Ended December 31,			
	2015		2014	
	(In Thousands)			
Regulatory Assets - Derivative liabilities	$	3,429	$	(78,510)
Regulatory Liabilities - Derivative assets	$	5,733	$	(6,472)

The fluctuations in the balances of the derivatives as well as the related unrealized gains in the year ended December 31, 2015 compared to 2014 are primarily due to decreases in forward prices for capacity and reserves.

Equity Investments

UI is party to a 50-50 joint venture with the NRG affiliates in GenConn, which operates two peaking generation plants in Connecticut. UI's investment in GenConn is being accounted for as an equity investment, the carrying value of which was $110.3 million and $114.2 million as of December 31, 2015 and 2014, respectively. As of December 31, 2015, there was $0.1 million of undistributed earnings from UI's equity investment in GenConn.

UI's pre-tax income from its equity investment in GenConn was $14.2 million and $13.9 million for the years ended December 31, 2015 and 2014, respectively.

Cash distributions from GenConn are reflected as either distributions of earnings or as returns of capital in the operating and investing sections of the Statement of Cash Flows, respectively. UI received cash distributions from GenConn of $18.1 million and $17.9 million during the years ended December 31, 2015 and 2014, respectively.

The following represents summarized financial information of GenConn as of and for the years ended December 31:

	2015	2014
	(In Thousands)	
Current assets	$ 35,749	$ 33,431
Noncurrent assets	$ 415,787	$ 437,854
Current liabilities	$ 15,734	$ 19,888
Noncurrent liabilities	$ 215,224	$ 222,836
Operating revenues	$ 78,304	$ 82,010
Income	$ 28,275	$ 27,871

Impairment of Long-Lived Assets and Investments

ASC 360 “Property, Plant, and Equipment” requires the recognition of impairment losses on long-lived assets when the book value of an asset exceeds the sum of the expected future undiscounted cash flows that result from the use of the asset and its eventual disposition. If impairment arises, then the amount of any impairment is measured based on discounted cash flows or estimated fair value.

ASC 360 also requires that rate-regulated companies recognize an impairment loss when a regulator excludes all or part of a cost from rates, even if the regulator allows the company to earn a return on the remaining costs allowed. Under this standard, the probability of recovery and the recognition of regulatory assets under the criteria of ASC 980 must be assessed on an ongoing basis. As discussed in the description of ASC 980 in this Note (A) under “Regulatory Accounting,” determination that certain regulatory assets no longer qualify for accounting as such could have a material impact on the financial condition of UI. In addition, as a result of PURA’s decision in a docket addressing UI’s semi-annual Generation Services Charge (GSC), bypassable federally mandated congestion charge and the nonbypassable federally mandated congestion charge reconciliations (NBFMCC), UI recorded a write-off during the fourth quarter of 2014. See Note (C) “Regulatory Proceedings, Electric Distribution and Transmission – Other Proceedings” for additional information.

ASC 323 “Investments” requires that a loss in the value of an investment that is other than a temporary decline should be recognized. In accordance with ASC 323, UI reviews its investments accounted for by the equity method for impairment by identifying and measuring losses in the value based upon a comparison of fair value to carrying value. At December 31, 2015, UI did not have any equity investments that were impaired under this standard.

Income Taxes

In accordance with ASC 740 “Income Taxes,” UI has provided deferred taxes for all temporary book‐ tax differences using the liability method. The liability method requires that deferred tax balances be adjusted to reflect enacted future tax rates that are anticipated to be in effect when the temporary differences reverse. In accordance with generally accepted accounting principles for regulated industries, UI has established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. For ratemaking purposes, UI normalizes all investment tax credits (ITCs) related to recoverable plant investments.

Under ASC 740, UI may recognize the tax benefit of an uncertain tax position only if management believes it is more likely than not that the tax position will be sustained on examination by the taxing authority based upon the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based upon the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. UI’s policy is to recognize interest accrued and penalties associated with uncertain tax positions as a component of operating expense. See – Note (E), “Income Taxes” for additional information.

Pension and Other Postretirement Benefits

UI accounts for pension plan costs and other postretirement benefits, consisting principally of health and life insurance, in accordance with the provisions of ASC 715 “Compensation - Retirement Benefits.” See Note (F), “Pension and Other Benefits”.

Property, Plant and Equipment

The cost of additions to property, plant and equipment and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including AFUDC. The costs of current repairs, major maintenance projects and minor replacements are charged to appropriate operating expense accounts as incurred. The original cost of utility property, plant and equipment retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation.

UI accrues for estimated costs of removal for certain of its plant-in-service. Such removal costs are included in the approved rates used to depreciate these assets. At the end of the service life of the applicable assets, the accumulated depreciation in excess of the historical cost of the asset provides for the estimated cost of removal. In accordance with ASC 980 “Regulated Operations,” the accrued costs of removal have been recorded as a regulatory liability.

UI’s property, plant and equipment as of December 31, 2015 and 2014 were comprised as follows:

	2015	2014
	(In Thousands)	
Distribution plant	$ 1,252,676	$ 1,135,317
Transmission plant	680,261	646,826
Software	102,542	108,248
Land	59,806	57,644
Building and improvements	193,947	187,047
Other plant	152,063	118,385
Total property, plant & equipment	2,441,295	2,253,467
Less accumulated depreciation	539,289	505,313
	1,902,006	1,748,154
Construction work in progress	187,212	194,900
Net property, plant & equipment	$ 2,089,218	$ 1,943,054

Regulatory Accounting

Generally accepted accounting principles for regulated entities in the United States of America allow UI to give accounting recognition to the actions of regulatory authorities in accordance with the provisions of Accounting Standards Codification (ASC) 980 “Regulated Operations.” In accordance with ASC 980, UI has deferred recognition of costs (a regulatory asset) or has recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or obligations relieved in the future through the ratemaking process. UI is allowed to recover all such deferred costs through its regulated rates. See Note (C) “Regulatory Proceedings”, for a discussion of the recovery of certain deferred costs, as well as a discussion of the regulatory decisions that provide for such recovery.

UI also has obligations under long-term power contracts, the recovery of which is subject to regulation. If UI, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs would be required in the year in which such criteria are no longer met (if such deferred costs are not recoverable in the portion of the business that continues to meet the criteria for application of ASC 980). UI expects to continue to meet the criteria for application of ASC 980 for the foreseeable future. If a change in accounting were to occur, it could have a material adverse effect on the earnings and retained earnings of UI in that year and could also have a material adverse effect on the ongoing financial condition of UI.

Unless otherwise stated below, all of UI's regulatory assets earn a return. UI's regulatory assets and liabilities as of December 31, 2015 and 2014 included the following:

	Remaining Period	December 31, 2015	December 31, 2014
		(In Thousands)	
Regulatory Assets:			
Unamortized redemption costs	7 to 19 years	9,697	10,499
Pension and other post-retirement benefit plans	(a)	181,030	201,345
Unfunded future income taxes	(b)	179,187	164,466
Contracts for differences	(c)	67,705	64,276
Deferred transmission expense	(d)	10,425	17,387
Other	(f)	28,348	24,709
Total regulatory assets		476,392	482,682
Less current portion of regulatory assets		44,469	52,419
Regulatory Assets, Net		$ 431,923	$ 430,263
Regulatory Liabilities:			
Accumulated deferred investment tax credits	29 years	$ 10,156	$ 4,319
Rate credits	1 year	9,359	-
Excess generation service charge	(e)	20,895	28,692
Middletown/Norwalk local transmission network service collections	35 years	20,255	20,828
Pension and other post-retirement benefit plans	(a)	6,537	-
Asset removal costs	(f)	63,272	68,789
Contracts for differences	(c)	739	6,472
Other	(f)	9,086	15,901
Total regulatory liabilities		140,299	145,001
Less current portion of regulatory liabilities		10,079	11,459
Regulatory Liabilities, Net		$ 130,220	$ 133,542

(a) Life is dependent upon timing of final pension plan distribution; balance, which is fully offset by a corresponding asset/liability, is recalculated each year in accordance with ASC 715 "Compensation-Retirement Benefits." See Note (F) "Pension and Other Benefits" for additional information.
(b) The balance will be extinguished when the asset, which is fully offset by a corresponding liability; or liability has been realized or settled, respectively.
(c) Asset life is equal to delivery term of related contracts (which vary from approximately 4 - 11 years); balance fluctuates based upon quarterly market analysis performed on the related derivatives (Note J); amount, which does not earn a return, is fully offset by corresponding derivative asset/liability. See "-Contracts for Differences" discussion above for additional information.
(d) Regulatory asset or liability which defers transmission income or expense and fluctuates based upon actual revenues and revenue requirements.
(e) Regulatory asset or liability which defers generation-related and nonbypassable federally mandated congestion costs or revenues for future recovery from or return to customers. Amount fluctuates based upon timing differences between revenues collected from rates and actual costs incurred.
(f) Amortization period and/or balance vary depending on the nature, cost of removal and/or remaining life of the underlying assets/liabilities; asset amount includes decoupling ($1.3 million) and certain other amounts that are not currently earning a return. See Note (C) "Regulatory Proceedings for a discussion of the decoupling recovery period.

Restricted Cash

UI's restricted cash at December 31, 2015 and 2014 totaled \$1.7 million and \$1.1 million, respectively, which primarily relates to electric distribution and transmission capital projects, which have been withheld by UI and will remain in place until the verification of fulfillment of contractor obligations.

Revenues

Regulated utility revenues are based on authorized rates applied to each customer. These retail rates are approved by regulatory bodies and can be changed only through formal proceedings.

UI utilizes a customer accounting software package integrated with the network meter reading system to estimate unbilled revenue on a customer-by-customer basis, utilizing actual daily meter readings at the end of each month to calculate consumption and pricing for each customer. A significant portion of utility retail kilowatt-hour consumption is read through the network meter reading system. For those customers still requiring manual meter readings, consumption is estimated based upon historical usage and actual pricing for each customer.

Variable Interest Entities

UI has identified GenConn as a variable interest entity (VIE), which is accounted for under the equity method. UI is not the primary beneficiary of GenConn, as defined in ASC 810 "Consolidation," because it shares control of all significant activities of GenConn with its joint venturer, NRG affiliates. As such, GenConn is not subject to consolidation. GenConn recovers its costs through CfDs, which are cost of service-based and have been approved by PURA. As a result, with the achievement of commercial operation by GenConn Devon and GenConn Middletown, UI's exposure to loss is primarily related to the potential for unrecovered GenConn operating or capital costs in a regulatory proceeding, the effect of which would be reflected in the carrying value of UI's 50% ownership position in GenConn and through "Income from Equity Investments" in UI's Financial Statements. Such exposure to loss cannot be determined at this time. For further discussion of GenConn, see "–Equity Investments" as well as Note (C) Regulatory Proceedings – Electric Distribution and Transmission – Equity Investment in Peaking Generation.

UI has identified the selected capacity resources with which it has CfDs as VIEs and has concluded that it is not the primary beneficiary as it does not have the power to direct any of the significant activities of these capacity resources. As such, UI has not consolidated the selected capacity resources. UI's maximum exposure to loss through these agreements is limited to the settlement amount under the CfDs as described in "–Derivatives – Contracts for Differences (CfDs)" above. UI has no requirement to absorb additional losses nor has UI provided any financial or other support during the periods presented that were not previously contractually required.

UI has identified the entities for which it is required to enter into long-term contracts to purchase Renewable Energy Credits (RECs) as VIEs. In assessing these contracts for VIE identification and reporting purposes, UI has aggregated the contracts based on similar risk characteristics and significance to UI. UI is not the primary beneficiary as it does not have the power to direct any of the significant activities of these entities. UI's exposure to loss is primarily related to the purchase and resale of the RECs, but, any losses incurred are recoverable through electric rates. For further discussion of RECs, see Note (C) Regulatory Proceedings – Electric Distribution and Transmission – New Renewable Source Generation.

New Accounting Pronouncements

In April 2015, the FASB issued Accounting Standards Update (ASU) 2015-03, "Interest—Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs" which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. ASU 2015-03 is effective for interim and annual reporting periods beginning after December 15, 2015 and is to be applied retrospectively. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. See Note (A) "Basis of Presentation" for a table.

In July 2015, the FASB issued Accounting Standards Update (ASU) 2015-11, "Inventory – Simplifying the Measurement of Inventory" which requires inventory that is measured using first-in, first-out or average cost methods to be measured using the lower of cost and net realizable value. ASU 2015-11 is effective for interim and annual reporting periods beginning after December 15, 2016 and is to be applied prospectively with earlier application permitted as of the beginning of an interim or annual reporting period. This is not expected to be material to UI's financial statements.

In August 2015, the FASB issued Accounting Standards Update (ASU) 2015-13, "Derivatives and Hedging" which specifies that the use of locational marginal pricing by an independent system operator does not constitute net settlement of a forward contract for the purchase or sale of electricity and does not cause that contract to fail to meet the physical delivery criterion of the normal purchases and normal sales scope exception. This guidance was effective upon issuance and does have an impact on UI's financial statements.

In August 2015, the FASB issued Accounting Standards Update (ASU) 2015-14, "Revenue from Contracts with Customers" which defers the effective date of ASU 2014-09 by one year. ASU 2014-09 requires entities to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services. We are currently evaluating the effect that adopting this new accounting guidance will have on our financial statements.

Also in August 2015, the FASB issued Accounting Standards Update (ASU) 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements" which incorporates SEC guidance into ASC 835 "Interest" that allows an entity to defer and present debt issuance costs related to line of credit arrangements as an asset and subsequently amortize such costs ratably over the term of the arrangement regardless of whether there are any outstanding borrowings on the line of credit. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. See Note (A) "Basis of Presentation" for a table.

In November 2015, the FASB issued Accounting Standards Update (ASU) 2015-17, "Balance Sheet Classification of Deferred Taxes" which requires that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. This Update is applies to all entities that present a classified statement of financial position. For non-public entities, ASU 2015-17 is effective for financial statements issued for annual periods beginning after December 15, 2017. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. See Note (A) "Basis of Presentation" for a table.

In January 2016, the FASB issued Accounting Standards Update (ASU) 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities". The new guidance requires that all equity investments in unconsolidated entities (other than those accounted for using the equity method of accounting) to be measured at fair value through earnings. There will no longer be an available-for-sale classification (changes in fair value reported in other comprehensive income) for equity securities with readily determinable fair values. For equity investments without readily determinable fair values, the cost method is also eliminated. When the fair value option has been elected for financial liabilities, changes in fair value due to instrument-specific credit risk will be recognized separately in other comprehensive income. The accumulated gains and losses due to these changes will be reclassified from accumulated other comprehensive income to earnings if the financial liability is settled before maturity. The amendments exempt all entities that are not public business entities from disclosing fair value information for financial instruments measured at amortized cost. In addition, the new guidance requires financial assets and financial liabilities to be presented separately in the notes to the financial statements, grouped by measurement category (e.g., fair value, amortized cost, lower of cost or market) and form of financial asset (e.g., loans, securities).

The classification and measurement guidance is effective for entities that are not public entities in fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. All entities that are not public entities may adopt the amendments earlier as of the fiscal years beginning after December 15, 2017 including interim periods within those fiscal years. An entity will record a cumulative-effect adjustment to beginning retained earnings as of the beginning of the first reporting period in which the guidance is adopted, with two exceptions. The amendments related to equity investments without readily determinable fair values (including disclosure requirements) will be effective prospectively. The requirement to use the exit price notion to measure the fair value of financial instruments for disclosure purposes will also be applied prospectively. We do not expect our adoption of the guidance to materially affect our results of operations, financial position, or cash flows.

In February 2016, the FASB issued Accounting Standards Update (ASU) 2016-02 "Leases". The guidance in this Update supersedes Topic 840, "Leases" and creates Topic 842, "Leases". Topic 842 defines a lease as a contract, or part of a contract, that conveys both the right to obtain substantially all economic benefits of an identified asset and the right to direct the use of the asset for a period of time in exchange for consideration. Leases are classified under this guidance as either operating or finance. For operating and finance leases, a lessee is required to recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, in the statement of financial position. For operating leases, a lessee is required to recognize a single lease cost, which will be recognized on a straight-line basis over the lease term similar to the current model. Lessor accounting is largely unchanged from that applied under previous GAAP. However, minor changes have been made to align with certain definition changes to the lessee model and the new revenue recognition standard. Leveraged lease accounting has been eliminated under this Update. Qualitative and specific quantitative disclosures are required under this guidance to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. For entities that are not public entities, the amendments in this Update are effective for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020. Early application is permitted for all entities. We are currently evaluating the effect that adopting this new accounting guidance will have on our financial statements.

(B) CAPITALIZATION

Common Stock

UI had 100 shares of common stock, no par value, outstanding at December 31, 2015 and 2014.

Long-Term Debt

	December 31, 2015	December 31, 2014
	(In Thousands)	
Pollution Control Revenue Refunding Bonds:		
4.50% 2010 Series, due 2027	$ -	$ 27,500
Auction Rate, 2003 Series, due 2033 (1)	64,460	64,460
Senior Unsecured Notes:		
6.06% Senior Notes, Series A and B, due 2017	70,000	70,000
2.98% Senior Notes, Series A due 2019	31,000	31,000
3.61% Senior Notes, Series B and C and 6.26% Senior Notes, Series C and D, due 2022	162,500	162,500
6.51% Senior Notes, Series E and F due 2037	28,000	28,000
6.46% Senior Notes , Series A and 6.51%, Senior Notes, Series B, due 2018	100,000	100,000
6.61% Senior Notes, Series C, due 2020	50,000	50,000
5.61% Senior Notes, due 2025	50,000	50,000
6.09% Senior Notes, due 2040	100,000	100,000
4.89% Senior Notes, Series D and E, due 2042	87,000	87,000
3.95% Senior Notes, Series F, due 2023	75,000	75,000
4.61% Senior Notes, Series G, due 2045	50,000	-
Long-Term Debt	867,960	845,460
Less: Unamortized debt issuance costs	5,223	5,425
Long-Term Debt	$ 862,737	$ 840,035

(1) On December 31, 2015, the interest rate on the Bonds was 0.57%. The interest rate on these Bonds is reset through an auction held every 35 days.

The weighted-average remaining fixed rate period of outstanding long-term debt obligations of UI as of December 31, 2015 was 11 years, at an average interest rate of 5.0%.

The fair value of UI's long-term debt was $955.4 million and $958.3 million as of December 31, 2015 and 2014, respectively, which was estimated by UI based on market conditions. The expenses to issue long-term debt are deferred and amortized over the life of the respective debt issue or the fixed interest-rate period in the case of pollution control revenue bonds.

Information regarding maturities and mandatory redemptions/repayments are set forth below:

	2016	2017	2018	2019	2020	2021 & thereafter	Total
				(In Thousands)			
Maturities	$ -	$ 70,000	$ 100,000	$ 31,000	$ 50,000	$ 616,960	$ 867,960

On October 25, 2013, UI entered into a note purchase agreement with a group of institutional accredited investors providing for the sale to such investors on October 25, 2013 of senior unsecured 3.95% notes in the principal amount of $75 million, due on October 25, 2023. UI used the net proceeds from this long-term debt issuance to repay short-term debt and for general corporate purposes.

On June 29, 2015 (the "execution date"), UI entered into a Note Purchase Agreement with a group of institutional accredited investors providing for the sale to such investors of UI's 4.61% Senior Notes, Series G, due June 29, 2045, in the principal amount of $50 million which was issued on the execution date. UI used the net proceeds from this long-term debt issuance to re-pay $27.5 million of pollution control refunding revenue bonds which were subject to mandatory purchase on July 1, 2015 and plans on using the remaining funds for general corporate purposes or other purposes described in its application to PURA for approval of the issuance of debt and as approved by PURA.

(C) REGULATORY PROCEEDINGS

Merger with Avangrid, Inc.

As discussed in Note A, "Organization and Statement of Accounting Policies", on December 16, 2015, UI's parent company, UIL Holdings, merged with Avangrid, Inc. PURA and DPU approvals were obtained upon commitments made by UIL Holdings and Avangrid, Inc. that included $9.4 million in rate credits to UI customers included in regulatory liabilities in the accompanying balance sheet, $7.0 million in contributions to a clean energy fund and disaster relief included in accrued liabilities in the accompanying balance sheet. These commitments were accrued upon completion of the merger and are included in the consolidated results of operations for the year ended December 31, 2015.

In addition, the commitments include a distribution rate freeze to January 1, 2017 for UI. UIL Holdings and Avangrid, Inc. further committed to no change in the day-to-day management and operation of UIL Holdings' Connecticut and Massachusetts utilities, to hiring 150 employees or contractors within the State of Connecticut over the next three years, to maintain UI's high service reliability and to improve certain customer service metrics in Connecticut over the next three years.

The commitments also included comprehensive "ring fencing" provisions to protect the Connecticut and Massachusetts utilities from involuntary bankruptcy associated with potential future adverse changes in financial circumstances of Avangrid, Inc. affiliates. These provisions include the creation of a special purpose entity with at least one independent director, dividend limitations on the Connecticut utilities where the investment grade credit rating is in jeopardy or if a minimum common equity ratio is not maintained, commitments to maintain separate books and records and a prohibition on commingling of funds.

In connection with the commitments, UI negotiated a proposed partial consent order with the Connecticut Department of Energy and Environmental Protection (DEEP) to remediate the English Station site in New Haven, Connecticut, formerly owned by UI. See Note (I) "Commitments and Contingencies" for further discussion regarding English Station.

Rates

Utilities are entitled by Connecticut statutes to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital and to maintain their financial integrity, while also protecting relevant public interests.

UI's allowed distribution return on equity established by PURA is 9.15%. UI is required to return to customers 50% of any distribution earnings over the allowed ROE in a calendar year by means of an earnings sharing mechanism. Under the settlement agreement entered into in connection with PURA's approval of the merger of UIL Holdings with Avangrid, Inc., UI agreed not to request new distribution rates effective prior to January 1, 2017.

Power Supply Arrangements

Under Connecticut law, UI's retail electricity customers are able to choose their electricity supplier while UI remains their electric distribution company. UI purchases power for those of its customers under standard service rates who do not choose a retail electric supplier and have a maximum demand of less than 500 kilowatts and its customers under supplier of last resort service for those who are not eligible for standard service and who do not choose to purchase electric generation service from a retail electric supplier. The cost of the power is a "pass-through" to those customers through the GSC charge on their bills.

UI must procure the power to serve its standard service load pursuant to a procurement plan approved by PURA. Under the procurement plan UI procures wholesale power for its standard service customers on a full requirements basis pursuant to contracts with a maximum duration of 12 months, with the delivery of such wholesale power to commence no later than six months from the applicable bid day.

UI has wholesale power supply agreements in place for its entire standard service load for the first half of 2016, 80% of its standard service load for the second half of 2016 and 30% of its standard service load for the first half of 2017. Supplier of last resort service is procured on a quarterly basis, however, from time to time there are no bidders in the procurement process for supplier of last resort service and in such cases UI manages the load directly. UI determined that its contracts for standard service and supplier of last resort service are derivatives under ASC 815 "Derivatives and Hedging" and elected the "normal purchase, normal sale" exception under ASC 815 "Derivatives and Hedging." UI regularly assesses the accounting treatment for its power supply contracts. These wholesale power supply agreements contain default provisions that include required performance assurance, including certain collateral obligations, in the event that UI's credit rating on senior debt were to fall below investment grade. If UI's credit rating were to decline one rating at Standard & Poor's or two ratings at Moody's and UI were to be placed on negative credit watch, monthly amounts due and payable to the power suppliers would be accelerated to semi-monthly payments. UI's credit rating would have to decline two ratings at Standard & Poor's and three ratings at Moody's to fall below investment grade. If this were to occur, UI would have to deliver collateral security in an amount equal to the receivables due to the sellers for the thirty-day period immediately preceding the default notice. If such an event had occurred as of December 31, 2015, UI would have had to post an aggregate of approximately $17.9 million in collateral. UI would have been and remains able to provide that collateral.

In addition, UI is authorized to seek long-term contracts for up to 20% of its standard service requirements and Connecticut Class I Renewable Energy Certificates (RECs) for UI's standard service customers that will result in an economic benefit to ratepayers, both in terms of risk and cost mitigation. UI continues to keep apprised of possible long-term contracts that could benefit customers, but has not executed any long-term contracts.

New Renewable Source Generation

Under Connecticut law Public Act (PA 11-80), Connecticut electric utilities are required to enter into long-term contracts to purchase Connecticut Class I Renewable Energy Certificates, or RECs, from renewable generators located on customer premises. Under this program, UI is required to enter into contracts totaling approximately $200 million in commitments over an approximate 21-year period. The obligations will phase in over a six-year solicitation period, and are expected to peak at an annual commitment level of about $13.6 million per year after all selected projects are online. Upon purchase, UI accounts for the RECs as inventory. UI expects to partially mitigate the cost of these contracts through the resale of the RECs. PA 11-80 provides that the remaining costs (and any benefits) of these contracts, including any gain or loss resulting from the resale of the RECs, are fully recoverable from (or credited to) customers through electric rates.

On October 23, 2013, PURA approved UI's renewable connections program filed in accordance with PA 11-80, through which UI will develop up to 10 MW of renewable generation. The costs for this program will be recovered on a cost of service basis. PURA established a base ROE to be calculated as the greater of: (A) the current UI authorized distribution ROE (currently 9.15%) plus 25 basis points and (B) the current authorized distribution ROE for CL&P (currently 9.17%), less target equivalent market revenues (reflected as 25 basis points). In addition, UI will retain a percentage of the market revenues from the project, which percentage is expected to equate to approximately 25 basis points on a levelized basis over the life of the project. UI expects the cost of this program, a planned 2.8 MW fuel cell facility in New Haven, solar photovoltaic and fuel cell facilities totaling 5 MW in Bridgeport, and a 2.2 MW fuel cell facility in Woodbridge to be approximately $47 million.

Pursuant to Connecticut law (PA 13-303), on September 19, 2013, at the direction DEEP UI entered into two contracts for energy and/or RECs from Class I renewable resources, totaling approximately 3.5% of UI's distribution load, which were subsequently approved by PURA. Costs of each of these agreements will be fully recoverable through electric rates. On December 18, 2013, Allco Finance Limited, an unsuccessful bidder for such contracts, filed a complaint against DEEP in the United States District Court in Connecticut alleging that DEEP's direction to UI and CL&P to enter into the contracts violated the Supremacy Clause of the U.S. Constitution and the Federal Power Act by setting wholesale electricity rates. This complaint was dismissed in December 2014. On January 2, 2015 Allco filed an appeal with the United States Court of Appeals for the Second Circuit. On November 6, 2015 the Second Circuit affirmed the district court's judgment on alternative grounds.

Pursuant to Section 8 of Public Act 13-303, "An Act Concerning Connecticut's Clean Energy Goals," (PA 13-303), in January 2014, at DEEP's direction, UI entered into three contracts for the purchase of RECs associated with an aggregate of 5.7 MW of energy production from biomass plants in New England. The costs of these agreements will be fully recoverable through electric rates.

Transmission

PURA decisions do not affect the revenue requirements determination for UI's transmission business, including the applicable ROE, which are within the jurisdiction of the FERC. The FERC has issued orders establishing allowable ROEs for transmission projects of transmission owners in New England, including UI. The FERC established a base-level ROE of 11.14%, as well as a 50 basis point ROE adder on Pool Transmission Facilities (PTF) for participation in the RTO for New England and a 100 basis point ROE incentive for projects included in the ISO-NE Regional System Plan that were completed and on line as of December 31, 2008.

UI's overall transmission ROE is determined by the mix of UI's transmission rate base between new and existing transmission assets, and whether such assets are PTF or non-PTF. UI's transmission assets are primarily PTF. For 2015, UI's overall allowed weighted-average ROE for its transmission business was 11.35%. This includes the impact of the FERC order issued on October 16, 2014 and excludes any impacts of the reserve adjustment, both of which are discussed below.

Beginning in 2011, several New England state attorneys general, state regulatory commissions, consumer advocates, consumer groups, municipal parties and other parties filed three separate complaints with the FERC against ISO-NE and several New England transmission owners, including UI. In the first complaint, filed in September 2011, the complainants claimed that the then current approved base ROE of 11.14% used in calculating formula rates for transmission service under the ISO-NE Open Access Transmission Tariff by the New England transmission owners was not just and reasonable and sought a reduction of the base ROE and a refund to customers for a refund period of October 1, 2011 through December 31, 2012. In 2012 and 2014, respectively, the complainants filed claims with the FERC similarly challenging the base ROE and seeking refunds for the 15-month periods beginning December 27, 2012 and July 31, 2014, respectively. The complainants in the third complaint also asked for a determination that the top of the zone of reasonableness caps the ROE for each individual project. The FERC issued an order consolidating the second and third complaints and establishing hearing procedures. The New England transmission owners petitioned FERC for a rehearing, which was denied in May 2015. Hearings were held in June 2015 on the second and third complaints before a FERC Administrative Law Judge, relating to the refund periods and going forward. On July 29, 2015, post-hearing briefs were filed by parties and on August 26, 2015 reply briefs were filed by parties. On July 13, 2015, the New England transmission owners filed a petition for review of FERC's orders establishing hearing and consolidation procedures for the second and third complaints with the U.S. Court of Appeals. On March 22, 2016, the Administrative Law Judge issued an initial decision which determined that, 1) for the 15 month refund period in the second complaint, the base ROE should be 9.59% and that the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and 2) for the 15 month refund period in the third complaint and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. If adopted as final, the impact of the initial decision would be an addition pre-tax reserve of $4.3 million. The initial decision is the Administrative Law Judge's recommendation to the FERC Commissioners. The FERC is expected to make its final decision in late 2016 or early 2017. We cannot predict the outcome of the second and third complaint proceedings.

In 2014, the FERC determined that the base ROE should be set at 10.57% for the first complaint refund period and that a utility's total or maximum ROE should not exceed 11.74%. The FERC ordered the New England transmission owners to provide refunds to customers for the first complaint refund period and set the new base ROE of 10.57% prospectively from October 16, 2014.

On March 3, 2015, the FERC issued an Order on Rehearing in the first complaint (the March Order) denying all rehearing requests from the complainants and the New England transmission owners. On April 30, 2015, the New England transmission owners filed a petition for review of the FERC's decisions on the first complaint with the U.S. Court of Appeals for the D.C. Circuit. On May 1, 2015, two additional petitions for review of those FERC decisions were also filed at the D.C. Circuit by the complainants and by several customers. The appeals of the FERC's decisions on the first complaint have been consolidated and are currently pending before the D.C. Circuit. UI recorded additional pre-tax reserves of $1.7 million in 2015 relating to the third complaint and the March Order. As of December 31, 2015, net pre-tax reserves relating to refunds and potential refunds to customers under all three claims were approximately $3.4 million and cumulative pre-tax reserves were approximately $9.8 million, of which $6.4 million has already been refunded to customers.

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

New England East-West Solution

Pursuant to an agreement with CL&P (the Agreement), UI has the right to invest in, and own transmission assets associated with, the Connecticut portion of CL&P's New England East West Solution (NEEWS) projects to improve regional energy reliability. NEEWS consists of four inter-related transmission projects being developed by subsidiaries of Northeast Utilities (doing business as Eversource Energy), the parent company of CL&P, in collaboration with National Grid USA. Three of the projects have portions located in Connecticut: (1) the Greater Springfield Reliability Project (GSRP), which was fully energized in November 2013, (2) the Interstate Reliability Project (IRP), which is expected to be placed in service in December 2015 and (3) the Central Connecticut Reliability Project (CCRP), which was reassessed as part of the Greater Hartford Central Connecticut Study (GHCC). As CL&P places assets in service, it will transfer title to certain NEEWS transmission assets to UI in proportion to UI's investments, but CL&P will continue to maintain these portions of the transmission system pursuant to an operating and maintenance agreement with UI. Any termination of the Agreement pursuant to its terms would have no effect on the assets previously transferred to UI.

Under the terms of the Agreement, UI has the option to make quarterly deposits to CL&P in exchange for ownership of specific NEEWS transmission assets as they are placed in service. UI has the right to invest up to the greater of $60 million or an amount equal to 8.4% of CL&P's costs for the originally proposed Connecticut portions of the NEEWS projects. Based upon the current projected costs, UI's investment rights in GSRP and IRP is approximately $45 million. In February 2015, ISO-NE issued its final GHCC transmission solutions report and, in March 2015, approved the proposed plan applications. Based on the ISO-NE reassessment of CCRP and the currently planned generation in Connecticut, UI does not anticipate making any investments in GHCC or further investment in NEEWS.

Deposits associated with NEEWS are recorded as assets at the time the deposit is made and they are reported in the 'Other' line item within the Deferred Charges and Other Assets section of the balance sheet. When title to the assets is transferred to UI, the amount of the corresponding deposit is reclassified from other assets to plant-in-service on the balance sheet and shown as a non-cash investing activity in the statement of cash flows.

As of December 31, 2015, UI had made aggregate deposits of $45 million under the Agreement since its inception, with assets associated with the GSRP valued at approximately $24.6 million and assets associated with the IRP valued at approximately $20 million having been transferred to UI. UI does not anticipate making any additional investments in NEEWS under the agreement.

Other Proceedings

On November 12, 2014, PURA issued a decision in a docket addressing UI's semi-annual Generation Services Charge (GSC), bypassable federally mandated congestion charge and the non-bypassable federally mandated congestion charge (NBFMCC) reconciliations. PURA's decision allowed for recovery of $7.7 million of the $11.3 million request included in UI's filing for the reconciliation of certain revenues and expenses relating to the period from 2004 through 2013. This resulted in UI recording a pre-tax write-off of approximately $3.8 million during the fourth quarter of 2014, which amount included the disallowed portion of UI's request as well as additional 2014 carrying charges.

Also on November 12, 2014, PURA issued a final decision in UI's final Competitive Transition Assessment (CTA) reconciliation proceeding which extinguished all remaining CTA balances. In addition, the final decision allowed for the application of an approximate $8.2 million remaining CTA regulatory liability, as well as an approximate $12.0 million regulatory liability related to the Connecticut Yankee Atomic Power Company litigation against the U.S. Department of Energy (DOE), against UI's storm regulatory asset balance. The final decision required that remaining regulatory liability balance be applied to the GSC "working capital allowance" and be returned to customers through the NBFMCC.

Because the two decisions noted above, among other things, fail to apply rate making principles on a consistent basis, UI filed appeals with the State of Connecticut Superior Court in December 2014 for both the GSC/NBFMCC and the CTA final decisions. On February 3, 2015, PURA filed a motion to dismiss UI's appeal of the CTA final decision. On June 17, 2015, the Superior Court denied PURA's motion to dismiss the CTA appeal.

UI filed a motion to stay the appeals in the two proceedings discussed above in connection with the settlement agreement filed with PURA in the change in control proceeding. On October 12, 2015, the motions to stay were granted. Upon resolution of any appeals of PURA's approval of UIL Holdings' merger with Avangrid, Inc., UI will withdraw the appeals.

Equity Investment in Peaking Generation

UI is party to a 50-50 joint venture with the NRG affiliates in GenConn, which operates two peaking generation plants in Connecticut. The two peaking generation plants, GenConn Devon and GenConn Middletown, are both participating in the ISO-New England markets. PURA has approved revenue requirements for the period from January 1, 2016 through December 31, 2016 of $29.3 million and $36.4 million for GenConn Devon and GenConn Middletown, respectively. In addition, PURA has ruled that GenConn project costs incurred that were in excess of the proposed costs originally submitted in 2008 were prudently incurred and are recoverable. Such costs are included in the determination of the 2015 approved revenue requirements.

(D) SHORT-TERM CREDIT ARRANGEMENTS

UIL Holdings and its regulated subsidiaries, including UI, are parties to a revolving credit agreement with a group of banks that will expire on November 30, 2016 (the UIL Holdings Credit Facility). The aggregate borrowing limit under the UIL Holdings Credit Facility is $400 million, of which $250 million is available to UI. The UIL Holdings Credit Facility permits borrowings at fluctuating interest rates and also permits borrowings for fixed periods of time specified by each borrower at fixed interest rates determined by the Eurodollar interbank market in London (LIBOR). The UIL Holdings Credit Facility also permits the issuance of letters of credit of up to $50 million.

As of December 31, 2015, UI did not have any borrowings outstanding under the Credit Facility. Available credit under the UIL Holdings Credit Facility at December 31, 2015 totaled $232.6 million for UIL Holdings and its subsidiaries in the aggregate.
UIL Holdings records borrowings under the UIL Holdings Credit Facility as short-term debt, but the UIL Holdings Credit Facility provides for longer term commitments from banks allowing UIL Holdings to borrow and reborrow funds, at its option, until the facility's expiration, thus affording us flexibility in managing our working capital requirements.

(E) INCOME TAXES

		2015		2014
		(In Thousands)		
Income tax expense consists of:				
Income tax provisions (benefits):				
Current				
Federal	$	10,437	$	5,491
State		(2,074)		(962)
Total current		8,363		4,529
Deferred				
Federal		13,005		34,824
State		733		4,951
Total deferred		13,738		39,775
Investment tax credits		(248)		(146)
Total income tax expense	$	21,853	$	44,158

Total income taxes differ from the amounts computed by applying the federal statutory tax rate to income before taxes. The reasons for the differences are as follows:

	2015	2014
	(In Thousands)	
Book income before income taxes	$ 79,117	$ 128,526
Computed tax at federal statutory rate	$ 27,691	$ 44,984
Increases (reductions) resulting from:		
Plant Flow- thru differences	(1,369)	193
State income taxes, net of federal income tax benefits	(871)	2,593
Allowance for equity funds used during construction	(2,275)	(2,468)
ITC taken into income	(248)	(146)
Other items, net	(1,075)	(998)
Total income tax expense	$ 21,853	$ 44,158
Effective income tax rates	27.6%	34.4%

The significant portion of UI’s income tax expense, including deferred taxes, is recovered through utility rates. UI’s annual income tax expense and associated effective tax rate is impacted by differences between the timing of deferred tax temporary difference activity and deferred tax recovery. UI’s effective tax rate is also impacted by permanent differences between the book and tax treatment of certain costs. The decrease in UI’s income tax expense and effective tax rate in 2015 compared to 2014 was primarily due to lower pre-tax earnings.

UI is subject to the United States federal income tax statutes administered by the IRS. For tax years ending with the December 16, 2015 change of control, UI filed or will file with its parent, UIL Holdings, a consolidated federal income tax return. Effective for tax periods beginning with the December 16, 2015 change in control, UI and its parent, UIL Holdings, will file a consolidated federal tax return with Avangrid, Inc. UI is also subject to certain state income tax statutes and as a result will file for the tax year ending December 31, 2015, combined Connecticut and Massachusetts unitary income tax returns. Beginning in 2016, UI and its UIL

Holdings affiliates, will file state unitary tax returns with Avangrid, Inc. and its subsidiaries. In conjunction with these changes, UI became a party to Avangrid, Inc.'s tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.

As of December 31, 2015 and 2014, UI does not have any gross income tax reserves for uncertain tax positions.

Open Tax Years

During 2015, the Internal Revenue Service completed its examination of UIL's income tax returns for the years 2011 and 2012. The closing of this audit did not have a significant impact on UI's 2015 income tax expense, net balance sheet position or cash flows. The following table summarizes UI's tax years that remain subject to examination as of December 31, 2015:

Jurisdiction	*Tax years*
Federal	2013 - 2015
Connecticut	2011 - 2015

Legislation

Federal: On December 18, 2015, the "Protecting Americans from Tax Hikes (PATH) Act of 2015" (the Act) became law. Among other things the Act generally extends bonus depreciation through 2019 (and 2020 for certain longer-lived and transportation property) providing bonus depreciation allowances for qualified property placed in service of 50% for years 2015 through 2017, 40% for 2018 and 30% in 2019.

Connecticut: Over the course of 2015, Connecticut enacted legislation that among other things extended the surtax, generally reduced the percentage of income tax that could be offset by credit utilization (from 70 to 50.01%) and mandated unitary reporting, effective January 1, 2016. The final legislation also allows a state-regulated utility company to defer until its next general rate case its recovery of any increased tax expenses under PA 15-244 (the Budget Act) that are not currently authorized in the company's rates.

The following table summarizes UI's deferred income tax assets and liabilities as of December 31, 2015 and 2014.

	2015	**2014**
	(In Thousands)	
Deferred income tax assets:		
Post-retirement benefits	$ 72,422	$ 80,249
Accrued removal obligation	$ 25,230	$ 27,430
Merger settlement agreement	18,938	-
Other	16,959	11,994
	133,549	119,673
Deferred income tax liabilities:		
Plant basis and Accelerated depreciation timing differences	$ 572,784	$ 523,482
Regulatory deferrals - pension and other post-retirement benefits	$ 63,630	$ 80,317
Investment in GenConn	54,184	53,378
Other	28,275	21,604
	718,873	678,781
Net deferred income tax assets (liabilities)	$ (585,324)	$ (559,108)

As of December 31, 2015, UI did not have any state tax credit carry forwards.

(F) PENSION AND OTHER BENEFITS

Disclosures pertaining to UI's pension and other postretirement benefit plans (the Plans) are in accordance with ASC 715 "Compensation-Retirement Benefits." UI, through its parent UIL Holdings, has an investment policy addressing the oversight and management of pension assets and procedures for monitoring and control. UIL Holdings has engaged State Street Bank as the trustee and investment manager to assist in areas of asset allocation and rebalancing, portfolio strategy implementation, and performance monitoring and evaluation.

The goals of the asset investment strategy are to:

- Achieve long-term capital growth while maintaining sufficient liquidity to provide for current benefit payments and pension plan operating expenses.
- Provide a total return that, over the long term, provides sufficient assets to fund pension plan liabilities subject to an appropriate level of risk, contributions and pension expense.
- Optimize the return on assets, over the long term, by investing primarily in a diversified portfolio of equities and additional asset classes with differing rates of return, volatility and correlation.
- Diversify investments within asset classes to maximize preservation of principal and minimize over-exposure to any one investment, thereby minimizing the impact of losses in single investments.

The Plans seek to maintain compliance with the Employee Retirement Income Security Act of 1974 (ERISA) as amended, and any applicable regulations and laws.

Prior to the merger with Avangrid, Inc., the Retirement Benefits Plans Investment Committee of the UIL Holdings' Board of Directors oversaw the investment of the Plans' assets in conjunction with management and conducted a review of the investment strategies and policies of the Plans. This review included an analysis of the strategic asset allocation, including the relationship of Plan assets to Plan liabilities, and portfolio structure. The 2016 target asset allocations, which may be revised by the Retirement Benefits Plans Investment Committee, are approximately as follows: 60% equity securities and 40% debt securities. In the event that the relationship of Plan assets to Plan liabilities changes, the Retirement Benefits Plans Investment Committee will consider changes to the investment allocations. The other postretirement employee benefit fund assets are invested in a balanced mutual fund and, accordingly, the asset allocation mix of the balanced mutual fund may differ from the target asset allocation mix from time to time.

The funding policy for the Plans is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the Plans. UI currently expects to make pension contributions of approximately $14.5 million in 2016. Such contribution levels will be adjusted, if necessary, based on actuarial calculations.

UI applies consistent estimation techniques regarding its actuarial assumptions, where appropriate, across its pension and postretirement plans. The estimation technique utilized to develop the discount rate for its pension and postretirement benefit plans is based upon the yield of a portfolio of high quality corporate bonds that could be purchased as of December 31, 2015 to produce cash flows matching the expected plan disbursements within reasonable tolerances. The expected return is based upon a combination of historical performance and anticipated future returns for a portfolio reflecting the mix of equity, debt and other investments included in plan assets. Average wage increases are determined from projected annual pay increases, which are used to determine the wage base used to project employees' pension benefits at retirement. The health care cost trend rate is derived from projections of expected increases in health care costs.

UI is utilizing a discount rate of 4.95% as of December 31, 2015 for its entire qualified pension plans, compared to 4.30% in 2014. The increase in the discount rate, which was due to changes in long-term interest rates, resulted in a decrease to the projected benefit obligation of approximately $45.6 million from 2014 to 2015. The discount rate for non-qualified pension plans as of December 31, 2015 was 4.90% compared to a rate of 4.20% in 2014.

The discount rate for UI's postretirement benefits plans reflects plan requirements and expected future cash flows. For the UI postretirement plan, the discount rate at December 31, 2015 was 4.90% as compared to a rate of 4.30% in 2014.

The pension and other postretirement benefits plans assumptions may be revised over time as economic and market conditions change. Changes in those assumptions could have a material impact on pension and other postretirement expenses. For example, if there had been a 0.25% change in the discount rate assumed for the pension plans, the 2015 pension expense would have increased or decreased inversely by $1.8 million If there had been a 1% change in the expected return on assets assumed for the pension plans, the 2015 pension expense would have increased or decreased inversely by $3.3 million. If there had been a 0.25% change in the discount rate assumed for the other postretirement benefits plans, the 2015 other postretirement benefits plan expenses would have increased or decreased inversely by $0.2 million. If there had been a 1% change in the expected return on assets assumed for the other postretirement benefits plans, the 2015 other postretirement benefits plan expenses would have increased or decreased inversely by $0.2 million.

Pension Plans

The United Illuminating Company Pension Plan (the UI Pension Plan) covers the majority of employees of UIL Holdings Corporate and UI. UI also has a non-qualified supplemental pension plan for certain employees and a non-qualified retiree-only pension plan for certain early retirement benefits.

UI has established a supplemental retirement benefit trust and through this trust purchased life insurance policies on certain officers of UIL Holdings and UI to fund the future liability under the non-qualified supplemental plan. The cash surrender value of these policies is included in “Other investments” on the Balance Sheet.

Other Postretirement Benefits Plans

In addition to providing pension benefits, UI also provides other postretirement benefits, consisting principally of health care and life insurance benefits, for retired employees and their dependents. UI does not provide prescription drug benefits for Medicare-eligible employees in its other postretirement health care plans. Non-union employees who are 55 years of age and whose sum of age and years of service at time of retirement is equal to or greater than 65 are eligible for benefits partially subsidized by UI. The amount of benefits subsidized by UI is determined by age and years of service at retirement. For funding purposes, UI established a 401(h) account in connection with the UI Pension Plan and Serial Voluntary Employee Benefit Association Trust (VEBA) accounts for the years 2007 through 2020 to fund other postretirement benefits for UI’s non-union employees who retire on or after January 1, 1994. These VEBA accounts were approved by the IRS and UI contributed $4.5 million to fund the Serial VEBA accounts in 2007. UI does not expect to make a contribution in 2016 to fund OPEB for non-union employees.

Union employees whose sum of age and years of service at the time of retirement is equal to or greater than 85 (or who are 62 with at least 20 years of service) are eligible for benefits partially subsidized by UI. The amount of benefits subsidized by UI is determined by age and years of service at retirement. For funding purposes, UI established a VEBA to fund other postretirement benefits for UI’s union employees. The funding strategy for the VEBA is to select funds that most clearly mirror the pension allocation strategy. Approximately 54% of UI’s employees are represented by Local 470-1, Utility Workers Union of America, AFL-CIO, for collective bargaining purposes. Plan assets for the union VEBA consist primarily of equity and fixed-income securities. UI does not expect to make a contribution in 2016 to fund other postretirement benefits for union employees.

Other Accounting Matters

ASC 715 requires an employer that sponsors one or more defined benefit pension or other postretirement plans to recognize an asset or liability for the overfunded or underfunded status of the plan. For a pension plan, the asset or liability is the difference between the fair value of the plan’s assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan’s assets and the accumulated postretirement benefit obligation. UI reflects all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in accumulated other comprehensive income, as management believes it is probable that such items will be recoverable through the ratemaking process. As of December 31, 2015 and 2014, UI has recorded regulatory assets of $174.5 million and $201.3 million, respectively.

In accordance with ASC 715, UI utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. UI amortizes prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits.

UI utilizes an alternative method to amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans over the lesser of the average remaining service period or 10 years. For ASC 715 purposes, UI does not recognize gains or losses until there is a variance in an amount equal to at least 5% of the greater of the projected benefit obligation or the market-related value of assets. There is no such allowance for a variance in capturing the amortization of other postretirement benefits unrecognized gains and losses.

The following table represents the change in benefit obligation, change in plan assets and the respective funded status of UI's pension and other postretirement plans as of December 31, 2015 and 2014. Plan assets and obligations have been measured as of December 31, 2015 and 2014.

	Pension Benefits		Other Post-Retirement Benefits	
	2015	**2014**	**2015**	**2014**
		(In Thousands)		
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 521,572	$ 452,234	$ 80,596	$ 69,559
Service cost	7,818	5,864	1,158	1,005
Interest cost	22,168	23,164	3,436	3,580
Participant contributions	-	-	1,223	1,171
Actuarial (gain) loss	(28,853)	70,739	(16,883)	9,711
Benefits paid (including expenses)	(29,884)	(30,429)	(3,540)	(4,430)
Benefit obligation at end of year	$ 492,821	$ 521,572	$ 65,990	$ 80,596
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 369,116	$ 350,751	$ 24,952	$ 24,414
Actual return on plan assets	(7,312)	30,432	38	2,987
Employer contributions	7,265	18,362	-	-
Participant contributions	-	-	1,223	1,171
Benefits paid (including expenses)	(29,884)	(30,429)	(2,710)	(3,620)
Fair value of plan assets at end of year	$ 339,185	$ 369,116	$ 23,503	$ 24,952
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 153,636	$ 152,456	$ 42,487	$ 55,644
Amounts Recognized in the Balance Sheet consist of:				
Non-current liabilities	$ 153,636	$ 152,456	$ 42,487	$ 55,644
Amounts Recognized as a Regulatory Asset consist of:				
Prior service cost	(15)	(20)	(11,805)	59
Net (gain) loss	181,044	191,715	5,268	9,591
Total recognized as a regulatory asset	$ 181,029	$ 191,695	$ (6,537)	$ 9,650
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 492,821	$ 521,572	N/A	N/A
Accumulated benefit obligation	$ 448,614	$ 461,620	N/A	N/A
Fair value of plan assets	$ 339,185	$ 369,116	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	4.95%	4.30%	N/A	N/A
Discount rate (Non-Qualified Plans)	4.90%	4.20%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	4.90%	4.30%
Average wage increase	3.80%	3.80%	N/A	N/A
Health care trend rate (current year)	N/A	N/A	7.00%	7.00%
Health care trend rate (2020 forward)	N/A	N/A	5.00%	5.00%

N/A – not applicable

THE UNITED ILLUMINATING COMPANY

NOTES TO FINANCIAL STATEMENTS

The components of net periodic benefit cost are:

	For the Year Ended December 31,			
	Pension Benefits		Other Post-Retirement Benefits	
	2015	2014	2015	2014
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 7,818	$ 5,864	$ 1,158	$ 1,005
Interest cost	22,168	23,164	3,436	3,580
Expected return on plan assets	(28,758)	(27,874)	(1,850)	(1,816)
Amortization of prior service costs	(5)	264	50	36
Amortization of actuarial (gain) loss	17,887	12,585	1,066	128
Net periodic benefit cost	$ 19,110	$ 14,003	$ 3,860	$ 2,933
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 7,217	$ 68,182	$ (3,257)	$ 8,541
Current year prior service cost	-	-	(11,815)	-
Amortization of prior service costs	5	(264)	(50)	(36)
Amortization of actuarial (gain) loss	(17,887)	(12,585)	(1,065)	(128)
Total recognized as regulatory asset (liability)	$ (10,665)	$ 55,333	$ (16,187)	$ 8,377
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 8,445	$ 69,336	$ (12,327)	$ 11,310
Estimated Amortizations from Regulatory Assets into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of prior service cost	(5)	(5)	598	50
Amortization of net (gain) loss	17,673	17,887	(1,527)	1,065
Total estimated amortizations	$ 17,668	$ 17,882	$ (929)	$ 1,115
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.20%-4.30%	4.90%-5.20%	4.30%	5.20%
Average wage increase	3.80%	3.80%	N/A	N/A
Return on plan assets	8.00%	8.00%	8.00%	8.00%
Health care trend rate (current year)	N/A	N/A	7.00%	7.50%
Health care trend rate (2019 forward)	N/A	N/A	5.00%	5.00%

N/A – not applicable

A one percentage point change in the assumed health care cost trend rate would have the following effects:

	1% Increase		1% Decrease	
	(In Thousands)			
Aggregate service and interest cost components	$	512	$	(420)
Accumulated post-retirement benefit obligation	$	6,239	$	(5,182)

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Year	Pension Benefits		Other Post-Retirement Benefits	
	(In Thousands)			
2016	$	28,204	$	3,899
2017	$	32,274	$	3,924
2018	$	30,645	$	3,954
2019	$	30,373	$	4,049
2020	$	31,557	$	4,195
2021-2025	$	166,178	$	22,387

Defined Contribution Retirement Plans/401(k)

UI employees are eligible to participate in the UIL Employee Stock Ownership Plan. Employees may defer a portion of the compensation and invest in various investment alternatives. Matching contributions are made in the form of cash which is subsequently invested according to the specific provisions of the plan. The matching expense for 2015 and 2014 was $2.5 million, and $2.4 million, respectively.

(G) RELATED PARTY TRANSACTIONS

During the years ended December 31, 2015 and 2014, UI received cash distributions from GenConn. See Note (A) Business Organization and Statement of Accounting Policies – Equity Investments.

A Director of UIL Holdings holds a beneficial interest in the building located at 157 Church Street, New Haven, Connecticut, where UIL Holdings leases office space, a portion of which is utilized by UI. UI's portion of the lease payments for this office space for each of the years ended December 31, 2015 and 2014 totaled $0.2 million.

Inter-company Transactions

UI receives various administrative and management services from and enters into certain inter-company transactions with UIL Holdings and its subsidiaries. For the year ended December 31, 2015, UI recorded inter-company expenses of $56.9 million which consisted primarily of operation and maintenance expenses. Costs of the services that are allocated amongst UI and other of UIL Holdings' regulated subsidiaries are settled periodically by way of inter-company billings and wire transfers. At December 31, 2015 and 2014, the Balance Sheet reflects inter-company receivables, included in other accounts receivable of $9.8 million and $3.3 million, respectively, and inter-company payables, included in accounts payable, of $19.3 million and $15.4 million, respectively.

Dividends/Capital Contributions

In 2015 and 2014, UI made wire transfers to UIL Holdings on a quarterly basis in order to maintain its capitalization structure as allowed per PURA's final decision in UI's 2008 distribution rate proceeding. For the years ended December 31, 2015 and 2014, UI accrued dividends to UIL Holdings of $59.7 million and $82.7 million, respectively.

(H) LEASE OBLIGATIONS

Operating leases, which are charged to operating expense, consist principally of leases for office space and facilities, land, railroad rights of way and a wide variety of equipment.

The future minimum lease payments under these operating leases are estimated to be as follows:

	(In Thousands)
2015	2,929
2016	2,935
2017	2,904
2018	2,938
2019	2,543
2020-after	40,219
	$ 54,468

Rental payments charged to operating expenses in 2015 and 2014 totaled $3.3 million and $3.1 million, respectively.

(I) COMMITMENTS AND CONTINGENCIES

In the ordinary course of business, UI and its subsidiaries are involved in various proceedings, including legal, tax, regulatory and environmental matters, which require management's assessment to determine the probability of whether a loss will occur and, if probable, an estimate of probable loss. When assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated, UI accrues a reserve and discloses the reserve and related matter. UI discloses material matters when losses are probable but for which an estimate cannot be reasonably estimated or when losses are not probable but are reasonably possible. Subsequent analysis is performed on a periodic basis to assess the impact of any changes in events or circumstances and any resulting need to adjust existing reserves or record additional reserves. However, given the inherent unpredictability of these legal and regulatory proceedings, we cannot assure you that our assessment of such proceedings will reflect the ultimate outcome, and an adverse outcome in certain matters could have a material adverse effect on our results of operations or cash flows.

Connecticut Yankee Atomic Power Company

UI has a 9.5% stock ownership share in the Connecticut Yankee Atomic Power Company, an inactive nuclear generating company (Connecticut Yankee), the carrying value of which was $0.2 million as of December 31, 2015. Connecticut Yankee has completed the physical decommissioning of its generation facilities and is now engaged primarily in the long-term storage of its spent nuclear fuel. Connecticut Yankee collects its costs through wholesale FERC-approved rates from UI and several other New England utilities. UI recovers these costs from its customers through electric rates.

DOE Spent Fuel Litigation

In 1998, Connecticut Yankee filed claims in the United States Court of Federal Claims seeking damages resulting from the breach of the 1983 spent fuel and high level waste disposal contract between Connecticut Yankee and the DOE. In September 2010, the court issued its decision and awarded Connecticut Yankee damages of $39.7 million for its spent fuel-related costs through 2001, which was affirmed in May 2012. Connecticut Yankee received payment of the damage award and, in light of its ownership share, in July 2013 UI received approximately $3.8 million of such award which was credited back to customers through the CTA.

In December 2007, Connecticut Yankee filed a second set of complaints with the United States Court of Federal Claims against the DOE seeking damages incurred since January 1, 2002 for the DOE's failure to remove Connecticut Yankee's spent fuel. In November 2013, the court issued a final judgment, which was not appealed, awarding Connecticut Yankee damages of $126.3 million. In light of its ownership share, in June 2014, UI received approximately $12.0 million of such award which was applied, in part, against the remaining storm regulatory asset balance. The remaining regulatory liability balance was applied to the GSC "working capital allowance" and will be returned to customers through the nonbypassable federally mandated congestion charge. See Note (C) "Regulatory Proceedings – Other Proceedings" for additional information.

In August 2013, Connecticut Yankee filed a third set of complaints (Phase III) with the United States Court of Federal Claims against the DOE seeking an unspecified amount of damages incurred since January 1, 2009 for the DOE's failure to remove Connecticut Yankee's spent fuel. In April 2015, Connecticut Yankee provided the DOE with a third set of damage claims totaling approximately $32.9 million for damages incurred from January 1, 2009 through December 31, 2012. The Phase II trial was completed in July 2015 and the Court has issued its decision on March 25, 2016 awarding Connecticut Yankee $32.6 million. UI's 9.5% ownership share will result in a receipt of approximately $3.1 million which will be refunded to customers.

Environmental Matters

In complying with existing environmental statutes and regulations and further developments in areas of environmental concern, including legislation and studies in the fields of water quality, hazardous waste handling and disposal, toxic substances, climate change and electric and magnetic fields, UI may incur substantial capital expenditures for equipment modifications and additions, monitoring equipment and recording devices, as well as additional operating expenses. The total amount of these expenditures is not now determinable. Environmental damage claims may also arise from the operations of our subsidiaries. Significant environmental issues known to UI at this time are described below.

Site Decontamination, Demolition and Remediation Costs

In January 2012, Evergreen Power, LLC (Evergreen Power) and Asnat Realty LLC (Asnat), then and current owners of a former generation site on the Mill River in New Haven (the "English Station site") that UI sold to Quinnipiac Energy in 2000, filed a lawsuit in federal district court in Connecticut against UI seeking, among other things: (i) an order directing UI to reimburse the plaintiffs for costs they have incurred and will incur for the testing, investigation and remediation of hazardous substances at the English Station site and (ii) an order directing UI to investigate and remediate the site. In December 2013, Evergreen and Asnat filed a subsequent lawsuit in Connecticut state court seeking among other things: (i) remediation of the property; (ii) reimbursement of remediation costs; (iii) termination of UI's easement rights; (iv) reimbursement for costs associated with securing the property; and (v) punitive damages. UI believes the claims are without merit. These lawsuits were stayed pending the resolution of the proposed partial consent order described below.

On April 8, 2013, DEEP issued an administrative order addressed to UI, Evergreen Power, Asnat and others, ordering the parties to take certain actions related to investigating and remediating the English Station site. These proceedings were stayed pending the resolution of the proposed partial consent order described below.

On September 16, 2015, UI signed a Proposed Partial Consent Order that, when issued by the Commissioner of DEEP, and subject to the terms and conditions in the Proposed Partial Consent Order, would require UI to investigate and remediate certain environmental conditions within the perimeter of the English Station site. Under the Proposed Partial Consent Order, to the extent that the cost of this investigation and remediation is less than $30 million, UI would remit to the State of Connecticut the difference between such cost and $30 million to be used for a public purpose as determined in the discretion of the Governor of the State of Connecticut, the Attorney General of the State of Connecticut, and the Commissioner of DEEP. Pursuant to the Proposed Partial Consent Order, upon its issuance and subject to its terms and conditions, UI would be obligated to comply with the Proposed Partial Consent Order, even if the cost of such compliance exceeds $30 million. The State will discuss options with UI on recovering or funding any cost above $30 million such as through public funding or recovery from third parties, however it is not bound to agree to or support any means of recovery or funding. We cannot predict the outcome of this matter. As of December 31, 2015 we reserved $20.5 million for this case and have accrued the remaining $9.5 million in accordance with the settlement with PURA approving the merger of UIL Holdings and Avangrid, Inc.

.

With respect to transmission-related property adjacent to the New Haven Harbor Generating Station, UI performed an environmental analysis that indicated remediation expenses would be approximately $3.2 million. UI has accrued these estimated expenses, which were recovered in transmission rates.

Middletown/Norwalk Transmission Project

The general contractor responsible for civil construction work in connection with the installation of UI's portion of the Middletown/Norwalk Transmission Project's underground electric cable system filed a lawsuit in Connecticut state court on September 22, 2009. On September 3, 2013, the court found for UI on all claims but one related to certain change orders, and ordered UI to pay the general contractor approximately $1.3 million, which has since been paid. On October 22, 2013, the general contractor filed an appeal of the trial court's decision and on June 23, 2015, the appellate court affirmed the trial court's judgment. The period to file a petition for review by the Connecticut Supreme Court has passed and the case is now concluded. UI expects to recover any amounts paid to resolve the contractor and subcontractor claims through UI's transmission revenue requirements.

In April 2013, an affiliate of the general contractor for the Middletown/Norwalk Transmission Project, purporting to act as a shareholder on behalf of UIL Holdings, filed a complaint against the UIL Holdings Board of Directors alleging that the directors breached a fiduciary duty by failing to undertake an independent investigation in response to a letter from the affiliate asking for an investigation regarding alleged improper practices by UI in connection with the Middletown/Norwalk Transmission Project. In October 2013, the court granted the defendants' motion to dismiss the complaint, which dismissal was affirmed by the Connecticut Appellate Court in March 2015. The period to file a petition for review by the Connecticut Supreme Court has passed and the case is now concluded.

(J) FAIR VALUE MEASUREMENTS

As required by ASC 820 "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety, based on the lowest level of input that is significant to the fair value measurement. UI's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables set forth the fair value of UI's financial assets and liabilities, other than pension benefits and other postretirement benefits, as of December 31, 2015 and December 31, 2014.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(In Thousands)		
December 31, 2015				
Assets:				
Derivative assets	$ -	$ -	$ 29,264	$ 29,264
Supplemental retirement benefit trust life insurance policies	-	9,544	-	9,544
	-	9,544	29,264	38,808
Liabilities:				
Derivative liabilities	-	-	96,230	96,230
Long-term debt	-	955,420	-	955,420
	-	955,420	96,230	1,051,650
Net fair value assets/(liabilities), December 31, 2015	$ -	$ (945,876)	$ (66,966)	$ (1,012,842)
December 31, 2014				
Assets:				
Derivative assets	$ -	$ -	$ 27,270	$ 27,270
Supplemental retirement benefit trust life insurance policies	-	8,498	-	8,498
	-	8,498	27,270	35,768
Liabilities:				
Derivative liabilities	-	-	85,074	85,074
Long-term debt	-	958,296	-	958,296
	-	958,296	85,074	1,043,370
Net fair value assets/(liabilities), December 31, 2014	$ -	$ (949,798)	$ (57,804)	$ (1,007,602)

Fair value measurements categorized in Level 3 of the fair value hierarchy are prepared by individuals with expertise in valuation techniques, pricing of energy and energy-related products, and accounting requirements. The derivative assets consist primarily of CfDs. The determination of fair value of the CfDs was based on a probability-based expected cash flow analysis that was discounted at the December 31, 2015 or December 31, 2014 risk-free interest rates, as applicable, and an adjustment for non-performance risk using credit default swap rates. Certain management assumptions were required, including development of pricing that extended over the term of the contracts. UI believes this methodology provides the most reasonable estimates of the amount of future discounted cash flows associated with the CfDs.
Additionally, on a quarterly basis, UI performs analytics to ensure that the fair value of the derivatives is consistent with changes, if any, in the various fair value model inputs. Additional quantitative information about Level 3 fair value measurements is as follows:

	Unobservable Input	Range at December 31, 2015	Range at December 31, 2014
Contracts for differences	Risk of non-performance	0.00% - 0.88%	0.00% - 0.66%
	Discount rate	1.31% - 2.27%	1.65% - 2.25%
	Forward pricing ($ per MW)	$3.15 - $11.19	$3.15 - $14.59

Significant isolated changes in the risk of non-performance, the discount rate or the contract term pricing would result in an inverse change in the fair value of the CfDs.

The determination of the fair value of the supplemental retirement benefit trust life insurance policies was based on quoted prices as of December 31, 2015 and December 31, 2014 in the active markets for the various funds within which the assets are held.

Long-term debt is carried at cost on the balance sheet. The fair value of long-term debt as displayed in the table above is based on evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes of new issue prices and relevant credit information.

The following tables set forth a reconciliation of changes in the fair value of the assets and liabilities above that are classified as Level 3 in the fair value hierarchy for the twelve month periods ended December 31, 2015 and 2014.

	Year Ended December 31, 2015 (In Thousands)
Net derivative assets/(liabilities), December 31, 2014	$ (57,804)
Unrealized gains and (losses), net	(9,162)
Net derivative assets/(liabilities), December 31, 2015	$ (66,966)
Change in unrealized gains (losses), net relating to net derivative assets/(liabilities), still held as of December 31, 2015	$ (9,162)

	December 31, 2014 (In Thousands)
Net derivative assets/(liabilities), December 31, 2013	$ (142,786)
Unrealized gains and (losses), net	84,982
Net derivative assets/(liabilities), December 31, 2014	$ (57,804)
Change in unrealized gains (losses), net relating to net derivative assets/(liabilities), still held as of December 31, 2014	$ 84,982

The following tables set forth the fair values of UI's pension and OPEB assets as of December 31, 2015 and 2014.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2015		(In Thousands)		
Pension assets				
Mutual funds	$ -	$ 339,185	$ -	$ 339,185
Hedge fund	-	-	-	-
	-	339,185	-	339,185
OPEB assets				
Mutual funds	24,952	-	-	24,952
	24,952	-	-	24,952
Fair value of plan assets, December 31, 2015	$ 24,952	$ 339,185	$ -	$ 364,137
December 31, 2014				
Pension assets				
Mutual funds	$ -	$ 351,480	$ -	$ 351,480
Hedge fund	-	-	17,636	17,636
	-	351,480	17,636	369,116
OPEB assets				
Mutual funds	24,952	-	-	24,952
	24,952	-	-	24,952
Fair value of plan assets, December 31, 2014	$ 24,952	$ 351,480	$ 17,636	$ 394,068

The determination of fair values of the Level 2 co-mingled mutual funds were based on the Net Asset Value (NAV) provided by the managers of the underlying fund investments and the unrealized gains and losses. The NAV provided by the managers typically reflect the fair value of each underlying fund investment. Changes in the fair value of pension benefits and OPEB are accounted for in accordance with ASC 715 Compensation – Retirement Benefits as discussed in "Note (F) Pension and Other Benefits".

The following tables set forth a reconciliation of changes in the fair value of the assets above that are classified as Level 3 in the fair value hierarchy for the twelve month periods ended December 31, 2015 and 2014.

THE UNITED ILLUMINATING COMPANY

NOTES TO FINANCIAL STATEMENTS

	Year Ended December 31, 2015 (In Thousands)
Pension assets-Level 3, December 31, 2014	$ 17,636
Unrealized/Realized gains and (losses), net	-
Settlements	(17,636)
Pension assets-Level 3, December 31, 2015	$ -

	Year Ended December 31, 2014 (In Thousands)
Pension assets-Level 3, December 31, 2013	$ 17,695
Unrealized/Realized gains and (losses), net	(59)
Settlements	-
Pension assets-Level 3, December 31, 2014	$ 17,636

THE BERKSHIRE GAS COMPANY

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2015 AND 2014

TABLE OF CONTENTS

pwc

Independent Auditor's Report

To the Board of Directors
of The Berkshire Gas Company:

We have audited the accompanying financial statements of The Berkshire Gas Company (the "Company"), which comprise the balance sheets as of December 31, 2015 and December 31, 2014, and the related statements of income, comprehensive income, shareholders' equity and cash flows for the years then ended.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

Our responsibility is to express an opinion on the financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from 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 our 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, we consider internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of The Berkshire Gas Company at December 31, 2015 and December 31, 2014, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

April 12, 2016

PricewaterhouseCoopers LLP, 101 Seaport Boulevard, Suite 500, Boston, MA 02210
T: (617) 530 5000, F: (617) 530 5001, www.pwc.com/us

THE BERKSHIRE GAS COMPANY
STATEMENT OF INCOME
(In Thousands)

	Year Ended December 31, 2015	Year Ended December 31, 2014
Operating Revenues	$ 73,198	$ 87,842
Operating Expenses		
Operation		
Natural gas purchased	27,303	38,579
Operation and maintenance	28,752	25,110
Depreciation and amortization	7,137	6,805
Taxes - other than income taxes	3,231	3,011
Total Operating Expenses	66,423	73,505
Operating Income	6,775	14,337
Other Income and (Deductions), net (Note A)		
Other income	1,477	221
Other (deductions)	(81)	(340)
Total Other Income and (Deductions), net	1,396	(119)
Interest Charges, net		
Interest on long-term debt	3,358	3,472
Other interest, net	(42)	7
	3,316	3,479
Amortization of debt expense and redemption premiums	124	124
Total Interest Charges, net	3,440	3,603
Income Before Income Taxes	4,731	10,615
Income Taxes (Note E)	1,693	4,275
Net Income	$ 3,038	$ 6,340

THE BERKSHIRE GAS COMPANY
STATEMENT OF COMPREHENSIVE INCOME
(In Thousands)

	Year Ended December 31, 2015	Year Ended December 31, 2014
Net Income	$ 3,038	$ 6,340
Other Comprehensive Income (Loss)	(9)	2
Comprehensive Income	$ 3,029	$ 6,342

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

THE BERKSHIRE GAS COMPANY
STATEMENT OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2015	Year Ended December 31, 2014
Cash Flows From Operating Activities		
Net income	$ 3,038	$ 6,340
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	7,261	6,929
Deferred income taxes	(1,481)	(1,419)
Pension expense	1,308	1,104
Regulatory activity, net	10,493	2,877
Other non-cash items, net	(323)	857
Changes in:		
Accounts receivable, net	3,795	(5,395)
Unbilled revenues	1,513	538
Natural gas in storage	1,591	(478)
Accounts payable	(3,829)	5,370
Taxes accrued/refundable, net	(1,644)	4,878
Accrued liabilities	1,010	(2,744)
Accrued pension	(1,368)	(544)
Other assets	(918)	(128)
Other liabilities	(1,372)	554
Total Adjustments	16,036	12,399
Net Cash provided by Operating Activities	19,074	18,739
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(16,003)	(13,040)
Net Cash used in Investing Activities	(16,003)	(13,040)
Cash Flows from Financing Activities		
Payments on long-term debt	(1,455)	(1,455)
Payment of common stock dividend	(5,400)	(4,400)
Net Cash used in Financing Activities	(6,855)	(5,855)
Unrestricted Cash and Temporary Cash Investments:		
Net change for the period	(3,784)	(156)
Balance at beginning of period	6,734	6,890
Balance at end of period	$ 2,950	$ 6,734
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 3,316	$ 3,476
Income taxes	$ 700	$ 750
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 755	$ 173

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

THE BERKSHIRE GAS COMPANY
BALANCE SHEET
December 31, 2015 and 2014

ASSETS
(In Thousands)

	2015	2014
Current Assets		
Unrestricted cash and temporary cash investments	$ 2,950	$ 6,734
Accounts receivable less allowance of $1,303 and $1,381, respectively	8,618	12,217
Unbilled revenues	4,003	5,516
Current regulatory assets (Note A)	3,960	6,496
Natural gas in storage, at average cost	2,344	3,935
Materials and supplies, at average cost	825	968
Other	2,812	1,720
Total Current Assets	25,512	37,586
Other investments	855	1,027
Total Property, Plant and Equipment	204,691	195,924
Less accumulated depreciation	68,546	65,899
	136,145	130,025
Construction work in progress	6,405	1,644
Net Property, Plant and Equipment (Note A)	142,550	131,669
Regulatory Assets (Note A)	33,878	37,725
Deferred Charges and Other Assets		
Unamortized debt issuance expenses	23	45
Goodwill (Note A)	51,933	51,933
Other	22	54
Total Deferred Charges and Other Assets	51,978	52,032
Total Assets	$ 254,773	$ 260,039

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

THE BERKSHIRE GAS COMPANY
BALANCE SHEET
December 31, 2015 and 2014

LIABILITIES AND CAPITALIZATION
(In Thousands)

	2015	2014
Current Liabilities		
Current portion of long-term debt (Note B)	$ 2,393	$ 2,393
Accounts payable	7,219	10,466
Accrued liabilities	4,519	3,509
Interest accrued	853	862
Taxes accrued	7,254	8,898
Total Current Liabilities	22,238	26,128
Deferred Income Taxes (Note E)	25,766	26,866
Regulatory Liabilities (Note A)	34,780	28,910
Other Noncurrent Liabilities		
Pension accrued (Note F)	10,758	10,856
Other post-retirement benefits accrued (Note F)	1,792	1,742
Environmental remediation costs	2,600	4,105
Other	4,774	4,702
Total Other Noncurrent Liabilities	19,924	21,405
Commitments and Contingencies (Note I)		
Capitalization (Note B)		
Long-term debt	42,592	44,886
Common Stock Equity		
Paid-in capital	106,095	106,095
Retained earnings	3,397	5,759
Accumulated other comprehensive income (loss)	(19)	(10)
Net Common Stock Equity	109,473	111,844
Total Capitalization	152,065	156,730
Total Liabilities and Capitalization	$ 254,773	$ 260,039

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

THE BERKSHIRE GAS COMPANY
STATEMENT OF CHANGES IN SHAREHOLDER'S EQUITY
December 31, 2015 and 2014
(Thousands of Dollars)

	Common Stock		Paid-in	Retained	Accumulated Other Comprehensive	
	Shares	Amount	Capital	Earnings	Income (Loss)	Total
Balance as of December 31, 2013	100	$ -	$ 106,095	$ 3,819	$ (12)	$ 109,902
Net income				6,340		6,340
Other comprehensive income, net of deferred income taxes					2	2
Payment of common stock dividend				(4,400)		(4,400)
Balance as of December 31, 2014	100	$ -	$ 106,095	$ 5,759	$ (10)	$ 111,844
Net income				3,038		3,038
Other comprehensive income, net of deferred income taxes					(9)	(9)
Payment of common stock dividend				(5,400)		(5,400)
Balance as of December 31, 2015	100	$ -	$ 106,095	$ 3,397	$ (19)	$ 109,473

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

NOTES TO FINANCIAL STATEMENTS

(A) STATEMENT OF ACCOUNTING POLICIES

The Berkshire Gas Company (Berkshire) engages in natural gas transportation, distribution and sales operations in Massachusetts serving approximately 40,000 customers in service areas totaling approximately 744 square miles. The service area in Massachusetts includes Berkshire County and portions of Franklin and Hampshire Counties, and includes the cities of Pittsfield, North Adams and Greenfield. The population of this area is approximately 193,000, which represents 2.9% of the population of Massachusetts. Of Berkshire's 2015 retail revenues, 55.3% were derived from residential sales, 25.3% from commercial sales, 17.4% of firm transportation, and 2.0% from industrial sales. Retail revenues vary by season, with the highest revenues typically in the first quarter of the year reflecting seasonal rates and cooler weather.

Berkshire is the principal operating utility of Berkshire Energy Resources (BER), a wholly owned subsidiary of UIL Holdings Corporation (UIL Holdings). BER is a holding company whose sole business is ownership of its operating regulated gas utility. Berkshire is regulated by the Massachusetts Department of Public Utilities (DPU) as it relates to utility service.

On December 16, 2015, UIL Holdings Corporation, a Connecticut corporation (Predecessor UIL) merged with and into Green Merger Sub, Inc., after which Green Merger Sub, Inc. changed its name to UIL Holdings Corporation (UIL Holdings). Throughout this document "UIL Holdings" shall refer to UIL Holdings and Predecessor UIL unless the context otherwise indicates. The primary business of UIL Holdings is ownership of its operating regulated utility businesses. See Note (C) "Regulatory Proceedings" for further information regarding the merger.

Accounting Records

The accounting records of Berkshire are maintained in conformity with generally accepted accounting principles in the United States of America (GAAP) and also maintained in accordance with the uniform systems of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and the DPU.

Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to use estimates and assumptions that affect (1) the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and (2) the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Berkshire has revised its previously issued Financial Statements to correct errors related to (1) operating revenues, depreciation and amortization expense, and other income to correct the classification of rental activity, (2) pension accrued, other post-retirement benefits accrued, and other noncurrent liabilities to correct the valuation of certain supplemental employee retirement, medical, and disability plans, and (3) other immaterial errors. Management believes that this revision is not material to the previously issued financial statements. In addition, certain amounts related to deferred tax liabilities, regulatory liabilities, operation and maintenance expense, depreciation and amortization expense, taxes other than income taxes, and other income and (deductions) that were reported as such in the Financial Statements in previous periods have been reclassified to conform to the current presentation as a result of UIL Holdings presenting such information consistent with its parent Avangrid, Inc. due to the merger. See further discussion regarding the merger in Note (A) "Statement of Accounting Policies – Merger with Avangrid, Inc." and Note (C) "Regulatory Proceedings".

The following table summarizes (1) the impact to the prior period Financial Statements of the adjustments noted above (2) the impacts to the prior period Financial Statements of the adjustments made as a result of the early adoption of certain new accounting standards (See Note (A) "Statement of Accounting Policies – New Accounting Standards"), and (3) certain immaterial amounts that have been reclassified to conform to the current presentation.

December 31, 2014 (in thousands)	As previously filed	Errors	Reclassifications	As currently reported
Statement of Income				
Operating Revenues	$ 86,685	$ 1,157	$ -	$ 87,842
Operation and maintenance	23,240	(70)	1,940	25,110
Depreciation and amortization	8,466	279	(1,940)	6,805
Operating Expenses	73,296	209	-	73,505
Operating Income	13,389	948	-	14,337
Other income	-	(840)	1,061	221
Other income and (deductions)	721	-	(1,061)	(340)
Income Before Income Taxes	10,507	108	-	10,615
Income Taxes	4,231	44	-	4,275
Net Income	6,276	64	-	6,340
Statement of Cash Flows *				
Net Income	6,276	64	-	6,340
Deferred income taxes	(1,463)	44	-	(1,419)
Depreciation and amortization	8,590	(1,661)	-	6,929
Other regulatory activity, net	938	1,939	-	2,877
Accrued pension	(648)	104	-	(544)
Other liabilities	1,044	(490)	-	554
Balance Sheet				
Accumulated depreciation	66,247	(348)	-	65,899
Net property, Plant and Equipment	131,321	348	-	131,669
Regulatory Assets	37,823	(98)	-	37,725
Unamortized debt issuance expenses	857	-	(812)	45
Total deferred charges and other assets	52,844	-	(812)	52,032
Total assets	260,601	250	(812)	260,039
Deferred income taxes (current)	1,439	-	(1,439)	-
Total Current Liabilities	27,567	-	(1,439)	26,128
Pension accrued	9,036	1,820	-	10,856
Other post-retirement benefits accrued	-	1,742	-	1,742
Other non-current liabilities	7,062	(2,360)	-	4,702
Total other noncurrent liabilities	20,203	1,202	-	21,405
Deferred income taxes	25,942	(515)	1,439	26,866
Long-term debt	45,698	-	(812)	44,886
Retained Earnings	6,196	(437)	-	5,759
Net Common Stock Equity	112,281	(437)	-	111,844
Total capitalization	157,979	(437)	(812)	156,730
Total liabilities and capitalization	260,601	250	(812)	260,039

* The errors did not result in any impact to net Cash provided by Operating Activities in the Statement of Cash Flows.

Berkshire has evaluated subsequent events through the date its financial statements were available to be issued, April 12, 2016.

Allowance for Funds Used During Construction

In accordance with the uniform systems of accounts, Berkshire capitalizes allowance for funds used during construction (AFUDC), which represents the approximate cost of debt and equity capital devoted to plant under construction. The portion of the allowance applicable to borrowed funds is presented as other interest and the portion of the allowance applicable to equity funds are presented as other income in the Statement of Income. Although the allowance does not represent current cash income, it has historically been recoverable under the ratemaking process over the service lives of the related properties. The weighted-average AFUDC rate for 2015 and 2014 was 11.90% and 4.93%, respectively.

Cash and Temporary Cash Investments

Berkshire considers all of its highly liquid debt instruments with an original maturity of three months or less at the date of purchase to be cash and temporary cash investments.

Depreciation

Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis, using estimated service lives. For utility plant other than software, service lives are determined by independent engineers and subject to review and approval by the DPU. Software service life is based upon management's estimate of useful life. The aggregate annual provisions for depreciation for the years 2015 and 2014 were approximately 3.3% and 3.5%, respectively, of the original cost of depreciable property.

Weather Insurance Contracts

On an annual basis, Berkshire assesses the need for weather insurance contracts for the upcoming heating season in order to provide financial protection from significant weather fluctuations. According to the terms of such contracts, if temperatures are warmer than normal at a prescribed level for the contract period, Berkshire would receive a payment. The premiums paid are amortized over the terms of the contracts. The intrinsic value of the contracts is carried on the balance sheet with changes in value recorded in the income statement as Other Income and (Deductions).

In September 2015, Berkshire entered into a weather insurance contract for the winter period of November 1, 2015 through April 30, 2016. If temperatures are warmer than normal, Berkshire will receive payments up to a maximum of $1 million. The contract had no value at December 31, 2014 since temperatures were colder than normal. As of December 31, 2015, the contract has a total value of $1 million since the variation from normal weather through December 31, 2015 reached the prescribed levels stated in the contract.

Goodwill

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

A goodwill impairment test is performed each year and the test will be updated between annual tests if events or circumstances occur that may reduce the fair value of a reporting unit below its carrying value. The annual analysis of the potential impairment of goodwill is a two-step process. Step one of the impairment test consists of comparing the fair values of reporting units with their aggregate carrying values, including goodwill. The estimated fair values for the reporting units are determined by using projections incorporated in our current operating plans as well as other available information.

If the carrying amount of a reporting unit exceeds the reporting unit's fair value, step two must be performed to determine the amount, if any, of the goodwill impairment loss. If the carrying amount is less than fair value, further testing of goodwill impairment is not performed.

Step two of the goodwill impairment test consists of comparing the implied fair value of the reporting unit's goodwill against the carrying value of the goodwill. 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.

As of October 1, 2015, the fair value of Berkshire exceeded its carrying value and therefore Step two was not performed and no impairment was recognized. No events or circumstances occurred subsequent to October 1, 2015 that would make it more likely than not that the fair value fell below the carrying value.

Impairment of Long-Lived Assets and Investments

Accounting Standards Codification (ASC) 360 “Property, Plant, and Equipment” requires the recognition of impairment losses on long-lived assets when the book value of an asset exceeds the sum of the expected future undiscounted cash flows that result from the use of the asset and its eventual disposition. If impairment arises, then the amount of any impairment is measured based on discounted cash flows or estimated fair value.

ASC 360 also requires that rate-regulated companies recognize an impairment loss when a regulator excludes all or part of a cost from rates, even if the regulator allows the company to earn a return on the remaining costs allowed. Under this standard, the probability of recovery and the recognition of regulatory assets under the criteria of ASC 980 must be assessed on an ongoing basis. As discussed in the description of ASC 980 in this Note (A) under “Regulatory Accounting”, determination that certain regulatory assets no longer qualify for accounting as such could have a material impact on the financial condition Berkshire. At December 31, 2015, Berkshire did not have any assets that were impaired under this standard.

Income Taxes

In accordance with ASC 740 “Income Taxes,” Berkshire has provided deferred taxes for all temporary book-tax differences using the liability method. The liability method requires that deferred tax balances be adjusted to reflect enacted future tax rates that are anticipated to be in effect when the temporary differences reverse. In accordance with generally accepted accounting principles for regulated industries, Berkshire has established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. For ratemaking purposes, Berkshire normalizes all investment tax credits (ITCs) related to recoverable plant investments.

Under ASC 740, Berkshire may recognize the tax benefit of an uncertain tax position only if management believes it is more likely than not that the tax position will be sustained on examination by the taxing authority based upon the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based upon the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. Berkshire’s policy is to recognize interest accrued and penalties associated with uncertain tax positions as a component of operating expense. See Note (E), Income Taxes for additional information.

Pension

Berkshire accounts for pension plan costs in accordance with the provisions of ASC 715 “Compensation - Retirement Benefits.” See – Note (F), Pension and Other Benefits.

Property, Plant and Equipment

The cost of additions to property, plant and equipment and the cost of renewals and betterments are capitalized. Costs consist of labor, materials, services and certain indirect construction costs, including AFUDC. The costs of current repairs, major maintenance projects and minor replacements are charged to appropriate operating expense accounts as incurred. The original cost of utility property, plant and equipment retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation.

Berkshire accrues for estimated costs of removal for certain of their plant-in-service. Such removal costs are included in the approved rates used to depreciate these assets. At the end of the service life of the applicable assets, the accumulated depreciation in excess of the historical cost of the asset provides for the estimated cost of removal. In accordance with ASC 980 “Regulated Operations,” the accrued costs of removal have been recorded as a regulatory liability.

Berkshire's property, plant and equipment as of December 31, 2015 and 2014 were comprised as follows:

	2015	2014
	(In Thousands)	
Gas distribution plant	$ 172,017	$ 164,706
Land	2,286	2,262
Buildings and improvements	15,135	14,703
Other plant	15,253	14,253
Total property, plant & equipment	204,691	195,924
Less accumulated depreciation	68,546	65,899
	136,145	130,025
Construction work in progress	6,405	1,644
Net property, plant & equipment	$ 142,550	$ 131,669

Regulatory Accounting

Generally accepted accounting principles for regulated entities in the United States of America allows Berkshire to give accounting recognition to the actions of regulatory authorities in accordance with the provisions of ASC 980 "Regulated Operations." In accordance with ASC 980, Berkshire has deferred recognition of costs (a regulatory asset) or have recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or obligations relieved in the future through the ratemaking process. Berkshire is allowed to recover all such deferred costs through its regulated rates. See Note (C) "Regulatory Proceedings", for a discussion of the recovery of certain deferred costs, as well as a discussion of the regulatory decisions that provide for such recovery.

If Berkshire, or a portion of their assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs would be required in the year in which such criteria are no longer met (if such deferred costs are not recoverable in the portion of the business that continues to meet the criteria for application of ASC 980). Berkshire expects to continue to meet the criteria for application of ASC 980 for the foreseeable future. If a change in accounting were to occur, it could have a material adverse effect on the Berkshire's earnings and retained earnings in that year and could also have a material adverse effect on Berkshire's ongoing financial condition.

Unless otherwise stated below, all of Berkshire's regulatory assets earn a return. Berkshire's regulatory assets and liabilities as of December 31, 2015 and 2014 included the following:

	Remaining Period	December 31, 2015	December 31, 2014
		(In Thousands)	
Regulatory Assets:			
Pension plans	(a)	$ 19,322	$ 20,581
Environmental Remediation Costs	7 years	9,273	12,445
Debt premium	5 to 7 years	3,967	4,911
Deferred purchased gas	(b)	46	1,243
Unfunded future income taxes	(c)	858	858
Other	(d)	4,372	4,183
Total regulatory assets		37,838	44,221
Less current portion of regulatory assets		3,960	6,496
Regulatory Assets, Net		$ 33,878	$ 37,725
Regulatory Liabilities:			
Rate credits	1 to 2 years	4,000	-
Asset removal costs	(d)	30,360	28,796
Other	(d)	420	114
Total regulatory liabilities		$ 34,780	$ 28,910

(a) Life is dependent upon timing of final pension plan distribution; balance, which is fully offset by a corresponding asset/liability, is recalculated each year in accordance with ASC 715 "Compensation-Retirement Benefits." See Note (F) Pension and Other Benefits for additional information.
(b) Deferred purchase gas costs balances at the end of the rate year are normally recorded / returned in the next year.
(c) The balance will be extinguished when the asset, which is fully offset by a corresponding liability, or liability has been realized or settled, respectively.
(d) Amortization period and/or balance vary depending on the nature, cost of removal and/or remaining life of the underlying assets/liabilities.

Revenues

Regulated utility revenues are based on authorized rates applied to each customer. These retail rates are approved by regulatory bodies and can be changed only through formal proceedings.

Unbilled revenues represent estimates of receivables for products and services provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer classification and weather.

New Accounting Standards

In April 2015, the FASB issued Accounting Standards Update (ASU) 2015-03, "Interest—Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs" which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. ASU 2015-03 is effective for interim and annual reporting periods beginning after December 15, 2015 and is to be applied retrospectively. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. See Note (A) "Statement of Accounting Policies – Basis of Presentation" for a table illustrating the reclassification to the prior year financial statements. In August 2015, the FASB issued Accounting Standards Update (ASU) 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements" which incorporates SEC guidance into ASC 835 "Interest" that allows an entity to defer and present debt issuance costs related to line of credit arrangements as an asset and subsequently amortize such costs ratably over the term of the arrangement regardless of whether there are any outstanding borrowings on the line of credit. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. See Note (A) "Statement of Accounting Policies – Basis of Presentation" for a table illustrating the reclassification to the prior year financial statements.

In July 2015, the FASB issued Accounting Standards Update (ASU) 2015-11, "Inventory – Simplifying the Measurement of Inventory" which requires inventory that is measured using first-in, first-out or average cost methods to be measured using the lower of cost and net realizable value. ASU 2015-11 is effective for interim and annual reporting periods beginning after December 15, 2016 and is to be applied prospectively with earlier application permitted as of the beginning of an interim or annual reporting period. This is not expected to be material to Berkshire's financial statements.

In August 2015, the FASB issued Accounting Standards Update (ASU) 2015-14, "Revenue from Contracts with Customers" which defers the effective date of ASU 2014-09 by one year. ASU 2014-09 requires entities to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services. We are currently evaluating the effect that adopting this new accounting guidance will have on our financial statements.

In November 2015, the FASB issued Accounting Standards Update (ASU) 2015-17, "Balance Sheet Classification of Deferred Taxes" which requires that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. This Update is applies to all entities that present a classified statement of financial position. For non-public entities, ASU 2015-17 is effective for financial statements issued for annual periods beginning after December 15, 2017. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. See Note

(A) "Statement of Accounting Policies – Basis of Presentation" for a table illustrating the reclassification to the prior year financial statements.

In January 2016, the FASB issued Accounting Standards Update (ASU) 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities". The new guidance requires that all equity investments in unconsolidated entities (other than those accounted for using the equity method of accounting) to be measured at fair value through earnings. There will no longer be an available-for-sale classification (changes in fair value reported in other comprehensive income) for equity securities with readily determinable fair values. For equity investments without readily determinable fair values, the cost method is also eliminated. When the fair value option has been elected for financial liabilities, changes in fair value due to instrument-specific credit risk will be recognized separately in other comprehensive income. The accumulated gains and losses due to these changes will be reclassified from accumulated other comprehensive income to earnings if the financial liability is settled before maturity. The amendments exempt all entities that are not public business entities from disclosing fair value information for financial instruments measured at amortized cost. In addition, the new guidance requires financial assets and financial liabilities to be presented separately in the notes to the financial statements, grouped by measurement category (e.g., fair value, amortized cost, lower of cost or market) and form of financial asset (e.g., loans, securities).

The classification and measurement guidance is effective for entities that are not public entities in fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. All entities that are not public entities may adopt the amendments earlier as of the fiscal years beginning after December 15, 2017 including interim periods within those fiscal years. An entity will record a cumulative-effect adjustment to beginning retained earnings as of the beginning of the first reporting period in which the guidance is adopted, with two exceptions. The amendments related to equity investments without readily determinable fair values (including disclosure requirements) will be effective prospectively. The requirement to use the exit price notion to measure the fair value of financial instruments for disclosure purposes will also be applied prospectively. We do not expect our adoption of the guidance to materially affect our results of operations, financial position, or cash flows.

In February 2016, the FASB issued Accounting Standards Update (ASU) 2016-02 "Leases". The guidance in this Update supersedes Topic 840, "Leases" and creates Topic 842, "Leases". Topic 842 defines a lease as a contract, or part of a contract, that conveys both the right to obtain substantially all economic benefits of an identified asset and the right to direct the use of the asset for a period of time in exchange for consideration. Leases are classified under this guidance as either operating or finance. For operating and finance leases, a lessee is required to recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, in the statement of financial position. For operating leases, a lessee is required to recognize a single lease cost, which will be recognized on a straight-line basis over the lease term similar to the current model. Lessor accounting is largely unchanged from that applied under previous GAAP. However, minor changes have been made to align with certain definition changes to the lessee model and the new revenue recognition standard. Leveraged lease accounting has been eliminated under this Update. Qualitative and specific quantitative disclosures are required under this guidance to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. For entities that are not public entities, the amendments in this Update are effective for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020. Early application is permitted for all entities. We are currently evaluating the effect that adopting this new accounting guidance will have on our financial statements.

B) CAPITALIZATION

Common Stock

Berkshire had 100 shares of its common stock, $2.50 par value, outstanding as of December 31, 2015 and 2014.

Long-Term Debt

	December 31, 2015	December 31, 2014
	(In Thousands)	
Unsecured Notes:		
9.60% Senior Unsecured Note, due September 1, 2020	$ 8,000	$ 8,000
7.80% Senior Unsecured Note, due November 15, 2021	8,727	10,180
5.33% Senior Unsecured Note, Series A, due December 10, 2043	15,000	15,000
Senior Secured Notes:		
10.06% First Mortgage Bond Series P, due February 1, 2019	10,000	10,000
Long-Term Debt	41,727	43,180
Less: Current portion of long-term debt (1)	2,393	2,393
Less: Unamortized debt issuance costs	710	812
Plus: Unamortized premium	3,968	4,911
Net Long-Term Debt	$ 42,592	$ 44,886

(1) Includes the current portion of unamortized premium.

Substantially all of Berkshire's properties are pledged as collateral for the First Mortgage Bonds.

The fair value of Berkshire's long-term debt was $38.0 million and $55.6 million as of December 31, 2015 and 2014, respectively, which was estimated by Berkshire based on market conditions. The expenses to issue long-term debt are deferred and amortized over the life of the respective debt issue.

Information regarding maturities and mandatory redemptions/repayments are set forth below:

	2016	2017	2018	2019	2020 & Thereafter	Total
	(In Thousands)					
Maturities:	$ 1,455	$ 1,455	$ 1,455	$ 11,455	$ 25,907	$ 41,727

In October 2013, Berkshire entered into a note purchase agreement with a group of institutional accredited investors providing for the sale to such investors on December 10, 2013 of senior unsecured 5.33% notes in the principal amount of $15 million, due on December 10, 2043. Berkshire used the net proceeds of this long-term debt issuance for the repayment of short-term debt and expects to use the remaining net proceeds for general working capital, environmental expenditures and capital expenditures.

(C) REGULATORY PROCEEDINGS

Merger with Avangrid, Inc.

As discussed in Note A, "Organization and Statement of Accounting Policies", on December 16, 2015 UIL Holdings merged with Avangrid, Inc. PURA and DPU approvals were obtained upon commitments made by UIL Holdings and Avangrid, Inc. that included $4.0 million in rate credits to Berkshire customers included in regulatory liabilities in the accompanying balance sheet. These commitments were accrued upon completion of the merger and are included in the consolidated results of operations for the year ended December 31, 2015.

In addition, the commitments include a distribution rate freeze to June 1, 2018 for Berkshire. UIL Holdings and Avangrid, Inc. further committed to no change in the day-to-day management and operation of UIL Holdings' Connecticut and Massachusetts utilities, and to maintain Berkshire's high levels of gas leak response.

The commitments also included comprehensive "ring fencing" provisions to protect the Connecticut and Massachusetts utilities from involuntary bankruptcy associated with potential future adverse changes in financial circumstances of Avangrid, Inc. affiliates. These provisions include the creation of a special purpose entity with at least one independent director, commitments to maintain separate books and records, and a prohibition on commingling of funds.

Rates

Utilities are entitled by Massachusetts statute to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital and to maintain their financial integrity, while also protecting relevant public interests.

Berkshire's rates are established by the DPU. Berkshire's 10-year rate plan, which was approved by the DPU and included an approved ROE of 10.5%, expired on January 31, 2012. Berkshire continues to charge the rates that were in effect at the end of the rate plan and currently anticipates that a base rate case would likely be filed in 2017, based on a calendar year 2016 test year, for rates to be effective in 2018. Based on existing tracking mechanisms in place for gas and other costs, discussions with the DPU, and precedence set by other utility companies, Berkshire believes that regulatory assets are recoverable and regulatory liabilities are fairly stated.

Additionally, Berkshire has a purchased gas adjustment clause approved by the DPU which enables them to pass the reasonably incurred cost of gas purchases through to customers. This clause allows Berkshire to recover changes in the market price of purchased natural gas, substantially eliminating exposure to natural gas price risk.

Under the settlement agreement entered into in connection with DPU's approval of the merger of UIL Holdings with Avangrid, Inc., Berkshire agreed not to request new distribution rates effective prior to June 1, 2018.

Gas Supply Arrangements

Berkshire satisfies its natural gas supply requirements through purchases from various producer/suppliers, withdrawals from natural gas storage capacity contracts and winter peaking supplies and resources. Berkshire operates diverse portfolios of gas supply, firm transportation, gas storage and peaking resources. Actual reasonable gas costs incurred by Berkshire are passed through to customers through state regulated purchased gas adjustment mechanisms subject to regulatory review.

Berkshire purchases the majority of the natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. Berkshire diversifies its sources of supply by amount purchased and by location while primarily acquiring gas in the Appalachia region.

Berkshire acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. Tennessee Gas Pipeline interconnects with Berkshire's distribution system upstream of the city gates. The prices and terms and conditions of the firm transportation capacity long-term contracts are regulated by the FERC. The actual reasonable cost of such contracts is passed through to customers through state regulated purchased gas adjustment mechanisms.

The future obligations under these contracts as of December 31, 2015 are as follows:

		(In Thousands)
2016	$	13,215
2017		8,607
2018		8,607
2018		7,615
2020		2,612
2021-after		26,378
	$	67,034

Berkshire acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer months for subsequent withdrawal in the winter months. The storage facilities are located in Pennsylvania, New York and West Virginia.

Winter peaking resources are primarily attached to the local distribution system and are owned by Berkshire. Berkshire owns or has rights to the natural gas stored in its Liquefied Natural Gas (LNG) facility that is directly attached to its distribution system.

(D) SHORT-TERM CREDIT ARRANGEMENTS

UIL Holdings and its regulated subsidiaries, including Berkshire, are parties to a revolving credit agreement with a group of banks that will expire on November 30, 2016 (the UIL Holdings Credit Facility). The borrowing limit under the UIL Holdings Credit Facility is $400 million, of which $25 million is available to Berkshire. The UIL Holdings Credit Facility permits borrowings at fluctuating interest rates and also permits borrowings for fixed periods of time specified by each Borrower at fixed interest rates determined by the Eurodollar interbank market in London (LIBOR). The UIL Holdings Credit Facility also permits the issuance of letters of credit of up to $50 million.

As of December 31, 2015, Berkshire did not have any borrowings outstanding under the Credit Facility. Available credit under the UIL Holdings Credit Facility at December 31, 2015 totaled $232.6 million for UIL Holdings and its subsidiaries in the aggregate. UIL Holdings records borrowings under the UIL Holdings Credit Facility as short-term debt, but the UIL Holdings Credit Facility provides for longer term commitments from banks allowing UIL Holdings to borrow and re-borrow funds, at its option, until the facility's expiration, thus affording it flexibility in managing its working capital requirements.

On March 9, 2016, Avangrid, Inc. engaged certain banks to act as joint lead arrangers and joint bookrunners for a new credit facility under which UIL Holdings and subsidiaries would be borrowers. The new credit facility, if successfully syndicated, will replace the UIL Holdings Credit Facility.

On April 5, 2016, Avangrid, Inc. entered into a new credit facility agreement which replaced the UIL Holdings Credit Facility.

(E) INCOME TAXES

	Year Ended December 31, 2015	Year Ended December 31, 2014
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions:		
Current		
Federal	$ 2,466	$ 4,469
State	754	1,274
Total current	3,220	5,743
Deferred		
Federal	(1,088)	(1,019)
State	(393)	(400)
Total deferred	(1,481)	(1,419)
Investment tax credits	(46)	(49)
Total income tax expense	$ 1,693	$ 4,275

Total income taxes differ from the amounts computed by applying the federal statutory tax rate to income before taxes. The reasons for the differences are as follows:

	Year Ended December 31, 2015	Year Ended December 31, 2014
	(In Thousands)	
Book income before income taxes	$ 4,731	$ 10,615
Computed tax at federal statutory rate	$ 1,656	$ 3,715
Increases (reductions) resulting from:		
State income taxes, net of federal income tax benefits	235	568
Other items, net	(198)	(8)
Total income tax expense	$ 1,693	$ 4,275
Effective income tax rates	35.8%	40.3%

The significant portion of Berkshire's income tax expense, including deferred taxes, is recovered through its regulated utility rates. Berkshire's annual income tax expense and associated effective tax rate is impacted by differences between the timing of deferred tax temporary difference activity and deferred tax recovery. Berkshire's effective tax rate is also impacted by permanent differences between the book and tax treatment of certain costs.

Berkshire is subject to the United States federal income tax statutes administered by the IRS. For tax years ending with the December 16, 2015 change of control, Berkshire filed or will file with its parent, UIL Holdings, a consolidated federal income tax return. Effective for tax periods beginning with the December 16, 2015 change in control, Berkshire and its parent, UIL Holdings, will file a consolidated federal tax return with Avangrid, Inc. Berkshire is also subject to certain state income tax statutes and as a result will file with its parent, UIL Holdings for the tax year ending December 31, 2015, a Massachusetts unitary income tax return. Beginning in 2016, Berkshire and its UIL Holdings affiliates, will file state unitary tax returns with Avangrid, Inc. and its subsidiaries. In conjunction with these changes, Berkshire became a party to Avangrid, Inc.'s tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.

As of December 31, 2015 and 2014, Berkshire did not have any uncertain tax positions.

Open Tax Years: During 2015, the Internal Revenue Service completed its examination of UIL's income tax returns for the years 2011 and 2012. The closing of this audit did not have a significant impact on Berkshire's 2015 income tax expense, net balance sheet position or cash flows. The following table summarizes Berkshire's tax years that remain subject to examination as of December 31, 2015:

Jurisdiction	*Tax years*
Federal	2013 - 2015
Massachusetts	2011 - 2015

The following table summarizes Berkshire's deferred tax assets and liabilities as of December 31, 2015 and 2014:

	2015	**2014**
	(In Thousands)	
Deferred income tax assets:		
Accrued removal obligation	$ 12,205	$ 11,576
Post-retirement benefits	3,653	3,633
Merger settlement agreement	2,010	-
Other	6,124	6,596
	$ 23,992	$ 21,805
Deferred income tax liabilities:		
Plant basis and accelerated depreciation timing differences	$ 38,025	$ 34,983
Regulatory deferrals related to pension benefits	7,767	7,648
Environmental	2,523	3,110
Deferred natural gas costs	1,338	1,665
Other	105	1,265
	$ 49,758	$ 48,671
Total net deferred income tax assets (liabilities)	$ (25,766)	$ (26,866)

(F) PENSION AND OTHER BENEFITS

Disclosures pertaining to Berkshire's pension benefit plans (the Plans) are in accordance with ASC 715 "Compensation-Retirement Benefits". Berkshire, through its parent UIL Holdings, has an investment policy addressing the oversight and management of pension assets and procedures for monitoring and control. UIL Holdings has engaged State Street Bank as the trustee and investment manager to assist in areas of asset allocation and rebalancing, portfolio strategy implementation, and performance monitoring and evaluation.

The goals of the asset investment strategy are to:

- Achieve long-term capital growth while maintaining sufficient liquidity to provide for current benefit payments and pension plan operating expenses.
- Provide a total return that, over the long term, provides sufficient assets to fund pension plan liabilities subject to an appropriate level of risk, contributions and pension expense.
- Optimize the return on assets, over the long term, by investing primarily in a diversified portfolio of equities and additional asset classes with differing rates of return, volatility and correlation.
- Diversify investments within asset classes to maximize preservation of principal and minimize over-exposure to any one investment, thereby minimizing the impact of losses in single investments.

The Plans seek to maintain compliance with the Employee Retirement Income Security Act of 1974 (ERISA) as amended, and any applicable regulations and laws.

Prior to the merger with Avangrid, Inc., the Retirement Benefits Plans Investment Committee of the UIL Holdings' Board of Directors oversaw the investment of the Plans' assets in conjunction with management and conducted a review of the investment strategies and policies of the Plans. This review included an analysis of the strategic asset allocation, including the relationship of Plan assets to Plan liabilities, and portfolio structure. The 2016 target asset allocations, which may be revised by the Retirement Benefits Plans Investment Committee, are approximately as follows: 50% Equity securities, 50% Debt securities. In the event that the relationship of Plan assets to Plan liabilities changes, the Retirement Benefits Plans Investment Committee will consider changes to the investment allocations.

The funding policy for the Plans is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the Plans. Berkshire currently expects to make pension contributions of approximately $0.8 million in 2016. Such contribution levels will be adjusted, if necessary, based on actuarial calculations.

Berkshire applies consistent estimation techniques regarding its actuarial assumptions, where appropriate, across its pension plans. The estimation technique utilized to develop the discount rate is based upon the yield of a portfolio of high quality corporate bonds that could be purchased as of December 31, 2015 to produce cash flows matching the expected plan disbursements within reasonable tolerances. The expected return is based upon a combination of historical performance and anticipated future returns for a portfolio reflecting the mix of equity, debt and other investments included in plan assets. Average wage increases are determined from projected annual pay increases, which are used to determine the wage base used to project employees' pension benefits at retirement. The health care cost trend rate is derived from projections of expected increases in health care costs.

Berkshire is utilizing a discount rate of 4.95% as of December 31, 2015 for all of its qualified pension plans, compared to 4.30% in 2014. The increase in the discount rate, which was due to changes in long-term interest rates, resulted in a decrease to the projected benefit obligation of approximately $2.6 million from 2014 to 2015.

The pension plans assumptions may be revised over time as economic and market conditions change. Changes in those assumptions could have a material impact on pension and other postretirement expenses. For example, if there had been a 0.25% change in the discount rate assumed for the pension plans, the 2015 pension expense would have increased or decreased inversely by $0.1 million. If there had been a 1% change in the expected return on assets assumed for the pension plans, the 2015 pension expense would have increased or decreased inversely by $0.4 million.

Pension Plans

Berkshire has multiple qualified pension plans covering substantially all of their union and management employees. The Plans are traditional defined benefit plans or cash balance plans for those hired on or after specified dates. In some cases, neither of these plans is offered to new employees and has been replaced with enhanced 401(k) plans for those hired on or after specified dates.

Other Post-Retirement Plans

Berkshire provides other post-retirement benefits for certain employees. These benefits consist primarily of medical benefits.

Other Accounting Matters

ASC 715 requires an employer that sponsors one or more defined benefit pension plans to recognize an asset or liability for the overfunded or underfunded status of the plan. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. Berkshire reflects all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in accumulated other comprehensive income, as management believes it is probable that such items will be recoverable through the ratemaking process. As of December 31, 2015 and 2014 Berkshire has recorded regulatory assets of $3.8 million.

In accordance with ASC 715, Berkshire utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. Berkshire amortizes prior service costs for the Plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. Berkshire utilizes an alternative method to amortize unrecognized actuarial gains and losses related to the Plans over the lesser of the average remaining service period or 10 years. For ASC 715 purposes, Berkshire does not recognize gains or losses until there is a variance in an amount equal to at least 5% of the greater of the projected benefit obligation or the market-related value of assets.

The following table represents the change in benefit obligation, change in plan assets and the respective funded status of Berkshire's pension plans as of December 31, 2015 and 2014. Plan assets and obligations have been measured as of December 31, 2015 and 2014.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2015	Year Ended December 31, 2014	Year Ended December 31, 2015	Year Ended December 31, 2014
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 46,454	$ 40,391	$ 1,743	$ 1,581
Service cost	616	519	-	-
Interest cost	1,973	2,062	65	68
Actuarial (gain) loss	(3,812)	5,187	112	231
Benefits paid (including expenses)	(1,333)	(1,705)	(128)	(138)
Benefit obligation at end of year	$ 43,898	$ 46,454	$ 1,792	$ 1,742
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 35,598	$ 33,916	$ -	$ -
Actual return on plan assets	(1,295)	3,217	-	-
Employer contributions	170	170	128	138
Benefits paid (including expenses)	(1,333)	(1,705)	(128)	(138)
Fair value of plan assets at end of year	$ 33,140	$ 35,598	$ -	$ -
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 10,758	$ 10,856	$ 1,792	$ 1,742
Amounts Recognized in the Balance Sheet consist of:				
Non-current liabilities	$ 10,758	$ 10,856	$ (1,792)	$ (1,742)
Amounts Recognized as a Regulatory Asset (Liability) consist of:				
Prior service cost	$ 550	$ 719	$ -	$ -
Net (gain) loss	$ 3,233	$ 3,102	-	-
Total recognized as a regulatory asset (liability)	$ 3,783	$ 3,821	$ -	$ -
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 42,228	$ 44,634	N/A	N/A
Accumulated benefit obligation	$ 38,297	$ 40,482	N/A	N/A
Fair value of plan assets	$ 33,141	$ 35,598	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	4.95%	4.30%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	4.45%	3.95%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year)	N/A	N/A	7.00%	7.00%
Health care trend rate (2020 forward)	N/A	N/A	5.00%	5.00%

N/A – Not applicable

The components of net periodic benefit cost are:

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2015	Year Ended December 31, 2014	Year Ended December 31, 2015	Year Ended December 31, 2014
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 616	$ 519	$ -	$ -
Interest cost	1,972	2,062	65	68
Expected return on plan assets	(2,690)	(2,562)	-	-
Amortization of actuarial (gain) loss	41	205	112	231
Amortization of prior service cost	169	-	-	-
Net periodic benefit cost	$ 108	$ 224	$ 177	$ 299
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 172	$ 3,816	$ 112	$ 231
Amortization of current year prior service costs	-	715	-	-
Amortization of prior service cost	(169)	-	-	-
Amortization of Actuarial (gain) loss	(41)	(205)	(112)	(231)
Total recognized as regulatory asset (liability)	$ (38)	$ 4,326	$ -	$ -
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 70	$ 4,550	$ 177	$ 299
Estimated Amortizations from Regulatory Assets (Liabilities) into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of transition obligation	$ -	$ 169	$ -	$ -
Amortization of prior service cost	169	-	-	-
Amortization of net (gain) loss	115	87	-	-
Total estimated amortizations	$ 284	$ 256	$ -	$ -
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.30%	5.20%	3.95%	4.55%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.75 - 8.00%	7.75%	N/A	N/A
Health care trend rate (current year)	N/A	N/A	7.00%	7.00%
Health care trend rate (2019 forward)	N/A	N/A	5.00%	5.00%

N/A – Not applicable

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Year		Pension Benefits		Other Post-Retirement Benefits
		(In Thousands)		
2016	$	1,957	$	142
2017	$	2,080	$	146
2018	$	2,183	$	148
2019	$	2,274	$	149
2020	$	2,407	$	149
2021-2025	$	13,793	$	708

Defined Contribution Retirement Plans/401(k)

Berkshire non-union employees are eligible to participate in UIL Holdings' Employee Stock Ownership Plan and in the Berkshire Gas Company Union 401(k) Plan. Employees may defer a portion of the compensation and invest in various investment alternatives. Matching contributions are made in the form of cash which is subsequently invested according to the specific provisions of each of the plans. The matching expense for 2015 and 2014 was $0.3 million and $0.4 million, respectively.

(G) RELATED PARTY TRANSACTIONS

Inter-company Transactions

Berkshire receives various administrative and management services from and enters into certain inter-company transactions with UIL Holdings and its subsidiaries. For the year ended December 31, 2015, Berkshire recorded inter-company expenses of $2.2 million. Costs of the services that are allocated amongst Berkshire and other of UIL Holdings' regulated subsidiaries are settled periodically by way of inter-company billings and wire transfers. At December 31, 2015 and 2014, the Balance Sheet reflects inter-company payables, included in accounts payable of $0.5 million and $1.3 million, respectively, and inter-company receivables, included in accounts receivable of $0.2 million and $0.5 million, respectively.

Dividends/Capital Contributions

For the years ended December 31, 2015 and 2014, Berkshire accrued dividends to UIL Holdings of $5.4 million and $4.4 million, respectively.

(H) LEASE OBLIGATIONS

Operating leases, which are charged to operating expense, consist principally of leases for office space and facilities, and a variety of equipment.

The future minimum lease payments under these operating leases are estimated to be as follows:

	(In Thousands)
2016	27
2017	4
2018	-
2019	-
2020	-
2021-after	-
	$ 31

(I) COMMITMENTS AND CONTINGENCIES

In the ordinary course of business, Berkshire is involved in various proceedings, including legal, tax, regulatory and environmental matters, which require management's assessment to determine the probability of whether a loss will occur and, if probable, an estimate of probable loss. When assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated, Berkshire accrues a reserve and discloses the reserve and related matter. Berkshire discloses material matters when losses are probable but for which an estimate cannot be reasonably estimated or when losses are not probable but are reasonably possible. Subsequent analysis is performed on a periodic basis to assess the impact of any changes in events or circumstances and any resulting need to adjust existing reserves or record additional reserves. However, given the inherent unpredictability of these legal and regulatory proceedings, Berkshire cannot assure you that its assessment of such proceedings will reflect the ultimate outcome, and an adverse outcome in certain matters could have a material adverse effect on its results of operations or cash flows.

Environmental Matters

Site Decontamination, Demolition and Remediation Costs

Berkshire owns or has previously owned properties where Manufactured Gas Plants (MGPs) had historically operated. MGP operations have led to contamination of soil and groundwater with petroleum hydrocarbons, benzene and metals, among other things, at these properties, the regulation and cleanup of which is regulated by the federal Resource Conservation and Recovery Act as well as other federal and state statutes and regulations. Berkshire has or had an ownership interest in one of such properties contaminated as a result of MGP-related activities. Under the existing regulations, the cleanup of such sites requires state and at times, federal, regulators' involvement and approval before cleanup can commence. In certain cases, such contamination has been evaluated, characterized and remediated. In other cases, the sites have been evaluated and characterized, but not yet remediated. Finally, at some of these sites, the scope of the contamination has not yet been fully characterized; no liability was recorded in respect of these sites as of December 31, 2014 and no amount of loss, if any, can be reasonably estimated at this time. In the past, Berkshire has received approval for the recovery of MGP-related remediation expenses from customers through rates and will seek recovery in rates for ongoing MGP-related remediation expenses for all of their MGP sites.

Berkshire owns property on Mill Street in Greenfield, Massachusetts, a former MGP site. We estimate that expenses associated with the remaining remedial activities, as well as the required ongoing monitoring and reporting to the Massachusetts Department of Environmental Protection will likely amount to approximately $0.1 million and have recorded a liability and offsetting regulatory asset for such expenses as of December 31, 2015. Historically, Berkshire has received approval from the DPU for recovery of environmental expenses in its customer rates.

Berkshire formerly owned a site on East Street (the East Street Site) in Pittsfield, Massachusetts, a former MGP site. The East Street Site is part of a larger site known as the GE–Pittsfield/Housatonic River Site. Berkshire sold the East Street Site to the General Electric Company (GE) in the 1970s and was named a potentially responsible party for the site by the EPA in 1990.

In December 2002, Berkshire reached a settlement with GE which provides, among other things, a framework for Berkshire and GE to allocate various monitoring and remediation costs at the East Street Site. As of December 31, 2015, we had accrued approximately $2.5 million and established a regulatory asset for these and future costs incurred by GE in responding to releases of hazardous substances at the East Street Site. Historically, Berkshire has received approval from the DPU for recovery of remediation expenses in its customer rates.

(J) FAIR VALUE MEASUREMENTS

As required by ASC 820, financial assets and liabilities are classified in their entirety, based on the lowest level of input that is significant to the fair value measurement. Berkshire's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables set forth the fair value Berkshire's financial assets and liabilities, other than pension benefits and OPEB, as of December 31, 2014 and December 31, 2015.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2015		(In Thousands)		
Assets:				
Noncurrent investments	$ 855	$ -	$ -	$ 855
Liabilities:				
Long-term debt	-	37,972	-	37,972
Net fair value assets/(liabilities), December 31, 2015	$ 855	$ (37,972)	$ -	$ (37,117)
December 31, 2014				
Assets:				
Noncurrent investments	$ 1,027	$ -	$ -	$ 1,027
Liabilities:				
Long-term debt	-	55,583	-	55,583
Net fair value assets/(liabilities), December 31, 2014	$ 1,027	$ (55,583)	$ -	$ (54,556)

The following tables set forth the fair values of Berkshire's pension assets as of December 31, 2014 and 2015.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2015		(In Thousands)		
Pension assets				
Mutual funds	$ -	$ 33,140	$ -	$ 33,140
Hedge fund	-	-	-	-
Fair value of plan assets, December 31, 2015	$ -	$ 33,140	$ -	$ 33,140
December 31, 2014				
Pension assets				
Mutual funds	$ -	$ 33,791	$ -	$ 33,791
Hedge fund	-	-	1,807	1,807
Fair value of plan assets, December 31, 2014	$ -	$ 33,791	$ 1,807	$ 35,598

The determination of fair values of the Level 2 co-mingled mutual funds and the Level 3 hedge fund were based on the Net Asset Value (NAV) provided by the managers of the underlying fund investments and the unrealized gains and losses. The NAV provided by the managers typically reflect the fair value of each underlying fund investment. Changes in the fair value of pension benefits are accounted for in accordance with ASC 715 Compensation – Retirement Benefits as discussed in Note (F) Pension and Other Benefits.

The following tables set forth a reconciliation of changes in the fair value of the assets above that are classified as Level 3 in the fair value hierarchy for the twelve month periods ended December 31, 2015 and 2014.

	Year Ended December 31, 2015
	(In Thousands)
Pension assets-Level 3, December 31, 2014	$ 1,807
Unrealized/Realized gains and (losses), net	-
Settlements	(1,807)
Pension assets-Level 3, December 31, 2015	$ -

	Year Ended December 31, 2014
	(In Thousands)
Pension assets-Level 3, December 31, 2013	$ 1,813
Unrealized/Realized gains and (losses), net	(6)
Purchases	-
Pension assets-Level 3, December 31, 2014	$ 1,807

CONNECTICUT NATURAL GAS CORPORATION

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2015 AND 2014

TABLE OF CONTENTS

pwc

Independent Auditor's Report

To the Board of Directors
of Connecticut Natural Gas Corporation:

We have audited the accompanying financial statements of Connecticut Natural Gas Corporation (the "Company"), which comprise the balance sheets as of December 31, 2015 and December 31, 2014, and the related statements of income, comprehensive income, shareholders' equity and cash flows for the years then ended.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

Our responsibility is to express an opinion on the financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from 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 our 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, we consider internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Connecticut Natural Gas Corporation at December 31, 2015 and December 31, 2014, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

April 4, 2016

PricewaterhouseCoopers LLP, 101 Seaport Boulevard, Suite 500, Boston, MA 02210
T: (617) 530 5000, F: (617) 530 5001, www.pwc.com/us

CONNECTICUT NATURAL GAS CORPORATION
STATEMENT OF INCOME
(In Thousands)

	Year Ended December 31, 2015	Year Ended December 31, 2014
Operating Revenues	$ 306,846	$ 370,961
Operating Expenses		
Operation		
Natural gas purchased	151,227	200,308
Operation and maintenance	84,145	78,215
Depreciation and amortization	29,821	27,574
Taxes - other than income taxes	22,219	23,038
Total Operating Expenses	287,412	329,135
Operating Income	19,434	41,826
Other Income and (Deductions), net (Note A)		
Other income	1,688	982
Other (deductions)	(449)	(393)
Total Other Income and (Deductions), net	1,239	589
Interest Charges, net		
Interest on long-term debt	8,741	9,295
Other interest, net	416	781
	9,157	10,076
Amortization of debt expense and redemption premiums	93	108
Total Interest Charges, net	9,250	10,184
Income Before Income Taxes	11,423	32,231
Income Taxes (Note E)	2,402	11,260
Net Income	9,021	20,971
Less:		
Preferred Stock Dividends of		
Subsidiary, Noncontrolling Interests	27	(14)
Net Income attributable to Connecticut Natural Gas Corporation	$ 8,994	$ 20,985

CONNECTICUT NATURAL GAS CORPORATION
STATEMENT OF COMPREHENSIVE INCOME
(In Thousands)

	Year Ended December 31, 2015	Year Ended December 31, 2014
Net Income	$ 9,021	$ 20,971
Other Comprehensive Income (Loss), net of income taxes		
Changes in unrealized gains(losses) related to pension and other post-retirement benefit plans	128	(242)
Total Other Comprehensive Income (Loss), net of income taxes	128	(242)
Comprehensive Income	9,149	20,729
Less:		
Preferred Stock Dividends of Subsidiary, Noncontrolling Interests	27	(14)
Comprehensive Income	$ 9,122	$ 20,743

The accompanying Notes to Financial Statements
are an integral part of the financial statements.
CONNECTICUT NATURAL GAS CORPORATION

STATEMENT OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2015	Year Ended December 31, 2014
Cash Flows From Operating Activities		
Net Income	$ 9,021	$ 20,971
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	29,913	27,682
Deferred income taxes	(3,659)	9,389
Pension expense	7,368	6,600
Regulatory activity, net	21,658	10,696
Other non-cash items, net	(3,252)	(2,137)
Changes in:		
Accounts receivable, net	15,362	7,913
Unbilled revenues	4,498	(286)
Natural gas in storage	10,790	1,324
Prepayments	58	1,490
Accounts payable	(19,539)	11,355
Interest accrued	(34)	(49)
Taxes accrued/refundable, net	5,490	(2,129)
Accrued pension	(9,232)	(8,556)
Accrued other post-employment benefits	(1,496)	(1,472)
Accrued liabilities	691	(4,074)
Other assets	(374)	1,622
Other liabilities	(62)	(119)
Total Adjustments	58,180	59,249
Net Cash provided by Operating Activities	67,201	80,220
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(61,913)	(54,596)
Intercompany receivable	-	4,000
Other	-	690
Net Cash (used in) Investing Activities	(61,913)	(49,906)
Cash Flows from Financing Activities		
Payment of common stock dividend	(17,500)	(774)
Distribution of capital	-	(42,100)
Payments on long-term debt	-	(10,000)
Intercompany payable	8,000	-
Equity infusion	-	21,000
Other	(27)	14
Net Cash (used in) Financing Activities	(9,527)	(31,860)
Unrestricted Cash and Temporary Cash Investments:		
Net change for the period	(4,239)	(1,546)
Balance at beginning of period	7,074	8,620
Balance at end of period	$ 2,835	$ 7,074
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 8,524	$ 9,372
Income taxes	$ 725	$ 1,675
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 5,840	$ 4,580

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

CONNECTICUT NATURAL GAS CORPORATION
BALANCE SHEET
December 31, 2015 and 2014

ASSETS
(In Thousands)

	2015	2014
Current Assets		
Unrestricted cash and temporary cash investments	$ 2,835	$ 7,074
Accounts receivable less allowance of $1,800 and $3,300, respectively	50,404	64,266
Unbilled revenues	16,904	21,402
Current regulatory assets (Note A)	17,090	13,761
Natural gas in storage, at average cost	28,837	39,627
Materials and supplies, at average cost	1,395	1,252
Refundable taxes	-	1,510
Prepayments	963	1,021
Other	175	175
Total Current Assets	118,603	150,088
Other investments	1,527	556
Total Property, Plant and Equipment	794,780	736,860
Less accumulated depreciation	265,758	252,150
	529,022	484,710
Construction work in progress	19,286	16,587
Net Property, Plant and Equipment	548,308	501,297
Regulatory Assets (Note A)	107,515	115,930
Deferred Charges and Other Assets		
Unamortized debt issuance expenses	125	249
Goodwill (Note A)	79,341	79,341
Other	230	-
Total Deferred Charges and Other Assets	79,696	79,590
Total Assets	$ 855,649	$ 847,461

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

CONNECTICUT NATURAL GAS CORPORATION
BALANCE SHEET
December 31, 2015 and 2014

LIABILITIES AND CAPITALIZATION
(In Thousands)

	2015	2014
Current Liabilities		
Current portion of long-term debt (Note B)	$ 11,527	$ 1,616
Accounts payable	41,236	59,515
Accrued liabilities	12,312	11,621
Current regulatory liabilities (Note A)	18,764	4,346
Interest accrued	2,064	2,098
Intercompany payable	8,000	-
Taxes accrued	7,595	3,615
Total Current Liabilities	101,498	82,811
Deferred Income Taxes (Note E)	10,705	16,322
Regulatory Liabilities (Note A)	192,774	171,596
Other Noncurrent Liabilities		
Pension accrued (Note G)	56,368	61,024
Other post-retirement benefits accrued (Note G)	12,061	13,390
Other	7,200	7,338
Total Other Noncurrent Liabilities	75,629	81,752
Commitments and Contingencies (Note J)		
Capitalization (Note B)		
Long-term debt, net of unamortized premium	129,738	141,297
Preferred Stock, not subject to mandatory redemption	340	340
Common Stock Equity		
Common stock	33,233	33,233
Paid-in capital	315,304	315,304
Retained earnings (Accumulated deficit)	(3,673)	4,833
Accumulated other comprehensive income (loss)	101	(27)
Net Common Stock Equity	344,965	353,343
Total Capitalization	475,043	494,980
Total Liabilities and Capitalization	$ 855,649	$ 847,461

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

CONNECTICUT NATURAL GAS CORPORATION
STATEMENT OF CHANGES IN SHAREHOLDER'S EQUITY
December 31, 2015 and 2014
(Thousands of Dollars)

	Common Stock			Paid-in	Retained Earnings (Accumulated	Accumulated Other Comprehensive		
	Shares		Amount	Capital	Deficit)	Income (Loss)		Total
Balance as of December 31, 2013	10,634,436	$	33,233	$ 336,404	$ (15,378)	$ 215	$	354,474
Net income					20,971			20,971
Other comprehensive income, net of income taxes						(242)		(242)
Distribution of capital				(42,100)				(42,100)
Equity infusion				21,000				21,000
Payment of common stock dividend					(774)			(774)
Payment of preferred stock dividend					14			14
Balance as of December 31, 2014	10,634,436	$	33,233	$ 315,304	$ 4,833	$ (27)	$	353,343
Net income					9,021			9,021
Other comprehensive income, net of income taxes						128		128
Payment of common stock dividend					(17,500)			(17,500)
Payment of preferred stock dividend					(27)			(27)
Balance as of December 31, 2015	10,634,436	$	33,233	$ 315,304	$ (3,673)	$ 101	$	344,965

The accompanying Notes to Financial Statements
are an integral part of the financial statements.

CONNECTICUT NATURAL GAS CORPORATION

NOTES TO FINANCIAL STATEMENTS

(A) STATEMENT OF ACCOUNTING POLICIES

Connecticut Natural Gas Corporation (CNG) engages in natural gas transportation, distribution and sales operations in Connecticut serving approximately 172,000 customers in service areas totaling approximately 716 square miles. The service area in Connecticut includes the greater Hartford-New Britain area and Greenwich. The population of this area is approximately 751,000, which represents approximately 21% of the population of the State. Of CNG's 2015 retail revenues, 62.9% were derived from residential sales, 29.5% from commercial sales, 4.7% from industrial sales and 3.0% from other sales. Retail revenues vary by season, with the highest revenues typically in the first quarter of the year reflecting cooler weather. In February 2015, CNG entered into an agreement with the Town of East Hampton, Connecticut to construct a large-scale gas infrastructure in the town.

CNG is the principal operating utility of CTG Resources, Inc. (CTG), a wholly-owned subsidiary of UIL Holdings Corporation. CTG is a holding company whose sole business is ownership of its operating regulated gas utility. CNG is regulated by the Connecticut Public Utilities Regulatory Authority (PURA).

On December 16, 2015, UIL Holdings Corporation, a Connecticut corporation (Predecessor UIL) merged with and into Green Merger Sub, Inc., after which Green Merger Sub, Inc. changed its name to UIL Holdings Corporation (UIL Holdings). Throughout this document "UIL Holdings" shall refer to UIL Holdings and Predecessor UIL unless the context otherwise indicates. The primary business of UIL Holdings is ownership of its operating regulated utility businesses. See Note (C) "Regulatory Proceedings" for further information regarding the merger.

Accounting Records

The accounting records of CNG are maintained in conformity with generally accepted accounting principles in the United States of America (GAAP) and in accordance with the uniform systems of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and PURA.

Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to use estimates and assumptions that affect (1) the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and (2) the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Certain amounts related to deferred tax liabilities, regulatory liabilities, operation and maintenance expense, depreciation and amortization expense, taxes other than income taxes, and other income and (deductions) that were reported as such in the Financial Statements in previous periods have been reclassified to conform to the current presentation as a result of UIL Holdings presenting such information consistent with its parent Avangrid, Inc. due to the merger. See further discussion regarding the merger in Note (A) "Statement of Accounting Policies – Merger with Avangrid, Inc." and Note (C) "Regulatory Proceedings".

The following table summarizes (1) the impact to the prior period Financial Statements of the adjustments noted above (2) the impacts to the prior period financials of the adjustments made as a result of the early adoption of certain new accounting standards (See Note (A) "Statement of Accounting Policies – New Accounting Standards"), and (3) certain immaterial amounts that have been reclassified to conform to the current presentation.

December 31, 2014 (in thousands)	As previously filed	Reclassifications	As currently reported
Consolidated Statement of Income			
Operation and maintenance	$ 75,320	$ 2,895	$ 78,215
Depreciation and amortization	30,336	(2,762)	27,574
Taxes - other than income taxes	23,171	(133)	23,038
Other income	-	982	982
Other income and (deductions)	589	(982)	(393)
Consolidated Statement of Cash Flows			
Depreciation and amortization	30,444	(2,762)	27,682
Other regulatory activity, net	7,934	2,762	10,696
Consolidated Balance Sheet			
Deferred income taxes (current)	2,267	(2,267)	-
Total Current Assets	152,355	(2,267)	150,088
Unamortized debt issuance expenses	725	(476)	249
Total deferred charges and other assets	80,066	(476)	79,590
Total assets	850,204	(2,743)	847,461
Deferred income taxes	18,589	(2,267)	16,322
Long-term debt	141,773	(476)	141,297
Total capitalization	495,456	(476)	494,980
Total liabilities and capitalization	850,204	(2,743)	847,461

CNG has evaluated subsequent events through the date its financial statements were available to be issued, April 4, 2016.

Allowance for Funds Used During Construction

In accordance with the uniform systems of accounts, CNG capitalizes allowance for funds used during construction (AFUDC), which represents the approximate cost of debt and equity capital devoted to plant under construction. The portion of the allowance applicable to borrowed funds is presented as other interest and the portion of the allowance applicable to equity funds is presented as other income in the Consolidated Statement of Income. Although the allowance does not represent current cash income, it has historically been recoverable under the ratemaking process over the service lives of the related properties. Weighted-average AFUDC rates for 2015 and 2014 were 7.81% and 4.67%, respectively.

Asset Retirement Obligations

The fair value of the liability for an asset retirement obligation (ARO) and/or a conditional ARO is recorded in the period in which it is incurred and the cost is capitalized by increasing the carrying amount of the related long-lived asset. The liability is adjusted to its present value periodically over time, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement, the obligation is settled either at its recorded amount or a gain or a loss is incurred. Any timing differences between rate recovery and depreciation expense are deferred 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 and/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.

CNG's ARO, including estimated conditional AROs, consist primarily of obligations related to the removal or retirement of asbestos, polychlorinated biphenyl contaminated equipment, gas pipeline and cast iron gas mains. The long-lived assets associated with the AROs are gas storage property, distribution property and other property. CNG's ARO is carried on the balance sheet as other long-term liabilities.

ARO activity for 2015 and 2014 is as follows:

	2015	2014
	(In Thousands)	
Balance as of January 1	$ 6,847	$ 6,841
Liabilities settled during the year	(466)	(353)
Accretion	356	359
Balance as of December 31	$ 6,737	$ 6,847

Cash and Temporary Cash Investments

CNG considers all of its highly liquid debt instruments with an original maturity of three months or less at the date of purchase to be cash and temporary cash investments.

Depreciation

Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis, using estimated service lives. For utility plant other than software, service lives are determined by independent engineers and subject to review and approval by PURA. Software service life is based upon management's estimate of useful life. The aggregate annual provisions for depreciation for the years 2015 and 2014 were approximately 3.9% of the original cost of depreciable property.

Goodwill

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

A goodwill impairment test is performed each year and the test will be updated between annual tests if events or circumstances occur that may reduce the fair value of a reporting unit below its carrying value. The annual analysis of the potential impairment of goodwill is a two-step process. Step one of the impairment test consists of comparing the fair values of reporting units with their aggregate carrying values, including goodwill. The estimated fair values for the reporting units are determined by using the income approach and the market approach methodologies.

The income approach is based on discounted cash flows which are derived from internal forecasts and economic expectations. Key assumptions used to determine fair value under the income approach include the cash flow period, terminal values based on a terminal growth rate, and the discount rate. The discount rate represents the estimated cost of debt and equity financing weighted by the percentage of debt and equity in a company's target capital structure.

The market approach utilizes the guideline company method, which calculates valuation multiples based on operating and valuation metrics from publicly traded guideline companies in the regulated natural gas distribution industry. Multiples derived from the guideline companies provide an indication of how much a knowledgeable investor in the marketplace would be willing to pay for an investment in a similar company. These multiples are then applied to the appropriate operating metric to determine indications of fair value.

If the carrying amount of a reporting unit exceeds the reporting unit's fair value, step two must be performed to determine the amount, if any, of the goodwill impairment loss. If the carrying amount is less than fair value, further testing of goodwill impairment is not performed.

Step two of the goodwill impairment test consists of comparing the implied fair value of the reporting unit's goodwill against the carrying value of the goodwill. 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.

As of October 1, 2015, the fair value of CNG exceeded its carrying value and therefore Step two was not performed and no impairment was recognized. No events or circumstances occurred subsequent to October 1, 2015 that would make it more likely than not that the fair value fell below the carrying value.

Impairment of Long-Lived Assets and Investments

Accounting Standards Codification (ASC) 360 "Property, Plant, and Equipment" requires the recognition of impairment losses on long-lived assets when the book value of an asset exceeds the sum of the expected future undiscounted cash flows that result from the use of the asset and its eventual disposition. If impairment arises, then the amount of any impairment is measured based on discounted cash flows or estimated fair value.

ASC 360 also requires that rate-regulated companies recognize an impairment loss when a regulator excludes all or part of a cost from rates, even if the regulator allows the company to earn a return on the remaining costs allowed. Under this standard, the probability of recovery and the recognition of regulatory assets under the criteria of ASC 980 must be assessed on an ongoing basis. As discussed in the description of ASC 980 in this Note (A) under "Regulatory Accounting", determination that certain regulatory assets no longer qualify for accounting as such could have a material impact on the financial condition CNG. At December 31, 2015, CNG did not have any assets that were impaired under this standard.

Income Taxes

In accordance with ASC 740 "Income Taxes," CNG has provided deferred taxes for all temporary book-tax differences using the liability method. The liability method requires that deferred tax balances be adjusted to reflect enacted future tax rates that are anticipated to be in effect when the temporary differences reverse. In accordance with generally accepted accounting principles for regulated industries, CNG has established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. For ratemaking purposes, CNG normalizes all investment tax credits related to recoverable plant investments. There were no accumulated investment tax credits as of December 31, 2015 and 2014.

Under ASC 740, CNG may recognize the tax benefit of an uncertain tax position only if management believes it is more likely than not that the tax position will be sustained on examination by the taxing authority based upon the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based upon the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. CNG's policy is to recognize interest accrued and penalties associated with uncertain tax positions as a component of operating expense. See Note (E), "Income Taxes" for additional information.

Pension and Other Postretirement Benefits

CNG accounts for pension plan costs and other postretirement benefits, consisting principally of health care, prescription drugs and life insurance, in accordance with the provisions of ASC 715 “Compensation - Retirement Benefits.” See Note (F), “Pension and Other Benefits”.

Property, Plant and Equipment

The cost of additions to property, plant and equipment and the cost of renewals and betterments are capitalized. Costs consist of labor, materials, services and certain indirect construction costs, including AFUDC. The costs of current repairs, major maintenance projects and minor replacements are charged to appropriate operating expense accounts as incurred. The original cost of utility property, plant and equipment retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation.

CNG accrues for estimated costs of removal for certain of their plant-in-service. Such removal costs are included in the approved rates used to depreciate these assets. At the end of the service life of the applicable assets, the accumulated depreciation in excess of the historical cost of the asset provides for the estimated cost of removal. In accordance with ASC 980 “Regulated Operations,” the accrued costs of removal have been recorded as a regulatory liability.

CNG’s property, plant and equipment as of December 31, 2015 and 2014 were comprised as follows:

	2015	2014
	(In Thousands)	
Gas distribution plant	$ 721,769	$ 672,327
Software	4,720	4,737
Land	1,618	1,618
Building and improvements	29,570	21,577
Other plant	37,103	36,601
Total property, plant & equipment	794,780	736,860
Less accumulated depreciation	265,758	252,150
	529,022	484,710
Construction work in progress	19,286	16,587
Net property, plant & equipment	$ 548,308	$ 501,297

Regulatory Accounting

Generally accepted accounting principles for regulated entities in the United States of America allow CNG to give accounting recognition to the actions of regulatory authorities in accordance with the provisions of ASC 980 “Regulated Operations.” In accordance with ASC 980, CNG has deferred recognition of costs (a regulatory asset) or has recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or obligations relieved in the future through the ratemaking process. CNG is allowed to recover all such deferred costs through its regulated rates. See Note (C) “Regulatory Proceedings”, for a discussion of the recovery of certain deferred costs, as well as a discussion of the regulatory decisions that provide for such recovery.

If CNG, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs would be required in the year in which such criteria are no longer met (if such deferred costs are not recoverable in the portion of the business that continues to meet the criteria for application of ASC 980). CNG expects to continue to meet the criteria for application of ASC 980 for the foreseeable future. If a change in accounting were to occur, it could have a material adverse effect on the CNG’s earnings and retained earnings in that year and could also have a material adverse effect on CNG’s ongoing financial condition.

Unless otherwise stated below, all of CNG's regulatory assets earn a return. CNG's regulatory assets and liabilities as of December 31, 2015 and 2014 included the following:

	Remaining Period	December 31, 2015	December 31, 2014
		(In Thousands)	
Regulatory Assets:			
Pension and other post-retirement benefit plans	(a)	$ 96,601	$ 102,184
Hardship programs	(b)	8,761	6,812
Debt premium	2 to 23 years	1,773	3,389
Unfunded future income taxes	(c)	10,175	12,897
Deferred purchased gas	(f)	3,099	311
Other	(d)	4,196	4,098
Total regulatory assets		124,605	129,691
Less current portion of regulatory assets		17,090	13,761
Regulatory Assets, Net		$ 107,515	$ 115,930
Regulatory Liabilities:			
Pension and other post-retirement benefit plans	(a)	$ 5,490	$ 3,217
Asset removal costs	(d)	154,574	144,322
Asset retirement obligation	(e)	7,702	7,248
Rate credits	1 to 12 years	18,225	-
Non-firm margin sharing credits	10 years	4,696	4,538
Decoupling	(g)	15,010	11,099
Other	(d)	5,841	5,518
Total regulatory liabilities		211,538	175,942
Less current portion of regulatory liabilities		18,764	4,346
Regulatory Liabilities, Net		$ 192,774	$ 171,596

(a) Life is dependent upon timing of final pension plan distribution; balance, which is fully offset by a corresponding asset/liability, is recalculated each year in accordance with ASC 715 "Compensation-Retirement Benefits." See Note (F) Pension and Other Benefits for additional information.

(b) Hardship customer accounts deferred for future recovery to the extent they exceed the amount in rates.

(c) The balance will be extinguished when the asset, which is fully offset by a corresponding liability, or liability has been realized or settled, respectively.

(d) Amortization period and/or balance vary depending on the nature, cost of removal and/or remaining life of the underlying assets/liabilities; asset amount includes certain amounts that are not currently earning a return.

(e) The liability will be extinguished simultaneous with the retirement of the assets and settlement of the corresponding asset retirement obligation.

(f) Deferred purchase gas costs balances at the end of the rate year are normally recorded / returned in the next year.

(g) The current portion is being returned to customers in 2015. The return of the long-term portion will be determined in a future proceeding with PURA.

Revenues

Regulated utility revenues are based on authorized rates applied to each customer. These retail rates are approved by regulatory bodies and can be changed only through formal proceedings.

Unbilled revenues represent estimates of receivables for products and services provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer classification and weather.

New Accounting Standards

In April 2015, the FASB issued Accounting Standards Update (ASU) 2015-03, "Interest—Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs" which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. ASU 2015-03 is effective for interim and annual reporting periods beginning after December 15, 2015 and is to be applied retrospectively. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. In August 2015, the FASB issued Accounting Standards Update (ASU) 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements" which incorporates SEC guidance into ASC 835 "Interest" that allows an entity to defer and present debt issuance costs related to line of credit arrangements as an asset and subsequently amortize such costs ratably over the term of the arrangement regardless of whether there are any outstanding borrowings on the line of credit. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. See Note (A) "Statement of Accounting Policies – Basis of Presentation" for a table illustrating the reclassification to the prior year Consolidated Financial Statements.

In July 2015, the FASB issued Accounting Standards Update (ASU) 2015-11, "Inventory – Simplifying the Measurement of Inventory" which requires inventory that is measured using first-in, first-out or average cost methods to be measured using the lower of cost and net realizable value. ASU 2015-11 is effective for interim and annual reporting periods beginning after December 15, 2016 and is to be applied prospectively with earlier application permitted as of the beginning of an interim or annual reporting period. This is not expected to be material to CNG's financial statements.

Also in August 2015, the FASB issued Accounting Standards Update (ASU) 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements" which incorporates SEC guidance into ASC 835 "Interest" that allows an entity to defer and present debt issuance costs related to line of credit arrangements as an asset and subsequently amortize such costs ratably over the term of the arrangement regardless of whether there are any outstanding borrowings on the line of credit. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented.

In November 2015, the FASB issued Accounting Standards Update (ASU) 2015-17, "Balance Sheet Classification of Deferred Taxes" which requires that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. This Update is applies to all entities that present a classified statement of financial position. For non-public entities, ASU 2015-17 is effective for financial statements issued for annual periods beginning after December 15, 2017. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. See Note (A) "Statement of Accounting Policies – Basis of Presentation" for a table illustrating the reclassification to the prior year Consolidated Financial Statements.

In January 2016, the FASB issued Accounting Standards Update (ASU) 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities". The new guidance requires that all equity investments in unconsolidated entities (other than those accounted for using the equity method of accounting) to be measured at fair value through earnings. There will no longer be an available-for-sale classification (changes in fair value reported in other comprehensive income) for equity securities with readily determinable fair values. For equity investments without readily determinable fair values, the cost method is also eliminated. When the fair value option has been elected for financial liabilities, changes in fair value due to instrument-specific credit risk will be recognized separately in other comprehensive income. The accumulated gains and losses due to these changes will be reclassified from accumulated other comprehensive income to earnings if the financial liability is settled before maturity. The amendments exempt all entities that are not public business entities from disclosing fair value information for financial instruments measured at amortized cost. In addition, the new guidance requires financial assets and financial liabilities to be presented separately in the notes to the financial statements, grouped by measurement category (e.g., fair value, amortized cost, lower of cost or market) and form of financial asset (e.g., loans, securities).

The classification and measurement guidance is effective for entities that are not public entities in fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. All entities that are not public entities may adopt the amendments earlier as of the fiscal years beginning after December 15, 2017 including interim periods within those fiscal years. An entity will record a cumulative-effect adjustment to beginning retained earnings as of the beginning of the first reporting period in which the guidance is adopted, with two exceptions. The amendments related to equity investments without readily determinable fair values (including disclosure requirements) will be effective prospectively. The requirement to use the exit price notion to measure the fair value of financial instruments for disclosure purposes will also be applied prospectively. We do not expect our adoption of the guidance to materially affect our results of operations, financial position, or cash flows.

In February 2016, the FASB issued Accounting Standards Update (ASU) 2016-02 “Leases”. The guidance in this Update supersedes Topic 840, “Leases” and creates Topic 842, “Leases”. Topic 842 defines a lease as a contract, or part of a contract, that conveys both the right to obtain substantially all economic benefits of an identified asset and the right to direct the use of the asset for a period of time in exchange for consideration. Leases are classified under this guidance as either operating or finance. For operating and finance leases, a lessee is required to recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, in the statement of financial position. For operating leases, a lessee is required to recognize a single lease cost, which will be recognized on a straight-line basis over the lease term similar to the current model. Lessor accounting is largely unchanged from that applied under previous GAAP. However, minor changes have been made to align with certain definition changes to the lessee model and the new revenue recognition standard. Leveraged lease accounting has been eliminated under this Update. Qualitative and specific quantitative disclosures are required under this guidance to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. For entities that are not public entities, the amendments in this Update are effective for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020. Early application is permitted for all entities. We are currently evaluating the effect that adopting this new accounting guidance will have on our financial statements.

B) CAPITALIZATION

Common Stock

CNG had 10,634,436 shares of its common stock, $3.125 par value, outstanding as of December 31, 2015 and 2014.

Redeemable Preferred Stock of Subsidiaries, Noncontrolling Interests

The preferred stock of subsidiaries 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.

CNG has authorized 884,315 shares of its 8.00% non-callable cumulative preferred stock with a par value of $3.125 per share. As of December 31, 2015, there were 108,706 shares issued and outstanding with a value of approximately $0.3 million.

Long-term Debt

	December 31, 2015	December 31, 2014
	(In Thousands)	
Unsecured Notes:		
9.10% Medium Term Note, Series A, due November 15, 2016	10,000	10,000
8.96% Medium Term Note, Series A, due April 3, 2017	20,000	20,000
5.63% Medium Term Note, Series C, due September 15, 2035	20,000	20,000
5.84% Medium Term Note, Series C, due October 28, 2035	25,000	25,000
6.66% Medium Term Note, Series C, due October 15, 2037	20,000	20,000
4.30% Medium Term Note, Series D, due October 25, 2028	25,000	25,000
5.23% Medium Term Note, Series D, due October 25, 2043	20,000	20,000
Long-Term Debt	140,000	140,000
Less: Current portion of long-term debt (1)	11,527	1,616
Less: Presentation adjustment - Unamortized debt issuance costs	508	476
Plus: Unamortized premium	1,773	3,389
Net Long-Term Debt	$ 129,738	$ 141,297

(1) Includes the current portion of unamortized premium.

The fair value of CNG's long-term debt was $162.0 million and $172.2 million as of December 31, 2015 and 2014, respectively, which was estimated by CNG based on market conditions. The expenses to issue long-term debt are deferred and amortized over the life of the respective debt issue.

Information regarding maturities and mandatory redemptions/repayments are set forth below:

	2016	2017	2018	2019	2020 & Thereafter	Total
	(In Thousands)					
Maturities:	$ 10,000	$ 20,000	$ -	$ -	$ 110,000	$ 140,000

(C) REGULATORY PROCEEDINGS

Merger with Avangrid, Inc.

As discussed in Note A, "Organization and Statement of Accounting Policies", on December 16, 2015 UIL Holdings merged with Avangrid, Inc. PURA and DPU approvals were obtained upon commitments made by UIL Holdings and Avangrid, Inc. that included $18.2 million in rate credits to CNG customers included in regulatory liabilities in the accompanying balance sheet. These commitments were accrued upon completion of the merger and are included in the consolidated results of operations for the year ended December 31, 2015.

In addition, the commitments include a distribution rate freeze to January 1, 2018 for CNG, accelerated capital investment in gas distribution system replacement of cast iron and bare steel. UIL Holdings and Avangrid, Inc. further committed to no change in the day-to-day management and operation of UIL Holdings' Connecticut and Massachusetts utilities, to hiring 150 employees or contractors within the State of Connecticut over the next three years, to maintain CNG's high levels of gas leak response, and to improve certain customer service metrics in Connecticut over the next three years.

The commitments also included comprehensive "ring fencing" provisions to protect the Connecticut and Massachusetts utilities from involuntary bankruptcy associated with potential future adverse changes in financial circumstances of Avangrid, Inc. affiliates. These provisions include the creation of a special purpose entity with at least one independent director, dividend limitations on the Connecticut utilities where the investment grade credit rating is in jeopardy or if a minimum common equity ratio is not maintained, commitments to maintain separate books and records and a prohibition on commingling of funds.

Rates

Utilities are entitled by Connecticut statute to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital and to maintain their financial integrity, while also protecting relevant public interests.

CNG's rates are established by PURA. The allowed return on equity established by PURA is 9.18%. Additionally, CNG has a purchased gas adjustment clause, approved by PURA, which enables them to pass their reasonably incurred cost of gas purchases through to customers. This clause allows CNG to recover costs associated with changes in the market price of purchased natural gas, substantially eliminating exposure to natural gas price risk.

CNG has a gas adjustment clause, approved by PURA and DPU, respectively, which enable them to pass their reasonably incurred cost of gas purchases through to customers. These clauses allow utilities to recover costs associated with changes in the market price of purchased natural gas, substantially eliminating exposure to natural gas price risk.

On January 22, 2014, PURA approved new base delivery rates for CNG, with an effective date of January 10, 2014, which, among other things, approved an allowed ROE of 9.18%, a decoupling mechanism, and two separate ratemaking mechanisms that reconcile actual revenue requirements related to CNG's cast iron and bare steel replacement program and system expansion. Additionally, the final decision requires the establishment of an earnings sharing mechanism by which CNG and customers share on a 50/50 basis all earnings above the allowed ROE in a calendar year. The decision also allows CNG, on a provisional basis, to reflect the increased rate base resulting from the accumulated deferred income tax (ADIT) impacts of the election of Section 338(h)(10) of the Internal Revenue Code upon its acquisition by UIL Holdings. The decision requires CNG to seek a private letter ruling from the Internal Revenue Service with regard to the specific question of whether, after extinguishment of an ADIT balance, a directive by a public utility commission to institute a ratemaking mechanism to reflect a credit to ratepayers of ADIT benefits lost through a Section 338(h)(10) election would result in a normalization violation. The decision states that in the event of a ruling from the Internal Revenue Service stating that imposing such a ratemaking mechanism would not create a normalization violation, PURA would adjust rates to offset the ratemaking impacts of the 338(h)(10) election on rate base. We estimate the impact to be an approximate $2.5 to $3.5 million decrease in annual revenue requirements.

During the first quarter of 2014, the OCC appealed PURA's decision to the Connecticut Superior Court with regard to the establishment of an adjustment mechanism for incremental cast iron and bare steel replacement as well as PURA's directive to seek a private letter ruling with respect to the extinguishment of ADITs rather than ordering a rate credit to hold customers harmless from the ratemaking effect of extinguishing the ADITs Upon the resolution of all appeals of PURA's approval of the merger of UIL Holdings and Avangrid, Inc., the proceeding would be terminated.

Under the settlement agreement entered into in connection with PURA's approval of the merger of UIL Holdings with Avangrid, Inc., CNG agreed not to request new distribution rates effective prior to January 1, 2018.

Other Proceedings

On June 11, 2014, PURA reopened the Expansion Plan Proceedings to modify the assignment of non-firm margin credits to comport with new statutory requirements that change the manner in which non-firm margin credits are allocated between existing customers and proposed gas expansion projects, and to consider a request made by CNG and The Southern Connecticut Gas Company (SCG) concerning the aggregating of potential customers when determining possible gas expansion projects. SCG, CNG, Yankee Gas Services Company, the OCC and the Bureau of Energy & Technology Policy entered into a settlement agreement on these issues that were approved by PURA on January 14, 2015. The settlement agreement specifically states how non-firm margin credits are to be allocated between existing customers and proposed gas expansion projects, streamlines reporting requirements for gas expansion projects, and among other issues, defines the methodology to be used for aggregating potential gas customers into possible gas expansion projects.

Gas Supply Arrangements

CNG satisfies its natural gas supply requirements through purchases from various producer/suppliers, withdrawals from natural gas storage capacity contracts and winter peaking supplies and resources. CNG operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual reasonable gas costs incurred by CNG are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

CNG purchases the majority of their natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. CNG diversifies its sources of supply by amount purchased and location and primarily acquires gas at various locations in the US Gulf of Mexico region, in the Appalachia region and in Canada.

CNG acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. Tennessee Gas Pipeline, Algonquin Gas Transmission and Iroquois Gas Transmission interconnect with CNG's distribution system and the other pipelines provide indirect services upstream of the city gates. The prices and terms and conditions of the long-term contracts for firm transportation capacity are regulated by the FERC. The actual reasonable cost of such contracts is passed through to customers through state regulated purchased gas adjustment mechanisms.

The future obligations under these contracts as of December 31, 2015 are as follows:

	(In Thousands)
2016	$ 51,183
2017	49,245
2018	44,532
2019	31,002
2020	23,844
2021-after	166,452
	$ 366,258

CNG acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer months for subsequent withdrawal in the winter months. The storage facilities are located in Pennsylvania, New York, West Virginia and Michigan.

CNG owns 100% of the Liquefied Natural Gas (LNG) stored in a LNG facility which is directly attached to its distribution system. CNG uses the LNG capacity as a winter peaking resource.

(D) SHORT-TERM CREDIT ARRANGEMENTS

UIL Holdings and its regulated subsidiaries, including CNG, are parties to a revolving credit agreement with a group of banks that will expire on November 30, 2016 (the UIL Holdings Credit Facility). The aggregate borrowing limit under the UIL Holdings Credit Facility is $400 million, of which $150 million is available to CNG. The UIL Holdings Credit Facility permits borrowings at fluctuating interest rates and also permits borrowings for fixed periods of time specified by each borrower at fixed interest rates determined by the Eurodollar interbank market in London (LIBOR). The UIL Holdings Credit Facility also permits the issuance of letters of credit of up to $50 million.

As of December 31, 2015, CNG did not have any borrowings outstanding under the Credit Facility. Available credit under the UIL Holdings Credit Facility at December 31, 2015 totaled $232.6 million for UIL Holdings and its subsidiaries in the aggregate. UIL Holdings records borrowings under the UIL Holdings Credit Facility as short-term debt, but the UIL Holdings Credit Facility provides for longer term commitments from banks allowing UIL Holdings to borrow and reborrow funds, at its option, until the facility's expiration, thus affording us flexibility in managing our working capital requirements.

(E) INCOME TAXES

	Year Ended December 31, 2015	Year Ended December 31, 2014
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ 5,215	$ -
State	846	1,871
Total current	6,061	1,871
Deferred		
Federal	(591)	11,306
State	(3,068)	(1,917)
Total deferred	(3,659)	9,389
Total income tax expense	$ 2,402	$ 11,260

Total income taxes differ from the amounts computed by applying the federal statutory tax rate to income before taxes.

The reasons for the differences are as follows:

	Year Ended December 31, 2015	Year Ended December 31, 2014
	(In Thousands)	
Book income before income taxes	$ 11,423	$ 32,231
Computed tax at federal statutory rate	$ 3,998	$ 11,282
Increases (reductions) resulting from:		
Removal costs	-	-
State income taxes, net of federal income tax benefits	(1,444)	(30)
Other items, net	(152)	8
Total income tax expense	$ 2,402	$ 11,260
Effective income tax rates	21.0%	34.9%

The significant portion of CNG's income tax expense, including deferred taxes, is recovered through its regulated utility rates. CNG's annual income tax expense and associated effective tax rate is impacted by differences between the timing of deferred tax temporary difference activity and deferred tax recovery. CNG's effective tax rate is also impacted by permanent differences between the book and tax treatment of certain costs.

CNG is subject to the United States federal income tax statutes administered by the IRS. For tax years ending with the December 16, 2015 change of control, CNG filed or will file with its parent, UIL Holdings, a consolidated federal income tax return. Effective for tax periods beginning with the December 16, 2015 change in control, CNG and its parent, UIL Holdings, will file a consolidated federal tax return with Avangrid, Inc. CNG is also subject to certain state income tax statutes and as a result will file for the tax year ending December 31, 2015, combined Connecticut and Massachusetts unitary income tax returns. Beginning in 2016, CNG and its UIL Holdings affiliates, will file state unitary tax returns with Avangrid, Inc. and its subsidiaries. In conjunction with these changes, CNG became a party to Avangrid, Inc.'s tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.

During 2015, the Internal Revenue Service completed its examination of UIL's income tax returns for the years 2011 and 2012. The closing of this audit did not have a significant impact on CNG's 2015 income tax expense, net balance sheet position or cash flows.

The following table summarizes CNG's tax years that remain subject to examination as of December 31, 2015:

Jurisdiction	*Tax years*
Federal	2013 - 2015
Connecticut	2011 - 2015

The following table summarizes CNG's deferred tax assets and liabilities as of December 31, 2015 and 2014:

	2015	**2014**
	(In Thousands)	
Deferred income tax assets:		
Post-retirement benefits	$ 25,232	$ 27,716
Merger settlement agreement	7,267	-
Accrued removal obligation	65,106	57,548
Other	15,402	6,713
	$ 113,007	$ 91,977
Deferred income tax liabilities:		
Plant basis and accelerated depreciation timing differences	$ 74,964	$ 59,772
Regulatory deferrals - pension and other post-retirement benefits	34,211	37,257
Other regulatory deferrals	12,166	8,540
Other	2,371	2,730
	$ 123,712	$ 108,299
Net deferred income tax assets (liabilities)	$ (10,705)	$ (16,322)

As of December 31, 2015, CNG had a state tax credit carry forward of $1.2 million that will begin to expire in 2020.

As of December 31, 2014, CNG had a state tax credit carry forward of $2.2 million that will begin to expire in 2018 and a federal net operating loss carry forward of $12.8 million that will begin to expire in 2032.

(F) PENSION AND OTHER BENEFITS

Disclosures pertaining to CNG's pension and other postretirement benefit plans (the Plans) are in accordance with ASC 715 "Compensation-Retirement Benefits". CNG, through its parent UIL Holdings, has an investment policy addressing the oversight and management of pension assets and procedures for monitoring and control. UIL Holdings has engaged State Street Bank as the trustee and investment manager to assist in areas of asset allocation and rebalancing, portfolio strategy implementation, and performance monitoring and evaluation.

The goals of the asset investment strategy are to:

- Achieve long-term capital growth while maintaining sufficient liquidity to provide for current benefit payments and pension plan operating expenses.
- Provide a total return that, over the long term, provides sufficient assets to fund pension plan liabilities subject to an appropriate level of risk, contributions and pension expense.
- Optimize the return on assets, over the long term, by investing primarily in a diversified portfolio of equities and additional asset classes with differing rates of return, volatility and correlation.
- Diversify investments within asset classes to maximize preservation of principal and minimize over-exposure to any one investment, thereby minimizing the impact of losses in single investments.

The Plans comply with the Employee Retirement Income Security Act of 1974 (ERISA) as amended, and any applicable regulations and laws.

Prior to the merger with Avangrid, Inc., the Retirement Benefits Plans Investment Committee of the UIL Holdings' Board of Directors oversaw the investment of the Plans' assets in conjunction with management and conducted a review of the investment strategies and policies of the Plans. This review included an analysis of the strategic asset allocation, including the relationship of Plan assets to Plan liabilities, and portfolio structure. The 2016 target asset allocations are approximately as follows: 60% equity securities and 40% debt securities. In the event that the relationship of Plan assets to Plan liabilities changes, CNG will consider changes to the investment allocations. The other postretirement employee benefit fund assets are invested in a balanced mutual fund and, accordingly, the asset allocation mix of the balanced mutual fund may differ from the target asset allocation mix from time to time.

The funding policy for the Plans is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the Plans. CNG currently expects to make pension contributions of approximately $3.9 million in 2016. Such contribution levels will be adjusted, if necessary, based on actuarial calculations.

CNG applies consistent estimation techniques regarding its actuarial assumptions, where appropriate, across its pension and postretirement plans. The estimation technique utilized to develop the discount rate for its pension and postretirement benefit plans is based upon the yield of a portfolio of high quality corporate bonds that could be purchased as of December 31, 2015 to produce cash flows matching the expected plan disbursements within reasonable tolerances. The expected return is based upon a combination of historical performance and anticipated future returns for a portfolio reflecting the mix of equity, debt and other investments included in plan assets. Average wage increases are determined from projected annual pay increases, which are used to determine the wage base used to project employees' pension benefits at retirement. The health care cost trend rate is derived from projections of expected increases in health care costs.

CNG is utilizing a discount rate of 4.95% as of December 31, 2015 for all of its qualified pension plans, compared to 4.30% in 2014. The increase in the discount rate, which was due to changes in long-term interest rates, resulted in a decrease to the projected benefit obligation of approximately $23 million from 2014 to 2015. The discount rate for non-qualified pension plans as of December 31, 2015 was 4.90% compared to 4.20% in 2014.

The discount rate for CNG's postretirement benefits plans reflects the plan requirements and expected future cash flows. For the CNG postretirement plan, the discount rate at December 31, 2015 was 4.90% as compared to a rate of 4.20% in 2014.

The pension and other postretirement benefits plans assumptions may be revised over time as economic and market conditions change. Changes in those assumptions could have a material impact on pension and other postretirement expenses. For example, if there had been a 0.25% change in the discount rate assumed for the pension plans, the 2015 pension expense would have increased or decreased inversely by $0.7 million. If there had been a 1% change in the expected return on assets assumed for the pension plans, the 2015 pension expense would have increased or decreased inversely by $1.9 million. If there had been a 0.25% change in the discount rate assumed for the other postretirement benefits plans, the 2015 other postretirement benefits plan expenses would have increased or decreased inversely by $0.1 million. If there had been a 1% change in the expected return on assets assumed for the other postretirement benefits plans, the 2015 other postretirement benefits plan expenses would have increased or decreased inversely by $0.1 million.

Pension Plans

CNG has multiple qualified pension plans covering substantially all of their union and management employees. CNG also has non-qualified supplemental pension plans for certain employees. The qualified pension plans are traditional defined benefit plans or, for those hired on or after specified dates, cash balance plans. In some cases, neither of these plans is offered to new employees and has been replaced with enhanced 401(k) plans for those hired on or after specified dates.

In addition, regarding the non-qualified plans, CNG has Rabbi Trusts which were established to provide a supplemental retirement benefit for certain officers and directors of CNG.

Other Postretirement Benefits Plans

CNG provides other postretirement benefits for substantially all of their employees. These benefits consist primarily of health care, prescription drug and life insurance benefits, for retired employees and their dependents. The eligibility for these benefits is determined by the employee's date of hire, number of years of service, age and whether the employee belongs to a certain group, such as a union. Dependents are also eligible at the employee's date of retirement provided the retired participant pays the necessary contribution. These plans are contributory with the level of participant's contributions evaluated annually. Benefits payments under these plans include annual caps for CNG participants hired after 1993. Union employees hired after December 1, 2009 are not eligible for these benefits. As such, CNG OPEB liabilities are not especially sensitive to increases in the healthcare trend rate. These plans are funded through a combination of 401(h) accounts and Voluntary Employee Benefit Association Trust accounts. CNG did not make any contributions to these plans in 2015, nor does it currently plan to make a contribution in 2016.

Other Accounting Matters

ASC 715 requires an employer that sponsors one or more defined benefit pension or other postretirement plans to recognize an asset or liability for the overfunded or underfunded status of the plan. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. CNG reflects all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in accumulated other comprehensive income, as management believes it is probable that such items will be recoverable through the ratemaking process. As of December 31, 2015 CNG has recorded regulatory assets of $15.5 million and as of December 31, 2014 CNG has recorded regulatory liabilities of $18.1 million, respectively.

In accordance with ASC 715, CNG utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. CNG amortizes prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. CNG utilizes an alternative method to amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans over the lesser of the average remaining service period or 10 years. For ASC 715 purposes, CNG does not recognize gains or losses until there is a variance in an amount equal to at least 5% of the greater of the projected benefit obligation or the market-related value of assets. There is no such allowance for a variance in capturing the amortization of other postretirement benefits unrecognized gains and losses.

CONNECTICUT NATURAL GAS CORPORATION

NOTES TO FINANCIAL STATEMENTS

The following table represents the change in benefit obligation, change in plan assets and the respective funded status of CNG's pension and other postretirement plans as of December 31, 2015 and 2014. Plan assets and obligations have been measured as of December 31, 2015 and 2014.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2015	Year Ended December 31, 2014	Year Ended December 31, 2015	Year Ended December 31, 2014
Change in Benefit Obligation:		(In Thousands)		
Benefit obligation at beginning of year	$ 253,965	$ 217,738	$ 22,970	$ 25,759
Service cost	4,136	3,450	233	344
Interest cost	10,876	11,235	939	1,218
Participant contributions	-	-	314	94
Actuarial (gain) loss	(20,733)	31,271	(1,124)	(215)
Benefits paid (including expenses)	(10,269)	(9,729)	(1,553)	(4,230)
Benefit obligation at end of year	$ 237,975	$ 253,965	$ 21,779	$ 22,970
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 192,941	$ 183,816	$ 9,580	$ 9,255
Actual return on plan assets	(4,064)	15,854	(156)	354
Employer contributions	3,000	3,000	-	-
Participant contributions	-	-	314	94
Benefits paid (including expenses)	(10,270)	(9,729)	(20)	(123)
Fair value of plan assets at end of year	$ 181,607	$ 192,941	$ 9,718	$ 9,580
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 56,368	$ 61,024	$ 12,061	$ 13,390
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 56,368	$ 61,024	$ 12,061	$ 13,390
Amounts Recognized as a Regulatory Asset (Liability) consist of:				
Prior service cost	$ 65	$ 91	$ 1,306	$ 407
Net (gain) loss	16,412	18,518	(2,318)	(927)
Total recognized as a regulatory asset (liability)	$ 16,477	$ 18,609	$ (1,012)	$ (520)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 237,976	$ 253,966	N/A	N/A
Accumulated benefit obligation	$ 216,449	$ 229,710	N/A	N/A
Fair value of plan assets	$ 181,607	$ 192,941	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	4.95%	4.30%	N/A	N/A
Discount rate (Non-Qualified Plans)	4.90%	4.20%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	4.90%	4.20%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year)	N/A	N/A	7.00%	7.00%
Health care trend rate (2019-2028 forward)	N/A	N/A	5.00%	5.00%

N/A – not applicable

CONNECTICUT NATURAL GAS CORPORATION

NOTES TO FINANCIAL STATEMENTS

The components of net periodic benefit cost are:

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2015	Year Ended December 31, 2014	Year Ended December 31, 2015	Year Ended December 31, 2014
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 4,136	$ 3,450	$ 233	$ 344
Interest cost	10,876	11,235	939	1,218
Expected return on plan assets	(15,161)	(14,434)	(486)	(460)
Amortization of prior service costs	26	26	104	104
Amortization of actuarial (gain) loss	600	(311)	(93)	(91)
Net periodic benefit cost	$ 477	$ (34)	$ 697	$ 1,115
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ (1,507)	$ 29,853	$ (1,485)	$ (2,709)
Amortization of current year prior service costs	-	-	1,003	-
Amortization of prior service costs	(26)	(26)	(104)	(104)
Amortization of actuarial (gain) loss	(600)	311	93	91
Total recognized as regulatory asset (liability)	$ (2,133)	$ 30,138	$ (493)	$ (2,722)
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ (1,656)	$ 30,104	$ 204	$ (1,607)
Estimated Amortizations from Regulatory Assets (Liabilities) into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of prior service cost	$ 23	$ 26	$ (232)	$ 104
Amortization of net (gain) loss	573	600	247	(93)
Total estimated amortizations	$ 596	$ 626	$ 15	$ 11
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.20%-4.30%	4.90-5.20%	4.20%	4.85%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	8.00%	8.00%	5.56%	5.56%
Health care trend rate (current year)	N/A	N/A	7.00%	7.00%
Health care trend rate (2019 forward)	N/A	N/A	5.00%	5.00%

N/A – not applicable

A one percentage point change in the assumed health care cost trend rate would have the following effects:

	1% Increase		1% Decrease	
	(In Thousands)			
Aggregate service and interest cost components	$	(5)	$	5
Accumulated post-retirement benefit obligation	$	(58)	$	51

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Year	Pension Benefits		Other Post-Retirement Benefits	
	(In Thousands)			
2016	$	10,476	$	1,707
2017	$	10,902	$	1,697
2018	$	11,211	$	1,680
2019	$	11,686	$	1,646
2020	$	12,195	$	1,601
2021-2024	$	69,315	$	7,227

Defined Contribution Retirement Plans/401(k)

CNG non-union employees are eligible to participate in UIL Holdings' Employee Stock Ownership Plan and union employees are eligible to participate in the Connecticut Natural Gas Corporation Union Employee 401(k) Plan. Employees may defer a portion of the compensation and invest in various investment alternatives. Matching contributions are made in the form of cash which is subsequently invested according to the specific provisions of each of the plans. The matching expense for 2015 and 2014 was $1.1 million, and $1.0 million, respectively.

(G) RELATED PARTY TRANSACTIONS

Inter-company Transactions

CNG receives various administrative and management services from and enters into certain inter-company transactions with UIL Holdings and its subsidiaries. For the year ended December 31, 2015, CNG recorded inter-company expenses of $12.4 million. Costs of the services that are allocated amongst CNG and other of UIL Holdings' regulated subsidiaries are settled periodically by way of inter-company billings and wire transfers. At December 31, 2015 and 2014, the Balance Sheet reflects inter-company receivables, included in accounts receivable of $1.7 million and $1.4 million, respectively, and inter-company payables, included in accounts payable of $7.5 million and $6.3 million, respectively.

Dividends/Capital Contributions

For the year ended December 31, 2015 and December 31, 2014, CNG accrued dividends to CTG of $17.5 million and $0.8 million, respectively.

(H) LEASE OBLIGATIONS

Operating leases, which are charged to operating expense, consist principally of leases for office space and facilities. The future minimum lease payments under these operating leases are estimated to be as follows:

	(In Thousands)	
2016	$	557
2017		598
2018		495
2019		394
2020		402
2020-after		265
	$	2,711

(I) COMMITMENTS AND CONTINGENCIES

In the ordinary course of business, CNG is involved in various proceedings, including legal, tax, regulatory and environmental matters, which require management's assessment to determine the probability of whether a loss will occur and, if probable, an estimate of probable loss. When assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated, CNG accrues a reserve and discloses the reserve and related matter. CNG discloses material matters when losses are probable but for which an estimate cannot be reasonably estimated or when losses are not probable but are reasonably possible. Subsequent analysis is performed on a periodic basis to assess the impact of any changes in events or circumstances and any resulting need to adjust existing reserves or record additional reserves. However, given the inherent unpredictability of these legal and regulatory proceedings, CNG cannot assure you that its assessment of such proceedings will reflect the ultimate outcome, and an adverse outcome in certain matters could have a material adverse effect on its results of operations or cash flows.

Environmental Matters

In complying with existing environmental statutes and regulations and further developments in areas of environmental concern, including legislation and studies in the fields of water quality, hazardous waste handling and disposal, toxic substances, climate change and electric and magnetic fields, CNG may incur substantial capital expenditures for equipment modifications and additions, monitoring equipment and recording devices, as well as additional operating expenses. The total amount of these expenditures is not now determinable. Significant environmental issues known to CNG at this time are described below.

Site Decontamination, Demolition and Remediation Costs

CNG owns or has previously owned properties where Manufactured Gas Plants (MGPs) had historically operated. MGP operations have led to contamination of soil and groundwater with petroleum hydrocarbons, benzene and metals, among other things, at these properties, the regulation and cleanup of which is regulated by the federal Resource Conservation and Recovery Act as well as other federal and state statutes and regulations. CNG has or had an ownership interest in one or more such properties contaminated as a result of MGP-related activities. Under the existing regulations, the cleanup of such sites requires state and at times, federal, regulators' involvement and approval before cleanup can commence. In certain cases, such contamination has been evaluated, characterized and remediated. In other cases, the sites have been evaluated and characterized, but not yet remediated. Finally, at some of these sites, the scope of the contamination has not yet been fully characterized; no liability was recorded in respect of these sites as of December 31, 2014 and no amount of loss, if any, can be reasonably estimated at this time. In the past, CNG has received approval for the recovery of MGP-related remediation expenses from customers through rates and will seek recovery in rates for ongoing MGP-related remediation expenses for all of their MGP sites.

CNG owns a property located on Columbus Boulevard in Hartford which is a former MGP site. Costs associated with the remediation of the site could be significant and will be subject to a review by PURA as to whether these costs are recoverable in rates. As of December 31, 2015, CNG has determined that remediation of the property in Hartford is not probable and therefore not reserved.

(J) FAIR VALUE MEASUREMENTS

As required by ASC 820, financial assets and liabilities are classified in their entirety, based on the lowest level of input that is significant to the fair value measurement. CNG's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables set forth the fair value CNG's financial assets and liabilities, other than pension benefits and OPEB, as of December 31, 2015 and December 31, 2014.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2015		(In Thousands)		
Assets:				
Noncurrent investments	$ 1,527	$ -	$ -	$ 1,527
Liabilities:	-	161,956	-	161,956
Long-term debt				
Net fair value assets/(liabilities), December 31, 2015	$ 1,527	$ (161,956)	$ -	$ (160,429)
December 31, 2014				
Assets:				
Noncurrent investments	$ 556	$ -	$ -	$ 556
Liabilities:	-	172,203	-	172,203
Long-term debt				
Net fair value assets/(liabilities), December 31, 2014	$ 556	$ (172,203)	$ -	$ (171,647)

The following tables set forth the fair values of CNG's pension and OPEB assets as of December 31, 2015 and 2014.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2015		(In Thousands)		
Pension assets				
Mutual funds	$ -	$ 181,607	$ -	$ 181,607
Hedge fund	-	-	-	-
	-	181,607	-	181,607
OPEB assets				
Mutual funds	2,560	7,158	-	9,718
Fair value of plan assets, December 31, 2015	$ 2,560	$ 188,765	$ -	$ 191,325

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
December 31, 2014		**(In Thousands)**		
Pension assets				
Cash and cash equivalents	$ -	$ 183,699	$ -	$ 183,699
Mutual funds				
Hedge fund	-	-	9,242	9,242
	-	183,699	9,242	192,941
OPEB assets				
Mutual funds	2,569	7,011	-	9,580
Fair value of plan assets, December 31, 2014	$ 2,569	$ 190,710	$ 9,242	$ 202,521

The determination of fair values of the Level 2 co-mingled mutual funds were based on the Net Asset Value (NAV) provided by the managers of the underlying fund investments and the unrealized gains and losses. The NAV provided by the managers typically reflect the fair value of each underlying fund investment. Changes in the fair value of pension benefits and OPEB are accounted for in accordance with ASC 715 Compensation – Retirement Benefits as discussed in Note (F) Pension and Other Benefits.

The following tables set forth a reconciliation of changes in the fair value of the assets above that are classified as Level 3 in the fair value hierarchy for the twelve month periods ended December 31, 2015 and 2014.

	Year Ended December 31, 2015
	(In Thousands)
Pension assets-Level 3, December 31, 2014	$ 9,242
Unrealized/Realized gains and (losses), net	-
Settlements	(9,242)
Pension assets-Level 3, December 31, 2015	$ -

	Year Ended December 31, 2014
	(In Thousands)
Pension assets-Level 3, December 31, 2013	$ 9,273
Unrealized/Realized gains and (losses), net	(31)
Pension assets-Level 3, December 31, 2014	$ 9,242

THE SOUTHERN CONNECTICUT GAS COMPANY

AUDITED CONSOLIDATED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2015 AND 2014

TABLE OF CONTENTS

pwc

Independent Auditor's Report

To the Board of Directors
of The Southern Connecticut Gas Company:

We have audited the accompanying consolidated financial statements of The Southern Connecticut Gas Company (the "Company"), which comprise the consolidated balance sheets as of December 31, 2015 and December 31, 2014, and the related consolidated statements of income, comprehensive income, shareholder's equity and cash flows for the years then ended.

Management's Responsibility for the Consolidated Financial Statements

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

Auditor's Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of The Southern Connecticut Gas Company at December 31, 2015 and December 31, 2014, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

As discussed in Note (A) to the consolidated financial statements, the Company changed the manner in which it classifies deferred taxes in 2015. Our opinion is not modified with respect to this matter.

PricewaterhouseCoopers LLP

April 4, 2016

THE SOUTHERN CONNECTICUT GAS COMPANY
CONSOLIDATED STATEMENT OF INCOME
(In Thousands)

	Year Ended December 31, 2015	Year Ended December 31, 2014
Operating Revenues	$ 314,939	$ 377,748
Operating Expenses		
Operation		
Natural gas purchased	136,823	187,492
Operation and maintenance	94,264	95,807
Depreciation and amortization	23,563	20,952
Taxes - other than income taxes	23,502	24,256
Total Operating Expenses	278,152	328,507
Operating Income	36,787	49,241
Other Income and (Deductions), net		
Other income	5,182	2,215
Other (deductions)	(755)	(2,785)
Total Other Income and (Deductions), net	4,427	(570)
Interest Charges, net		
Interest on long-term debt	13,374	13,374
Other interest, net	(37)	477
	13,337	13,851
Amortization of debt expense and redemption premiums	306	306
Total Interest Charges, net	13,643	14,157
Income Before Income Taxes	27,571	34,514
Income Taxes (Note E)	8,575	12,789
Net Income	$ 18,996	$ 21,725

THE SOUTHERN CONNECTICUT GAS COMPANY
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(In Thousands)

	Year Ended December 31, 2015	Year Ended December 31, 2014
Net Income	$ 18,996	$ 21,725
Other Comprehensive Income (Loss), net of income taxes		
Changes in unrealized gains(losses) related to pension and other post-retirement benefit plans	(124)	(573)
Other	-	-
Total Other Comprehensive Income (Loss), net of income taxes	(124)	(573)
Comprehensive Income	$ 18,872	$ 21,152

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

THE SOUTHERN CONNECTICUT GAS COMPANY
CONSOLIDATED STATEMENT OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2015	Year Ended December 31, 2014
Cash Flows From Operating Activities		
Net income	$ 18,996	$ 21,725
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	23,869	21,258
Deferred income taxes	9,153	12,471
Pension expense	5,376	6,708
Environmental liabilities	49,000	-
Regulatory activity, net	(35,058)	17,290
Other non-cash items, net	507	(2,756)
Changes in:		
Accounts receivable, net	7,012	11,503
Unbilled revenues	6,505	(853)
Natural gas in storage	10,757	1,549
Prepayments	259	1,640
Accounts payable	(8,635)	3,665
Taxes accrued/refundable, net	(6,267)	(3,939)
Accrued liabilities	1,221	(4,097)
Accrued pension	(10,503)	(8,035)
Accrued other post-employment benefits	(2,372)	(2,727)
Other assets	(2,979)	1,803
Other liabilities	(747)	2,414
Total Adjustments	47,098	57,894
Net Cash provided by Operating Activities	66,094	79,619
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(64,576)	(64,692)
Net Cash (used in) Investing Activities	(64,576)	(64,692)
Cash Flows from Financing Activities		
Payment of common stock dividend	(26,000)	(8,500)
Distribution of capital	-	(12,700)
Intercompany payable	31,000	(1,000)
Net Cash (used in) provided by Financing Activities	5,000	(22,200)
Unrestricted Cash and Temporary Cash Investments:		
Net change for the period	6,518	(7,273)
Balance at beginning of period	428	7,701
Balance at end of period	$ 6,946	$ 428
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 12,499	$ 13,593
Income taxes	$ 840	$ 1,595
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 8,169	$ 4,370

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

THE SOUTHERN CONNECTICUT GAS COMPANY
CONSOLIDATED BALANCE SHEET
December 31, 2015 and 2014

ASSETS
(In Thousands)

	2015	2014
Current Assets		
Unrestricted cash and temporary cash investments	$ 6,946	$ 428
Accounts receivable less allowance of $1,800 and $1,400, respectively	53,681	61,093
Unbilled revenues	15,805	22,310
Current regulatory assets (Note A)	27,272	21,642
Natural gas in storage, at average cost	32,109	42,866
Materials and supplies, at average cost	2,311	2,060
Refundable taxes	10,793	5,172
Prepayments	523	782
Other	3,005	278
Total Current Assets	152,445	156,631
Other investments	9,645	10,832
Total Property, Plant and Equipment	833,145	762,048
Less accumulated depreciation	205,176	191,052
	627,969	570,996
Construction work in progress	13,102	21,488
Net Property, Plant and Equipment (Note A)	641,071	592,484
Regulatory Assets (Note A)	146,440	101,178
Deferred Charges and Other Assets		
Unamortized debt issuance expenses	125	249
Goodwill (Note A)	134,931	134,931
Total Deferred Charges and Other Assets	135,056	135,180
Total Assets	$ 1,084,657	$ 996,305

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

THE SOUTHERN CONNECTICUT GAS COMPANY
CONSOLIDATED BALANCE SHEET
December 31, 2015 and 2014

LIABILITIES AND CAPITALIZATION
(In Thousands)

	2015	2014
Current Liabilities		
Current portion of long-term debt (Note B)	$ 2,517	$ 2,517
Accounts payable	41,516	46,352
Accrued liabilities	16,148	14,927
Current regulatory liabilities (Note A)	7,929	5,360
Interest accrued	2,271	2,437
Taxes accrued	3,687	4,333
Intercompany payable	46,000	15,000
Total Current Liabilities	120,068	90,926
Deferred Income Taxes (Note E)	34,876	25,856
Regulatory Liabilities (Note A)	170,205	157,720
Other Noncurrent Liabilities		
Pension accrued (Note F)	42,173	42,496
Other post-retirement benefits accrued (Note F)	15,913	16,743
Environmental liabilities	49,000	-
Other	13,350	14,029
Total Other Noncurrent Liabilities	120,436	73,268
Commitments and Contingencies (Note H)		
Capitalization		
Long-term debt, net of unamortized premium (Note B)	224,856	227,191
Noncontrolling interest (Note A)	20,369	20,369
Common Stock Equity		
Common stock	18,761	18,761
Paid-in capital	369,737	369,737
Retained earnings	5,714	12,718
Accumulated other comprehensive income (loss)	(365)	(241)
Net Common Stock Equity	393,847	400,975
Total Capitalization	639,072	648,535
Total Liabilities and Capitalization	$ 1,084,657	$ 996,305

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

THE SOUTHERN CONNECTICUT GAS COMPANY
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER'S EQUITY
December 31, 2015 and 2014
(Thousands of Dollars)

	Common Stock		Paid-in	Retained Earnings (Accumulated	Accumulated Other Comprehensive	
	Shares	Amount	Capital	Deficit)	Income (Loss)	Total
Balance as of December 31, 2013	1,407,072	$ 18,761	$ 379,737	$ 2,193	$ 332	$ 401,023
Net income				21,725		21,725
Other comprehensive loss, net of income taxes					(573)	(573)
Distribution of capital			(10,000)			(10,000)
Payment of common stock dividend				(11,200)		(11,200)
Balance as of December 31, 2014	1,407,072	$ 18,761	$ 369,737	$ 12,718	$ (241)	$ 400,975
Net income				18,996		18,996
Other comprehensive loss, net of income taxes					(124)	(124)
Payment of common stock dividend				(26,000)		(26,000)
Balance as of December 31, 2015	1,407,072	$ 18,761	$ 369,737	$ 5,714	$ (365)	$ 393,847

The accompanying Notes to Consolidated Financial
Statements are an integral part of the financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(A) STATEMENT OF ACCOUNTING POLICIES

The Southern Connecticut Gas Company (SCG) engages in natural gas transportation, distribution and sales operations in Connecticut serving approximately 190,000 customers in service areas totaling approximately 522 square miles. The service territory extends along the southern Connecticut coast from Westport to Old Saybrook and includes the communities of Bridgeport and New Haven. The population of this area is approximately 836,000, which represents approximately 23% of the population of the State. In 2014, SCG expanded into Essex, Connecticut. Of SCG's 2015 retail revenues, 60.8% were derived from residential sales, 27.4% from commercial sales, 8.6% from industrial sales and 3.2% from other sales. Retail revenues vary by season, with the highest revenues typically in the first quarter of the year reflecting cooler weather.

SCG is the principal operating utility of Connecticut Energy Corporation (CEC), a wholly owned subsidiary of UIL Holdings Corporation (UIL Holdings). CEC is a holding company whose sole business is ownership of its operating regulated gas utility. SCG is regulated by the Connecticut Public Utilities Regulatory Authority (PURA).

On December 16, 2015, UIL Holdings Corporation, a Connecticut corporation (Predecessor UIL) merged with and into Green Merger Sub, Inc., after which Green Merger Sub, Inc. changed its name to UIL Holdings Corporation (UIL Holdings). Throughout this document "UIL Holdings" shall refer to UIL Holdings and Predecessor UIL unless the context otherwise indicates. The primary business of UIL Holdings is ownership of its operating regulated utility businesses. See Note (C) "Regulatory Proceedings" for further information regarding the merger.

Accounting Records

The accounting records of SCG are maintained in conformity with generally accepted accounting principles in the United States of America (GAAP) and in accordance with the uniform systems of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and PURA.

Basis of Presentation

The preparation of consolidated financial statements in conformity with GAAP requires management to use estimates and assumptions that affect (1) the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and (2) the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Consolidated Financial Statements include the accounts of all variable interest entities (VIEs) where SCG has identified that it is the primary beneficiary.

Certain amounts related to deferred tax liabilities, regulatory liabilities, operation and maintenance expense, depreciation and amortization expense, taxes other than income taxes, and other income and (deductions) that were reported as such in the Consolidated Financial Statements in previous periods have been reclassified to conform to the current presentation as a result of UIL Holdings presenting such information consistent with its parent Avangrid, Inc. due to the merger. See further discussion regarding the merger in Note (A) "Statement of Accounting Policies – Merger with Avangrid, Inc." and Note (C) "Regulatory Proceedings".

The following table summarizes (1) the impact to the prior period Financial Statements of the adjustments noted above (2) the impacts to the prior period financials of the adjustments made as a result of the early adoption of certain new accounting standards (See Note (A) "Statement of Accounting Policies – New Accounting Standards"), and (3) certain immaterial amounts that have been reclassified to conform to the current presentation.

December 31, 2014 (in thousands)	As previously filed	Reclassifications	As currently reported
Consolidated Statement of Income			
Operation and maintenance	$ 81,882	$ 13,925	$ 95,807
Depreciation and amortization	34,835	(13,883)	20,952
Taxes - other than income taxes	24,298	(42)	24,256
Other income	-	2,215	2,215
Other income and (deductions)	(570)	(2,215)	(2,785)
Consolidated Statement of Cash Flows			
Depreciation and amortization	35,141	(13,883)	21,258
Other regulatory activity, net	3,407	13,883	17,290
Consolidated Balance Sheet			
Unamortized debt issuance expenses	3,739	(3,490)	249
Total deferred charges and other assets	138,670	(3,490)	135,180
Total assets	999,795	(3,490)	996,305
Deferred income taxes (current)	8,458	(8,458)	-
Total Current Liabilities	99,384	(8,458)	90,926
Deferred income taxes	17,398	8,458	25,856
Long-term debt	230,681	(3,490)	227,191
Total capitalization	652,025	(3,490)	648,535
Total liabilities and capitalization	999,795	(3,490)	996,305

SCG has evaluated subsequent events through the date its financial statements were available to be issued, April 4, 2016.

Variable Interest Entities

On July 31, 2014, United Resources, Inc. (URI), a wholly owned subsidiary of UIL Holdings, purchased from Avangrid, Inc., formerly Iberdrola USA, Inc., and certain of its subsidiaries, all of the outstanding equity of certain entities (the Purchased Entities) owning (a) a 14.6 million gallon liquefied natural gas (LNG) storage tank operated by SCG and located on property owned by SCG in Milford, Connecticut (the Tank), (b) certain equipment, materials and supplies used in or useful for the operation of the Tank (together with the Tank, the Assets) and (c) the LNG inventory, for a cash purchase price of approximately $20.3 million. The structure and the pricing of the transaction are intended to maintain the current regulatory structure of the Purchased Entities and the Assets, and have no impact on customers. The Assets earn a rate of return equal to SCG's allowed rate of return. The Purchased Entities have been identified as Variable Interest Entities (VIEs). SCG has been determined to be the primary beneficiary as SCG has the power to direct significant activities at the Purchased Entities with SCG operating the storage tank and all of the revenues at the Purchased Entities being derived from SCG. As a result, the Purchased Entities have been consolidated into the financial statements of SCG, which include total assets of $24.2 million and income of $2.4 million as of and for the year ended December 31, 2015. Intercompany operating revenues and operation and maintenance operating expenses of $13.7 million and intercompany receivables and payables of $0.8 million have been eliminated upon consolidation. The equity interests in the Purchased Entities held by URI are reflected as a noncontrolling interest in the accompanying Consolidated Balance Sheet.

Allowance for Funds Used During Construction

In accordance with the uniform systems of accounts, SCG capitalizes allowance for funds used during construction (AFUDC), which represents the approximate cost of debt and equity capital devoted to plant under construction. The portion of the allowance applicable to borrowed funds is presented as other interest and the portion of the allowance applicable to equity funds are presented as other income in the Statement of Income. Although the allowance does not represent current cash income, it has historically been recoverable under the ratemaking process over the service lives of the related properties. Weighted-average AFUDC rates for 2015 and 2014 were 8.40% and 3.30%, respectively.

Asset Retirement Obligations

The fair value of the liability for an asset retirement obligation (ARO) and/or a conditional ARO is recorded in the period in which it is incurred and the cost is capitalized by increasing the carrying amount of the related long-lived asset. The liability is adjusted to its present value periodically over time, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement, the obligation is settled either at its recorded amount or a gain or a loss is incurred. Any timing differences between rate recovery and depreciation expense are deferred 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 and/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.

SCG's ARO, including estimated conditional AROs, consist primarily of obligations related to the removal or retirement of asbestos, polychlorinated biphenyl contaminated equipment, gas pipeline and cast iron gas mains. The long-lived assets associated with the AROs are gas storage property, distribution property and other property. SCG's ARO is carried on the consolidated balance sheet as other long-term liabilities.

ARO activity for 2015 and 2014 is as follows:

	2015	2014
	(In Thousands)	
Balance as of January 1	$ 11,568	$ 11,380
Liabilities settled during the year	(448)	(409)
Accretion	607	597
Balance as of December 31	$ 11,727	$ 11,568

Cash and Temporary Cash Investments

SCG considers all of its highly liquid debt instruments with an original maturity of three months or less at the date of purchase to be cash and temporary cash investments.

Depreciation

Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis, using estimated service lives. For utility plant other than software, service lives are determined by independent engineers and subject to review and approval by PURA. Software service life is based upon management's estimate of useful life. The aggregate annual provisions for depreciation for each of the years 2015 and 2014 were approximately 3.0% and 2.9%, respectively, of the original cost of depreciable property.

Weather Insurance Contracts

On an annual basis, SCG assesses the need for weather insurance contracts for the upcoming heating season in order to provide financial protection from significant weather fluctuations. According to the terms of such contracts, if temperatures are warmer than normal at a prescribed level for the contract period, SCG will receive a payment; in addition, under certain of the contracts, if temperatures are colder than normal at a prescribed level for the contract period, SCG is required to make a payment. The premiums

paid are amortized over the terms of the contracts. The intrinsic value of the contracts is carried on the consolidated balance sheet with changes in value recorded in the income statement as Other Income and (Deductions).
In September 2015, SCG entered into weather insurance contracts for the winter period of November 1, 2015 through April 30, 2016. If temperatures are warmer than normal, SCG will receive payments up to a maximum of $3 million. As of December 31, 2015, the contract has a total value of $3 million since the variation from normal weather through December 31, 2015 reached the prescribed levels stated in the contract.

Goodwill

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

A goodwill impairment test is performed each year and the test will be updated between annual tests if events or circumstances occur that may reduce the fair value of a reporting unit below its carrying value. The annual analysis of the potential impairment of goodwill is a two-step process. Step one of the impairment test consists of comparing the fair values of reporting units with their aggregate carrying values, including goodwill. The estimated fair values for the reporting units are determined by using projections incorporated in our current operating plans as well as other available information.

If the carrying amount of a reporting unit exceeds the reporting unit's fair value, step two must be performed to determine the amount, if any, of the goodwill impairment loss. If the carrying amount is less than fair value, further testing of goodwill impairment is not performed.

Step two of the goodwill impairment test consists of comparing the implied fair value of the reporting unit's goodwill against the carrying value of the goodwill. 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.

As of October 1, 2015, the fair value of SCG exceeded its carrying value and therefore Step two was not performed and no impairment was recognized. No events or circumstances occurred subsequent to October 1, 2015 that would make it more likely than not that the fair value fell below the carrying value.

Impairment of Long-Lived Assets and Investments

Accounting Standards Codification (ASC) 360 "Property, Plant, and Equipment" requires the recognition of impairment losses on long-lived assets when the book value of an asset exceeds the sum of the expected future undiscounted cash flows that result from the use of the asset and its eventual disposition. If impairment arises, then the amount of any impairment is measured based on discounted cash flows or estimated fair value.

ASC 360 also requires that rate-regulated companies recognize an impairment loss when a regulator excludes all or part of a cost from rates, even if the regulator allows the company to earn a return on the remaining costs allowed. Under this standard, the probability of recovery and the recognition of regulatory assets under the criteria of ASC 980 must be assessed on an ongoing basis. As discussed in the description of ASC 980 in this Note (A) under "Regulatory Accounting", determination that certain regulatory assets no longer qualify for accounting as such could have a material impact on the financial condition SCG. At December 31, 2015, SCG did not have any assets that were impaired under this standard.

Income Taxes

In accordance with ASC 740 "Income Taxes," SCG has provided deferred taxes for all temporary book-tax differences using the liability method. The liability method requires that deferred tax balances be adjusted to reflect enacted future tax rates that are anticipated to be in effect when the temporary differences reverse. In accordance with generally accepted accounting principles for regulated industries, SCG has established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences. For ratemaking purposes, SCG normalizes all investment tax credits (ITCs) related to recoverable plant investments. There were no accumulated investment tax credits as of December 31, 2015 and 2014.

Under ASC 740, SCG may recognize the tax benefit of an uncertain tax position only if management believes it is more likely than not that the tax position will be sustained on examination by the taxing authority based upon the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based upon the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. SCG's policy is to recognize interest accrued and penalties associated with uncertain tax positions as a component of operating expense. See Note (E), Income Taxes for additional information.

Pension and Other Postretirement Benefits

SCG accounts for pension plan costs and other postretirement benefits, consisting principally of health care, prescription drug and life insurance, in accordance with the provisions of ASC 715 "Compensation - Retirement Benefits." See Note (F), Pension and Other Benefits.

Property, Plant and Equipment

The cost of additions to property, plant and equipment and the cost of renewals and betterments are capitalized. Costs consist of labor, materials, services and certain indirect construction costs, including AFUDC. The costs of current repairs, major maintenance projects and minor replacements are charged to appropriate operating expense accounts as incurred. The original cost of utility property, plant and equipment retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation.

SCG accrues for estimated costs of removal for certain of their plant-in-service. Such removal costs are included in the approved rates used to depreciate these assets. At the end of the service life of the applicable assets, the accumulated depreciation in excess of the historical cost of the asset provides for the estimated cost of removal. In accordance with ASC 980 "Regulated Operations," the accrued costs of removal have been recorded as a regulatory liability.

SCG's property, plant and equipment as of December 31, 2015 and 2014 were comprised as follows:

	2015	2014
	(In Thousands)	
Gas distribution plant	$ 744,367	$ 689,928
Software	2,315	2,208
Land	3,748	3,748
Building and improvements	23,519	21,779
VIE	17,333	17,007
Other plant	41,863	27,378
Total property, plant & equipment	833,145	762,048
Less accumulated depreciation	205,176	191,052
	627,969	570,996
Construction work in progress	13,102	21,488
Net property, plant & equipment	$ 641,071	$ 592,484

Regulatory Accounting

Generally accepted accounting principles for regulated entities in the United States of America allow SCG to give accounting recognition to the actions of regulatory authorities in accordance with the provisions of ASC 980 “Regulated Operations.” In accordance with ASC 980, SCG has deferred recognition of costs (a regulatory asset) or has recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or obligations relieved in the future through the ratemaking process. SCG is allowed to recover all such deferred costs through its regulated rates. See Note (C) “Regulatory Proceedings”, for a discussion of the recovery of certain deferred costs, as well as a discussion of the regulatory decisions that provide for such recovery.

If SCG, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs would be required in the year in which such criteria are no longer met (if such deferred costs are not recoverable in the portion of the business that continues to meet the criteria for application of ASC 980).
SCG expects to continue to meet the criteria for application of ASC 980 for the foreseeable future. If a change in accounting were to occur, it could have a material adverse effect on the SCG’s earnings and retained earnings in that year and could also have a material adverse effect on SCG’s ongoing financial condition.

Unless otherwise stated below, all of SCG’s regulatory assets earn a return. SCG’s regulatory assets and liabilities as of December 31, 2015 and 2014 included the following:

	Remaining Period	December 31, 2015	December 31, 2014
		(In Thousands)	
Regulatory Assets:			
Pension and other post-retirement benefit plans	(a)	$ 79,350	$ 78,590
Hardship programs	(b)	13,830	17,932
Deferred purchased gas	(c)	9,181	-
Environmental remediation costs	(g)	50,662	-
Debt premium	5 to 23 years	16,681	19,198
Other	(e)	4,008	7,100
Total regulatory assets		173,712	122,820
Less current portion of regulatory assets		27,272	21,642
Regulatory Assets, Net		$ 146,440	$ 101,178
Regulatory Liabilities:			
Pension and other post-retirement benefit plans	(a)	4,637	6,319
Asset removal costs	(e)	95,811	94,122
Rate Credits	0 to 12 years	12,416	-
Unfunded future income taxes	(d)	26,587	26,318
Low income program	(f)	31,062	19,065
Deferred purchased gas	(c)	-	2,455
Non-firm margin sharing credits	9 years	4,027	4,396
Other	(e)	3,594	10,405
Total regulatory liabilities		178,134	163,080
Less current portion of regulatory liabilities		7,929	5,360
Regulatory Liabilities, Net		$ 170,205	$ 157,720

(a) Life is dependent upon timing of final pension plan distribution; balance, which is fully offset by a corresponding asset/liability, is recalculated each year in accordance with ASC 715 "Compensation-Retirement Benefits." See Note (F) "Pension and Other Benefits" for additional information.
(b) Hardship customer accounts deferred for future recovery to the extent they exceed the amount in rates.
(c) Deferred purchase gas costs balances at the end of the rate year are normally recorded / returned in the next year.
(d) The balance will be extinguished when the asset, which is fully offset by a corresponding liability, or liability, has been realized or settled, respectively.
(e) Amortization period and/or balance vary depending on the nature, cost of removal and/or remaining life of the underlying assets/liabilities.
(f) Various hardship and payment plan programs approved for recovery.
(g) Liability relates to the remediation of the property owned by SCG on Chapel Street in New Haven. See Note (H) "Commitments and Contingencies" for additional information.

Revenues

Regulated utility revenues are based on authorized rates applied to each customer. These retail rates are approved by regulatory bodies and can be changed only through formal proceedings.

Unbilled revenues represent estimates of receivables for products and services provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer classification and weather.

New Accounting Standards

In April 2015, the FASB issued Accounting Standards Update (ASU) 2015-03, "Interest—Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs" which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. ASU 2015-03 is effective for interim and annual reporting periods beginning after December 15, 2015 and is to be applied retrospectively. In August 2015, the FASB issued Accounting Standards Update (ASU) 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements" which incorporates SEC guidance into ASC 835 "Interest" that allows an entity to defer and present debt issuance costs related to line of credit arrangements as an asset and subsequently amortize such costs ratably over the term of the arrangement regardless of whether there are any outstanding borrowings on the line of credit. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. See Note (A) "Statement of Accounting Policies – Basis of Presentation" for a table illustrating the reclassification to the prior year Consolidated Financial Statements.

In July 2015, the FASB issued Accounting Standards Update (ASU) 2015-11, "Inventory – Simplifying the Measurement of Inventory" which requires inventory that is measured using first-in, first-out or average cost methods to be measured using the lower of cost and net realizable value. ASU 2015-11 is effective for interim and annual reporting periods beginning after December 15, 2016 and is to be applied prospectively with earlier application permitted as of the beginning of an interim or annual reporting period. This is not expected to be material to SCG's consolidated financial statements.

In August 2015, the FASB issued Accounting Standards Update (ASU) 2015-14, "Revenue from Contracts with Customers" which defers the effective date of ASU 2014-09 by one year. ASU 2014-09 requires entities to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services. We are currently evaluating the effect that adopting this new accounting guidance will have on our consolidated financial statements.

In November 2015, the FASB issued Accounting Standards Update (ASU) 2015-17, "Balance Sheet Classification of Deferred Taxes" which requires that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. This Update is applies to all entities that present a classified statement of financial position. For non-public entities, ASU 2015-17 is effective for financial statements issued for annual periods beginning after December 15, 2017. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. See Note (A) "Statement of Accounting Policies – Basis of Presentation" for a table illustrating the reclassification to the prior year Consolidated Financial Statements.

In January 2016, the FASB issued Accounting Standards Update (ASU) 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities". The new guidance requires that all equity investments in unconsolidated entities (other than those accounted for using the equity method of accounting) to be measured at fair value through earnings. There will no longer be an available-for-sale classification (changes in fair value reported in other comprehensive income) for equity securities with readily determinable fair values. For equity investments without readily determinable fair values, the cost method is also eliminated. When the fair value option has been elected for financial liabilities, changes in fair value due to instrument-specific credit risk will be recognized separately in other comprehensive income. The accumulated gains and losses due to these changes will be reclassified from accumulated other comprehensive income to earnings if the financial liability is settled before maturity. The amendments exempt all entities that are not public business entities from disclosing fair value information for financial instruments measured at amortized cost. In addition, the new guidance requires financial assets and financial liabilities to be presented separately in the notes to the financial statements, grouped by measurement category (e.g., fair value, amortized cost, lower of cost or market) and form of financial asset (e.g., loans, securities).

The classification and measurement guidance is effective for entities that are not public entities in fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. All entities that are not public entities may adopt the amendments earlier as of the fiscal years beginning after December 15, 2017 including interim periods within those fiscal years. An entity will record a cumulative-effect adjustment to beginning retained earnings as of the beginning of the first reporting period in which the guidance is adopted, with two exceptions. The amendments related to equity investments without readily determinable fair values (including disclosure requirements) will be effective prospectively. The requirement to use the exit price notion to measure the fair value of financial instruments for disclosure purposes will also be applied prospectively. We do not expect our adoption of the guidance to materially affect our results of operations, financial position, or cash flows.

In February 2016, the FASB issued Accounting Standards Update (ASU) 2016-02 "Leases". The guidance in this Update supersedes Topic 840, "Leases" and creates Topic 842, "Leases". Topic 842 defines a lease as a contract, or part of a contract, that conveys both the right to obtain substantially all economic benefits of an identified asset and the right to direct the use of the asset for a period of time in exchange for consideration. Leases are classified under this guidance as either operating or finance. For operating and finance leases, a lessee is required to recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, in the statement of financial position. For operating leases, a lessee is required to recognize a single lease cost, which will be recognized on a straight-line basis over the lease term similar to the current model. Lessor accounting is largely unchanged from that applied under previous GAAP. However, minor changes have been made to align with certain definition changes to the lessee model and the new revenue recognition standard. Leveraged lease accounting has been eliminated under this Update. Qualitative and specific quantitative disclosures are required under this guidance to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. For entities that are not public entities, the amendments in this Update are effective for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020. Early application is permitted for all entities. We are currently evaluating the effect that adopting this new accounting guidance will have on our financial statements.

B) CAPITALIZATION

Common Stock

SCG had 1,407,072 shares of its common stock, $13.33 par value, outstanding as of December 31, 2015 and 2014.

Long-Term Debt

	December 31, 2015	December 31, 2014
	(In Thousands)	
Senior Secured Notes:		
7.50% Medium Term Note IV, due December 15, 2018	$ 50,000	$ 50,000
3.88% Medium Term Note IV, due September 22, 2021	25,000	25,000
5.778% Medium Term Note III, due November 1, 2025	25,000	25,000
7.95% Medium Term Note I, due August 5, 2026	15,000	15,000
6.88% Medium Term Note I, due September 11, 2028	14,000	14,000
5.772% Medium Term Note III, due December 1, 2035	20,000	20,000
6.38% Medium Term Note III, due September 15, 2037	40,000	40,000
5.39% Medium Term Note IV, due September 22, 2041	25,000	25,000
Long-Term Debt	214,000	214,000
Less: Current portion of long-term debt (1)	2,517	2,517
Less: Presentation adjustment - Unamortized debt issuance cost	3,308	3,490
Plus: Unamortized premium	16,681	19,198
Net Long-Term Debt	$ 224,856	$ 227,191

(1) Includes the current portion of unamortized premium.

Substantially all of SCG's properties are pledged as collateral for the Senior Secured Medium Term Notes.

The fair value of SCG's long-term debt was $262.0 million and $273.7 million as of December 31, 2015 and 2014, respectively, which was estimated by SCG based on market conditions. The expenses to issue long-term debt are deferred and amortized over the life of the respective debt issue.

Information regarding maturities and mandatory redemptions/repayments are set forth below:

	2016	2017	2018	2019	2020 & Thereafter	Total
			(In Thousands)			
Maturities:	$ -	$ -	$ 50,000	$ -	$ 164,000	$ 214,000

(C) REGULATORY PROCEEDINGS

Merger with Avangrid, Inc.

As discussed in Note A, "Organization and Statement of Accounting Policies", on December 16, 2015 UIL Holdings merged with Avangrid, Inc. PURA and DPU approvals were obtained upon commitments made by UIL Holdings and Avangrid, Inc. that included $12.4 million in rate credits to SCG customers included in regulatory liabilities in the accompanying balance sheet. These commitments were accrued upon completion of the merger and are included in the consolidated results of operations for the year ended December 31, 2015.

In addition, the commitments include a distribution rate freeze to January 1, 2018 for SCG, accelerated capital investment in gas distribution system replacement of cast iron and bare steel. UIL Holdings and Avangrid, Inc. further committed to no change in the day-to-day management and operation of UIL Holdings' Connecticut and Massachusetts utilities, to hiring 150 employees or contractors within the State of Connecticut over the next three years, to maintain SCG's high levels of gas leak response, and to improve certain customer service metrics in Connecticut over the next three years.

The commitments also included comprehensive "ring fencing" provisions to protect the Connecticut and Massachusetts utilities from involuntary bankruptcy associated with potential future adverse changes in financial circumstances of Avangrid, Inc. affiliates. These provisions include the creation of a special purpose entity with at least one independent director, dividend limitations on the Connecticut utilities where the investment grade credit rating is in jeopardy or if a minimum common equity ratio is not maintained, commitments to maintain separate books and records and a prohibition on commingling of funds.

Rates

Utilities are entitled by Connecticut statute to charge rates that are sufficient to allow them an opportunity to cover their reasonable operating and capital costs, to attract needed capital and to maintain their financial integrity, while also protecting relevant public interests.

SCG's rates are established by PURA. The allowed return on equity established by PURA is 9.36%. Additionally, SCG has a purchased gas adjustment clause, approved by PURA, which enables them to pass their reasonably incurred cost of gas purchases through to customers. This clause allows utilities to recover costs associated with changes in the market price of purchased natural gas, substantially eliminating exposure to natural gas price risk.

Under the settlement agreement entered into in connection with PURA's approval of the merger of UIL Holdings with Avangrid, Inc., SCG agreed not to request new distribution rates effective prior to January 1, 2018.

Other Proceedings

On June 11, 2014, PURA reopened the Expansion Plan Proceedings to modify the assignment of non-firm margin credits to comport with new statutory requirements that change the manner in which non-firm margin credits are allocated between existing customers and proposed gas expansion projects, and to consider a request made by SCG and the Connecticut Natural Gas Corporation (CNG) concerning the aggregating of potential customers when determining possible gas expansion projects. SCG, CNG, Yankee Gas Services Company, the OCC and the Bureau of Energy & Technology Policy entered into a settlement agreement on this issue that was approved by PURA on January 14, 2015. The settlement agreement specifically states how non-firm margin credits are to be allocated between existing customers and proposed gas expansion projects, streamlines reporting requirements for gas expansion projects, and among other issues, defines the methodology to be used for aggregating potential gas customers into possible gas expansion projects.

Gas Supply Arrangements

SCG satisfies its natural gas supply requirements through purchases from various producer/suppliers, withdrawals from natural gas storage capacity contracts and winter peaking supplies and resources. SCG operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual reasonable gas costs incurred by SCG are passed through to customers through state regulated purchased gas adjustment mechanisms subject to regulatory review.

SCG purchases the majority of their natural gas supply at market prices under seasonal, monthly or mid-term supply contracts and the remainder is acquired on the spot market. SCG diversifies its sources of supply by amount purchased and location. SCG primarily acquires gas at various locations in the US Gulf of Mexico region, in the Appalachia region and in Canada.

SCG acquires firm transportation capacity on interstate pipelines under long-term contracts and utilizes that capacity to transport both natural gas supply purchased and natural gas withdrawn from storage to the local distribution system. Tennessee Gas Pipeline, Algonquin Gas Transmission and Iroquois Gas Transmission interconnect with SCG's distribution system and the other pipelines provide indirect services upstream of the city gates. The prices and terms and conditions of the firm transportation capacity long-term contracts for firm transportation capacity are regulated by the FERC. The actual reasonable cost of such contracts is passed through to customers through state regulated purchased gas adjustment mechanisms.

The future obligations under these contracts as of December 31, 2015 are as follows:

	(In Thousands)
2016	$ 66,373
2017	75,390
2018	67,372
2019	54,708
2020	43,150
2021-after	193,041
	$ 500,034

SCG acquires firm underground natural gas storage capacity using long-term contracts and fills the storage facilities with gas in the summer for subsequent withdrawal in the winter months. The storage facilities are located in Pennsylvania, New York, West Virginia and Michigan.

SCG has the rights to 100% of the Liquefied Natural Gas (LNG) stored in a LNG facility which is directly attached to its distribution system. SCG uses the LNG capacity as a winter peaking resource.

(D) SHORT-TERM CREDIT ARRANGEMENTS

UIL Holdings and its regulated subsidiaries, including SCG, are parties to a revolving credit agreement with a group of banks that will expire on November 30, 2016 (the UIL Holdings Credit Facility). The borrowing limit under the UIL Holdings Credit Facility is $400 million, of which $150 million is available to SCG. The UIL Holdings Credit Facility permits borrowings at fluctuating interest rates and also permits borrowings for fixed periods of time specified by each Borrower at fixed interest rates determined by the Eurodollar interbank market in London (LIBOR). The UIL Holdings Credit Facility also permits the issuance of letters of credit of up to $50 million.

As of December 31, 2015, SCG did not have any borrowings outstanding under the Credit Facility. Available credit under the UIL Holdings Credit Facility at December 31, 2015 totaled $232.6 million for UIL Holdings and its subsidiaries in the aggregate. UIL Holdings records borrowings under the UIL Holdings Credit Facility as short-term debt, but the UIL Holdings Credit Facility provides for longer term commitments from banks allowing UIL Holdings to borrow and re-borrow funds, at its option, until the facility's expiration, thus affording it flexibility in managing its working capital requirements.

(E) INCOME TAXES

	Year Ended December 31, 2015	Year Ended December 31, 2014
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ 911	$ -
State	(1,489)	318
Total current	(578)	318
Deferred		
Federal	8,373	12,283
State	780	188
Total deferred	9,153	12,471
Total Income tax expense	$ 8,575	$ 12,789

Total income taxes differ from the amounts computed by applying the federal statutory tax rate to income before taxes. The reasons for the differences are as follows:

	Year Ended December 31, 2015	Year Ended December 31, 2014
	(In Thousands)	
Book income before income taxes	$ 27,571	$ 34,514
Computed tax at federal statutory rate	$ 9,650	$ 12,080
Increases (reductions) resulting from:		
Removal costs	(740)	(508)
Uncollectible reserves and programs	992	992
State taxes, net of federal income tax benefits	(461)	329
Variable interest entity	(846)	(249)
Other items, net	(20)	145
Total income tax expense	$ 8,575	$ 12,789
Effective income tax rates	31.1%	37.1%

The significant portion of SCG's income tax expense, including deferred taxes, is recovered through its regulated utility rates. SCG's annual income tax expense and associated effective tax rate is impacted by differences between the timing of deferred tax temporary difference activity and deferred tax recovery. SCG's effective tax rate is also impacted by permanent differences between the book and tax treatment of certain costs.

SCG is subject to the United States federal income tax statutes administered by the IRS. For tax years ending with the December 16, 2015 change of control, SCG filed or will file with its parent, UIL Holdings, a consolidated federal income tax return. Effective for tax periods beginning with the December 16, 2015 change in control, SCG and its parent, UIL Holdings, will file a consolidated federal tax return with Avangrid, Inc. SCG is also subject to certain state income tax statutes and as a result will file for the tax year ending December 31, 2015, combined Connecticut and Massachusetts unitary income tax returns. Beginning in 2016, SCG and its UIL Holdings affiliates, will file state unitary tax returns with Avangrid, Inc. and its subsidiaries. In conjunction with these changes, SCG became a party to Avangrid, Inc.'s tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.

As of December 31, 2015 and 2014, SCG did not have any gross income tax reserves for uncertain tax positions.

During 2015, the Internal Revenue Service completed its examination of UIL's income tax returns for the years 2011 and 2012. The closing of this audit did not have a significant impact on SCG's 2015 income tax expense, net balance sheet position or cash flows.

The following table summarizes SCG's tax years that remain subject to examination as of December 31, 2015:

Jurisdiction	*Tax years*
Federal	2013 - 2015
Connecticut	2011 - 2015

The following table summarizes SCG's deferred tax assets and liabilities as of December 31, 2015 and 2014:

	2015	**2014**
	(In Thousands)	
Deferred income tax assets:		
Post-retirement benefits	$ 19,582	$ 18,824
Accrued removal obligation	38,324	37,621
Merger settlement agreement	24,489	-
Tax regulatory liability - gross up	10,691	10,584
Debt premium	6,651	6,651
Net operating loss carry forward	6,827	1,827
Other	35,755	6,756
	$ 142,319	$ 82,263
Deferred income tax liabilities:		
Plant basis and accelerated depreciation timing differences	$ 99,919	$ 75,030
Regulatory deferrals related to pension and other post-retirement benefits	25,622	23,310
Other regulatory deferrals	21,036	5,689
Other	30,618	4,090
	$ 177,195	$ 108,119
Net deferred income tax assets (liabilities)	$ (34,876)	$ (25,856)

As of December 31, 2015 and December 31, 2014, SCG had a state tax credit carry forward of $4.3 million and $3.0 million, respectively, that will begin to expire in 2018 and a federal net operating loss carry forward of $19.5 million and $5.8 million, respectively, that will begin to expire in 2032.

(F) PENSION AND OTHER BENEFITS

Disclosures pertaining to SCG's pension and other postretirement benefit plans (the Plans) are in accordance with ASC 715 "Compensation-Retirement Benefits". SCG, through its parent UIL Holdings, has an investment policy addressing the oversight and management of pension assets and procedures for monitoring and control. UIL Holdings has engaged State Street Bank as the trustee and investment manager to assist in areas of asset allocation and rebalancing, portfolio strategy implementation, and performance monitoring and evaluation.

The goals of the asset investment strategy are to:

- Achieve long-term capital growth while maintaining sufficient liquidity to provide for current benefit payments and pension plan operating expenses.
- Provide a total return that, over the long term, provides sufficient assets to fund pension plan liabilities subject to an appropriate level of risk, contributions and pension expense.
- Optimize the return on assets, over the long term, by investing primarily in a diversified portfolio of equities and additional asset classes with differing rates of return, volatility and correlation.
- Diversify investments within asset classes to maximize preservation of principal and minimize over-exposure to any one investment, thereby minimizing the impact of losses in single investments.

The Plans seek to maintain compliance with the Employee Retirement Income Security Act of 1974 (ERISA) as amended, and any applicable regulations and laws.

Prior to the merger with Avangrid, Inc., the Retirement Benefits Plans Investment Committee of the UIL Holdings' Board of Directors oversaw the investment of the Plans' assets in conjunction with management and conducted a review of the investment strategies and policies of the Plans. This review included an analysis of the strategic asset allocation, including the relationship of Plan assets to Plan liabilities, and portfolio structure. The 2015 target asset allocations, which may be revised by the Retirement Benefits Plans Investment Committee, are approximately as follows: 60% Equity securities, and 40% Debt securities, which consists primarily of real assets, hedge funds and high yield securities. In the event that the relationship of Plan assets to Plan liabilities changes, the Retirement Benefits Plans Investment Committee will consider changes to the investment allocations. The other postretirement employee benefit fund assets are invested in a balanced mutual fund and, accordingly, the asset allocation mix of the balanced mutual fund may differ from the target asset allocation mix from time to time.

The funding policy for the Plans is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the Plans. SCG currently expects to make pension contributions of approximately $3.3 million in 2016. Such contribution levels will be adjusted, if necessary, based on actuarial calculations.

SCG applies consistent estimation techniques regarding its actuarial assumptions, where appropriate, across its pension and postretirement plans. The estimation technique utilized to develop the discount rate for its pension and postretirement benefit plans is based upon the yield of a portfolio of high quality corporate bonds that could be purchased as of December 31, 2015 to produce cash flows matching the expected plan disbursements within reasonable tolerances. The expected return is based upon a combination of historical performance and anticipated future returns for a portfolio reflecting the mix of equity, debt and other investments included in plan assets. Average wage increases are determined from projected annual pay increases, which are used to determine the wage base used to project employees' pension benefits at retirement. The health care cost trend rate is derived from projections of expected increases in health care costs.

SCG is utilizing a discount rate of 4.95% as of December 31, 2015 for all of its qualified pension plans, compared to 4.30% in 2014. The increase in the discount rate, which was due to changes in long-term interest rates, resulted in a decrease to the projected benefit obligation of approximately $13 million from 2014 to 2015. The discount rate for non-qualified pension plans as of December 31, 2015 was 4.90% compared to 4.20% in 2014.

The discount rate for SCG's postretirement benefits plans reflects the plan requirements and expected future cash flows. For the SCG postretirement plan, the discount rate at December 31, 2015 was 4.90% as compared to a rate of 4.20% in 2014.

The pension and other postretirement benefits plans assumptions may be revised over time as economic and market conditions change. Changes in those assumptions could have a material impact on pension and other postretirement expenses. For example, if there had been a 0.25% change in the discount rate assumed for the pension plans, the 2015 pension expense would have increased or decreased inversely by $0.3 million. If there had been a 1% change in the expected return on assets assumed for the pension plans, the 2015 pension expense would have increased or decreased inversely by $1.3 million. If there had been a 0.25% change in the discount rate assumed for the other postretirement benefits plans, the 2015 other postretirement benefits plan expenses would have increased or decreased inversely by an immaterial amount. If there had been a 1% change in the expected return on assets assumed for the other postretirement benefits plans, the 2015 other postretirement benefits plan expenses would have increased or decreased inversely by $0.1 million.

Pension Plans

SCG has multiple qualified pension plans covering substantially all of their union and management employees. SCG also has non-qualified supplemental pension plans for certain employees. The qualified pension plans are traditional defined benefit plans or, for those hired on or after specified dates, cash balance plans. In some cases, neither of these plans is offered to new employees and has been replaced with enhanced 401(k) plans for those hired on or after specified dates.

In addition, regarding the non-qualified plans, SCG has Rabbi Trusts which were established to provide a supplemental retirement benefit for certain officers and directors of SCG.

Other Postretirement Benefits Plans

SCG provides other postretirement benefits for substantially all of their employees. These benefits consist primarily of health care, prescription drug and life insurance benefits, for retired employees and their dependents. The eligibility for these benefits is determined by the employee’s date of hire, number of years of service, age and whether the employee belongs to a certain group, such as a union. Dependents are also eligible at the employee’s date of retirement provided the retired participant pays the necessary contribution. These plans are contributory with the level of participant’s contributions evaluated annually. Benefits payments under these plans include annual caps for SCG participants hired after 1996. Union employees hired after April 1, 2010 are not eligible for these benefits. As such, SCG OPEB liabilities are not especially sensitive to increases in the healthcare trend rate. These plans are funded through a combination of 401(h) accounts and Voluntary Employee Benefit Association Trust accounts. SCG did not make any contributions to these plans in 2015, nor does it currently plan to make a contribution in 2016.

Other Accounting Matters

ASC 715 requires an employer that sponsors one or more defined benefit pension or other postretirement plans to recognize an asset or liability for the overfunded or underfunded status of the plan. For a pension plan, the asset or liability is the difference between the fair value of the plan’s assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan’s assets and the accumulated postretirement benefit obligation. SCG reflects all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in accumulated other comprehensive income, as management believes it is probable that such items will be recoverable through the ratemaking process. As of December 31, 2015 and 2014, SCG has recorded regulatory assets of $18.1 million and $12.1 million, respectively.

In accordance with ASC 715, SCG utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. SCG amortizes prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. SCG utilizes an alternative method to amortize unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans over the lesser of the average remaining service period or 10 years. For ASC 715 purposes, SCG does not recognize gains or losses until there is a variance in an amount equal to at least 5% of the greater of the projected benefit obligation or the market-related value of assets. There is no such allowance for a variance in capturing the amortization of other postretirement benefits unrecognized gains and losses.

The following table represents the change in benefit obligation, change in plan assets and the respective funded status of SCG’s pension and other postretirement plans as of December 31, 2015 and 2014. Plan assets and obligations have been measured as of December 31, 2015 and 2014.

THE SOUTHERN CONNECTICUT GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Year Ended December 31, 2015	Year Ended December 31, 2014	Year Ended December 31, 2015	Year Ended December 31, 2014
		(In Thousands)		
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 166,866	$ 150,614	$ 22,910	$ 24,384
Service cost	1,850	1,747	180	270
Interest cost	7,070	7,685	934	1,149
Actuarial (gain) loss	(6,082)	15,321	(342)	1,374
Benefits paid (including expenses)	(8,758)	(8,501)	(1,991)	(4,267)
Benefit obligation at end of year	$ 160,946	$ 166,866	$ 21,691	$ 22,910
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 124,370	$ 119,925	$ 6,167	$ 7,494
Actual return on plan assets	(2,721)	10,173	(149)	216
Employer contributions	5,881	2,773	-	-
Benefits paid (including expenses)	(8,757)	(8,501)	(240)	(1,543)
Fair value of plan assets at end of year	$ 118,773	$ 124,370	$ 5,778	$ 6,167
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 42,173	$ 42,496	$ 15,913	$ 16,743
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 42,173	$ 42,496	$ 15,913	$ 16,743
Amounts Recognized as a Regulatory Asset (Liability) consist of:				
Prior service cost	-	-	2,133	696
Net (gain) loss	$ 19,371	$ 13,668	$ (3,339)	$ (2,257)
Total recognized as a regulatory asset (liability)	$ 19,371	$ 13,668	$ (1,206)	$ (1,561)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 160,946	$ 166,863	N/A	N/A
Accumulated benefit obligation	$ 151,861	$ 157,131	N/A	N/A
Fair value of plan assets	$ 118,823	$ 124,370	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	4.95%	4.30%	N/A	N/A
Discount rate (Non-Qualified Plans)	4.90%	4.20%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	4.90%	4.20%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year)	N/A	N/A	7.00%	7.00%
Health care trend rate (2020 forward)	N/A	N/A	5.00%	5.00%

N/A – not applicable

THE SOUTHERN CONNECTICUT GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The components of net periodic benefit cost are:

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2015	**Year Ended December 31, 2014**	**Year Ended December 31, 2015**	**Year Ended December 31, 2014**
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 1,850	$ 1,747	$ 180	$ 270
Interest cost	7,070	7,685	934	1,149
Expected return on plan assets	(9,867)	(9,373)	(425)	(523)
Amortization of prior service cost	-	-	145	145
Amortization of actuarial (gain) loss	803	112	(267)	(724)
Net periodic benefit cost	$ (144)	$ 171	$ 567	$ 317
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 3,317	$ 14,566	$ (1,349)	$ 681
	3,190	-	1,581	(145)
Amortization of current year prior service (credit)/costs				
Amortization of prior service cost			(145)	-
Amortization of actuarial (gain) loss	(803)	(112)	267	724
Total recognized as regulatory asset (liability)	$ 5,704	$ 14,454	$ 354	$ 1,260
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 5,560	$ 14,625	$ 921	$ 1,577
Estimated Amortizations from Regulatory Assets (Liabilities) into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of prior service (cost) credit	$ 759	$ -	$ 489	$ 145
Amortization of net (gain) loss	1,055	803	(404)	(267)
Total estimated amortizations	$ 1,814	$ 803	$ 85	$ (122)
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.20-4.30%	4.90-5.20%	4.20%	4.85%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	8.00%	8.00%	8.00%	8.00%
Health care trend rate (current year)	N/A	N/A	7.00%	7.00%
Health care trend rate (2019 forward)	N/A	N/A	5.00%	5.00%

N/A – not applicable

A one percentage point change in the assumed health care cost trend rate would have the following effects:

	1% Increase	1% Decrease
	(In Thousands)	
Aggregate service and interest cost components	$ 54	$ (43)
Accumulated post-retirement benefit obligation	$ 864	$ (708)

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Year	Pension Benefits	Other Post-Retirement Benefits
	(In Thousands)	
2016	$ 8,732	$ 1,778
2017	$ 8,921	$ 1,729
2018	$ 9,240	$ 1,658
2019	$ 9,480	$ 1,605
2020	$ 9,767	$ 1,535
2021-2024	$ 52,612	$ 7,433

Defined Contribution Retirement Plans/401(k)

SCG employees are eligible to participate in the UIL Holdings' Employee Stock Ownership Plan. Employees may defer a portion of the compensation and invest in various investment alternatives. Matching contributions are made in the form of cash which is subsequently invested according to the specific provisions of the plan. The matching expense for 2015 and 2014 was $0.7 million and $0.6 million, respectively.

(G) RELATED PARTY TRANSACTIONS

Inter-company Transactions

SCG receives various administrative and management services from and enters into certain inter-company transactions with UIL Holdings and its subsidiaries. For the year ended December 31, 2015, SCG recorded inter-company expenses of $15.3 million. Costs of the services that are allocated amongst SCG and other of UIL Holdings' regulated subsidiaries are settled periodically by way of inter-company billings and wire transfers. At December 31, 2015 and 2014, the Consolidated Balance Sheet reflects inter-company receivables, included in accounts receivable of $1.6 million and $2.7 million, respectively, and inter-company payables, included in accounts payable of $7.3 million and $6.7 million, respectively.

Dividends/Capital Contributions

For the years ended December 31, 2015 and December 31, 2014, SCG accrued dividends to UIL Holdings of $26 million and $11.2 million respectively.

(H) COMMITMENTS AND CONTINGENCIES

In the ordinary course of business, SCG is involved in various proceedings, including legal, tax, regulatory and environmental matters, which require management's assessment to determine the probability of whether a loss will occur and, if probable, an estimate of probable loss. When assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated, SCG accrues a reserve and discloses the reserve and related matter. SCG discloses material matters when losses are probable but for which an estimate cannot be reasonably estimated or when losses are not probable but are reasonably possible. Subsequent analysis is performed on a periodic basis to assess the impact of any changes in events or circumstances and any resulting need to adjust existing reserves or record additional reserves. However, given the inherent unpredictability of these legal and regulatory proceedings, SCG cannot assure you that it's assessment of such proceedings will reflect the ultimate outcome, and an adverse outcome in certain matters could have a material adverse effect on its results of operations or cash flows.

Environmental Matters

In complying with existing environmental statutes and regulations and further developments in areas of environmental concern, including legislation and studies in the fields of water quality, hazardous waste handling and disposal, toxic substances, climate change and electric and magnetic fields, we may incur substantial capital expenditures for equipment modifications and additions, monitoring equipment and recording devices, as well as additional operating expenses. The total amount of these expenditures is not now determinable. Significant environmental issues known to SCG at this time are described below.

Site Decontamination, Demolition and Remediation Costs

SCG owns or has previously owned properties where Manufactured Gas Plants (MGPs) had historically operated. MGP operations have led to contamination of soil and groundwater with petroleum hydrocarbons, benzene and metals, among other things, at these properties, the regulation and cleanup of which is regulated by the federal Resource Conservation and Recovery Act as well as other federal and state statutes and regulations. SCG has or had an ownership interest in one or more such properties contaminated as a result of MGP-related activities. Under the existing regulations, the cleanup of such sites requires state and at times, federal, regulators' involvement and approval before cleanup can commence. In certain cases, such contamination has been evaluated, characterized and remediated. In other cases, the sites have been evaluated and characterized, but not yet remediated. Finally, at some of these sites, the scope of the contamination has not yet been fully characterized; no liability was recorded in respect of these sites as of December 31, 2015 and no amount of loss, if any, can be reasonably estimated at this time. In the past, SCG has received approval for the recovery of MGP-related remediation expenses from customers through rates and will seek recovery in rates for ongoing MGP-related remediation expenses for all of their MGP sites.

SCG owns properties on Housatonic Avenue in Bridgeport, and on Chapel Street in New Haven, which are former MGP sites. Costs associated with the remediation of the sites could be significant and will be subject to a review by PURA as to whether these costs are recoverable in rates. As of December 31, 2015, UIL Holdings reserved $49 million related to the property located in New Haven which was offset by a regulatory asset. Additionally, as of December 31, 2015, UIL Holdings has determined that remediation of the properties in Bridgeport is not probable and therefore not reserved.

(I) FAIR VALUE MEASUREMENTS

As required by ASC 820, financial assets and liabilities are classified in their entirety, based on the lowest level of input that is significant to the fair value measurement. SCG's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables set forth the fair value SCG's financial assets and liabilities, other than pension benefits and OPEB, as of December 31, 2015 and December 31, 2014.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(In Thousands)		
December 31, 2015				
Assets:				
Noncurrent investments	$ 9,644	$ -	$ -	$ 9,644
Liabilities:				
Long-term debt	-	262,042	-	262,042
Net fair value assets/(liabilities), December 31, 2015	$ 9,644	$ (262,042)	$ -	$ (252,398)
December 31, 2014				
Assets:				
Noncurrent investments	$ 10,832	$ -	$ -	$ 10,832
Liabilities:				
Long-term debt	-	273,675	-	273,675
Net fair value assets/(liabilities), December 31, 2014	$ 10,832	$ (273,675)	$ -	$ (262,843)

The following tables set forth the fair values of SCG's pension and OPEB assets as of December 31, 2015 and 2014.

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2015		(In Thousands)		
Pension assets				
Mutual funds	$ -	$ 118,773	$ -	$ 118,773
Hedge funds	-	-	-	-
	-	118,773	-	118,773
OPEB assets				
Mutual funds	5,778	-	-	5,778
Fair value of plan assets, December 31, 2015	$ 5,778	$ 118,773	$ -	$ 124,551
December 31, 2014				
Pension assets				
Mutual funds	$ -	$ 118,340	$ -	$ 118,340
Hedge funds	-	-	6,030	6,030
	-	118,340	6,030	124,370
OPEB assets				
Mutual funds	6,167	-	-	6,167
Fair value of plan assets, December 31, 2014	$ 6,167	$ 118,340	$ 6,030	$ 130,537

The determination of fair values of the Level 2 co-mingled mutual funds were based on the Net Asset Value (NAV) provided by the managers of the underlying fund investments and the unrealized gains and losses. The NAV provided by the managers typically reflect the fair value of each underlying fund investment. Changes in the fair value of pension benefits and OPEB are accounted for in accordance with ASC 715 Compensation – Retirement Benefits as discussed in Note (F) "Pension and Other Benefits".

The following tables set forth a reconciliation of changes in the fair value of the assets above that are classified as Level 3 in the fair value hierarchy for the twelve month periods ended December 31, 2015 and 2014.

	Year Ended December 31, 2015
	(In Thousands)
Pension assets-Level 3, December 31, 2014	$ 6,030
Unrealized/Realized gains and (losses), net	-
Settlements	(6,030)
Pension assets-Level 3, December 31, 2015	$ -

	Year Ended December 31, 2014
	(In Thousands)
Pension assets-Level 3, December 31, 2013	$ 6,050
Unrealized/Realized gains and (losses), net	(20)
Purchases	-
Pension assets-Level 3, December 31, 2014	$ 6,030

Central Maine Power Company and Subsidiaries

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

Central Maine Power Company
and Subsidiaries

Index

Page(s)

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

EY
Building a better working world

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

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

Report of Independent Auditors

To the Shareholders and Board of Directors
Central Maine Power Company

We have audited the accompanying consolidated financial statements of Central Maine Power Company and subsidiaries, which comprise the consolidated balance sheets as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for the years then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

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

Building a better
working world

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

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

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Central Maine Power Company and subsidiaries at December 31, 2015 and 2014, and the consolidated results of their operations and their cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

Ernst + Young LLP

April 19, 2016

Central Maine Power Company and Subsidiaries
Consolidated Statements of Income

Year Ended December 31, (Thousands)	2015	2014
Operating Revenues		
Sales and services	**$819,716**	$737,339
Operating Expenses		
Electricity purchased	**57,165**	61,921
Operations and maintenance	**377,423**	318,762
Depreciation and amortization	**98,654**	80,220
Other taxes	**47,482**	34,967
Total Operating Expenses	**580,724**	495,870
Operating Income	**238,992**	241,469
Other (Income)	**(7,629)**	(3,560)
Other Deductions	**391**	959
Interest Charges, Net	**54,751**	52,328
Income Before Income Tax	**191,479**	191,742
Income Tax Expense	**77,038**	79,634
Net Income	**114,441**	112,108
Less: Net Income Attributable to Other Noncontrolling Interest	**353**	483
Net Income Attributable to CMP	**114,088**	111,625
Preferred Stock Dividends	**34**	34
Net Income Available for CMP Common Stock	**$114,054**	$111,591

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Comprehensive Income

Year ended December 31, (Thousands)	2015	2014
Net Income	**$ 114,441**	$112,108
Other Comprehensive Income (Loss), Net of Tax		
Amortization of pension cost for nonqualified plans	**163**	(233)
Unrealized (loss) gain on derivatives qualified as hedges:		
Unrealized (loss) during period on derivatives qualified as hedges	**(562)**	(682)
Reclassification adjustment for loss included in net income	**623**	197
Reclassification adjustment for loss on settled cash flow treasury hedges	**1,315**	1,315
Net unrealized gain on derivatives qualified as hedges	**1,376**	830
Other Comprehensive Income, Net of Tax	**1,539**	597
Comprehensive Income	**115,980**	112,705
Less:		
Comprehensive Income Attributable to Other Noncontrolling Interests	**353**	483
Comprehensive Income Attributable to CMP	**$115,627**	$112,222

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

Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets

December 31,	**2015**	**2014**
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	**$5,360**	$5,023
Accounts receivable and unbilled revenues, net	**149,281**	149,967
Accounts receivable from affiliates	**1,762**	942
Notes receivable from affiliates	**23,437**	690
Materials and supplies	**15,828**	27,476
Prepayments and other current assets	**121,095**	66,277
Regulatory assets	**22,032**	27,470
Total Current Assets	**338,795**	277,845
Utility Plant, at Original Cost	**3,675,772**	3,189,010
Less accumulated depreciation	**826,309**	738,470
Net Utility Plant in Service	**2,849,463**	2,450,540
Construction work in progress	**152,707**	394,546
Total Utility Plant	**3,002,170**	2,845,086
Other Property and Investments	**1,506**	8,275
Regulatory and Other Assets		
Regulatory assets	**521,482**	552,972
Goodwill	**324,938**	324,938
Other	**5,304**	14,617
Total Regulatory and Other Assets	**851,724**	892,527
Total Assets	**$4,194,195**	$4,023,733

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

Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets

December 31, (Thousands)	2015	2014
Liabilities		
Current Liabilities		
Current portion of long-term debt	**$41,312**	$2,031
Notes payable to affiliates	**-**	118,192
Accounts payable and accrued liabilities	**123,070**	114,674
Accounts payable to affiliates	**32,893**	11,237
Interest accrued	**18,671**	16,303
Taxes accrued	**7,454**	1,069
Other current liabilities	**59,781**	89,874
Regulatory liabilities	**44,799**	79,054
Total Current Liabilities	**327,980**	432,434
Regulatory and Other Liabilities		
Regulatory liabilities	**100,228**	103,182
Deferred income taxes regulatory	**165,119**	163,857
Other Non-current liabilities		
Deferred income taxes	**626,868**	565,590
Pension and other postretirement benefits	**226,560**	244,326
Other	**54,678**	48,457
Total Regulatory and Other Liabilities	**1,173,453**	1,125,412
Long-term debt	**1,043,512**	934,747
Total Liabilities	**2,544,945**	2,492,593
Commitments and Contingencies		
Preferred Stock		
Preferred stock	**571**	571
CMP Common Stock Equity		
Common stock ($5 par value, 80,000 shares authorized and 31,211 shares outstanding at December 31, 2015 and 2014)	**156,057**	156,057
Capital in excess of par value	**713,893**	713,893
Retained earnings	**777,406**	663,352
Accumulated other comprehensive (loss)	**(8,514)**	(10,053)
Total CMP Common Stock Equity	**1,638,842**	1,523,249
Other Noncontrolling Interest	**9,837**	7,320
Total Equity	**1,648,679**	1,530,569
Total Liabilities and Equity	**$ 4,194,195**	$4,023,733

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Cash Flows

Year Ended December 31,	2015	2014
(Thousands)		
Cash Flow from Operating Activities		
Net income	**$114,441**	$112,108
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**98,654**	80,220
Amortization of regulatory and other assets and liabilities	**(14,835)**	(12,954)
Carrying cost of regulatory assets and liabilities	**1,195**	7,483
Deferred income taxes and investment tax credits, net	**70,198**	73,056
Pension expense	**26,274**	13,145
Changes in current operating assets and liabilities		
Accounts receivable and unbilled revenues, net	**(134)**	(487)
Materials and supplies	**11,648**	(10,325)
Accounts payable and accrued liabilities	**30,052**	20,143
Other current liabilities	**(52,276)**	(25,335)
Changes in other assets		
Changes in regulatory assets and liabilities	**19,775**	53,435
Other assets	**(50,201)**	(19,918)
Net Cash Provided by Operating Activities	**254,791**	290,571
Cash Flow from Investing Activities		
Utility plant additions,	**(280,224)**	(415,404)
Contribution in aid of construction	**16,565**	11,687
Grants received from governmental entities	**-**	1,660
(Issuance of) proceeds from notes receivable with affiliates	**(22,747)**	15,060
Changes in other investments	**166**	(38)
Net Cash (Used in) Investing Activities	**(286,240)**	(387,035)
Cash Flow from Financing Activities		
Costs associated with borrowings	**-**	(120)
Repayment of debts and capital leases	**(2,152)**	(24,018)
Long-term note issuance	**150,000**	-
(Repayments of) proceeds from notes payable with affiliates	**(118,192)**	118,192
Dividends paid on preferred stock	**(34)**	(34)
Capital contribution from noncontrolling interests	**2,164**	4,291
Net Cash Provided by Financing Activities	**31,786**	98,311
Net Increase in Cash and Cash Equivalents	**337**	1,847
Cash and Cash Equivalents, Beginning of Year	**5,023**	3,176
Cash and Cash Equivalents, End of Year	**$5,360**	$5,023

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

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

(Thousands, except per share amounts)	CMP Stockholder Shares	Common Stock Outstanding $5 Par Value Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stock Equity	Other Noncon-trolling Interest	Total
Balance, January 1, 2014	31,211	$156,057	$713,893	$551,761	$(10,650)	$1,411,061	$3,028	$1,414,089
Net income				111,625		111,625	483	112,108
Other comprehensive income, net of tax					597	597		597
Comprehensive income								112,705
Capital contribution from noncontrolling interests							3,809	3,809
Dividends paid, preferred stock				(34)		(34)		(34)
Balance, December 31, 2014	31,211	156,057	713,893	663,352	(10,053)	1,523,249	7,320	1,530,569
Net income				**114,088**		**114,088**	**353**	**114,441**
Other comprehensive income, net of tax					**1,539**	**1,539**		**1,539**
Comprehensive income								**115,980**
Capital contribution from noncontrolling interests							**2,164**	**2,164**
Dividends paid, preferred stock				**(34)**		**(34)**		**(34)**
Balance, December 31, 2015	**31,211**	**$156,057**	**$713,893**	**$777,406**	**$(8,514)**	**$1,638,842**	**$9,837**	**$1,648,679**

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

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Background: Central Maine Power Company and subsidiaries (CMP, the company, we, our, us) conduct regulated electricity transmission and distribution operations in Maine serving approximately 615,000 customers in a service territory of approximately 11,000 square miles with a population of approximately one million people. The service territory is located in the southern and central areas of Maine and contains most of Maine's industrial and commercial centers, including the city of Portland and the Lewiston-Auburn, Augusta-Waterville, Saco-Biddeford and Bath-Brunswick areas.

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

Networks was formed on November 20, 2013, when AGR was reorganized to become the parent company of Networks. Networks' wholly-owned subsidiaries, and their principal operating companies, include: CMP Group, Inc. - Central Maine Power Company (CMP), and RGS Energy Group, Inc. - New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RGE). We operate under the authority of the Maine Public Utility Commission (MPUC) in Maine and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

Accounts receivable**:** Accounts receivable at December 31 include unbilled revenues of $23 million for 2015 and $21 million for 2014, and are shown net of an allowance for doubtful accounts at December 31 of $3 million for 2015 and $4 million for 2014. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $3 million in 2015 and $4 million in 2014.

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

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

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

$2 million for 2015 and 2014. DPA receivable balances at December 31 were $10 million for 2015 and $12 million for 2014.

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

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

Our ARO at December 31, including our conditional ARO, was less than $1 million for 2015 and 2014. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of asbestos and PCB-contaminated equipment.

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

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

Consolidated statements of cash flows: We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and those investments are included in cash and cash equivalents.

Supplemental Disclosure of Cash Flows Information	**2015**	**2014**
(Thousands)		
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	**$48,889**	$46,729
Income taxes paid, net	**$46,696**	$10,341

Interest capitalized was $2.1 million 2015 and $0.6 million in 2014.

Depreciation and amortization: We determine depreciation expense using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Our depreciation accruals were equivalent to 2.5% of average depreciable property for 2015 and 2.7% in 2014. We amortize our capitalized software cost which is included in other plant, using the straight line method, based on useful lives of 5 to 10 years. Capitalized software costs of approximately $87 million as of December 31, 2015 and $61 million as of December 31, 2014. Depreciation expense was $91 million in 2015 and $76 million in 2014. Amortization of capitalized software was $8 million in 2015 and $4 million in 2014.

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

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

Plant	Estimated useful life (years)	2015	2014
(thousands)			
Electric			
Transmission	47.2	**$2,136,532**	$1,696,193
Distribution	47.0	**1,316,746**	1,213,264
Vehicles	7	**52,168**	48,599
Other	34.8	**170,326**	230,954
Total Electric Plant		**$3,675,772**	$3,189,010

Electric plant includes capital leases of $40 million for 2015 and 2014. Accumulated depreciation related to these leases was $37 million for 2015 and 2014.

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

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

Goodwill is not amortized, but is subject to an assessment for impairment at least annually or more frequently if events occur or circumstances change that will more likely than not reduce the fair value of the reporting unit to which goodwill is assigned below its carrying amount. A reporting unit is an operating segment or one level below an operating segment and is the level at which goodwill is tested for impairment. In assessing goodwill for impairment we have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary (step zero). If it is determined, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If we bypass step zero or perform the qualitative assessment, but determine that it is more likely than not that its fair value is less than its carrying amount, a quantitative two step fair value based test is performed. Step one compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, step two is performed. Step two requires an allocation of fair value to the individual assets and liabilities using business combination accounting guidance to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than its carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

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

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

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

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

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

Simplifying the Presentation of Debt Issuance Costs: The FASB issued an amendment in April 2015 that is intended to simplify the presentation of debt issuance costs. Instead of presenting debt issuance costs as a deferred charge (that is, as an asset), the amendments require debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with the presentation for debt discounts. The amendment is effective for public entities for financial statements issued for fiscal years beginning after December 15, 2015, and for interim periods within those fiscal years. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. Accordingly, we reclassified the debt issuance costs from other noncurrent assets to noncurrent debt on our December 31, 2014 consolidated balance sheet, which decreased total assets, noncurrent debt and total liabilities by $5 million.

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

Balance Sheet Classification of Deferred Taxes: The FASB issued an amendment in November 2015 that is intended to simplify the presentation of deferred income taxes by requiring entities that present a classified statement of financial position to classify deferred tax liabilities and assets as noncurrent in their balance sheet. This aligns the presentation of deferred income tax liabilities and assets with International Financial Reporting Standards. The amendments do not affect the current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount. The amendments are effective for public entities for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. As permitted, we have early adopted the amendments as of the beginning of the fourth quarter of 2015, and have elected retrospective application to all periods presented in order to simplify the presentation in our balance sheet. Accordingly, we reclassified the current deferred taxes to noncurrent on our December 31, 2014 consolidated balance sheet, which decreased noncurrent deferred taxes by $21 million due to right of offset.

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

Revenue from Contracts with Customers: In May 2014 the FASB issued an amendment related to the recognition of revenue from contracts with customers and required disclosures. The core principle is for an entity to recognize revenue to represent the transfer of goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. The standard is effective for public entities for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. In August 2015 the FASB issued an accounting standards update that defers by one year the effective date of the standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption as of the original effective date permitted. In March 2016 the FASB issued an accounting standards update that amends and clarifies the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, with the same deferred effective date. We are currently evaluating how our adoption of the amendment will affect our results of operation, financial position, and cash flows.

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

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

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

Leases: In February 2016 the FASB issued new guidance that affects all companies and organizations that lease assets, and requires them to record on their balance sheet assets and liabilities for the rights and obligations created by those leases. A lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Concerning lease expense recognition, after extensive consultation, the FASB has ultimately concluded that the economics of leases can vary for a lessee, and those economics should be reflected in the financial statements. As a result, the amendments retain a distinction between finance leases and operating leases, while requiring both types of leases to be recognized on the balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in current GAAP. By retaining a distinction between finance leases and operating leases, the effect of leases on the statement of comprehensive income and the statement of cash flows is largely unchanged from current GAAP. Lessor accounting will remain substantially the same as current GAAP, but with some targeted improvements intended to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance issued in 2014. The updated guidance is effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early application is permitted. We expect our adoption of the new guidance will materially affect our results of operation and financial position.

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

Other (Income) and Other Deductions:

Year Ended December 31,	**2015**	**2014**
(Thousands)		
Gain on Sale of Property	**$(160)**	-
Interest and dividend income	**(953)**	$(906)
Allowance for funds used during construction	**(5,763)**	(1,467)
Earnings from equity investments	**-**	(45)
Carrying costs on regulatory assets	**(581)**	(1,044)
Miscellaneous	**(172)**	(98)
Total other (income)	**$(7,629)**	$(3,560)
Miscellaneous	**$391**	$959
Total other deductions	**$391**	$959

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

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

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

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

Avangrid Service Company provides administrative and management services to Networks operating utilities, including CMP, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for services provided to CMP by Avangrid Service Company was $32 million for 2015 and $42 million for 2014 and charge for services provided by

CMP to AGR and its subsidiaries were approximately $4 million for 2015 and $3 million for 2014. All charges for services are at cost. Balance in accounts payable to affiliates of $32 million at December 31, 2015 and $11 million at December 31, 2014 is associated to Avangrid Service Company.

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

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

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

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

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

The aggregate amount of the intercompany income tax receivable balance due from AGR is $92.5 million and $53.4 million at December 31, 2015 and December 31, 2014, respectively.

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

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

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

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

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

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

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

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

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

- Maintenance and Other operating expenses have been combined into Operations and maintenance in the consolidated statement of income for the year ended December 31, 2014.
- Non-current regulatory assets and liabilities items have been combined into Regulatory assets and Regulatory liabilities, respectively, in the consolidated balance sheet as of December 31, 2014.

- Accounts payable for electricity purchased have been combined into Accounts payable and accrued liabilities in the consolidated balance sheet as of December 31, 2014.
- Current and non-current liabilities pertaining to the Rate refund – FERC ROE proceeding of $12 million and $23 million, respectively, have been reclassified to current and non-current Regulatory liabilities in the consolidated balance sheet as of December 31, 2014.
- Accounts payable for construction purchases have been moved to Other current liabilities in the consolidated balance sheet as of December 31, 2014.

Note 2. Industry Regulation

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

CMP Distribution Rate Stipulation and New Renewable Source Generation

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

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

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

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

Under Maine law 35-A M.R.S.A §§ 3210-C, 3210-D, the MPUC is authorized to conduct periodic requests for proposals seeking long-term supplies of energy, capacity or Renewable Energy Certificates, or RECs, from qualifying resources. The MPUC is further authorized to order Maine Transmission and Distribution Utilities to enter into contracts with sellers selected from the MPUC’s competitive solicitation process. Pursuant to a MPUC Order dated October 8, 2009, CMP entered into a 20-year agreement with Evergreen Wind Power III, LLC, on March 31, 2010, to purchase capacity and energy from Evergreen’s 60 MW Rollins wind farm in Penobscot County, Maine. CMP’s purchase obligations under the Rollins contract are approximately $7 million per year. In accordance with subsequent MPUC orders, CMP periodically auctions the purchased Rollins energy to wholesale buyers in the New England regional market. Under applicable law, CMP is assured recovery of any differences between power purchase costs and achieved market revenues through a reconcilable component of its retail distribution rates. Although the MPUC has conducted multiple requests for proposals under M.R.S.A §3210-C and has tentatively accepted long-term proposals from other sellers, these selections have not yet resulted in additional currently effective contracts with CMP.

Transmission - FERC ROE Proceeding

CMP's transmission rates are determined by a tariff regulated by the FERC and administered by ISO New England, Inc. (ISO-NE). Transmission rates are set annually pursuant to a FERC authorized formula that allows for recovery of direct and allocated transmission operating and maintenance expenses, and for a return of and on investment in assets. The FERC currently provides a base ROE of 10.57% and additional ROE incentive adders applicable to assets based upon vintage, voltage and other factors.

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

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

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $488 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

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

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

December 31,	2015	2014
(Thousands)		
Current		
Storm costs	**$7,544**	$14,198
Transmission revenue reconciliation mechanism	**4,136**	2,854
Deferred meter replacement costs	**2,216**	2,216
Legacy meter retirement deferral	**-**	2,861
Merger related	**1,666**	1,666
Stranded costs	**2,808**	466
Environmental remediation costs	**2,616**	1,606
Other	**1,046**	1,603
Total current regulatory assets	**$22,032**	$27,470
Long-term		
Federal tax depreciation normalization adjustment	**$10,349**	$10,279
Merger related	**1,000**	2,716
Storm costs	**4,393**	18,008
Unamortized losses on reacquired debt	**1,021**	1,333
Pension and other postretirement benefits	**243,458**	263,587
Unfunded future income taxes	**225,166**	218,944
Deferred meter replacement costs	**34,077**	35,960
Other	**2,018**	2,145
Total long-term regulatory assets	**$521,482**	$552,972

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

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

Storm costs are allowed in rates based on an estimate of the routine costs of service restoration. CMP is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration. CMP's deferred service restoration costs, primarily as a result of an ice storm in late December 2014, reflecting over (under) spending of actual costs compared with amounts allowed in rates, was $(6) million and $15 million for the years ended December 31, 2015 and 2014, respectively. CMP's total deferral, including carrying costs was $12 million at December 31, 2015 and $32 million at December 31, 2014.

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

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

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

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

December 31,	**2015**	**2014**
(Thousands)		
Current		
Accrued removal obligations	**$2,251**	$2,251
Transmission revenue reconciliation mechanism	**5,490**	6,795
Yankee DOE refund	**5,234**	23,475
Stranded cost	**7,004**	16,110
Unfunded future income taxes	**10,104**	16,423
Rate refund-FERC ROE proceeding	**3,092**	12,322
Revenue decoupling mechanism	**10,143**	-
Other	**1,481**	1,678
Total current regulatory liabilities	**$44,799**	$79,054
Other long-term		
Environmental remediation costs	**$4,934**	$5,895
Rate refund-FERC ROE proceeding	**21,039**	23,259
Accrued removal obligations	**71,188**	74,028
Other	**3,067**	-
Total non-current regulatory liabilities	**100,228**	103,182
Deferred income taxes regulatory	**165,119**	163,857
Total long-term regulatory liabilities	**$265,347**	$267,039

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

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

Note 4. Goodwill

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

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

The carrying amount of goodwill was $325 million at December 31, 2015 and 2014 with no accumulated impairment losses and no changes during 2015 and 2014.

Notes to Consolidated Financial Statements

Note 5. Income Taxes

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

Years Ended December 31,	2015	2014
(Thousands)		
Current		
Federal	**$(15,058)**	$(14,371)
State	**21,898**	6,700
Current taxes charged to expense (benefit)	**6,840**	(7,671)
Deferred		
Federal	**75,273**	86,167
State	**(5,075)**	1,637
Deferred taxes charged to expense	**70,198**	87,804
Investment tax credit adjustments	**-**	(499)
Total Income Tax Expense	**$77,038**	$79,634

The differences between tax expense per the statements of income and tax expense at the 35% statutory federal tax rate for the years ended December 31, 2015 and 2014 consisted of:

Years Ended December 31,	2015	2014
(Thousands)		
Tax expense at federal statutory rate	**$67,018**	$67,110
Depreciation and amortization not normalized	**(178)**	7,863
Investment tax credit amortization	**-**	(499)
Tax return and audit adjustments	**(34)**	(681)
State taxes, net of federal benefit	**10,935**	5,419
Other, net	**(703)**	422
Total Income Tax Expense	**$77,038**	$79,634

Income tax expense for the year ended December 31, 2015 was $10 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, (net of federal benefit). This resulted in an effective tax rate of 40.2%. Income tax expense for the year ended December 31, 2014 was $12.5 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, (net of federal benefit), and depreciation and amortization not normalized. This resulted in an effective tax rate of 41.5%.

Notes to Consolidated Financial Statements

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

December 31,	2015	2014
(Thousands)		
Noncurrent Deferred Income Tax Liabilities (Assets)		
Property related	**$685,724**	$662,736
Unfunded future income taxes	**91,541**	89,339
Employee benefits	**14,957**	9,648
Derivative assets	**(4,567)**	(5,044)
Other	**(4,656)**	(36,531)
Noncurrent Deferred Income Tax Liabilities	**782,999**	720,148
Add: Valuation allowance	**8,988**	9,299
Total Noncurrent Deferred Income Tax Liabilities	**791,987**	729,447
Less amounts classified as regulatory liabilities		
Noncurrent deferred income taxes	**165,119**	163,857
Noncurrent Deferred Income Tax Liabilities	**$626,868**	$565,590
Deferred tax assets	**$9,224**	$41,575
Deferred tax liabilities	**801,211**	771,022
Net Accumulated Deferred Income Tax Liabilities	**$791,987**	$729,447

CMP has $11.7 million of federal and state research and development credits offset by $8.9 million of valuation allowance.

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

Years Ended December 31,	2015	2014
(Thousands)		
Balance as of January 1	**$20,760**	$16,148
Increases for tax positions related to prior years	**-**	10,422
Reduction for tax positions related to settlements with taxing authorities	**(683)**	(5,810)
Balance as of December 31	**$20,077**	$20,760

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

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2015 and there was an accrual of less than $0.1 million as of December 31, 2014. If recognized, $3 million of the total gross unrecognized tax benefits would affect the effective tax rate. Gross unrecognized tax benefits decreased $0.7 million in 2015 due to settlements with taxing authorities.

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

Note 6. Long-term Debt

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

As of December 31,	2015			2014	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds[1]	2019-2045	$900,000	3.07%-5.70%	$750,000	3.07%-5.70%
Senior unsecured debt	2016-2037	180,000	5.27-6.40%	180,000	5.27%-6.40%
Chester: Promissory and Senior Notes[2]	2020	5,725	7.05%-10.48%	6,908	7.05%-10.48%
Total Debt		**$1,085,725**		**$ 936,908**	
Obligations under capital leases	2016-2020	4,187		5,033	
Unamortized debt (costs) premium, net		(5,088)		(5,163)	
Less: debt due within one year, included in current liabilities		41,312		2,031	
Total Non-Current Debt		**$1,043,512**		**$ 934,747**	

[1]The first mortgage bonds are secured by a first mortgage lien on substantially all of our net utility plant in service.
[2]Chester SVC Partnership notes are secured by the assets of this partnership.

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

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

2016	2017	2018	2019	2020
$41,312	$2,069	$2,069	$152,069	$1,878

We have no debt covenant requirements related to the maintenance of financial ratios in our long term debt agreements at December 31, 2015 and 2014.

Note 7. Bank Loans and Other Borrowings

CMP relies on bank provided revolving credit facilities and on inter-company revolving credit facilities with AGR, the parent of Networks, to fund short-term liquidity needs. We had no short-term debt outstanding at December 31, 2015 and $118 million outstanding at December 31, 2014.

In July 2011, CMP jointly entered into a bank provided revolving credit facility (the “Joint Facility”) with NYSEG and RGE that allows maximum borrowings of up to $600 million in aggregate and expires in 2018. We currently have a $200 million sublimit under the agreement and pay a facility fee of 15 basis points annually. CMP has a commercial paper program backstopped by the Joint Facility.

We also have an intercompany credit facility under a demand note agreement with AGR that provides financing of up to $250 million. Under the terms of that agreement, which expires in 2019, we borrow at the market A2/P2 commercial paper rate. Under this agreement, we had no Notes payable to affiliates outstanding at December 31, 2015 and $118 million at December 31, 2014.

In April 2013 CMP entered into an agreement with NYSEG and RGE under which each company may lend to the other, under certain circumstances, excess cash on hand. At December 31, 2015, we had a note receivable from RGE of $23 million which has been subsequently received.

In our Joint Facility we covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. For purposes of calculating the maximum ratio of consolidated indebtedness to total capitalization, the facility excludes from consolidated net worth the balance of Accumulated other comprehensive (loss) as it appears on the consolidated balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied 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. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.40 to 1.00 at December 31, 2015. We are not in default as of December 31, 2015.

Note 8. Redeemable Preferred Stock

We have redeemable preferred stock that contains a feature allowing the holders to elect a majority of the CMP's Board of Directors if preferred stock dividends are in default in an amount equivalent to four full quarterly dividends. Such a potential redemption-triggering event is not solely within our control.

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

Series	Par Value per Share	Redemption Price per Share	Shares Authorized and Outstanding[1]	Amount (Thousands) 2015	2014
CMP, 6% Noncallable	$100	-	5,713	**$571**	$571
Total				**$571**	$571

[1] At December 31, 2015 CMP had 2,300,000 shares of $100 par value preferred stock authorized but unissued.

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

Note 9. Commitments and Contingencies

CMP Transmission - ROE Complaint

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

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

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

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

On July 31, 2014, the Complainants filed a third, related, complaint (Complaint III) for a subsequent rate period requesting the ROE be reduced to 8.84%. On November 24, 2014, FERC accepted the third complaint, established a refund effective date of July 31, 2014, and set for consolidated hearing with Complaint II in June 2015. Hearings were held in June 2015 on the Complaints II and III before a FERC Administrative Law Judge, relating to the refund periods and going forward. On July 29, 2015, post-hearing briefs were filed by parties and on August 26, 2015 reply briefs were filed by parties. On July 13, 2015, the New England transmission owners filed a petition for review of FERC's orders establishing hearing and consolidation procedures for the Complaints II and III with the U.S. Court of Appeals. The Administrative Law Judge issued an Initial Decision on March 22, 2016. The Initial Decision determined that, 1) for the 15 month refund period in Complaint II, the base ROE should be 9.59% and that the ROE Cap (base ROE plus incentive ROEs) should be 10.42% and 2) for the 15 month refund period in Complaint III and prospectively, the base ROE should be 10.90% and that the ROE Cap should be 12.19%. The Initial Decision is the Administrative Law Judge's recommendation to the FERC Commissioners. The FERC is expected to make its final decision in late 2016 or early 2017.

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

Yankee Nuclear Spent Fuel Disposal Claim

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

In 2012, the U.S. Court of Appeals issued a favorable decision in the Yankee Companies' claim for the first six year period (Phase I). Total damages awarded to the Yankee companies were nearly $160 million. The Yankee Companies won on all appellate points in the U.S. Court of Appeals for the Federal Circuit's unanimous decision. The Federal Appeals Court affirmed the September 2010 U.S. Court of Federal Claims award of $40.3 million to Connecticut Yankee Atomic Power Company; affirmed the Court of Federal Claims award of $65 million to Maine Yankee Atomic Power Company; and increased Yankee Atomic Electric Company's damages award from $21.4 million to $37.8 million. The Phase I damage award became final on December 4, 2012. The Yankee Companies received payment from DOE in January 2013. CMP's share of the award was approximately $36.5 million which was credited back to customers.

In November 2013 the U.S. Court of Claims issued its decision in the Phase II case (the second 6 year period). The Trial Court decision awards the Yankee companies a combined $235.4 million

(Connecticut Yankee $126.3 million, Maine Yankee $37.7 million, and Yankee Atomic $73.3 million). The Phase II period covers January 1, 2002 through December 31, 2008 for Connecticut Yankee and Yankee Atomic, and January 1, 2003 through December 31, 2008 for Maine Yankee. Maine Yankee's damage award was lower because it recovered a larger amount in the Phase I case ($82 million) and its decommissioning was both less expensive and completed sooner than the other Yankee companies. The damage awards flow through the Yankees to shareholders to reduce retail customer charges. In January 2014 the government informed the Yankee Companies it would not appeal the Trial Court decision, as a result the Yankee Companies received full payment in April 2014. CMP's share of the award was approximately $28.2 million which was credited back to customers.

In August 2013, the Yankees filed a third round of claims against the government seeking damages for the years 2009-2014 (Phase III). The Phase III trial was completed in July 2015 and the Court issued its decision on March 25, 2016 awarding the Yankee companies a combined $76.8 million (Connecticut Yankee $32.6 million, Maine Yankee $24.6 million and Yankee Atomic $19.6 million). CMP will receive its proportionate share of the awards based on percentage ownership. The damage awards will potentially flow through the Yankee Companies to shareholders, including CMP upon FERC approval, and will reduce retail customer charges or otherwise as specified by law. CMP will receive its proportionate share of the awards based on percentage ownership. We cannot predict the timing or amount of damage awards that may ultimately flow through to shareholders.

Power purchase contracts including nonutility generator

We recognized expense of approximately $57 million for NUG power in 2015 and $55 million in 2014. We estimate that our power purchases will total $63 million in 2016 and $11 million in 2017 and 2018, 12 million 2019, $12 million in 2020 and $154 million thereafter.

Note 10. Environmental Liability

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

The United States Environmental Protection Agency 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 seven waste sites. The seven sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the seven sites, five sites are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and two sites are also included on the National Priorities list. Any liability may be joint and several for certain of those sites. We have recorded an estimated liability of $1.5 million related to the seven sites at December 31, 2015.

We have recorded an estimated liability of $2.2 million at December 31, 2015, related to three additional sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties or are regulated under State Resource Conservation and Recovery Act (RCRA) program. It is reasonably possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. 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 three sites where gas was manufactured in the past. All three sites are part of Maine's Voluntary Response Action Program and two are on the Maine's Uncontrolled Sites Program.

Our estimate for all costs related to investigation and remediation of the three sites range from $2.1 million to $2.3 million at December 31, 2015. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $2.1 million at December 31, 2015, and $1.2, million at December 31, 2014. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

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

Note 11. Accounting for Derivative Instruments and Hedging Activities

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

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

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

Our derivatives designated as hedging instruments, which are other commodity contracts (fleet fuel), had a fair value of $(0.9) million as of December 31, 2015, and $(1.0) million as of December 31, 2014, and are included in current liabilities.

The effect of hedging instruments on OCI and income was:

Year Ended December 31,	Gain (Loss) Recognized in OCI on Derivatives	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Gain(Loss) Reclassified from Accumulated OCI into Income
Derivatives in Cash Flow Hedging Relationships	**Effective Portion**	**Effective Portion**	
(Thousands)			
2015			
Interest rate contracts	**-**	Interest expense	**$(2,222)**
Commodity contracts:			
Fleet Fuel	**$(950)**	Other operating expenses	**(1,053)**
Total	**$(950)**		**$(3,275)**
2014			
Interest rate contracts	-	Interest expense	$(2,222)
Commodity contracts:			
Fleet Fuel	$(1,153)	Other operating expenses	(332)
Total	$(1,153)		$(2,554)

The amount in OCI related to previously settled interest rate hedging contracts, after tax and accumulated amortization, at December 31 is a net loss of $10.1 million for 2015 and a net loss of $12.4 million for 2014. For the year ended December 31, 2015, we recorded $2.2 million in net derivative losses related to discontinue cash flow hedges. We will amortize approximately $2.2 million of discontinued cash flow hedges in 2016.

At December 31, 2015, $0.9 million in losses are reported in OCI because the forecasted transaction is considered to be probable. We expect that those losses in OCI will be reclassified into earnings within the next 24 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions. There was no ineffective portion of the hedge recognized during the year ended December 31, 2015.

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

The estimated fair value of debt amounted to $1,171 million and $1,060 million as of December 31, 2015 and 2014, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2.

Assets and liabilities measured at fair value on a recurring basis

		Fair Value Measurements at December 31, Using		
Description	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2015				
Assets				
Noncurrent investments available for sale	**$415**	**$415**	**-**	**-**
Total	**$415**	**$415**	**-**	**-**
Liabilities				
Derivatives	**$935**	**-**	**-**	**$935**
Total	**$935**	**-**	**-**	**$935**
2014				
Assets				
Noncurrent investments available for sale	$322	$322	-	-
Total	$322	$322	-	-
Liabilities				
Derivatives	$1,038	-	-	$1,038
Total	$1,038	-	-	$1,038

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2015 and 2014. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

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

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

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

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	
	Derivatives, Net	
Year ended December 31,	2015	2014
(Thousands)		
Beginning balance	**$1,038**	$217
Total gain or loss for the period		
Included in earnings	**(1,053)**	(332)
Included in other comprehensive income	**950**	1,153
Ending balance	**$935**	$1,038

The amounts of realized and unrealized gain and loss included in earnings for the period (above), which are reported in Other operating expense are:

(Thousands)	
Total gain (loss) included in earnings for year ended December 31,	
2015	**$(1,053)**
2014	$(332)

Note 13. Accumulated Other Comprehensive (Loss) Income

	Balance January 1, 2014	2014 Change	Balance December 31, 2014	2015 Change	Balance December 31, 2015
(Thousands)					
Amortization of pension cost for nonqualified plans, net of income tax (benefit) of $(161) for 2014 and $112 for 2015	(1,889)	$(233)	$(2,122)	**$163**	**$(1,959)**
Unrealized (loss) gain on derivatives qualified as hedges:					
Unrealized (loss) during period on derivatives qualified as hedges, net of income tax benefit of $471 for 2014 and $388 for 2015		(682)		**(562)**	
Reclassification adjustment for loss included in net income, net of income tax (benefit) of $(136) for 2014 and $(430) for 2015		197		**623**	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax (benefit) of $(907) for 2014 and 2015		1,315		**1,315**	
Net unrealized (loss) gain on derivatives qualified as hedges	$(8,761)	$830	$(7,931)	**$1,376**	**$(6,555)**
Accumulated Other Comprehensive (Loss) Income	$(10,650)	$597	$(10,053)	**$1,539**	**$(8,514)**

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

Note 14. Retirement Benefits

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

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately $3 million for 2015 and $2 million for 2014.

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.

Obligations and funded status:

	Pension Benefits		**Postretirement Benefits**	
	2015	**2014**	**2015**	**2014**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	**$419,710**	$343,966	**$117,567**	$93,816
Service cost	**7,711**	7,119	**835**	681
Interest cost	**15,620**	16,430	**4,331**	4,414
Plan participants' contributions	**-**	-	**399**	603
Actuarial loss (gain)	**(20,756)**	91,445	**(3,320)**	26,795
Special termination benefits	**824**	-	**-**	-
Benefits paid	**(17,828)**	(39,250)	**(5,950)**	(8,742)
Benefit obligation at December 31	**$405,281**	$419,710	**$113,862**	$117,567
Change in plan assets				
Fair value of plan assets at January 1	**$254,164**	$245,149	**$38,787**	$41,279
Actual return on plan assets	**(4,070)**	16,958	**(929)**	1,579
Employer contributions	**24,682**	31,307	**5,551**	8,139
Withdrawal from VEBA	**-**	-	**(2,223)**	(4,071)
Employer and plan participants' contributions	**-**	-	**399**	603
Benefits paid	**(17,828)**	(39,250)	**(5,950)**	(8,742)
Fair value of plan assets at December 31	**$256,948**	$254,164	**$35,635**	$38,787
Funded status at December 31	**(148,333)**	$(165,546)	**$(78,227)**	$(78,780)

Amounts recognized in the balance sheet	**Pension Benefits**		**Postretirement Benefits**	
December 31,	**2015**	**2014**	**2015**	**2014**
(Thousands)				
Noncurrent liabilities	**(148,333)**	$(165,546)	**$(78,227)**	$(78,780)

Notes to Consolidated Financial Statements

During 2014, we offered retired employees who are currently receiving benefits an option to receive their future pension benefit as a lump sum. Approximately $16.4 million of payments were made in 2014 as a result of employees exercising that option. The lump sums paid did not trigger any settlement accounting.

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

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

	Pension Benefits		Postretirement Benefits	
December 31,	**2015**	**2014**	**2015**	**2014**
(Thousands)				
Net loss	**$205,258**	$223,946	**$50,898**	$54,270
Prior service cost (credit)	**$16**	$133	**$(12,713)**	$(14,762)

Our accumulated benefit obligation for all defined benefit pension plans at December 31 was $363 million for 2015 and $371 million for 2014.

Our postretirement benefits were partially funded at December 31, 2015 and 2014.

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

December 31,	**2015**	**2014**
(Thousands)		
Projected benefit obligation	**$405,281**	$419,710
Accumulated benefit obligation	**$362,643**	$371,156
Fair value of plan assets	**$256,948**	$254,164

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

Years ended December 31,	Pension Benefits 2015	Pension Benefits 2014	Postretirement Benefits 2015	Postretirement Benefits 2014
(Thousands)				
Net periodic benefit cost				
Service cost	**$7,710**	$7,119	**$835**	$681
Interest cost	**15,621**	16,430	**4,331**	4,414
Expected return on plan assets	**(18,742)**	(18,541)	**(2,674)**	(2,848)
Amortization of prior service cost (benefit)	**117**	179	**(2,049)**	(3,875)
Special termination benefit charge	**824**	-	**-**	-
Amortization of net loss	**20,744**	10,492	**3,656**	1,502
Net periodic benefit cost	**$26,274**	$15,679	**$4,099**	$(126)
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss/(gain)	**$2,056**	$93,028	**$283**	$28,065
Amortization of net (loss)	**(20,744)**	(10,492)	**(3,656)**	(1,502)
Amortization of prior service (cost) credit	**(117)**	(179)	**2,049**	3,875
Total recognized in regulatory assets and regulatory liabilities	**(18,805)**	$82,357	**(1,324)**	30,438
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$7,469**	$98,036	**$2,775**	$30,312

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

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2016	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	**18,274**	**$3,579**
Estimated prior service cost (credit)	**$9,275**	**$(2,013)**

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ended December 31, 2016.

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits 2015	Pension Benefits 2014	Postretirement Benefits 2015	Postretirement Benefits 2014
Discount rate	**4.10%**	3.80%	**4.10%**	3.80%
Rate of compensation increase	**4.10%**	4.20%	**NA**	NA

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

Weighted-average assumptions used to determine net periodic benefit cost for Years ended December 31,	Pension Benefits 2015	Pension Benefits 2014	Postretirement Benefits 2015	Postretirement Benefits 2014
Discount rate	**3.80%**	4.90%	**3.80%**	4.90%
Expected long-term return on plan assets	**7.50%**	7.50%	**-**	-
Expected long-term return on plan assets - nontaxable trust	**-**	-	**7.50%**	7.50%
Expected long-term return on plan assets - taxable trust	**-**	-	**5.00%**	5.00%
Rate of compensation increase	**4.30%**	4.40%	**N/A**	N/A

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

Assumed health care cost trend rates to determine benefit obligations at December 31,	2015	2014
Health care cost trend rate (pre 65/post 65)	**7.0%/9.0%**	7.5%/7.0%
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	**2026**	2027

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

(Thousands)	1% Increase	1% Decrease
Effect on total of service and interest cost	**$263**	**$(219)**
Effect on postretirement benefit obligation	**$6,434**	**$(5,349)**

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 $20.7 million to our pension benefit plans in 2016.

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

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2016	$17,232	$7,297	$133
2017	$18,036	$7,282	$153
2018	$18,660	$7,247	$171
2019	$19,432	$7,280	$189
2020	$20,226	$7,290	$208
2021 - 2025	$114,713	$36,189	$1,344

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

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

The fair values of Networks' pension benefits plan assets at December 31, 2015 and 2014, by asset category are shown in the following table. CMP's share of the total consolidated assets is approximately 13% for 2015 and 12% for 2014.

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2015				
Cash and cash equivalents	**$57,526**	**$3,290**	**$54,236**	**-**
U.S. government securities	**171,024**	**171,024**	**-**	**-**
Common stocks	**313,911**	**313,911**	**-**	**-**
Registered investment companies	**81,308**	**81,308**	**-**	**-**
Corporate bonds	**323,900**	**-**	**323,900**	**-**
Preferred stocks	**4,926**	**295**	**4,631**	**-**
Common/collective trusts	**511,504**	**-**	**21,476**	**$490,028**
Partnership/joint venture interests	**78,519**	**-**	**-**	**78,519**
Real estate investments	**88,865**	**-**	**-**	**88,865**
Other investments, principally annuity and fixed income	**318,247**	**(21)**	**-**	**318,268**
Total	**$1,949,730**	**$569,807**	**$404,243**	**$975,680**

2014				
Cash and cash equivalents	$47,941	$3,795	$44,146	-
U.S. government securities	177,379	177,379	-	-
Common stocks	430,900	343,757	87,143	-
Registered investment companies	115,930	115,930	-	-
Corporate bonds	344,216	-	344,216	-
Preferred stocks	4,050	281	3,769	-
Common/collective trusts	476,581	-	26,440	$450,141
Partnership/joint venture interests	79,489	-	-	79,489
Real estate investments	74,871	-	-	74,871
Other investments, principally annuity and fixed income	345,885	-	4,200	341,685
Total	$2,097,242	$641,142	$509,914	$946,186

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

- Cash and cash equivalents – Level 1: at cost, plus accrued interest, which approximates fair value. Level 2: proprietary cash associated with other investments, based on yields currently available on comparable securities of issuers with similar credit ratings.
- U.S. government securities, Common stocks and registered investment companies - at the closing price reported in the active market in which the security is traded.
- Corporate bonds – based on yields currently available on comparable securities of issuers with similar credit ratings.
- Preferred stocks – at the closing price reported in the active market in which the individual investment is traded.
- Common/collective trusts and Partnership/joint ventures – using the Net Asset Value (NAV) provided by the administrator of the fund. The NAV is based on the value of the underlying assets owned by the fund, minus its liabilities, and then divided by the number of shares outstanding. The NAV is classified as Level 2 if the plan has the ability to redeem the investment with the investee at NAV per share at the measurement date. Redemption restrictions or adjustments to NAV based on unobservable inputs result in the fair value measurement being classified as Level 3 if those inputs are significant to the overall fair value measurement.
- Real estate investments – based on a discounted cash flow approach that includes the projected future rental receipts, expenses and residual values because the highest and best use of the real estate from a market participant view is as rental property.
- Other investments, principally annuity and fixed income - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: based on yields currently available on comparable securities of issuers with similar credit ratings. Level 3: when quoted prices are not available for identical or similar instruments, under a discounted cash flows approach that maximizes observable inputs such as current yields of similar instruments but includes adjustments for certain risks that may not be observable such as credit and liquidity risks.

(Thousands)	Common/ Collective Trusts	Partner-ship/ Joint Venture Interests	Real Estate Invest-ments	Other Invest-ments	Total
	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)				
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
Actual return on plan assets:					
Relating to assets still held at the reporting date	**(5,873)**	**18,518**	**10,235**	**(20,169)**	**2,711**
Relating to assets sold during the year	**(3,115)**	**(19,488)**	**-**	**904**	**(21,699)**
Purchases, sales and settlements	**48,875**	**-**	**3,759**	**(4,152)**	**48,482**
Balance, December 31, 2015	**$490,028**	**$78,519**	**$88,865**	**$318,268**	**$975,680**

Our postretirement benefits plan assets are held with a trustee in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes in order to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 100% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes. The remainder is invested in arrangements subject to income taxes.

We have established a target asset allocation policy within allowable ranges for our postretirement benefits plan assets of 47% equity securities, 38% fixed income and 15% for all other types of investments. The target allocations within allowable ranges are further diversified into 20% large cap domestic equities, 12% medium and small cap domestic equities, 10% international developed market and 5% emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at 38%. Other, alternative investment targets are 5% for real estate, 5% absolute return and 5% tangible assets. Systematic rebalancing within target ranges, should any asset categories drift outside their specified ranges, increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk.

The fair values of Networks' other postretirement benefits plan assets at December 31, 2015 and 2014, by asset category are shown in the following table. CMP's share of the total consolidated assets is approximately 30% for 2015 and 30% for 2014:

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2015				
Money market funds	**$4,163**	**$4,163**	**-**	**-**
Mutual funds, fixed	**35,438**	**35,438**	**-**	**-**
Government & corporate bonds	**1,703**	**-**	**$1,703**	**-**
Mutual funds, equity	**45,679**	**45,679**	**-**	**-**
Common stocks	**22,939**	**22,793**	**-**	**$146**
Mutual funds, other	**11,519**	**11,519**	**-**	**-**
Total assets measured at fair value	**$121,441**	**$119,592**	**$1,703**	**$146**
2014				
Money market funds	$4,478	$4,478	-	-
Mutual funds, fixed	35,914	35,914	-	-
Government & corporate bonds	2,126	-	$2,126	-
Mutual funds, equity	44,877	44,877	-	-
Common stocks	28,459	28,459	-	-
Mutual funds, other	12,011	12,011	-	-
Total assets measured at fair value	$127,865	$125,739	$2,126	-

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

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

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

Note 15. Subsequent events

The company has performed a review of subsequent events through April 19, 2016, which is the date these financial statements were available to be issued, and the financial statements reflect events occurring from January 1, 2016 through such date.

On February 4, 2016, AVANGRID subsidiary, CMP, declared a dividend of $100 million payable to AGR which was paid on March 16, 2016.

See also Note 9 relating to ROE Complaint proceeding update on March 22, 2016 and the Yankee Nuclear Spent Fuel Disposal Claim update on March 25, 2016.

On April 5, 2016, AGR, NYSEG, RGE, CMP, The United Illuminating Company (“UI”), Connecticut Natural Gas Corporation (“CNG”), The Southern Connecticut Gas Company (“SCG”) and The Berkshire Gas Company (“BGC”) entered into a revolving credit facility with a syndicate of banks (the “Credit Facility”), that provides for maximum borrowings of up to $1.5 billion in the aggregate. Under the terms of the Credit Facility, each joint borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit established by the banks. AGR’s maximum sublimit is $1 billion, NYSEG, RGE, CMP and UI have maximum sublimits of $250 million, CNG, and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $25 million. Under the Credit Facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. The initial facility fees will range from 12.5 to 17.5 basis points. The maturity date for the Credit Facility is April 5, 2021.

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

New York State Electric & Gas Corporation

Financial Statements

For the Years Ended December 31, 2015 and 2014

New York State Electric & Gas Corporation

Index

Page(s)

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

Building a better
working world

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

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

Report of Independent Auditors

To the Shareholders and Board of Directors
New York State Electric & Gas Corporation

We have audited the accompanying financial statements of New York State Electric & Gas Corporation which comprise the balance sheets as of December 31, 2015 and 2014, and the related statements of income, comprehensive income, changes in common stock equity and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

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

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of New York State Electric & Gas Corporation at December 31, 2015 and 2014, and the results of its operations and its cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

Ernst + Young LLP

April 28, 2016

New York State Electric & Gas Corporation
Statements of Income

Year Ended December 31,	2015	2014
(Thousands)		
Operating Revenues		
Electric	**$ 1,293,601**	$1,416,935
Natural gas	**318,339**	338,399
Total Operating Revenues	**1,611,940**	1,755,334
Operating Expenses		
Electricity purchased	**409,154**	560,303
Natural gas purchased	**101,095**	142,801
Operations and maintenance	**607,724**	583,165
Depreciation and amortization	**140,896**	123,030
Other taxes	**136,342**	130,214
Total Operating Expenses	**1,395,211**	1,539,513
Operating Income	**216,729**	215,821
Other (Income)	**(32,995)**	(31,955)
Other Deductions	**1,696**	943
Interest Charges, Net	**83,331**	76,351
Income Before Income Tax	**164,697**	170,482
Income Tax Expense	**66,375**	55,503
Net Income	**$98,322**	$114,979

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

New York State Electric & Gas Corporation
Statements of Comprehensive Income

Year Ended December 31,	2015	2014
(Thousands)		
Net Income	**$98,322**	$114,979
Other Comprehensive Income, Net of Tax		
Amortization of pension for nonqualified plans	**1,601**	(493)
Unrealized (loss) gain on derivatives qualified as hedges:		
Unrealized loss during period on derivatives qualified as hedges	**(799)**	(1,120)
Reclassification adjustment for loss included in net income	**1,022**	226
Reclassification adjustment for loss on settled cash flow treasury hedges	**380**	563
Net unrealized gain on derivatives qualified as hedges	**603**	(331)
Other Comprehensive (Loss) Income, Net of Tax	**2,204**	(824)
Comprehensive Income	**$100,526**	$114,155

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

New York State Electric & Gas Corporation
Balance Sheets

December 31,	2015	2014
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	**$3,408**	$7,143
Accounts receivable and unbilled revenues, net	**215,172**	248,305
Accounts receivable from affiliates	**10,981**	7,500
Fuel and natural gas in storage, at average cost	**13,336**	23,124
Materials and supplies	**14,758**	13,532
Broker margin accounts	**24,001**	40,880
Prepaid taxes	**34,819**	36,940
Other current assets	**10,224**	12,184
Regulatory assets	**70,395**	34,585
Total Current Assets	**397,094**	424,193
Utility Plant at Original Cost	**4,950,776**	4,800,188
Less accumulated depreciation	**1,981,015**	1,885,048
Net Utility Plant in Service	**2,969,761**	2,915,140
Construction work in progress	**323,565**	225,892
Total Utility Plant	**3,293,326**	3,141,032
Other Property and Investments	**10,402**	16,173
Regulatory and Other Assets		
Regulatory assets	**1,249,977**	1,294,704
Other	**-**	442
Total Regulatory and Other Assets	**1,249,977**	1,295,146
Total Assets	**$4,950,799**	$4,876,544

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

New York State Electric & Gas Corporation
Balance Sheets

December 31,	2015	2014
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	**$100,417**	$132,384
Notes payable to affiliates	**340,845**	418,055
Accounts payable and accrued liabilities	**128,087**	126,602
Accounts payable to affiliates	**73,379**	48,132
Interest accrued	**7,296**	8,061
Taxes accrued	**21,491**	1,560
Derivative liabilities	**981**	19,586
Environmental remediation costs	**27,805**	28,119
Customer deposits	**13,193**	13,345
Regulatory liabilities	**45,926**	46,648
Other	**58,732**	49,210
Total Current Liabilities	**818,152**	891,702
Regulatory and Other Liabilities		
Regulatory liabilities	**782,659**	713,489
Deferred income taxes regulatory	**195,403**	234,675
Other non-current liabilities		
Deferred income taxes	**644,485**	643,219
Other postretirement benefits	**330,835**	312,767
Asset retirement obligation	**14,902**	15,260
Environmental remediation costs	**140,176**	146,552
Other	**31,761**	36,515
Total Regulatory and Other Liabilities	**2,140,221**	2,102,477
Long-term debt	**844,908**	735,373
Total Liabilities	**3,803,281**	3,729,552
Commitments and Contingencies		
Common Stock Equity		
Common stock ($6.66 2/3 par value, 90,000 shares authorized and 64,508 shares outstanding at December 31, 2015 and 2014)	**430,057**	430,057
Capital in excess of par value	**268,364**	268,364
Retained earnings	**450,890**	452,568
Accumulated other comprehensive loss	**(1,793)**	(3,997)
Total NYSEG Common Stock Equity	**1,147,518**	1,146,992
Total Liabilities and Equity	**$4,950,799**	$4,876,544

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

New York State Electric & Gas Corporation
Statements of Cash Flows

Year Ended December 31,	2015	2014
(Thousands)		
Operating Activities		
Net income	**$98,322**	$114,979
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**140,896**	123,030
Amortization of regulatory and other assets and liabilities	**90,154**	(25,109)
Deferred income taxes and investment tax credits, net	**(31,905)**	9,859
Carrying cost of regulatory assets and liabilities	**14,382**	6,428
Pension expense	**64,345**	30,837
Changes in operating assets and liabilities		
Accounts receivable and unbilled revenues, net	**29,652**	5,499
Inventories	**8,562**	896
Accounts payable and accrued liabilities	**41,807**	19,811
Taxes accrued	**19,931**	(36,339)
Other liabilities	**(108,451)**	(52,014)
Changes in regulatory assets and liabilities	**68,229**	43,161
Other assets	**(67,323)**	(68,146)
Net Cash Provided by operating activities	**368,601**	172,892
Investing Activities		
Utility plant additions	**(275,415)**	(271,381)
Grants received from governmental entities	**-**	(601)
Contribution in aid of construction	**13,244**	20,692
Other investments	**67**	683
Net Cash (used in) investing activities	**(262,104)**	(250,607)
Financing Activities		
Long term note issuance	**200,000**	(664)
Long term note retirements	**(132,025)**	-
Purchase in lieu of redemption	**-**	(3,150)
Notes payable short term debts and capital leases	**(997))**	(13,800)
Notes payable to affiliates	**(77,210)**	199,081
Dividends paid on common stock	**(100,000)**	(100,000)
Net Cash Provided by (used in) Financing Activities	**(110,232)**	81,467
Net Increase (Decrease)/Increase in Cash and Cash Equivalents	**(3,735)**	3,752
Cash and Cash Equivalents, Beginning of Year	**7,143**	3,391
Cash and Cash Equivalents, End of Year	**$3,408**	$7,143

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

New York State Electric & Gas Corporation
Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)	$6.66 2/3 Shares	Common Stock Outstanding Par Value Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, January 1, 2014	64,508	$430,057	$268,364	$437,589	$(3,173)	$1,132,837
Net income				114,979		114,979
Other comprehensive income, net of tax					(824)	(824)
Comprehensive income						114,155
Cash dividends paid				(100,000)		(100,000)
Balance, December 31, 2014	64,508	430,057	268,364	452,568	(3,997)	1,146,992
Net income				**98,322**		**98,322**
Other comprehensive income, net of tax					**2,204**	**2,204**
Comprehensive income						**100,526**
Cash dividends paid				**(100,000)**		**(100,000)**
Balance, December 31, 2015	**64,508**	**$430,057**	**$268,364**	**$450,890**	**$(1,793)**	**$1,147,518**

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

Notes to Financial Statements

Note 1. Significant Accounting Policies

Background: New York State Electric & Gas Corporation (NYSEG, the company, we, our, us) conducts regulated electricity transmission and distribution operations and regulated natural gas transportation, storage and distribution operations in upstate New York. It also generates electricity, primarily from its several hydroelectric stations. NYSEG serves approximately 884,000 electricity and 264,000 natural gas customers in its service territory of approximately 20,000 square miles, which is located in the central, eastern and western parts of the state of New York and has a population of approximately 2.5 million. The larger cities in which NYSEG serves electricity and natural gas customers are Binghamton, Elmira, Auburn, Geneva, Ithaca and Lockport. We operate under the authority of the New York State Public Service Commission (NYPSC) and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

NYSEG is a subsidiary of Avangrid Networks, Inc., which is a wholly-owned subsidiary of AVANGRID (AGR), which is a wholly-owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the law of the Kingdom of Spain. Networks' wholly-owned subsidiaries, and their principal operating companies, include: CMP Group, Inc. – Central Maine Power Company (CMP), and RGS Energy Group, Inc. - NYSEG and Rochester Gas and Electric Corporation (RGE).

***Accounts receivable*:** Accounts receivable at December 31 include unbilled revenues of $64 million for 2015 and $69 million for 2014, and are shown net of an allowance for doubtful accounts at December 31 of $26 million for 2015 and $26 million for 2014. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $20 million in 2015 and $21 million in 2014.

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

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

Our accounts receivable include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the NYPSC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments over an extended time by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: pays a reasonable portion of the balance; agrees to pay the balance in installments; and agrees to pay future bills within 30 days until the DPA is paid in full or is otherwise considered to be delinquent. We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses and by establishing specific provisions for known credit issues. Amounts are written off when reasonable collection efforts have been exhausted. The allowance for doubtful accounts for DPAs at December 31 was $17 million for both 2015 and 2014. DPA receivable balances at December 31 were: $28 million for 2015 and $34 million for 2014.

Notes to Financial Statements

Asset retirement obligations**:** We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability to its present value periodically to reflect revisions to either the timing or the amount of the original estimated undiscounted cash flows, and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. We 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 $15 million for 2015 and for 2014. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of: asbestos, PCB-contaminated equipment, gas pipeline and cast iron gas mains.

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

Broker margin accounts: We maintain accounts with clearing firms that require initial margin deposits upon the establishment of new positions, primarily related to natural gas and electricity derivatives, as well as maintenance margin deposits in the event of unfavorable movements in market valuation for those positions. The amount reflecting those activities is shown as broker margin accounts on our balance sheets.

Statements of cash flows**:** We consider all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and those investments are included in cash and cash equivalents.

Supplemental Disclosure of Cash Flows Information	**2015**	**2014**
(Thousands)		
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	**$37,874**	$39,945
Income taxes, paid net	**$65,220**	$84,070

Interest capitalized was $3.6 million in 2015 and in 2014. Included in the income taxes paid, $60 million was paid to AGR under the tax sharing agreement.

Depreciation and amortization**:** We determine depreciation expense using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Our depreciation accruals were equivalent to 2.7% of average depreciable property for 2015 and 2.6% for 2014. We amortize our capitalized software cost which is included in common plant, using the straight line method, based on useful lives of 3 to 5 years. Capitalized software costs of approximately $170 million as of December 31, 2015 and $138 million as of December 31, 2014. Depreciation expense was $131 million in 2015 and $118 million in 2014. Amortization of capitalized software was $10 million in 2015 and $5 million in 2014.

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

Plant	**Estimated useful life range (years)**	**2015**	**2014**
(thousands)			
Electric	44-62	**$3,597,722**	$3,572,353
Natural Gas	22-62	**905,491**	879,727
Common	9-40	**447,563**	348,108
Total plant		**$4,950,776**	$4,800,188

Electric plant includes capital leases of $10 million in 2015 and $2 million in 2014. Accumulated depreciation related to these leases was $2.4 million in 2015 and $1.7 million in 2014.

Environmental remediation liability: In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. Our environmental liabilities are recorded on an undiscounted basis. Our environmental liability accruals are expected to be paid through the year 2048.

Inventory: Inventory comprises fuel and gas in storage and materials and supplies. We own natural gas that is stored in third-party owned underground storage facilities. This gas is recorded as inventory. Injections of inventory into storage are priced at the market purchase cost at the time of injection, and withdrawals of working gas from storage are priced at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at, or below market value. Inventories to support gas operations are reported on the balance sheet within “Fuel and natural gas in storage.”

We also have materials and supplies inventories that are used for construction of new facilities and repairs of existing facilities. The inventories are valued at lower of cost or market. Cost is determined using the weighted average method

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

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

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

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

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

Simplifying the Presentation of Debt Issuance Costs: The FASB issued an amendment in April 2015 that is intended to simplify the presentation of debt issuance costs. Instead of presenting debt issuance costs as a deferred charge (that is, as an asset), the amendments require debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with the presentation for debt discounts. The amendment is effective for public entities for financial statements issued for fiscal years beginning after December 15, 2015, and for interim periods within those fiscal years. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. Accordingly, we reclassified the debt issuance costs from other noncurrent assets to noncurrent debt on our December 31, 2014 balance sheet, which decreased total assets, noncurrent debt and total liabilities by $10 million.

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

Notes to Financial Statements

Balance Sheet Classification of Deferred Taxes: The FASB issued an amendment in November 2015 that is intended to simplify the presentation of deferred income taxes by requiring entities that present a classified statement of financial position to classify deferred tax liabilities and assets as noncurrent in their balance sheet. This aligns the presentation of deferred income tax liabilities and assets with International Financial Reporting Standards. The amendments do not affect the current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount. The amendments are effective for public entities for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. As permitted, we have early adopted the amendments as of the beginning of the fourth quarter of 2015, and have elected retrospective application to all periods presented in order to simplify the presentation in our balance sheet. Accordingly, we reclassified the current deferred taxes to noncurrent on our December 31, 2014 balance sheet, which decreased current assets and noncurrent deferred taxes by $32 million due to right of offset.

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

Revenue from Contracts with Customers: In May 2014 the FASB issued an amendment related to the recognition of revenue from contracts with customers and required disclosures. The core principle is for an entity to recognize revenue to represent the transfer of goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. The standard is effective for public entities for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. In August 2015 the FASB issued an accounting standards update that defers by one year the effective date of the standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption as of the original effective date permitted. In March 2016 the FASB issued an accounting standards update that amends and clarifies the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, with the same deferred effective date. We are currently evaluating how our adoption of the amendment will affect our results of operation, financial position, and cash flows.

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

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

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

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

Leases: In February 2016 the FASB issued new guidance that affects all companies and organizations that lease assets, and requires them to record on their balance sheet assets and liabilities for the rights and obligations created by those leases. A lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Concerning lease expense recognition, after extensive consultation, the FASB has ultimately concluded that the economics of leases can vary for a lessee, and those economics should be reflected in the financial statements. As a result, the amendments retain a distinction between finance leases and operating leases, while requiring both types of leases to be recognized on the balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in current GAAP. By retaining a distinction between finance leases and operating leases, the effect of leases on the statement of comprehensive income and the statement of cash flows is largely unchanged from current GAAP. Lessor accounting will remain substantially the same as current GAAP, but with some targeted improvements intended to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance issued in 2014. The updated guidance is effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early application is permitted. We expect our adoption of the new guidance will materially affect our results of operation and financial position.

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

Other (Income) and Other Deductions:

Year Ended December 31,	**2015**	**2014**
(Thousands)		
Interest and dividend income	**$(1001)**	$(215)
Carrying costs on regulatory assets	**23,265**	(23,938)
Allowance for funds used during construction	**(7,162)**	(7,426)
Gain on Sale of property	**(1,457)**	-
Miscellaneous	**(110)**	(376)
Total other (income)	**$(32,995)**	$(31,955)
Civic donations	**$720**	$650
Miscellaneous	**976**	293
Total other deductions	**$1,696**	$943

Reclassifications: Certain amounts have been reclassified in our 2014 statements of cash flows to conform to the 2015 presentation which have not affected the operating, investing, and financing activity sections. Additionally, certain amounts have been reclassified in the 2014 statements of income and balance sheet to conform to the 2015 presentation as follows:

- Operations and maintenance expenses have been combined into Operations and maintenance in the statement of income for the year ended December 31, 2014.
- Non-current regulatory assets and liabilities items have been combined into Regulatory assets and Regulatory liabilities, respectively, in the balance sheet as of December 31, 2014.
- Accounts payable for electricity and natural gas purchased have been combined into Accounts payable and accrued liabilities in the balance sheet as of December 31, 2014.

- Prepaid taxes were reclassified from Prepayments and other current assets to a separate line in the balance sheet as of December 31, 2014.
- Utility plant line items for Electricity, Natural gas and Common have been combined into Property, plant and equipment in the balance sheet as of December 31, 2014.

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

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

Related party transactions: Certain Networks subsidiaries, including NYSEG, borrow from AGR, the parent of Networks, through intercompany revolving credit agreements. For NYSEG, the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 6 for further detail on the credit facility with AGR.

Avangrid Service Corporation provides administrative and management services to Networks operating utilities, including NYSEG, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The charge for services provided to NYSEG by AGR and its affiliates was approximately $75 million for 2015 and $90 million for 2014 and charge for services provided by NYSEG to AGR and its subsidiaries were approximately $16 million for 2015 and $12 million for 2014. All charges for services are at cost. All of the charges associated with services provided are recorded as offsetting credits to other operating expenses on the financial statements. Balance in accounts payable to affiliates of $73 million at December 31, 2015 and $48 million at December 31, 2014 is mostly associated to Avangrid Service Company.

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

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

NYSEG electric and natural gas rate plans each contain a revenue decoupling mechanism under which our actual energy delivery revenues are compared on a periodic basis with the authorized delivery revenues and the difference accrued, with interest, for refund to or recovery from customers, as applicable (See Note 2).

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

***Taxes*:** AGR, 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. As a member, NYSEG settles its current tax liability or benefit each year directly with AGR pursuant to a tax sharing agreement between AGR and its members.

The aggregate amount of the intercompany income tax payable balance due to AGR is $20.3 million at December 31, 2015. The aggregate amount of the intercompany income tax receivable balance due from AGR is $14.8 million at December 31, 2014.

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

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

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

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

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

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

Notes to Financial Statements

Use of estimates and assumptions: The preparation of our financial statements in conformity with generally accepted accounting principles in the United States of America 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 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; (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; and (8) earnings sharing mechanism (ESM); (9) environmental remediation liability; (10) pension and Other Postretirement Employee Benefit (OPEB); (11) fair value measurements and (12) AROs. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our 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: Approximately 76% of the company's employees are covered by a collective bargaining agreement. There are no agreements which will expire within the coming year.

Note 2. Industry Regulation

Electricity and Natural Gas Distribution

Our revenues are essentially regulated, being based on tariffs established in accordance with administrative procedures set by the New York State Public Service Commission (NYPSC). The tariffs applied to regulated activities are approved by the NYPSC and are based on the cost of providing service. Our revenues are set to be sufficient to cover all of our operating costs, including energy costs, finance costs, and the costs of equity, the last of which reflect our capital ratio and a reasonable return on equity (ROE).

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

NYSEG Rate Plans

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

The revenue requirements were based on a 10% allowed ROE applied to an equity ratio of 48%. If annual earnings exceed the allowed return, a tiered Earnings Sharing Mechanism (ESM) will capture a portion of the excess for the ratepayers' benefit. The ESM is subject to specified downward adjustments if NYSEG fails to meet certain reliability and customer service measures.

Notes to Financial Statements

Key components of the rate plan include electric reliability performance mechanisms, natural gas safety performance measures, customer service quality metrics and targets, and electric distribution vegetation management programs that establish threshold performance targets. There will be downward revenue adjustments if NYSEG fails to meet the targets.

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

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

On May 20, 2015, NYSEG filed electric and gas rate cases with the NYPSC. We requested rate increases for NYSEG electric and NYSEG gas. On February 19, 2016, the NYSEG and other signatory parties filed a Joint Proposal (Proposal) with the NYPSC for a three-year rate plan for electric and gas service at NYSEG commencing May 1, 2016. The Proposal balances the varied interests of the signatory parties including but not limited to maintaining the company’s credit quality and mitigating the rate impacts to customers. The Proposal reflects many customer attributes including: acceleration of the companies’ natural gas leak prone main replacement programs and enhanced electric vegetation management to provide continued safe and reliable service. The delivery rate increase in the Proposal can be summarized as follows:

	May 1, 2016		May 1, 2017		May 1, 2018	
	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %	Rate Increase (Millions)	Delivery Rate Increase %
Electric	29.6	4.10%	29.9	4.10%	30.3	4.10%
Gas	13.1	7.30%	13.9	7.30%	14.8	7.30%

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

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

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

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

Reforming the Energy Vision (REV)

In April 2014, the NYPSC commenced a proceeding entitled REV which is a wide ranging initiative to reform New York State's energy industry and regulatory practices. REV has been divided into two tracks, Track 1 for Market Design and Technology, and Track 2 for Regulatory Reform. REV proposes regulatory changes that are intended to promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar and wider deployment of distributed energy resources, such as micro grids, on-site power supplies and storage.

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

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

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $864 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

We are allowed in rates an estimate of the routine costs of service restoration. We 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 2), we have experienced unusually high levels of restoration costs resulting from various storms including Hurricane Sandy, Hurricane Irene and tropical storm Lee.

NYSEG's deferred storm costs, reflecting the over (under) spending of actual costs compared with amounts currently allowed in rates, was $(9) million and $5 million for the years ended December 31, 2015 and 2014, respectively. NYSEG's total deferral, including carrying costs was $247 million at December 31, 2015 and $241 million at December 31, 2014. The method and timing of recovery of the costs will be determined in the future rate cases.

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

Most of the items for which the amortization period has been characterized as to be determined in a future proceeding have been addressed in the Joint Proposal. If the Joint Proposal is approved, most of these items would be amortized over a five year period, except the portion of storm costs to be recovered over ten years and plant related tax items which will be amortized over the life of associated plant. Annual amortization expense for NYSEG would be approximately $16.5 million.

Notes to Financial Statements

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

December 31,	2015	2014
(Thousands)		
Current		
Environmental remediation costs	**$22,498**	-
Merchant function charge	**5,066**	$1,101
Pension and other post retirement benefits cost deferrals	**7,530**	-
Unamortized loss on reacquired debt	**2,037**	2,177
Hedges losses	**25,563**	23,937
Supplemental assessment surcharge	**4,276**	7,266
Other	**3,425**	104
Total current regulatory assets	**$70,395**	$34,585
Other long-term		
Federal tax depreciation normalization adjustment	**$72,951**	$58,361
Asset retirement obligation	**14,889**	15,167
Property tax deferrals electric & gas	**45,044**	30,163
Pension and other post retirement benefits cost deferrals	**121,301**	108,790
Merger capital expenditure	**10,486**	10,486
Low income program	**18,115**	13,706
Unamortized losses on reacquired debt	**16,121**	18,169
Pension and other postretirement benefits	**618,598**	652,073
Environmental remediation costs	**67,886**	117,866
Unfunded future income taxes	**-**	18,908
Storm costs	**246,933**	240,861
Other	**17,653**	10,154
Total long-term regulatory assets	**$1,249,977**	$1,294,704

Environmental remediation costs include spending that has occurred and is eligible for future return/ 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. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs. It also includes the anticipated future rate recovery of costs that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base.

Pension and other postretirement benefits represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base. Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. The recovery of these amounts will be determined in future proceedings.

Storm costs for NYSEG are allowed in rates based on an estimate of the routine costs of service restoration. NYSEG is also allowed to defer unusually high levels of service restoration costs resulting from major storms when they meet certain criteria for severity and duration.

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

Notes to Financial Statements

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

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

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

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

December 31,	**2015**	**2014**
(Thousands)		
Current		
Energy efficiency portfolio standard	**$12,597**	$14,716
Gas supply charge and deferred natural gas cost	**5,064**	3,793
Electric supply reconciliation	**6,661**	-
Revenue decoupling mechanism	**3,805**	6,532
Reliability Support Services	**15,968**	18,135
Other	**1,831**	3,472
Total current regulatory liabilities	**$45,926**	$46,648
Other long-term		
Carrying costs on deferred income tax bonus depreciation	**$60,263**	$42,601
Economic development	**19,307**	16,202
Merger capital expense target customer credits	**6,800**	6,800
Positive benefit adjustment	**13,423**	13,423
Variable rate debt	**17,265**	13,070
Unfunded future income taxes	**1,700**	7,327
New York State tax rate change	**13,378**	13,378
Other taxes	**56,537**	43,573
Pension and other postretirement benefits	**11,398**	5,801
Pension deferrals	**63,054**	44,049
Accrued removal obligation	**487,710**	480,478
Other	**31,824**	26,787
Total non-current regulatory liabilities	**782,659**	713,489
Deferred income taxes regulatory	**195,403**	234,675
Total long-term regulatory liabilities	**$978,062**	$948,164

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

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

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

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

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

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

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

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

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

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

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

Notes to Financial Statements

Note 4. Income Taxes

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

Year Ended December 31, (Thousands)	2015	2014
Current		
Federal	**$83,907**	$36,205
State	**14,373**	9,439
Current taxes charged to expense	**98,280**	45,644
Deferred		
Federal	**(28,550)**	24,024
State	**(2,845)**	(13,478)
Deferred taxes charged to expense	**(31,395)**	10,546
Investment tax credit adjustments	**(510)**	(687)
Total Income Tax expense	**$66,375**	$55,503

In March of 2014, New York Senate Bill 6359 was enacted that, in pertinent part, reduced the state income tax rate from 7.1% to 6.5% beginning with tax year 2016. This change in the state income tax rate resulted in a reduction in our net deferred tax liabilities and decrease in state deferred tax expense of $8 million, which is net of the federal benefit.

The differences between tax expense per the statements of income and tax expense at the 35% statutory federal tax rate for the years ended December 31, 2015 and 2014 consisted of:

Year Ended December 31, (Thousands)	2015	2014
Tax expense at statutory rate	**$57,644**	$59,669
Depreciation and amortization not normalized	**4,802**	3,580
Allowance for funds used during construction	**(3,755)**	(3,854)
Investment tax credit amortization	**(510)**	(687)
Tax return and related adjustments	**437**	(2,476)
State taxes net of federal benefit	**7,493**	(2,625)
Other, net	**264**	1,896
Total Income Tax expense	**$66,375**	$55,503

Income tax expense for the year ended December 31, 2015 was $8.7 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, (net of federal benefit), and depreciation not normalized, partially offset by allowance for funds used during construction. This resulted in an effective tax rate of 40.3%. Income tax expense for the year ended December 31, 2014 was $4.2 million lower than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, (net of federal benefit) and favorable audit adjustments. This resulted in an effective tax rate of 32.6%.

.

Notes to Financial Statements

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

December 31, (Thousands)	2015	2014
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	**$690,450**	$713,111
Storm Costs	**97,822**	95,417
Accumulated deferred investment tax credits	**15,168**	15,678
Pension and other postretirement benefits	**158,053**	104,261
Environmental	**(31,498)**	(20,722)
Positive benefits adjustments merger order	**(5,318)**	(5,318)
Other	**(84,789)**	(24,533)
Non-current Deferred Income Tax Liabilities	**839,888**	877,894
Add: Valuation allowance	-	-
Total Non-current Deferred Income Tax Liabilities	**839,888**	877,894
Less amounts classified as regulatory liabilities		
Non-current deferred income taxes	**195,403**	234,675
Non-current Deferred Income Tax Liabilities	**$644,485**	$643,219
Deferred tax assets	**$121,605**	$57,687
Deferred tax liabilities	**961,493**	935,581
Net Accumulated Deferred Income Tax Liabilities	**$839,888**	$877,894

We have no federal or state net operating losses or tax credit carryforwards.

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

Year Ended December 31, (Thousands)	2015	2014
Balance as of January 1	**$8,480**	$21,424
Reduction for tax positions related to prior years	**-**	(12,944)
Reduction for tax positions related to settlements with taxing authorities	**(2,543)**	-
Balance as of December 31	**$5,937**	$8,480

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

Accruals for interest and penalties on tax reserves were $1.6 million as of December 31, 2015 and $2.6 million as of December 31, 2014. If recognized, $(1.8) million of the total gross unrecognized tax benefits would affect the effective tax rate. Gross unrecognized tax benefits decreased $2.5 million in 2015 due to settlements with taxing authorities.

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

Notes to Financial Statements

Note 5. Long-term Debt

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

As of December 31,		2015		2014	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
Unsecured PCNs - fixed	2020	$200,000	2.00-2.375%	$132,000	2.125-2.25%
Unsecured PCNs – variable	2034	96,850	1.18%	96,875	0.040-0.464%
Senior unsecured debt	2016-2042	650,000	3.24%-6.15%	650,000	3.24%-6.15%
Total Debt		**$946,850**		**$878,875**	
Obligations under capital leases	2016-2030	7,813		512	
Unamortized debt (costs) premium, net		(9,338)		(11,630)	
Less: debt due within one year, included in current liabilities		100,417		132,384	
Total Non-current Debt		**$844,908**		**$735,373**	

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

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

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

2016	2017	2018	2019	2020
$100,417	$201,146	$1,146	$1,146	$201,146

NYSEG sold $150 million on unsecured notes in a private placement in 2012. In the note purchase agreement, NYSEG agreed to a covenant not to permit, without the consent of the lender, our ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. We were in compliance with this covenant at December 31, 2015 and 2014.

Note 6. Bank Loans and Other Borrowings

NYSEG and the other Avangrid operating utilities rely on a combination of bank provided and intercompany revolving credit facilities to fund short-term liquidity needs. We had a total of $341 million of short-term debt outstanding at December 31, 2015 and $418 million outstanding at December 31, 2014. As of December 31, 2015, borrowing rate was 0.40%.

In July 2011, NYSEG jointly entered into a bank provided revolving credit facility (the "Joint Facility") that allows maximum borrowings of up to $600 million in aggregate and expires in 2018. NYSEG currently has a $200 million sublimit under the agreement and pays a facility fee of 15 basis points annually. NYSEG has a commercial paper program backstopped by the Joint Facility.

We also have an intercompany credit facility under a demand note agreement with AGR that provides financing of up to $500 million. Under the terms of that agreement, which expires in 2018, we pay a rate equivalent to our external short-term borrowing costs or the A2/P2 commercial paper rate published by the Federal Reserve. Under this agreement, we had a total of $341 million of Notes payable to affiliates at December 31, 2015 and $418 million outstanding at December 31, 2014.

In 2013 NYSEG became a party to an intercompany agreement along with CMP and RGE, under which each party to the agreement may lend to the other, under certain circumstances, excess cash on hand. At December 31, 2015 and 2014, there was nothing outstanding under the agreement.

In our Joint Facility we covenant not to permit, without the consent of the lender, our 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 indebtedness to total capitalization, the facility excludes from net worth the balance of Accumulated other comprehensive (loss) as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied 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. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was 0.53 to 1.00 at December 31, 2015. We are not in default as of December 31, 2015.

Note 7. Preferred Stock Redeemable Solely at the Option of the Company

At December 31, 2015, NYSEG had 2,455,000 shares of $100 par value preferred stock, 10,800,000 shares of $25 par value preferred stock and 1,000,000 shares of $100 par value preference stock authorized but unissued.

Note 8. Commitments and Contingencies

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

NYSEG satisfies its natural gas supply requirements through purchases from various producers and suppliers, withdrawals from natural gas storage, capacity contracts and winter peaking supplies and resources. The company operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual reasonable gas costs incurred by the company are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

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

We recognized expenses of approximately $91 million for NUG power in 2015 and $61 million in 2014. We estimate that our power purchases will total $91 million in 2016, $62 million in 2017, $34 million annually in 2018 and 2019, $30 million in 2020 and $114 million thereafter.

NYPSC Staff Review of Earnings Sharing Calculations and Other Regulatory Deferrals

In December 2012, the NYPSC Staff (Staff) informed NYSEG 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 their current rate plan, September 1, 2010 through August 31, 2011. The Staff's preliminary findings indicated adjustments to deferred balances primarily associated with storm costs and the treatment of certain incentive compensation costs for purposes of the 2011 ACF. The Staff's findings approximate $8.2 million of adjustments to deferral balances and customer earnings sharing accruals. We reviewed the Staff's adjustments and work papers and provided a response in 2013. We disagreed with certain staff conclusions and as a result recorded a $2.4 million reserve in December 2012. In the Joint Proposal the parties agreed that $1.9 million would be added to customer share of Earnings Sharing.

Lease

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

Note 9. 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 the New York State Department of Environmental Conservation (NYSDEC), 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 12 waste sites. The 12 sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the 12 sites, 11 sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites and four sites are also included on the National Priorities list. Any liability may be joint and several for certain of those sites.

We have a liability recorded of $5.1 million as of December 31, 2015, related to the 12 sites. We have paid remediation costs related to the 12 sites, and do not expect to incur any additional liability. 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.

Notes to Financial Statements

We have a program to investigate and perform necessary remediation at our 39 sites where gas was manufactured in the past. In 1994 and 1996 we entered into orders on consent with the NYSDEC. Those orders require us to investigate and, where necessary, remediate 36 of our 39 sites. Eight sites are included in the New York State Registry.

Our estimate for all costs related to investigation and remediation of the 39 sites ranges from $141 million to $259 million at December 31, 2015. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $162 million at December 31, 2015, and $174 million at December 31, 2014. We recorded a corresponding regulatory asset, net of insurance recoveries and the amount collected from FirstEnergy described below, because we expect to recover the net costs in rates.

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

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

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

Century Indemnity and OneBeacon: On August 14, 2013, NYSEG filed suit in federal court against two excess insurers, Century Indemnity and OneBeacon, who provided excess liability coverage to NYSEG. NYSEG seeks payment for clean-up costs associated with contamination at twenty-two former manufactured gas plants. Based on estimated clean-up costs of $282 million, the carriers' allocable share is approximately $89 million, excluding pre-judgment interest. Any recovery will be flowed through to NYSEG ratepayers.

Century and One Beacon have answered admitting issuance of the excess policies, but contesting coverage and providing documentation proving they received notice of the claims in the 1990s. We cannot predict the outcome of this matter.

Our environmental liability accruals have been established on an undiscounted basis. We have received insurance settlements which we accounted for as reductions to our related regulatory asset.

Note 10. Accounting for Derivative Instruments and Hedging Activities

We are exposed to certain risks relating to our ongoing business operations. The primary risk we manage by using derivative instruments is commodity price risk. In accordance with the accounting requirements concerning derivative instruments and hedging activities, we recognize all derivative instruments as either assets or liabilities at fair value on our balance sheet.

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

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

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

We currently have a non by-passable wires charge adjustment that allows us to pass through rates any changes in the market price of electricity. We use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations. At December 31, 2015, the loss recognized in regulatory assets was $25.1 million for electricity derivatives. For the year ended December 31, the amount reclassified from regulatory assets/liabilities into income, which is included in electricity purchased, was loss of $34.6 million for 2015 and a gain of $(26.5) million for 2014.

We have a purchased gas adjustment clause that allows us to recover through rates any changes in the market price of purchased natural gas, substantially eliminating our exposure to natural gas price risk. We use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations. At December 31, 2015, the loss recognized in regulatory assets was $0.6 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 $3 million in 2015 and $0.7 million in 2014.

Notes to Financial Statements

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

Year to settle	Electricity Contracts Mwhs	Natural Gas Contracts Dths	Other Fuel Contracts Gallons
As of December 31, 2015			
2016	**3,274,750**	**820,000**	**1,302,100**
2017	**1,399,800**	**320,000**	**636,000**
As of December 31, 2014			
2015	3,139,200	1,500,000	1,488,800
2016	1,679,600	270,000	-

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

	Asset Derivatives		Liability Derivatives	
As of December 31,	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
(Thousands)				
Derivatives designated as hedging instruments				
2015				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	-	Current liabilities	-
Long-term	Other assets	-	Other liabilities	-
Natural gas derivatives Current	Current assets	-	Current liabilities	-
Long-term	Other assets	-	Other liabilities	-
Fleet fuel contracts	Current assets		Current liabilities	$**981**
	Other assets	-	Other liabilities	**369**
Total		-		**$1,350**
2014				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	-	Current liabilities	$15,705
Long-term	Other assets	-	Other liabilities	5,904
Natural gas derivatives Current	Current assets	-	Current liabilities	2,162
Long-term	Other assets	-	Other liabilities	166
Fleet fuel contracts	Current assets	-	Current liabilities	1,719
Total		-		$25,656

Notes to Financial Statements

The effect of hedging instruments on other comprehensive income (OCI) and income was:

Year Ended December 31,	Gain (Loss) Recognized in OCI on Derivatives	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Gain (Loss) Reclassified from Accumulated OCI into Income
Derivatives in Cash Flow Hedging Relationships	**Effective Portion**	**Effective Portion**	
(Thousands)			
2015			
Interest rate contracts	-	Interest expense	**$(629)**
Commodity contracts:	**$(1,323)**	Other operating expenses	**(1,692)**
Total	**$(1,323)**		**$(2,321)**
2014			
Interest rate contracts	-	Interest expense	$(933)
Commodity contracts:	$(1,855)	Other operating expenses	$(374)
Total	$(1,855)		$(1,307)

The amounts in AOCI related to previously settled forward starting swaps, and accumulated amortization, as of December 31, 2015, is a net loss of $0.8 million as compared to a net loss of $1.4 million for 2014. For the year ended December 31, 2015, we recorded $0.6 million in net derivative losses related to discontinue cash flow hedges. We will amortize approximately $0.1 million of discontinued cash flow hedges in 2016.

As of December 31, 2015, $1.4 million in losses are reported in AOCI because the forecasted transaction is considered to be probable. We expect that those losses will be reclassified into earnings within the next 24 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions. There was no ineffective portion of hedge recognized during the year ended December 31, 2015.

Notes to Financial Statements

Offsetting Assets and Liabilities

Offsetting of Derivative Assets

Description (Thousands)	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet: Financial Instruments	Gross Amounts Not Offset in the Balance Sheet: Cash Collateral Pledged	Net Amount
As of December 31, 2015						
Derivatives	**$6,453**	**$(6,453)**	**$-**	**-**	**-**	**$-**
As of December 31, 2014						
Derivatives	$8,746	$(8,746)	$-	-	-	$-

Offsetting of Derivative Liabilities

Description (Thousands)	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	Gross Amounts Not Offset in the Balance Sheet: Cash Collateral Pledged	Net Amount
As of December 31, 2015						
Derivatives	**$(33,543)**	**$32,193**	**$(1,350)**	**-**	**-**	**$1,350**
As of December 31, 2014						
Derivatives	$(34,402)	$8,746	$(25,656)	-	$25,656	-

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

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of default on or termination of any one contract. For financial statement presentation, we offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement. The amount of cash collateral used to offset against net derivative positions was $25.7 million as of December 31, 2015. Under the master netting arrangements our obligation to return cash collateral was $0.1 million at December 31, 2015 and 2014.

Certain of our derivative instruments contain provisions that require us to maintain an investment grade credit rating on our debt from each of the major credit rating agencies. If our debt were to fall below investment grade, it would be in violation of those provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2015, is $27.1 million for which we have posted collateral of $48.5 million in the normal course of business.

Note 11. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $990 million and $947 million as of December 31, 2015 and 2014, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2, except for unsecured pollution controls notes-variable, with a fair value of $89 million both as of December 31, 2015 and 2014, which are considered Level 3. The fair value of these unsecured pollution control notes-variable are determined using unobservable interest rates as the market for these notes is inactive.

Notes to Financial Statements

Assets and liabilities measured at fair value on a recurring basis

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

Description (Thousands)	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Netting**	**Total**
2015					
Assets					
Noncurrent investments available for sale, primarily money market funds	**$10,402**	**-**	**-**		**$10,402**
Derivatives					
Commodity contracts:					
Electricity	**6,423**	**-**	**-**	**$(6,423)**	**-**
Natural Gas	**30**	**-**	**-**	**(30)**	**-**
Total	**$16,855**	**-**	**-**	**$(6,453)**	**$10,402**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	**$(31,527)**	**-**	**-**	**$31,527**	
Natural gas	**(666)**	**-**	**-**	**666**	
Other	**-**	**-**	**$(1,350)**	**-**	**$(1,350)**
Total	**$(32,193)**	**-**	**$(1,350)**	**$32,193**	**$(1,350)**
2014					
Assets					
Noncurrent investments available for sale, primarily money market funds	$10,227	-	-		$10,227
Derivatives					
Commodity contracts:					
Electricity	8,746	-	-	$(8,746)	-
Total	$18,973	-	-	$(8,746)	$10,227
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$(30,014)	$(340)	-	$8,745	$21,609
Natural gas	(2,329)	-	-	1	2,328
Other	-	-	$(1,719)		1,719
Total	$(32,343)	$(340)	$(1,719)	$8,746	$25,656

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2015 and 2014. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

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

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

- We enter into electric energy derivative contracts to hedge the forecasted purchases required to serve their electric load obligations. We hedge their electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. We have a combination of Level 1 and Level 2 fair values for our electric energy derivative contracts. A portion of its electric load obligations are exchange traded contracts in a NYISO location where an active market exists. The forward market prices used to value these open electric energy derivative contracts are based on quoted prices in active markets for identical assets or liabilities, with no adjustment required and therefore we include the fair value in Level 1. A portion of our electric energy derivative contracts, are non-exchange traded contracts that are valued using inputs that are directly observable for the asset or liability, or indirectly observable through corroboration with observable market data and therefore, we include the fair value in Level 2.
- We enter into natural gas derivative contracts to hedge the forecasted purchases required to serve our natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.
- We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in level 3.

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

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	
	Derivatives, Net	
Year Ended December 31,	**2015**	**2014**
(Thousands)		
Beginning balance	**$1,719**	$238
Total gains (losses) (realized/unrealized)		
Included in earnings	**(1,692)**	(374)
Included in other comprehensive income	**1,323**	1,855
Ending balance	**$1,350**	$1,719

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

(Thousands)	
Total gains (losses) included in earnings for year ended December 31,	
2015	**$(1,692)**
2014	$(374)

Notes to Financial Statements

Note 12. Accumulated Other Comprehensive Income (Loss)

(Thousands)	Balance January 1, 2014	2014 Change	Balance December 31, 2014	2015 Change	Balance December 31, 2015
Amortization of pension cost for nonqualified plans, net of income tax benefit (expense) of $323 for 2014 and $(1,033) for 2015	$(1,618)	$(493)	$(2,111)	$1,601	$(510)
Unrealized (loss) gain on derivatives qualified as hedges:		-		-	
Unrealized (loss) during period on derivatives qualified as hedges, net of income tax benefit of $735 for 2014 and $(524) for 2015		(1,120)		(799)	
Reclassification adjustment for loss included in net income, net of income tax (benefit) of $(148) for 2014 and $671 for 2015		226		1,022	
Reclassification adjustment for gain on settled cash flow treasury hedges, net of income tax (benefit) of $(370) for 2014 and $(249) for 2015		563		380	
Net unrealized (loss) gain on derivatives qualified as hedges	(1,555)	(331)	(1,886)	603	(1,283)
Accumulated Other Comprehensive (Loss) Income	$(3,173)	$(824)	$(3,997)	$2,204	$(1,793)

Note 13. 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. NYSEG's unionized employees covered under the cash balance plans ceased to receive accruals as of December 31, 2015.Their earned balances would continue to accrue interest, but would no longer be increased by a percentage of earnings. In place of the pension benefit for those employees, they will receive a minimum contribution to their account under their respective company's defined contribution plan. There was no change to the defined benefit plans for employees covered under the plans that provide defined benefits based on years of service and final average salary.

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately $3.6 million for 2015 and $3 million for 2014.

Notes to Financial Statements

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.

Obligations and funded status:	**Pension Benefits**		**Postretirement Benefits**	
	2015	**2014**	**2015**	**2014**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	**$1,666,545**	$1,480,949	**$208,254**	$187,735
Service cost	**21,603**	17,921	**2,890**	2,445
Interest cost	**61,692**	70,363	**7,654**	8,822
Plan participants' contributions	**-**	-	**2,645**	2,750
Amendments	**-**	-	**(913)**	-
Actuarial (gain)/loss	**(63,172)**	271,519	**(14,695)**	33,365
Special termination benefits	**342**	-	**-**	-
Benefits paid	**(93,646)**	(174,207)	**(13,658)**	(26,904)
Federal subsidy on benefits paid	**-**	-	**4**	41
Benefit obligation at December 31	**$1,593,364**	$1,666,545	**$192,181**	$208,254
Change in plan assets				
Fair value of plan assets at January 1	**$1,472,953**	$1,533,599	**$89,078**	$86,751
Actual return on plan assets	**(10,404)**	113,561	**(3,271)**	2,327
Employer & plan participants' contributions	-	-	**13,654**	26,862
Federal subsidy on benefits paid	-	-	**4**	41
Benefits paid	**(93,646)**	(174,206)	**(13,658)**	(26,903)
Fair value of plan assets at December 31	**$1,368,903**	$1,472,954	**$85,807**	$89,078
Funded status	**$(224,461)**	$(193,591)	**$(106,374)**	$(119,176)

Amounts recognized in the balance sheet December 31,	**Pension Benefits**		**Postretirement Benefits**	
	2015	**2014**	**2015**	**2014**
(Thousands)				
Noncurrent assets	**-**	-	**-**	**-**
Noncurrent liabilities	**$(224,461)**	$(193,591)	**$(106,374)**	**$(119,176)**
	$(224,461)	$(193,591)	**$(106,374)**	**$(119,176)**

During 2014 we offered to retired employees who are currently receiving benefits an option to receive their future pension benefit as a lump sum. Approximately $81.8 million of payments were made in 2014 as a result of retirees exercising the lump sum option. Settlement accounting was not triggered by these payments.

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

	Pension Benefits		**Postretirement Benefits**	
December 31,	**2015**	**2014**	**2015**	**2014**
(Thousands)				
Net (gain) loss	**$610,459**	$641,533	**$19,162**	$29,239
Prior service cost (credit)	**$8,138**	$10,540	**$(30,560)**	$(35,040)

Our accumulated benefit obligation for all defined benefit pension plans was $1.6 billion for December 31, 2015 and 2014.

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

December 31,	2015
(Thousands)	
Projected benefit obligation	**$1,593,363**
Accumulated benefit obligation	**$1,511,557**
Fair value of plan assets	**$1,368,903**

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

	Pension Benefits		Postretirement Benefits	
Year Ended December 31,	**2015**	**2014**	**2015**	**2014**
(Thousands)				
Net periodic benefit cost				
Service cost	**$21,603**	$17,921	**$2,890**	$2,445
Interest cost	**61,692**	70,363	**7,654**	8,822
Expected return on plan assets	**(108,661)**	(113,774)	**(4,454)**	(4,337)
Amortization of prior service cost (benefit)	**2,401**	3,442	**(5,394)**	(5,394)
Amortization of net loss	**86,967**	65,441	**3,108**	(1,243)
Special termination benefit charge	**343**	-	**-**	-
Net periodic benefit cost	**$64,345**	$43,393	**$3,804**	$293
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss (gain)	**$55,893**	$271,732	**$(6,969)**	$35,375
Amortization of net (loss)	**(86,967)**	(65,441)	**(3,108)**	1,243
Amortization of prior service (cost) credit	**(2,401)**	(3,442)	**5,394**	5,394
Current year prior service (credit)/ lost	**-**	-	**(914)**	-
Total recognized in regulatory assets and regulatory liabilities	**$(33,475)**	$202,849	**$(5,597)**	$42,012
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$30,870**	$246,242	**$(1,793)**	$42,305

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

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ended December 31, 2016	**Pension Benefits**	**Postretirement Benefits**
(Thousands)		
Estimated net loss (gain)	$83,229	$2,407
Estimated prior service cost (benefit)	$1,369	$(5,597)

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ended December 31, 2016.

Weighted-average assumptions used to	**Pension Benefits**		**Postretirement Benefits**	
determine benefit obligations at December 31,	**2015**	**2014**	**2015**	**2014**
Discount rate	**4.10%**	3.80%	**4.10%**	3.80%
Rate of compensation increase	**3.90%**	4.10%	**N/A**	N/A

Notes to Financial Statements

As of December 31, 2015, we increased our discount rate from 3.80% to 4.10%. The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate developing a yield curve derived from a portfolio of high grade non-callable bonds with above median yields that closely matches the duration of the expected cash flows of our benefit obligations.

Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31,	Pension Benefits 2015	Pension Benefits 2014	Postretirement Benefits 2015	Postretirement Benefits 2014
Discount rate	**3.80%**	4.90%	**3.80**	4.90%
Expected long-term return on plan assets	**7.50%**	7.50%	**-**	-
Expected long-term return on plan assets - nontaxable trust	**-**	-	**7.50%**	7.50%
Expected long-term return on plan assets - taxable trust	**-**	-	**5.00%**	5.00%
Rate of compensation increase	**4.10%**	4.10%	**N/A**	N/A

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses over 10 years from the time they are incurred.

Assumed health care cost trend rates to determine benefit obligations at December 31,	2015	2014
Health care cost trend rate (pre 65/post 65)	**7.50%/ 9.00%**	7.50%/ 7.00%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	**4.50%**	4.50%
Year that the rate reaches the ultimate trend rate	**2026**	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:

(Thousands)	1% Increase	1% Decrease
Effect on total of service and interest cost	$38	$(37)
Effect on postretirement benefit obligation	$450	$(443)

Cash Flows

Contributions: In accordance with our funding policy we make annual contributions of not less than the minimum required by applicable regulations. We do not expect to contribute to our pension benefit plans or our other postretirement plans in 2016.

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

	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
(Thousands)			
2016	$88,684	$13,241	-
2017	$92,090	$13,371	-
2018	$94,965	$13,441	-
2019	$97,304	$13,582	-
2020	$99,469	$13,590	-
2021- 2025	$516,626	$67,412	-

***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 dated corporate bonds, annuity contracts, and 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 Financial Statements

The fair values of Networks' pension benefits plan assets at December 31, 2015 and 2014, by asset category are shown in the following table. NYSEG's share of the total consolidated assets is approximately 70% for 2015 and 2014:

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2015				
Cash and cash equivalents	**$57,526**	**$3,290**	**$54,236**	**-**
U.S. government securities	**171,024**	**171,024**	**-**	**-**
Common stocks	**313,911**	**313,911**	**-**	**-**
Registered investment companies	**81,308**	**81,308**	**-**	**-**
Corporate bonds	**323,900**	**-**	**323,900**	**-**
Preferred stocks	**4,926**	**295**	**4,631**	**-**
Common/collective trusts	**511,504**	**-**	**21,476**	**$490,028**
Partnership/joint venture interests	**78,519**	**-**	**-**	**78,519**
Real estate investments	**88,865**	**-**	**-**	**88,865**
Other investments, principally annuity and fixed income	**318,247**	**(21)**	**-**	**318,268**
Total	**1,949,730**	**$569,807**	**$404,243**	**$975,680**
2014				
Cash and cash equivalents	$47,941	$3,795	$44,146	-
U.S. government securities	177,379	177,379	-	-
Common stocks	430,900	343,757	87,143	-
Registered investment companies	115,930	115,930	-	-
Corporate bonds	344,216	-	344,216	-
Preferred stocks	4,050	281	3,769	-
Common/collective trusts	476,581	-	26,440	$450,141
Partnership/joint venture interests	79,489	-	-	79,489
Real estate investments	74,871	-	-	74,871
Other investments, principally annuity and fixed income	345,885	-	4,200	341,685
Total	$2,097,242	$641,142	$509,914	$946,186

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

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

- Real estate investments – based on a discounted cash flow approach that includes the projected future rental receipts, expenses and residual values because the highest and best use of the real estate from a market participant view is as rental property.
- Other investments, principally annuity and fixed income - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: based on yields currently available on comparable securities of issuers with similar credit ratings. Level 3: when quoted prices are not available for identical or similar instruments, under a discounted cash flows approach that maximizes observable inputs such as current yields of similar instruments but includes adjustments for certain risks that may not be observable such as credit and liquidity risks.

	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, 2013	$458,313	$56,880	$67,266	$336,595	$919,054
Actual return on plan assets:					
Relating to assets still held at the reporting date	60,324	2,609	4,670	(834)	66,769
Relating to assets sold during the year	(48,286)	-	-	6,251	(42,035)
Purchases, sales and settlements	(20,210)	20,000	2,935	(327)	2,398
Balance, December 31, 2014	$450,141	$79,489	$74,871	$341,685	$946,186
Actual return on plan assets:					
Relating to assets still held at the reporting date	**(5,873)**	**18,518**	**10,235**	**(20,169)**	**2,711**
Relating to assets sold during the year	**(3,115)**	**(19,488)**	**-**	**904**	**(21,699)**
Purchases, sales and settlements	**48,875**	**-**	**3,759**	**(4,152)**	**48,482**
Balance, December 31, 2015	**$490,028**	**$78,519**	**$88,865**	**$318,268**	**$975,680**

Our postretirement benefits plan assets are held with a trustee in multiple voluntary employees' beneficiary association (VEBA) and 401(h) arrangements and are invested among and within various asset classes in order to achieve sufficient diversification in accordance with our risk tolerance. This is achieved for our postretirement benefits plan assets through the utilization of multiple institutional mutual and money market funds, providing exposure to different segments of the fixed income, equity and short-term cash markets. Approximately 100% of the postretirement benefits plan assets are invested in VEBA and 401(h) arrangements that are not subject to income taxes. The remainder is invested in arrangements subject to income taxes.

We have established a target asset allocation policy within allowable ranges for our postretirement benefits plan assets of 47% equity securities, 38% fixed income and 15% for all other types of investments. The target allocations within allowable ranges are further diversified into 20% large cap domestic equities, 12% medium and small cap domestic equities, 10% international developed market and 5% emerging market equity securities. Fixed income investment targets and ranges are segregated into core fixed income at 38%. Other, alternative investment targets are 5% for real estate, 5% absolute return and 5% tangible assets. Systematic rebalancing within target ranges, should any asset categories drift outside their specified ranges, increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk.

The fair values of Networks' other postretirement benefits plan assets at December 31, 2015 and 2014, by asset category are shown in the following table. NYSEG's share of the total consolidated assets is approximately 70% for 2015 and 2014.

		Fair Value Measurements at December 31, Using		
Asset Category	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(Thousands)				
2015				
Money market funds	**$4,163**	**$4,163**	**-**	**-**
Mutual funds, fixed	**35,438**	**35,438**	**-**	**-**
Government & corporate bonds	**1,703**	**-**	**$1,703**	**-**
Mutual funds, equity	**45,679**	**45,679**	**-**	**-**
Common stocks	**22,939**	**22,793**	**-**	**$146**
Mutual funds, other	**11,519**	**11,519**	**-**	**-**
Total assets measured at fair value	**$121,441**	**$119,592**	**$1,703**	**$146**
2014				
Money market funds	$4,478	$4,478	-	-
Mutual funds, fixed	35,914	35,914	-	-
Government & corporate bonds	2,126	-	$2,126	-
Mutual funds, equity	44,877	44,877	-	-
Common stocks	28,459	28,459	-	-
Mutual funds, other	12,011	12,011	-	-
Total assets measured at fair value	$127,865	$125,739	$2,126	-

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

- Money market funds and Mutual funds – based upon quoted market prices in active markets, which represent the NAV of the shares held.
- Government bond, 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, 2015.

Note 14. Subsequent events

The company has performed a review of subsequent events through April 28, 2016, which is the date these financial statements were available to be issued, and the financial statements reflect events occurring from January 1, 2016 through such date.

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

Under the terms of the Credit Facility, each joint borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit established by the banks. AGR's maximum sublimit is $1 billion, NYSEG, RGE, CMP and UI have maximum sublimits of $250 million, CNG, and SCG have maximum sublimit of $150 million and BGC has a maximum sublimit of $25 million. Under the Credit Facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. The initial facility fees will range from 12.5 to 17.5 basis points. The maturity date for the Credit Facility is April 5, 2021.

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

Rochester Gas and Electric Corporation
Financial Statements
For the Years Ended December 31, 2015 and 2014

Rochester Gas and Electric Corporation

Index

Page(s)

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

Building a better
working world

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

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

Report of Independent Auditors

To the Shareholders and Board of Directors
Rochester Gas and Electric Corporation

We have audited the accompanying financial statements of Rochester Gas and Electric Corporation which comprise the balance sheets as of December 31, 2015 and 2014, and the related statements of income, comprehensive income, changes in common stock equity and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

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

Building a better
working world

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Rochester Gas and Electric Corporation at December 31, 2015 and 2014, and the results of its operations and its cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

Ernst + Young LLP

April 29, 2016

Rochester Gas and Electric Corporation
Statements of Income

Year Ended December 31,	2015	2014
(Thousands)		
Operating Revenues		
Electric	**$657,073**	$576,065
Natural gas	**269,996**	306,603
Total Operating Revenues	**927,069**	882,668
Operating Expenses		
Electricity purchased and fuel used in generation	**117,068**	150,175
Natural gas purchased	**89,213**	127,166
Operations and maintenance	**386,290**	277,353
Depreciation and amortization	**74,050**	63,182
Other taxes	**119,421**	94,082
Total Operating Expenses	**786,042**	711,958
Operating Income	**141,027**	170,710
Other (Income)	**(12,421)**	(12,348)
Other Deductions	**1,614**	1,219
Interest Charges, Net	**78,665**	67,915
Income Before Tax	**73,169**	113,924
Income Tax Expense	**35,704**	40,862
Net Income	**$37,465**	$73,062

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

Rochester Gas and Electric Corporation
Statements of Comprehensive Income

Year ended December 31,	2015	2014
(Thousands)		
Net Income	**$37,465**	$73,062
Other Comprehensive Income (Loss), Net of Tax		
Net unrealized holding income on investments	**17**	16
Amortization of pension for nonqualified plans	**632**	(1,457)
Unrealized (loss) on derivatives qualified as hedges:		
Unrealized (loss) during period on derivatives qualified as hedges	**(255)**	(367)
Reclassification adjustment for loss included in net income	**346**	83
Reclassification adjustment for loss on settled cash flow treasury hedges	**3,483**	3,483
Net unrealized loss on derivatives qualified as hedges	**3,574**	3,199
Other Comprehensive Income, net of income taxes	**4,223**	1,758
Comprehensive Income	**$41,688**	$74,820

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

Rochester Gas and Electric Corporation
Balance Sheets

December 31,	2015	2014
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	**$1,136**	$811
Accounts receivable and unbilled revenues, net	**139,282**	156,077
Accounts receivable from affiliates	**5,007**	4,182
Natural gas in storage	**5,891**	19,746
Materials and supplies	**10,382**	10,441
Broker margin accounts	**10,570**	15,937
Income tax receivable	**11,002**	-
Prepaid property taxes	**30,516**	27,926
Other current assets	**5,321**	7,498
Regulatory assets	**32,980**	23,820
Total Current Assets	**252,087**	266,438
Utility plant, at original cost	**2,904,955**	2,854,022
Less accumulated depreciation	**854,747**	812,403
Net Utility Plant in Service	**2,050,208**	2,041,619
Construction work in progress	**329,307**	233,701
Total Utility Plant in Service	**2,379,515**	2,275,320
Other Property and Investments	**4,745**	8,740
Regulatory and Other Assets		
Regulatory assets	**508,381**	519,749
Other	**365**	1,074
Total Regulatory and Other Assets	**508,746**	520,823
Total Assets	**$3,145,093**	$3,071,321

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

Rochester Gas and Electric Corporation
Balance Sheets

December 31,	2015	2014
(Thousands)		
Liabilities		
Current Liabilities		
Notes payable to affiliates	**$69,717**	$169,737
Current portion of long term debt	**39,873**	-
Accounts payable and accrued liabilities	**144,698**	73,508
Accounts payable to affiliates	**47,643**	18,628
Interest accrued	**13,155**	13,977
Taxes accrued	**1,835**	5,747
Environmental remediation costs	**4,745**	6,246
Other	**36,941**	40,207
Regulatory liabilities	**18,558**	38,858
Total Current Liabilities	**377,165**	366,908
Regulatory and Other Liabilities		
Regulatory liabilities	**433,100**	412,168
Deferred income taxes regulatory	**14,547**	24,579
Other Non-current Liabilities		
Deferred income taxes	**399,063**	374,381
Nuclear plant obligations	**122,258**	122,238
Pension and other postretirement benefits	**187,542**	186,668
Asset retirement obligations	**8,388**	22,725
Environmental remediation costs	**133,513**	134,060
Other	**53,181**	27,878
Total Regulatory and Other Liabilities	**1,351,592**	1,304,697
Long-term debt	**665,066**	690,134
Total Liabilities	**2,393,823**	2,361,739
Commitments and Contingencies		
Equity		
Common stock ($5 par value, 50,000 shares authorized, 38,886 shares outstanding at December 31, 2015 and 2014)	**194,429**	194,429
Capital in excess of par value	**529,943**	529,943
Retained earnings	**190,933**	153,468
Accumulated other comprehensive (loss)	**(46,797)**	(51,020)
Treasury stock, at cost (4,379 shares at December 31, 2015 and 2014)	**(117,238)**	(117,238)
Total Equity	**751,270**	709,582
Total Liabilities and Equity	**$3,145,093**	$3,071,321

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

Rochester Gas and Electric Corporation
Statements of Cash Flows

Year Ended December 31,	2015	2014
(Thousands)		
Operating Activities		
Net income	**$37,465**	$73,062
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**74,050**	63,182
Amortization of regulatory and other assets and liabilities,	**25,784**	(233)
Carrying cost of regulatory assets and liabilities	**25,532**	21,576
Deferred income taxes and investment tax credits, net	**23,354**	7,929
Pension expense	**20,762**	12,925
Changes in operating assets and liabilities		
Accounts receivable and unbilled revenues, net	**15,970**	28,456
Inventory	**13,914**	(1,471)
Accounts payable and accrued liabilities	**114,472**	(10,345)
Taxes accrued	**(1,559)**	(20,109)
Other liabilities	**(15,716)**	(35,932)
Changes in regulatory assets and liabilities	**(41,840)**	66,207
Changes in other assets	**(25,927)**	(26,151)
Net Cash Provided by Operating Activities	**266,261**	179,096
Investing Activities		
Utility plant additions	**(191,075)**	(206,800)
Grants received from governmental entities	**16,479**	2,732
Contribution in aid of construction	**8,657**	10,653
Other investments	**1,282**	1,311
Net Cash Used in Investing Activities	**(164,657)**	(192,104)
Financing Activities		
Dividends on common stock	**-**	(100,000)
Notes payable short term debt and capital leases	**(1,259)**	-
Notes payable affiliates	**(100,020)**	114,657
Purchase in Lieu of redemption	**-**	(5,850)
Net Cash Provided by (Used in) Financing Activities	**(101,279)**	8,807
Net Increase (Decrease) Increase in Cash and Cash Equivalents	**325**	(4,201)
Cash and Cash Equivalents, Beginning of Year	**811**	5,012
Cash and Cash Equivalents, End of Year	**$1,136**	$811

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

Rochester Gas and Electric Corporation
Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)	Shares	Common Stock Outstanding $5 Par Value Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Loss	Treasury Stock	Total
Balance, January 1, 2014	38,886	$194,429	$529,943	$180,406	$(52,778)	$(117,238)	$734,762
Net income				73,062			73,062
Other comprehensive income, net of tax					1,758		1,758
Comprehensive income							74,820
Common stock dividends paid				(100,000)			(100,000)
Balance, December 31, 2014	38,886	194,429	529,943	153,468	(51,020)	(117,238)	709,582
Net income				**37,465**			**37,465**
Other comprehensive income, net of tax					**4,223**		**4,223**
Comprehensive income							**41,688**
Balance, December 31, 2015	**38,886**	**$194,429**	**$529,943**	**$ 190,933**	**$(46,797)**	**$(117,238)**	**$751,270**

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

Notes to Financial Statements

Note 1. Significant Accounting Policies

Background: Rochester Gas and Electric Corporation's (RGE, the company, we, our, us), principal business consists of its regulated electricity transmission, distribution and generation operations and regulated natural gas transportation and distribution operations in western New York. RGE generates electricity from three natural gas turbine plants and several smaller hydroelectric stations. RGE serves approximately 374,000 electricity and 309,000 natural gas customers in its service territory of approximately 2,700 square miles. The service territory contains a substantial suburban area and a large agricultural area in parts of nine counties including and surrounding the city of Rochester, New York with a population of approximately one million people. We operate under the authority of the New York State Public Service Commission (NYPSC) and are also subject to regulation by the Federal Energy Regulatory Commission (FERC).

RGE is a subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of AVANGRID (AGR) formerly Iberdrola USA, Inc. which is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain. Networks' wholly-owned subsidiaries, and their principal operating companies, include: CMP Group, Inc. – Central Maine Power Company (CMP), and RGS Energy Group, Inc. - New York State Electric & Gas Corporation (NYSEG) and RGE.

Accounts receivable: Accounts receivable at December 31 include unbilled revenues of $44 million for 2015 and $51 million for 2014, and are shown net of an allowance for doubtful accounts at December 31 of $25 million for 2015 and $22 million for 2014. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $20 million in 2015 and $17 million in 2014.

Unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the estimates 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 we review our allowance for doubtful accounts and past due accounts by age. When we believe that a receivable will not be recovered, we charge off the account balance against the allowance. Changes in assumptions about input factors and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful account estimates.

Our accounts receivable include amounts due under deferred payment arrangements (DPAs). When a residential customer becomes delinquent in making payments, the NYPSC requires us to allow the customer to enter into a DPA to settle the account balance. A DPA allows the account balance to be paid in installments over an extended time by negotiating mutually acceptable payment terms. Generally, we must continue to serve a customer who cannot pay an account balance in full if the customer: pays a reasonable portion of the balance; agrees to pay the balance in installments; and agrees to pay future bills within 30 days until the DPA is paid in full or is otherwise considered to be delinquent. We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses and by establishing specific provisions for known credit issues. Amounts are written off when reasonable collection efforts have been exhausted. The allowance for doubtful accounts for DPAs at December 31 was $16 million for 2015 and 2014. DPA receivable balances at December 31 were: $24 million for 2015 and $31 million in 2014.

Notes to Financial Statements

Asset retirement obligations: We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability to its present value periodically to reflect revisions to either the timing or the amount of the original estimated undiscounted cash flows, and depreciate the capitalized cost over the useful life of the related asset. Upon settlement we will either settle the obligation at its recorded amount or incur a gain or a loss. We 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 $8 million for 2015 and $23 million for 2014. The ARO is associated with our long-lived assets and primarily consists of obligations related to removal or retirement of: asbestos, PCB-contaminated equipment, gas pipeline and cast iron gas mains.

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

Year ended December 31,	**2015**	**2014**
(Thousands)		
ARO, beginning of year	**$22,725**	$15,833
Liabilities settled during the year	**(14,534)**	(122)
Liabilities incurred during the year	**-**	-
Accretion expense	**197**	1,178
Revisions in estimated cash flows	**-**	5,836
ARO, end of year	**$8,388**	$22,725

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

Broker margin accounts: We maintain accounts with clearing firms that require initial margin deposits upon the establishment of new positions, primarily related to natural gas and electricity derivatives, as well as maintenance margin deposits in the event of unfavorable movements in market valuation for those positions. The amount reflecting those activities is shown as broker margin accounts on our balance sheets.

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 Financial Statements

Supplemental Disclosure of Cash Flows Information

	2015	2014
(Thousands)		
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	**$40,110**	$34,323
Income taxes paid, net	**$25,219**	$51,457

Interest capitalized was $7 million in 2015 and $6 million in 2014. Included in the income taxes paid, $22 million was paid to AGR under the tax sharing agreement.

Depreciation: We determine depreciation expense using the straight-line method, based on the average service lives of groups of depreciable property, which include estimated cost of removal. Our depreciation accruals were equivalent to 2.5% of average depreciable property for 2015 and 2.3% for 2014. We amortize our capitalized software cost which is included in common plant, using the straight line method, based on useful lives of 5 to 10 years. Capitalized software costs at December 31 were approximately $110 million for 2015 and $93 million for 2014. Depreciation expense was $69 million in 2015 and $59 million in 2014. Amortization of capitalized software was $5 million in 2015 and $4 million in 2014.

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.

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

Plant	**Estimated useful life range (years)**	**2015**	**2014**
(Thousands)			
Electric	24-66	**$1,856,532**	$1,863,617
Natural Gas	26-60	**761,135**	742,387
Common	12-32	**287,288**	248,018
Total Property, Plant and Equipment		**$2,904,955**	$2,854,022

Electric plant includes capital leases of $14 million in 2015. Accumulated depreciation related to these leases was $1.6 million in 2015. RGE had no capital leases in 2014.

Environmental remediation liability: In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. Our environmental liabilities are recorded on an undiscounted basis. Our environmental liability accruals are expected to be paid through the year 2039.

Inventory: Inventory comprises fuel and gas in storage and materials and supplies. We own natural gas that is stored in third-party owned underground storage facilities. This gas is recorded as inventory. Injections of inventory into storage are priced at the market purchase cost at the time of injection, and withdrawals of working gas from storage are priced at the weighted-average cost in storage. We continuously monitor the weighted-average cost of gas value to ensure it remains at, or below market value. Inventories to support gas operations are reported on the balance sheet within “Natural gas in storage.”

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

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

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

Limited voting junior preferred stock: We have a class of preferred stock having one share and a par value of $1, which is issued and outstanding and has voting authority only with respect to whether RGE may file a voluntary bankruptcy petition.

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

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

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

Simplifying the Presentation of Debt Issuance Costs: The FASB issued an amendment in April 2015 that is intended to simplify the presentation of debt issuance costs. Instead of presenting debt issuance costs as a deferred charge (that is, as an asset), the amendments require debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with the presentation for debt discounts. The amendment is effective for public entities for financial statements issued for fiscal years beginning after December 15, 2015, and for interim periods within those fiscal years. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2015 and have applied it retrospectively to all periods presented. Accordingly, we reclassified the debt issuance costs from other noncurrent assets to noncurrent debt on our December 31, 2014 balance sheet, which decreased total assets, noncurrent debt and total liabilities by $11 million.

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

Balance Sheet Classification of Deferred Taxes: The FASB issued an amendment in November 2015 that is intended to simplify the presentation of deferred income taxes by requiring entities that present a classified statement of financial position to classify deferred tax liabilities and assets as noncurrent in their balance sheet. This aligns the presentation of deferred income tax liabilities and assets with International Financial Reporting Standards. The amendments do not affect the current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount. The amendments are effective for public entities for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. As permitted, we have early adopted the amendments as of the beginning of the fourth quarter of 2015, and have elected retrospective application to all periods presented in order to simplify the presentation in our balance sheet. Accordingly, we reclassified the current deferred taxes to noncurrent on our December 31, 2014 balance sheet, which decreased current assets and noncurrent deferred tax liabilities by $20 million due to right of offset.

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

Revenue from Contracts with Customers: In May 2014 the FASB issued an amendment related to the recognition of revenue from contracts with customers and required disclosures. The core principle is for an entity to recognize revenue to represent the transfer of goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. The standard is effective for public entities for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. In August 2015 the FASB issued an accounting standards update that defers by one year the effective date of the standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption as of the original effective date permitted. In March 2016 the FASB issued an accounting standards update that amends and clarifies the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, with the same deferred effective date. We are currently evaluating how our adoption of the amendment will affect our results of operation, financial position, and cash flows.

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

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

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

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

Leases: In February 2016 the FASB issued new guidance that affects all companies and organizations that lease assets, and requires them to record on their balance sheet assets and liabilities for the rights and obligations created by those leases. A lease is an arrangement that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Concerning lease expense recognition, after extensive consultation, the FASB has ultimately concluded that the economics of leases can vary for a lessee, and those economics should be reflected in the financial statements. As a result, the amendments retain a distinction between finance leases and operating leases, while requiring both types of leases to be recognized on the balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the criteria for distinguishing between capital leases and operating leases in current GAAP. By retaining a distinction between finance leases and operating leases, the effect of leases on the statement of comprehensive income and the statement of cash flows is largely unchanged from current GAAP. Lessor accounting will remain substantially the same as current GAAP, but with some targeted improvements intended to align lessor accounting with the lessee accounting model and with the revised revenue recognition guidance issued in 2014. The updated guidance is effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early application is permitted. We expect our adoption of the new guidance will materially affect our results of operation and financial position.

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

Notes to Financial Statements

Other (Income) and Other Deductions:

Year Ended December 31, (Thousands)	2015	2014
Interest and dividend income	**$(222)**	$(83)
Allowance for funds used during construction	**(7,672)**	(8,599)
Gain on sale of property	**(174)**	-
Carrying costs on regulatory assets	**(4,281)**	(3,666)
Miscellaneous	**(73)**	-
Total other (income)	**$(12,422)**	$(12,348)
Miscellaneous	**$1,614**	$1,219
Total other deductions	**$1,614**	$1,219

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

- Other operating expenses and Maintenance have been combined into Operations and maintenance in the statement of income for the year ended December 31, 2014.
- Non-current regulatory assets and liabilities items have been combined into Regulatory assets and Regulatory liabilities, respectively, in the balance sheet as of December 31, 2014.
- Accounts payable for electricity and natural gas purchased have been combined into Accounts payable and accrued liabilities in the balance sheet as of December 31, 2014.
- Prepaid property taxes were reclassified from Prepayments and other current assets to a separate line in the balance sheet as of December 31, 2014.
- Utility plant line items for Electricity, Natural gas and Common have been combined into Property, plant and equipment in the balance sheet as of December 31, 2014.

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

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric 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. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. (See Note 3)

Related party transactions: Certain Networks subsidiaries borrow from AGR, the parent of Networks, through intercompany revolving credit agreements, including RGE. For RGE the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 6 for further detail on the credit facility with AGR.

Notes to Financial Statements

Avangrid Service Corporation provides some administrative and management services to Networks operating utilities, including RGE, pursuant to service agreements. The cost of those services is allocated in accordance with methodologies set forth in the service agreements. The cost allocation methodologies vary depending on the type of service provided. Management believes such allocations are reasonable. The cost for services provided to RGE by AGR and its affiliates were approximately $47 million for 2015 and $51 million for 2014 and charge for services provided by RGE to AGR and its subsidiaries were approximately $7 million for 2015 and $12 million for 2014. All charges for services are at cost. All of the charges associated with services provided are recorded as offsetting credits to other operating expenses on the financial statements. Of the Balance in accounts payable to affiliates of $48 million at December 31, 2015, $35 million is associated to Avangrid Service Company and $10 million to NYSEG and the balance of $19 million at December 31, 2014 is mostly associated to Avangrid Service Company.

AGR, on behalf of RGE, guarantees $123 million to fund the clean-up of the Ginna Nuclear Power Plant, LLC.

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

RGE enters into power purchase and sales transactions with the New York Independent System Operator (NYISO). When RGE sells 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 and RGE net their purchase and sale transactions with the NYISO on an hourly basis.

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

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

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

The aggregate amount of the intercompany income tax receivable balance due from AGR is $11.0 million at December 31, 2015. The aggregate amount of the intercompany income tax payable balance due to AGR is $1.6 million at December 31, 2014.

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

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

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

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

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

Use of estimates and assumptions: The preparation of our financial statements in conformity with US 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 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; (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) earnings sharing mechanism (ESM); (9) environmental remediation liability; (10) pension benefits; (11) fair value measurements and (12) AROs. Future events and their effects cannot be predicted with certainty; accordingly, our accounting estimates require the exercise of judgment. The accounting estimates used in the preparation of our 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: Approximately 41% of the company's employees are covered by a collective bargaining agreement. RGE has no agreements which will expire within the coming year.

Notes to Financial Statements

Note 2. Industry Regulation

Our revenues are regulated, being based on tariffs established in accordance with administrative procedures set by the New York State Public Service commission (NYPSC). The tariffs applied to regulated activities and are approved by the NYPSC and are based on the cost of providing service. Our revenues are set to be sufficient to cover all operating costs, including energy costs, finance costs, and the costs of equity, the last of which reflect our capital ratio and a reasonable return on equity (ROE).

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

Rate Plans

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

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

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

On September 1, 2012, RGE began amortizing $5.3 million per year of its $105 million theoretical excess depreciation reserve. This amortization reflects a twenty year amortization period. Theoretical excess depreciation is the difference between actual accumulated depreciation taken to date and a theoretical reserve. The actual accumulated depreciation is the result of depreciation rates allowed in prior rate orders based on estimates of useful lives and net salvage values as determined in those cases. The theoretical reserve is the amount that would have accumulated if the depreciation rates in the new rate plan had been in place for the entire useful lives of the affected assets. Differences between the actual reserve and the theoretical reserve are normal aspects of utility ratemaking. In accordance with the rate plan, we will moderate electric rates by recording the theoretical reserve amortization as a debit to accumulated depreciation and a credit to other revenues, and normalize a portion of the amortization from a tax perspective.

On May 20, 2015, RGE filed electric and gas rate cases with the NYPSC. We requested a rate increase for RGE gas and proposed a rate decrease for RGE electric. On February 19, 2016, the RGE and other signatory parties filed a Joint Proposal (Proposal) with the NYPSC for a three-year rate plan for electric and gas service at RGE commencing May 1, 2016. The Proposal balances the varied interests of the signatory parties including but not limited to maintaining the company's credit quality and mitigating the rate impacts to customers. The Proposal reflects many customer attributes including: acceleration of the companies' natural gas leak prone main replacement programs and enhanced electric vegetation management to provide continued safe and reliable service. The delivery rate increases in the Proposal can be summarized as follows:

	May 1, 2016		May 1, 2017		May 1, 2018	
	Rate Increase (Millions)	**Delivery Rate Increase %**	**Rate Increase (Millions)**	**Delivery Rate Increase %**	**Rate Increase (Millions)**	**Delivery Rate Increase %**
Electric	3.0	0.70%	21.6	5.0%	25.9	5.7%
Gas	8.8	5.20%	7.7	4.4%	9.5	5.2%

The allowed rate of return on common equity for RGE Electric and RGE Gas is 9.00%. The equity ratio for each is 48%. The Proposal includes an Earnings Sharing Mechanism (ESM) applicable to each company. The customer share of earnings would increase at higher earnings levels, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first year. Earnings thresholds would increase in subsequent years. The Proposal maintains our current electric reliability performance measures (and associated potential negative revenue adjustments for failing to meet established performance levels) which include the system average interruption frequency index and the customer average interruption duration index. The Proposal also modifies certain gas safety performance measures at the companies, including those relating to the replacement of leak prone main, leak backlog management, emergency response, and damage prevention. The Proposal establishes threshold performance levels for designated aspects of customer service quality and continues and expands our bill reduction and arrears forgiveness Low Income Programs at increased funding levels. REV-related incremental costs and fees will be included in the Rate Adjustment Mechanism (RAM) to the extent cost recovery is not provided for elsewhere. Under the Proposal, we will implement a RAM, which will be applicable to all customers, to return or collect RAM Eligible Deferrals and Costs, including: (1) property taxes; (2) Major Storm deferral balances; (3) gas leak prone pipe replacement; and (4) REV costs and fees which are not covered by other recovery mechanisms.

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

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

Reforming the Energy Vision (REV)

In April 2014, the NYPSC commenced a proceeding entitled REV which is a wide ranging initiative to reform New York State's energy industry and regulatory practices. REV has been divided into two tracks, Track 1 for Market Design and Technology, and Track 2 for Regulatory Reform. REV proposes regulatory changes that are intended to promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar and wider deployment of distributed energy resources, such as micro grids, on-site power supplies and storage.

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

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

Ginna Reliability Support Service Agreement

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

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

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

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

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

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. We base our assessment of whether recovery is probable on the existence of regulatory orders that allow for recovery of certain costs over a specific period, or allow for reconciliation or deferral of certain costs. When costs are not treated in a specific order we use regulatory precedent to determine if recovery is probable. We also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs. Of the total regulatory assets net of regulatory liabilities, approximately $484 million represents the offset of accrued liabilities for which funds have not been expended. The remainder is either included in rate base or accruing carrying costs.

Details of regulatory assets and 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.

The items that would begin being amortized assuming the Joint Proposal is approved are plant related tax items. A majority of the other items, which net to a regulatory liability, will not be amortized until future proceedings or will be used to recover costs of the Ginna RSSA agreement.

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

December 31, (Thousands)	2015	2014
Current		
Revenue decoupling mechanism	**6,493**	5,775
Temporary supplemental assessment surcharge	**2,269**	4,398
Hedge losses	**11,167**	9,565
Gas supply charge and deferred natural gas costs	**-**	1,576
Environmental remediation costs	**11,111**	-
Other	**1,940**	2,506
Total short term regulatory assets	**$32,980**	$23,820
Long-Term		
Asset retirement obligation	**$8,061**	$16,129
Unamortized losses on reacquired debt	**5,385**	5,934
Decommissioning	**7,442**	-
Pension and other postretirement benefits cost deferrals	**29,700**	15,621
Federal tax depreciation normalization adjustment	**74,482**	59,586
Environmental remediation costs	**98,826**	120,917
Pension and other postretirement benefits	**141,296**	160,150
Unfunded future income taxes	**128,371**	128,638
Other	**14,818**	12,774
Total long-term regulatory assets	**$508,381**	$519,749

Environmental remediation costs include spending that has occurred and is eligible for future recovery in customer rates. Environmental costs are currently recovered through a reserve mechanism whereby projected spending is included in rates with any variance recorded as a regulatory asset or a regulatory liability. The amortization period will be established in future proceedings and will depend upon the timing of spending for the remediation costs. It also includes the anticipated future rate recovery of costs that are recorded as environmental liabilities since these will be recovered when incurred. Because no funds have yet been expended for the regulatory asset related to future spending, it does not accrue carrying costs and is not included within rate base.

Pension and other postretirement benefits represent the actuarial losses on the pension and other postretirement plans that will be reflected in customer rates when they are amortized and recognized in future pension expenses. Because no funds have yet been expended for this regulatory asset, it does not accrue carrying costs and is not included within the rate base. Pension and other postretirement benefits cost deferrals include the difference between actual expense for pension and other postretirement benefits and the amount provided for in rates. The recovery of these amounts will be determined in future proceedings.

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

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

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

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

December 31, (Thousands)	2015	2014
Current		
Energy efficiency portfolio standard	**$20,318**	$19,378
Gas supply charge and deferred natural gas costs	**1,140**	2,692
Decommissioning	**-**	12,539
Merchant function charge	**(2,579)**	29
Other	**(321)**	4,220
Total short term regulatory liabilities	**$18,558**	$38,858
Other long-Term		
Asset sale gain account	**$10,616**	$9,943
Earnings sharing	**6,791**	8,249
Economic development	**16,632**	16,563
Merger capital expense target customer credits	**10,000**	10,000
Other taxes	**11,227**	6,718
Deferred transmission congestion contracts	**14,430**	11,472
Post term amortizations	**22,268**	18,850
Net plant reconciliation	**9,690**	9,720
Spent nuclear fuel interest	**14,155**	11,536
Accrued removal obligations	**178,242**	166,360
Positive benefit adjustment	**37,505**	37,505
Deferred property taxes	**14,605**	51,481
Carrying costs on deferred income tax bonus depreciation	**55,480**	37,939
Other	**31,459**	15,832
Total other long term regulatory liabilities	**433,100**	412,168
Deferred income taxes regulatory	**14,547**	24,579
Total long term regulatory liabilities	**$447,647**	$436,747

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

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

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

Economic development represents the economic development program which enables us and to foster economic development through attraction, expansion, and retention of businesses within its service territory. If the level of actual expenditures for economic development varies in any rate year from the level provided for in rates, the difference is refunded to ratepayers. The amortization period is awaiting a future NYPSC rate proceeding.
Merger capital expense target customer credit account was created as a result of not meeting certain capital expenditure requirements established in the order approving the purchase of Energy East by Iberdrola. The amortization period is awaiting a future NYPSC rate proceeding.

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

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

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

Note 4. Income Taxes

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

Year Ended December 31,	**2015**	**2014**
(Thousands)		
Current		
Federal	**$ 11,923**	$26,523
State	**427**	6,410
Current taxes charged to expense	**12,350**	32,933
Deferred		
Federal	**14,917**	9,877
State	**8,437**	(1,410)
Deferred taxes charged to expense	**23,354**	8,467
Investment tax credit adjustments	**-**	(538)
Total Income Tax expense	**$35,704**	$40,862

Notes to Financial Statements

The differences between tax expense per the statements of income and tax expense at the 35% statutory federal tax rate for the years ended December 31, 2015 and 2014 consisted of:

Year Ended December 31,	2015	2014
(Thousands)		
Tax expense at federal statutory rate	**$25,609**	$39,873
Depreciation and amortization not normalized	**8,734**	3,565
Allowance for funds used during construction	**(5,074)**	(4,829)
Investment tax credit amortization	**-**	(538)
State taxes, net of federal benefit	**5,762**	3,250
Tax return and audit adjustments	**(191)**	(351)
Other, net	**864**	(108)
Total Income Tax expense	**$35,704**	$40,862

In March of 2014, New York Senate Bill 6359 was enacted that, in pertinent part, reduced the state income tax rate from 7.1% to 6.5% beginning with tax year 2016. This change in the state income tax rate resulted in a reduction in our net deferred tax liabilities and decrease in state deferred tax expense of $1.6 million, which is net of the federal benefit.

Income tax expense for the year ended December 31, 2015 was $10.1 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, (net of federal benefit), and depreciation not normalized, partially offset by allowance for funds used during construction. This resulted in an effective tax rate of 48.8%. Income tax expense for the year ended December 31, 2014 was $1.0 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to depreciation not normalized, partially offset by allowance for funds used during construction. This resulted in an effective tax rate of 35.9%.

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

As of December 31,	2015	2014
(Thousands)		
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	**$496,139**	$489,000
Unfunded future income taxes	**50,854**	51,704
Derivative asset	**(30,701)**	(25,333)
Non-cash return – bonus depreciation	**(21,979)**	(15,030)
Pension and other postretirement benefits	**(6,126)**	(9,325)
Positive benefits adjustments merger order	**(14,857)**	(14,857)
Other	**(59,720)**	(77,199)
Total Non-current Deferred Income Tax Liabilities	**$413,610**	$398,960
Less amounts classified as regulatory liabilities		
Non-current deferred income taxes	**14,547**	24,579
Non-current Deferred Income Tax Liabilities	**$399,063**	$374,381
Deferred tax assets	**$133,383**	$141,744
Deferred tax liabilities	**546,993**	540,704
Net Accumulated Deferred Income Tax Liabilities	**$413,610**	$398,960

We have no federal or state net operating loss or tax credit carryforwards.

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

Year Ended December 31,	2015	2014
(Thousands)		
Balance as of January 1	**$ 2,358**	$4,143
Reductions for tax position related to settlements with taxing authorities	**(1,866)**	(1,785)
Balance as of December 31	**$492**	$2,358

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

Accruals for interest and penalties on tax reserves were $0.1 million as of December 31, 2015 and $1.0 million as of December 31, 2014. Gross unrecognized tax benefits decreased $1.8 million in 2015 due to settlements with taxing authorities.

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

Note 5. Long-term Debt

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

As of December 31,	2015			2014	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds[1]	2019 - 2033	$600,000	4.10%-8.00%	$600,000	4.10%8.00%
Secured PCNs[2][3] - fixed	2016	39,850	4.75%-5.00%	39,850	4.75%5.00%
Unsecured PCNs – variable	2032	62,150	0.195%	62,150	0.104%
Total Debt		**$702,000**		**$ 702,000**	
Obligations under capital leases	2016-2023	12,451		-	
Unamortized debt (costs) premium, net		(9,512)		(11,866)	
Less: debt due within one year, included in current liabilities		39,873		-	
Total Non-current Debt		**$665,066**		**$690,134**	

(1) The first mortgages bonds are secured by a first mortgage lien on substantially all of Net Utility Plant In Service. We have no other secured indebtedness. None of our other debt obligations are guaranteed or secured by any of our affiliates.
(2) PCNs = pollution control notes.
(3) Secured PCNs – fixed of $39,850 thousand are secured by the first mortgage lien.

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

2016	2017	2018	2019	2020
$39,873	1,354	1,434	$151,519	1,609

We have no financial debt covenant requirements related to our long-term debt at December 31, 2015 and 2014.

Note 6. Bank Loans and Other Borrowings

RGE relies on bank provided revolving credit facilities and on inter-company revolving credit facilities with AGR, to fund short-term liquidity needs. We had a total of $70 million of short-term debt outstanding at December 31, 2015 and $170 million outstanding at December 31, 2014. As of December 31, 2015, borrowing rate was 0.42%.

In July 2011, RGE jointly entered into a bank provided revolving credit facility (the “Joint Facility”) that allows maximum borrowings of up to $600 million in aggregate and expires in 2018. RGE currently has $200 million sublimit under the agreement and pays a facility fee of 20 basis points annually.

We also have an intercompany credit facility under a demand note agreement with AGR that provides financing of up to $250 million. Under the terms of that agreement, which expires in

2018, we pay a rate equivalent to our external short-term borrowing costs or the A2/P2 commercial paper rate published by the Federal Reserve. Under this agreement, we had a total of $47 million of notes payable to affiliates at December 31, 2015 and $170 million outstanding at December 31, 2014.

In April 2013 RGE entered into an agreement with NYSEG and CMP under which each company may lend to the other, under certain circumstances, excess cash on hand. As of December 31, 2015, there were $23 million in Notes payable to CMP which has been subsequently repaid.

In the joint facility we covenant not to permit, without the consent of the lender, our 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 indebtedness to total capitalization, the facility excludes from net worth the balance of accumulated other comprehensive (loss) as it appears on the balance sheet. The facility contains various other covenants, including a restriction on the amount of secured indebtedness we may maintain. Continued un-remedied 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. Our ratio of indebtedness to total capitalization pursuant to the revolving credit facility was .49 to 1.00 at December 31, 2015. We are not in default as of December 31, 2015.

Note 7. Commitments and Contingencies

Nuclear entitlement power purchase contracts

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

RGE satisfies its natural gas supply requirements through purchases from various producers and suppliers, withdrawals from natural gas storage, capacity contracts and winter peaking supplies and resources. The company operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual reasonable gas costs incurred by each company are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

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

In connection with our sales of nuclear generating assets in 2004, we entered into four entitlement contracts under which we purchase electricity at a fixed contract price. We expensed approximately $86 million for nuclear entitlement power in 2014. We have no future commitments for the purchase of nuclear entitlement power.

Purchase power and natural gas contracts, including nonutility generators:

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

RGE satisfies its natural gas supply requirements through purchases from various producers and suppliers, withdrawals from natural gas storage, capacity contracts and winter peaking supplies and resources. The company operates diverse portfolios of gas supply, firm transportation capacity, gas storage and peaking resources. Actual reasonable gas costs incurred by each of the companies are passed through to customers through state regulated purchased gas adjustment mechanisms, subject to regulatory review.

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

We recognized expenses of approximately $49 million for purchase power and natural gas contracts including nonutility generators, in 2015 and $54 million in 2014. We estimate that our power purchases will total $55 million in 2016, and $44 million in 2017, $31 million each year for 2018 and 2019 and $72 million thereafter.

NYPSC Staff Review of Earnings Sharing Calculations and Other Regulatory Deferrals

In December 2012, the NYPSC Staff (Staff) informed RGE that the Staff had conducted an audit of the company's annual compliance filings (ACF) for 2009 through August 31, 2010, and the first rate year of the rate plan, September 1, 2010 through August 31, 2011. The Staff's preliminary findings indicated adjustments to deferred balances primarily associated with the treatment of certain incentive compensation costs for purposes of the 2011 ACF. The Staff's findings approximate $1.6 million of adjustments to deferral balances and customer earnings sharing accruals. We reviewed the Staff's adjustments and work papers and provided a response in 2013. We disagreed with certain staff conclusions and as a result recorded a $1.0 million reserve in December 2012. In the proposal filed with the NYPSC (see Note 2) the parties agreed that $0.6 million would be added to customer share of Earnings Sharing.

Leases

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

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 the New York State Department of Environmental Conservation (NYSDEC), 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 eight waste sites. The eight sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the eight sites, six sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites and three 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 $160 thousand at December 31, 2015, related to the seven sites. We have recorded an estimated liability of $4.3 million related to another six 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. 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 11 sites where gas was manufactured in the past. In 1994 and 1996 we entered into orders on consent with the NYSDEC. Those orders require us to investigate and, where necessary, remediate all of our eleven sites. All 11 sites are included in the New York Voluntary Clean-up Program.

Our estimate for all costs related to investigation and remediation of the 11 sites ranges from $91 million to $207 million at December 31, 2015. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $134 million at December 31, 2015, and $137 million at December 31, 2014. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis unless payments are fixed and determinable. We have received insurance settlements which we accounted for as reductions to our related regulatory asset.

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 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 this risk through a combination of regulatory mechanisms, such as the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. Those measures mitigate our commodity price exposure, but do not completely eliminate it. Owned electric generation and long-term supply contracts reduce our exposure to market fluctuations.

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

We currently have a non by-passable wires charge adjustment that allows us to pass through rates any changes in the market price of electricity. We use electricity contracts, both physical and financial, to manage fluctuations in electricity commodity prices in order to provide price stability to customers. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. We record changes in the fair value of electric hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations. At December 31, 2015, the loss recognized in regulatory assets was $8.7 million for electricity derivatives. For the year ended December 31, the amount reclassified from regulatory assets into income, which is included in electricity purchased, was a loss of $12.3 million for 2015 and a loss of $5.3 million for 2014.

We have a purchased gas adjustment clause that allows us to recover through rates any changes in the market price of purchased natural gas, substantially eliminating our exposure to natural gas price risk. We use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts to derivative assets and/or liabilities with an offset to regulatory assets and/or regulatory liabilities in accordance with the requirements concerning accounting for regulated operations. At December 31 the loss recognized in regulatory assets for natural gas hedges was $2.4 million for 2015 and 2014 in regulatory assets. For the year ended December 31, the loss reclassified from regulatory assets into income, which is included in natural gas purchased, was $3.3 million for 2015 and $1.5 million for 2014.

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

Year to settle	Electricity Contracts Mwhs	Natural Gas Contracts Dths	Fleet Fuel Contracts Gals
As of December 31, 2015			
2016	**1,232,750**	**3,030,000**	**447,500**
2017	**758,600**	**600,000**	**234,000**
As of December 31, 2014			
2015	1,138,600	1,680,000	477,200
2016	684,400	340,000	-

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

	Asset Derivatives		Liability Derivatives	
As of December 31,	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
(Thousands)				
Derivatives designated as hedging instruments				
2015				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	**$180**	Current liabilities	
Long-term	Other assets	**-**	Other liabilities	**-**
				-
Natural gas derivatives:				
Current	Current assets		Current liabilities	
Long-term	Other assets	**-**	Other liabilities	
Fleet fuel contracts	Current assets	**-**	Current liabilities	**$273**
	Other assets		Other Liabilities	**140**
Total		**$180**		**$413**
2014				
Commodity contracts:				
Electricity derivatives:				
Current	Current assets	-	Current liabilities	$4,297
Long-term	Other assets	-	Other liabilities	2,854
Natural gas derivatives:				
Current	Current assets	-	Current liabilities	1,956
Long-term	Other assets	-	Other liabilities	458
Fleet fuel contracts	Current assets	-	Current liabilities	562
Total		-		$10,127

Offsetting Assets and Liabilities

Offsetting of Derivative Assets

				Gross Amounts Not Offset in the Balance Sheet		
Description	**Gross Amounts of Recognized Assets**	**Gross Amounts Offset in the Balance Sheet**	**Net Amounts of Assets Presented in the Balance Sheet**	**Financial Instruments**	**Cash Collateral Pledged**	**Net Amount**
(Thousands)						
As of December 31, 2015						
Derivatives	$2,985	$(2,805)	$180	-	-	$180
As of December 31, 2014						
Derivatives	$2,636	$(2,636)	-	-	-	-

Notes to 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	Gross Amounts Not Offset in the Balance Sheet: Cash Collateral Pledged	Net Amount
(Thousands)						
As of December 31, 2015						
Derivatives	$(14,547)	$14,134	$(413)	-	-	$413
As of December 31, 2014						
Derivatives	$(12,763)	$2,636	$(10,127)	-	$10,127	-

The effect of hedging instruments on other comprehensive income (OCI) and income was:

Year Ended December 31,	Gain (Loss) Recognized in OCI on Derivatives	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Gain (Loss) Reclassified from Accumulated OCI into Income	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives
Derivatives in Cash Flow Hedging Relationships	**Effective Portion**	**Effective Portion**		**Ineffective Portion**	
(Thousands)					
2015					
Interest rate contracts	**-**	Interest expense	**$(5,768)**	Interest expense	**-**
Commodity contracts	**$(423)**	Other operating expenses	**(573)**		
Total	**$(423)**		**$(6,341)**	**-**	**-**
2014					
Interest rate contracts	-	Interest expense	$(5,768)	Interest expense	**-**
Commodity contracts	$(608)	Other operating expenses	(137)		
Total	$(608)		$(5,905)	**-**	**-**

The amount in AOCI related to previously settled forward starting interest rate swaps and accumulated amortization, at December 31 is a net loss of $74.0 million for 2015 as compared to a net loss of $79.8 million for 2014. For the year ended December 31, 2015, we recorded $5.8 million in net derivative losses related to discontinue cash flow hedges. We will amortize approximately $5.8 million of discontinued cash flow hedges in 2016.

As of December 31, 2015, $0.4 million in losses are reported in AOCI because the forecasted transaction is considered to be probable. We expect that those losses will be reclassified into earnings within the next 24 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions.

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

We have various master netting arrangements in the form of multiple contracts with various single counterparties that are subject to contractual agreements that provide for the net settlement of all contracts through a single payment. Those arrangements reduce our exposure to a counterparty in the event of default on or termination of any one contract. For financial statement presentation, we offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement. The amount of cash collateral used to offset against net derivative positions was $11.3 million as of December 31, 2015. Under the master netting arrangements our obligation to return cash collateral was less than $0.1 million at December 31, 2015 and 2014.

Certain of our derivative instruments contain provisions that require us to maintain an investment grade credit rating on our debt from each of the major credit rating agencies. If our debt were to fall below investment grade, it would be in violation of those provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2015, is $11.7 million for which we have posted collateral of $20.1 million in the normal course of business.

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

The estimated fair value of debt amounted to $863 million and $886 million as of December 31, 2015 and 2014, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2, except for unsecured pollution control notes-variable, with a fair value of $56 million both as of December 31, 2015 and 2014, which are considered Level 3. The fair value of these unsecured pollution control notes-variable are determined using unobservable interest rates as the market for these notes is inactive.

Notes to Financial Statements

Assets and liabilities measured at fair value on a recurring basis

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

Description (Thousands)	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Netting**	**Total**
2015					
Assets					
Noncurrent investments available for sale, primarily money market funds	**$4,745**	**-**	**-**		**$4,745**
Derivatives					
Commodity contracts:					
Electricity	**$2,985**	**-**	**-**	**$(2,805)**	**$180**
Total	**$7,730**	**-**	**-**	**$(2,805)**	**$4,925**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	**$(11,640)**			**$11,640**	**-**
Natural gas	**(2,494)**			**2,494**	**-**
Other		**-**	**$(413)**		**$(413)**
Total	**$(14,134)**	**-**	**$(413)**	**$14,134**	**$(413)**
2014					
Assets					
Noncurrent investments available for sale, primarily money market funds	$5,886	-	-		$5,886
Derivatives					
Commodity contracts:					
Electricity	2,635	-	-	$(2,635)	-
Natural gas	1			(1)	-
- Total	$8,522	-	-	$(2,636)	$5,886
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$(9,785)	-	-	$2,635	$(7,150)
Natural gas	(2,415)	-	-	1	(2,414)
Other		-	(563)		(563)
Total	$(12,200)	-	$(563)	$2,636	(10,127)

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2015 and 2014. Our policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that causes a transfer, if any.

<u>Valuation techniques</u>: We measure the fair value of our noncurrent investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments which are Rabbi Trusts for deferred compensation plans primarily consist of money market funds.

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

- We enter into electric energy derivative contracts to hedge the forecasted purchases required to serve our electric load obligations. We hedge our electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. We hedge all of our electric load obligations in a NYISO location where an active market exists. The forward market prices used to value our open electric energy derivative contracts are readily available with no adjustment required and we include the fair values in Level 1.
- We enter into natural gas derivative contracts to hedge the forecasted purchases required to serve our natural gas load obligations. The forward market prices used to value our open natural gas derivative contracts are exchange-based prices for the identical derivative contracts traded actively on the New York Mercantile Exchange. Because we use prices quoted in an active market, we include those fair value measurements in Level 1.
- We enter into fuel derivative contracts to hedge our unleaded and diesel fuel requirements for our fleet vehicles. Exchange based forward market prices are used but because a basis adjustment is added to the forward prices, we include the fair value measurement for these contracts in level 3.

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

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	
	Derivatives, Net	
Year ended December 31,	**2015**	**2014**
(Thousands)		
Beginning balance	**$563**	$92
Total gain (loss) (realized/unrealized)		
Included in earnings	**(573)**	(137)
Included in other comprehensive income	**423**	608
Ending balance	**$413**	$563

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

(Thousands)	
Total (loss) included in earnings for year ended December 31,	
2015	**$(573)**
2014	$(137)

Note 11. Accumulated Other Comprehensive (Loss) Income

(Thousands)	Balance January 1, 2014	2014 Change	Balance December 31, 2014	2015 Change	Balance December 31, 2015
Net unrealized holding gain (loss) on investments, net of income tax (expense) benefit of $(11) for 2014 and 2015	-	$16	$16	**$17**	**$33**
Amortization of pension cost for nonqualified plans, net of income tax benefit (expense) of $956 for 2014 and $(417) for 2015	$(1,073)	(1,457)	(2,530)	**632**	**(1,898)**
Unrealized (loss) gain on derivatives qualified as hedges:					
Unrealized (loss) during period on derivatives qualified as hedges, net of income tax benefit of $241 for 2014 and $168 for 2015		(367)		**(255)**	
Reclassification adjustment for loss included in net income, net of income tax (benefit) of $(54) for 2014 and $228 for 2015		83		**346**	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax benefit of (2,285) for 2014 and (2,294) for 2015.		3,483		**3,483**	
Net unrealized (loss) gain on derivatives qualified as hedges	(51,705)	3,199	(48,506)	**3,574**	**(44,932)**
Accumulated Other Comprehensive (Loss) Income	$(52,778)	$1,758	$(51,020)	**$4,223**	**$(46,797)**

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 there benefit accumulates based on a percentage of annual salary and credited interest. During 2013 the company announced that we would freeze the benefits for all non-union employees covered under the cash balance plans effective December 31, 2013. Their earned balances would continue to accrue interest, but would no longer be increased by a percentage of earnings. In place of the pension benefit for these employees, they will receive a minimum contribution to their account under their respective company's defined contribution plan. There was no change to the defined benefit plans for employees covered under the plans that provide defined benefits based on years of service and final average salary.

The company maintains a 401(k) Savings and Retirement Plan (the Plan) for all eligible employees as defined in the Plan agreement. Participants in the Plan may contribute a percentage of their compensation and the company may match a predetermined percentage of the participant contributions. Expenses under the Plan for the Company totaled approximately $3 million in 2015 and 2014.

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.

Obligations and funded status:

	Pension Benefits 2015	Pension Benefits 2014	Postretirement Benefits 2015	Postretirement Benefits 2014
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	**$473,472**	$436,509	**$85,635**	$77,892
Service cost	**5,323**	5,076	**451**	378
Interest cost	**17,189**	20,345	**3,152**	3,670
Plan amendments	**-**	-		-
Plan participants' contributions	**-**	-	**354**	582
Actuarial loss (gain)	**(21,211)**	68,320	**(5,656)**	8,426
Special Termination Benefits	**435**	-		
Benefits paid	**(37,914)**	(56,778)	**(4,385)**	(5,317)
Federal subsidy on benefits paid	**-**	-	**-**	4
Benefit obligation at December 31	**$437,294**	$473,472	**$79,551**	$85,635
Change in plan assets				
Fair value of plan assets at January 1	**$366,360**	$394,910	**-**	-
Actual return on plan assets	**(4,568)**	28,228	**-**	-
Employer and plan participants' contributions	**-**	-	**$4,385**	$5,313
Federal subsidy on benefits paid	**-**	-	**-**	4
Benefits paid	**(37,914)**	(56,778)	**(4,385)**	(5,317)
Fair value of plan assets at December 31	**$323,878**	$366,360	**-**	-
Funded status at December 31	**$(113,416)**	$(107,112)	**$(79,551)**	$(85,635)

Amounts recognized in the balance sheet December 31,	Pension Benefits 2015	Pension Benefits 2014	Postretirement Benefits 2015	Postretirement Benefits 2014
(Thousands)				
Other current liabilities	**-**	**-**	**$(5,274)**	$(5,424)
Noncurrent liability	**$(113,416)**	$(107,112)	**(74,277)**	(80,211)
Total	**$(113,416)**	$(107,112)	**$(79,551)**	$(85,635)

During 2014 we made an offer to retired employees who are currently receiving benefits an option to receive their future pension as a lump sum. Approximately $20.6 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 we are allowed to defer as regulatory assets or regulatory liabilities items that would otherwise be recorded in accumulated other comprehensive income pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities consist of:

December 31,	Pension Benefits 2015	Pension Benefits 2014	Postretirement Benefits 2015	Postretirement Benefits 2014
(Thousands)				
Net loss	**$139,122**	$152,440	**$ 6,304**	$12,109
Prior service cost (benefit)	**1,477**	$2,616	**$(5,607)**	$(7,016)

Our accumulated benefit obligation for all defined benefit pension plans was $406 million at December 31, 2015, and $437 million at December 31, 2014.

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

December 31	2015	2014
(Thousands)		
Projected benefit obligation	**$437,294**	$473,472
Accumulated benefit obligation	**$405,659**	$436,572
Fair value of plan assets	**$323,878**	$366,360

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

	Pension Benefits		Postretirement Benefits	
Years ended December 31,	**2015**	**2014**	**2015**	**2014**
(Thousands)				
Net periodic benefit cost				
Service cost	**$5,322**	$5,076	**$451**	$378
Interest cost	**17,189**	20,345	**3,152**	3,670
Expected return on plan assets	**(26,010)**	(28,148)	**-**	-
Amortization of prior service cost (benefit)	**1,140**	1,140	**(1,409)**	(1,409)
Amortization of net loss (gain)	**22,686**	18,502	**148**	(346)
Special termination benefit charge	**435**	-	**-**	-
Net periodic benefit cost	**$20,762**	$16,915	**$2,342**	$2,293
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	**$9,368**	$68,239	**$(5,657)**	$8,426
Amortization of net (loss) gain	**(22,686)**	(18,502)	**(148)**	346
Amortization of prior service (cost)	**(1,140)**	(1,140)	**1,409**	1,409
Total recognized in regulatory assets and regulatory liabilities	**(14,458)**	48,597	**(4,396)**	10,181
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$6,304**	$65,512	**$(2,054)**	$12,474

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

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2016	**Pension Benefits**	**Postretirement Benefits**
(Thousands)		
Estimated net loss	**$21,227**	**$ 902**
Estimated prior service cost	**$851**	**$(1,409)**

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ended December 31, 2016.

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

As of December 31, 2015, we increased our discount rate from 3.80% to 4.10%. The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate by developing a yield curve derived from a portfolio of high grade non-callable bonds with above median 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 the year ended December 31,	Pension Benefits 2015	Pension Benefits 2014	Postretirement Benefits 2015	Postretirement Benefits 2014
Discount rate	**3.80%**	4.90%	**3.80%**	4.90%
Expected long-term return on plan assets	**7.50%**	7.50%	**N/A**	N/A
Rate of compensation increase	**4.10%**	4.20%	**N/A**	N/A

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses either over 10 years from the time they are incurred.

Assumed health care cost trend rates to determine benefit obligations at December 31,	2015	2014
Health care cost trend rate (pre 65/post 65)	**7.00%/9.00%**	7.50%/7.00%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	**4.50%**	4.50%
Year that the rate reaches the ultimate trend rate	**2026**	2027

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans, however, because the RGE retirees have moved into a different program, and is no longer sensitive to medical trend changes. The company is limited to a specific dollar amount and will not change in the future.

Cash Flows

Contributions: In accordance with our funding policy we make annual contributions of not less than the minimum required by applicable regulations. We do not expect to contribute to our pension benefit plans or our other postretirement plans in 2016.

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

	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
(Thousands)			
2016	$42,097	$5,274	-
2017	$42,361	$5,292	-
2018	$41,496	$5,300	-
2019	$40,469	$5,294	-
2020	$39,854	$5,283	-
2021 - 2025	$177,532	$25,941	-

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 45% in equity securities and 35% in equity alternative investments. The Liability-Hedging asset class has a target allocation percentage of 20%. 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.

The fair values of Network's pension benefits plan assets at December 31, 2015 and 2014, by asset category are shown in the following table. RGE's share of the total consolidated assets is approximately 17% for 2015 and 18% for 2014.

		Fair Value Measurements at December 31, Using		
Asset Category	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(Thousands)				
2015				
Cash and cash equivalents	**$57,526**	**$3,290**	**$54,236**	**-**
U.S. government securities	**171,024**	**171,024**	**-**	**-**
Common stocks	**313,911**	**313,911**	**-**	**-**
Registered investment companies	**81,308**	**81,308**	**-**	**-**
Corporate bonds	**323,900**	**-**	**323,900**	**-**
Preferred stocks	**4,926**	**295**	**4,631**	**-**
Common/collective trusts	**511,504**	**-**	**21,476**	**$490,028**
Partnership/joint venture interests	**78,519**	**-**	**-**	**78,519**
Real estate investments	**88,865**	**-**	**-**	**88,865**
Other investments, principally annuity and fixed income	**318,247**	**(21)**	**-**	**318,268**
Total	**1,949,730**	**$569,807**	**$404,243**	**$975,680**
2014				
Cash and cash equivalents	$47,941	$3,795	$44,146	-
U.S. government securities	177,379	177,379	-	-
Common stocks	430,900	343,757	87,143	-
Registered investment companies	115,930	115,930	-	-
Corporate bonds	344,216	-	344,216	-
Preferred stocks	4,050	281	3,769	-
Common/collective trusts	476,581	-	26,440	$450,141
Partnership/joint venture interests	79,489	-	-	79,489
Real estate investments	74,871	-	-	74,871
Other investments, principally annuity and fixed income	345,885	-	4,200	341,685
Total	$2,097,242	$641,142	$509,914	$946,186

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

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

value measurement.

- Real estate investments – based on a discounted cash flow approach that includes the projected future rental receipts, expenses and residual values because the highest and best use of the real estate from a market participant view is as rental property.
- Other investments, principally annuity and fixed income - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: based on yields currently available on comparable securities of issuers with similar credit ratings. Level 3: when quoted prices are not available for identical or similar instruments, under a discounted cash flows approach that maximizes observable inputs such as current yields of similar instruments but includes adjustments for certain risks that may not be observable such as credit and liquidity risks.

	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, 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
Actual return on plan assets:					
Relating to assets still held at the reporting date	**(5,873)**	**18,518**	**10,235**	**(20,169)**	**2,711**
Relating to assets sold during the year	**(3,115)**	**(19,488)**	**-**	**904**	**(21,699)**
Purchases, sales and settlements	**48,875**	**-**	**3,759**	**(4,152)**	**48,482**
Balance, December 31, 2015	**$490,028**	**$78,519**	**$88,865**	**$318,268**	**$975,680**

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

Note 13. Subsequent Events

The company has performed a review of subsequent events through April 29, 2016, which is the date these financial statements were available to be issued, and the financial statements reflect events occurring from January 1, 2016 through such date.

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

Under the terms of the Credit Facility, each joint borrower has a maximum borrowing entitlement, or sublimit, which can be periodically adjusted to address specific short-term capital funding needs, subject to the maximum limit established by the banks. AGR's maximum sublimit is $1 billion, NYSEG, RGE, CMP and UI have maximum sublimits of $250 million, CNG, and SCG have maximum sublimits of $150 million and BGC has a maximum sublimit of $25 million. Under the Credit Facility, each of the borrowers will pay an annual facility fee that is dependent on their credit rating. The initial facility fees will range from 12.5 to 17.5 basis points. The maturity date for the Credit Facility is April 5, 2021.

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