THE UNITED ILLUMINATING COMPANY

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2016 AND 2015

TABLE OF CONTENTS

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Report of Independent Auditors

To the Board of Directors of the United Illuminating Company

We have audited the accompanying financial statements of The United Illuminating Company, which comprise the balance sheet as of December 31, 2016, and the related statements of income, changes in shareholder's equity and cash flows for the year 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 audit. We did not audit the financial statements of GenConn Energy LLC in which the Company has a 50% interest. In the financial statements, the Company's investment in GenConn Energy LLC is stated at $106.2 million as of December 31, 2016, and the Company's income from equity investment in GenConn Energy LLC is $13.1 million for the year then ended. Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for GenConn Energy LLC, is based solely on the report of the other auditors. We conducted our audit in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, 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

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In our opinion, based on our audit and the report of the other auditors, the financial statements referred to above present fairly, in all material respects, the financial position of the United Illuminating Company at December 31, 2016, and the results of its operations and its cash flows for the year then ended in conformity with U.S. generally accepted accounting principles..

Report of Other Auditors on December 31, 2015 Financial Statements

The financial statements of The United Illuminating Company for the year ended December 31, 2015, were audited by other auditors who expressed an unmodified opinion on those statements on April 4, 2016.

Ernst & Young LLP

April 18, 2017

THE UNITED ILLUMINATING COMPANY
STATEMENT OF INCOME
For the Years Ended December 31, 2016 and 2015
(In Thousands)

	2016	2015
Operating Revenues	$ 866,975	$ 887,811
Operating Expenses		
Operation		
Purchased power	188,712	226,973
Operation and maintenance	258,300	308,435
Transmission wholesale	99,818	93,078
Depreciation and amortization	79,138	68,870
Taxes - other than income taxes	98,611	92,220
Total Operating Expenses	724,579	789,576
Operating Income	142,396	98,235
Other Income and (Deductions), net		
Other income	11,626	10,338
Other (deductions)	(150)	(659)
Total Other Income and (Deductions), net	11,476	9,679
Interest Charges, net		
Interest on long-term debt	43,711	42,819
Other interest, net	(3,318)	(1,217)
	40,393	41,602
Amortization of debt expense and redemption premiums	1,419	1,441
Total Interest Charges, net	41,812	43,043
Income from Equity Investments	13,114	14,246
Income Before Income Taxes	125,174	79,117
Income Taxes (Note E)	40,819	21,853
Net Income	$ 84,355	$ 57,264

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, 2016 and 2015
(In Thousands)

	2016	2015
Cash Flows From Operating Activities		
Net income	$ 84,355	$ 57,264
Adjustments to reconcile net income		
to net cash provided by operating activities:		
Depreciation and amortization	80,557	70,313
Deferred income taxes	34,681	13,738
Uncollectible expense	17,276	29,761
Pension expense	29,671	22,980
Allowance for funds used during construction (AFUDC) - equity	(6,222)	(6,500)
Undistributed (earnings) losses in equity investments	(13,115)	(14,246)
Environmental liabilities	-	30,000
Regulatory assets/liabilities amortization	(284)	(9,932)
Regulatory assets/liabilities carrying cost	(243)	1,300
Other non-cash items, net	(802)	(346)
Changes in:		
Accounts receivable, net	(17,399)	(32,835)
Unbilled revenues	(346)	6,708
Accounts payable	7,845	(7,253)
Cash distribution received from GenConn	13,126	14,100
Taxes accrued and refundable	1,268	(9,915)
Accrued liabilities	2,203	7,307
Accrued pension	(15,049)	(7,270)
Accrued post-employment benefits	(518)	(834)
Regulatory assets/liabilities	(34,533)	3,656
Other assets	(107)	(1,028)
Other liabilities	1,622	(495)
Total Adjustments	99,631	109,209
Net Cash provided by Operating Activities	183,986	166,473
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(187,529)	(187,086)
Cash distribution from GenConn	4,074	4,029
Deposits in New England West Solution (NEEWS)	-	(1,451)
Intercompany receivable	54,000	(39,000)
Net Cash (used in) Investing Activities	(129,455)	(223,508)
Cash Flows from Financing Activities		
Issuances of non-current debt	-	50,000
Payments on non-current debt	(64,460)	(27,500)
Payment of common stock dividend	-	(59,700)
Equity infusion from parent	-	4,500
Intercompany payable	7,197	-
Other	(333)	(295)
Net Cash (used in) Financing Activities	(57,596)	(32,995)
Unrestricted Cash, Restricted Cash and Temporary Cash Investments:		
Net change for the period	(3,065)	(90,030)
Balance at beginning of period	7,384	97,414
Balance at end of period	$ 4,319	$ 7,384
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 40,571	$ 40,130
Income taxes	$ -	$ 1,600
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 11,277	$ 22,940
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, 2016 and 2015

ASSETS
(In Thousands)

	2016	2015
Current Assets		
Unrestricted cash and temporary cash investments	$ 2,590	$ 5,657
Restricted cash	1,729	1,727
Utility accounts receivable less allowance of $2,800 and $3,500, respectively	107,009	106,186
Unbilled revenues	40,226	39,880
Current regulatory assets (Note A)	33,462	44,469
Materials and supplies, at average cost	7,197	7,619
Refundable taxes	22,518	11,741
Prepayments	2,976	2,242
Current portion of derivative assets (Note A), (Note K)	8,785	10,507
Intercompany receivable	-	54,000
Other current assets	138	107
Total Current Assets	226,630	284,135
Other Investments		
Equity investment in GenConn (Note A)	106,214	110,306
Other	9,811	9,702
Total Other Investments	116,025	120,008
Total Property, Plant and Equipment	2,615,742	2,441,295
Less accumulated depreciation	537,736	539,289
	2,078,006	1,902,006
Construction work in progress	119,879	187,212
Net Property, Plant and Equipment	2,197,885	2,089,218
Regulatory Assets (Note A)	509,627	431,923
Deferred Charges and Other Assets		
Unamortized debt issuance expenses	284	210
Other long-term receivable	1,477	1,484
Derivative assets (Note A), (Note K)	10,631	18,757
Other	168	380
Total Deferred Charges and Other Assets	12,560	20,831
Total Assets	$ 3,062,727	$ 2,946,115

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

THE UNITED ILLUMINATING COMPANY
BALANCE SHEET
December 31, 2016 and 2015

LIABILITIES AND CAPITALIZATION
(In Thousands)

	2016	2015
Current Liabilities		
Current portion of non-current debt	$ 70,000	$ -
Accounts payable	107,096	110,955
Accrued liabilities	25,767	23,524
Current regulatory liabilities (Note A)	720	10,079
Interest accrued	10,864	10,888
Taxes accrued	24,325	12,280
Intercompany payable	7,197	-
Current portion of derivative liabilities (Note A), (Note K)	22,917	28,466
Total Current Liabilities	268,886	196,192
Deferred Income Taxes (Note E)	444,159	438,446
Regulatory Liabilities	293,877	277,098
Other Noncurrent Liabilities		
Pension accrued (Note F)	221,309	153,636
Other post-retirement benefits accrued (Note F)	40,936	42,487
Derivative liabilities (Note A), (Note K)	71,783	67,764
Environmental liabilties	29,897	33,011
Other	9,867	5,800
Total Other Noncurrent Liabilities	373,792	302,698
Commitments and Contingencies (Note J)		
Capitalization (Note B)		
Long-term debt	728,714	862,737
Common Stock Equity		
Common stock	1	1
Paid-in capital	709,230	709,230
Retained earnings	244,068	159,713
Net Common Stock Equity	953,299	868,944
Total Capitalization	1,682,013	1,731,681
Total Liabilities and Capitalization	$ 3,062,727	2,946,115

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, 2016 and 2015
(Thousands of Dollars)

	Common Stock				Paid-in		Retained		
	Shares		Amount		Capital		Earnings		Total
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
Net income							84,355		84,355
Balance as of December 31, 2016	100	$	1	$	709,230	$	244,068	$	953,299

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

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. 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 uncollectible expense, regulatory activity, net, regulatory assets/liabilities amortization and regulatory assets/liabilities carrying costs that were reported as such in Statement of Cash Flows in previous periods have been reclassified to conform to the current presentation. Such reclassifications had no impact on the 2015 "Net Cash provided by Operating Activities." Certain amounts related to regulatory assets and deferred tax liabilities that were reported as such in the Balance Sheet in previous periods have been reclassified to conform to the current presentation. Changes in the current presentation are 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 the impact to the prior period Statement of Cash Flows and Balance Sheet of the adjustments noted above.

December 31, 2015 (in thousands)	As previously filed	Reclassifications	As currently reported
Consolidated Statement of Cash Flows			
Adjustments to reconcile net income to net cash provided by operating activities:			
Uncollectible expense	$ -	29,761	$ 29,761
Regulatory activity, net	(4,976)	4,976	-
Regulatory assets/liabilities amortization	-	(9,932)	(9,932)
Regulatory assets/liabilities carrying costs	-	1,300	1,300
Changes in:			
Accounts receivable, net	(3,074)	(29,761)	(32,835)
Regulatory assets/liabilities	-	3,656	3,656
Cash Flows from Investing Activities			
Changes in restricted cash	(676)	676	-
Unrestricted Cash, Restricted Cash and Temporary Cash Investments:			
Balance at beginning of period	96,363	1,051	97,414
Consolidated Balance Sheet			
Deferred Income Taxes	585,324	(146,878)	438,446
Regulatory Liabilities	130,220	146,878	277,098

UI has evaluated subsequent events through the date its financial statements were available to be issued, April18, 2017.

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 2016 and 2015 were 7.65% and 7.67%, respectively.

Accounts receivable and allowance for bad debt

UI records accounts receivable at amounts billed to customers. The allowance for bad debts is established by using both historical average loss percentages to project future losses, and a specific allowance is established for known credit issues. Amounts are written off when UI believes that a receivable will not be recovered.

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 2016 and 2015 is as follows:

	2016	2015
	(In Thousands)	
Balance as of January 1	$ -	$ 303
Accretion	-	11
Liabilities settled during the year	-	(314)
Balance as of December 31	$ -	$ -

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 composite rates based on the estimated service lives of the various classes of assets. For utility plant other than software, service lives are determined by independent depreciation consultants 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 2016 and 2015 were approximately 3.1% and 2.9% respectively, of the original cost of depreciable property.

Derivatives

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

Contracts for Differences (CfDs)

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, 2016, UI has recorded a gross derivative asset of $19.4, a regulatory asset of $75.3 million and a gross derivative liability of $94.7 million ($70.4 million of which is related to UI's portion of the CfD signed by CL&P). See Note (J) "Fair Value of Financial Instruments" for additional CfD information.

The gross derivative assets and liabilities as of December 31, 2016 and 2015 were as follows:

	December 31, 2016	December 31, 2015
	(In Thousands)	
Gross derivative assets:		
Current Assets	$ 8,785	$ 10,507
Deferred Charges and Other Assets	$ 10,631	$ 18,757
Gross derivative liabilities:		
Current Liabilities	$ 22,917	$ 28,466
Noncurrent Liabilities	$ 71,783	$ 67,764

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, 2016 and 2015 were as follows:

	Year Ended December 31, 2016	2015
	(In Thousands)	
Regulatory Assets - Derivative liabilities	$ 7,578	$ 3,429
Regulatory Liabilities - Derivative assets	$ 739	$ 5,733

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 $106.2 million and $110.3 million as of December 31, 2016 and 2015, respectively. As of December 31, 2016, 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 $13.1 million and $14.2 million for the years ended December 31, 2016 and 2015, 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 $17.2 million and $18.1 million during the years ended December 31, 2016 and 2015, respectively.

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

	2016	2015
	(In Thousands)	
Current assets	$ 36,283	$ 35,136
Noncurrent assets	$ 388,468	$ 404,503
Current liabilities	$ 15,907	$ 15,734
Noncurrent liabilities	$ 196,344	$ 203,327
Operating revenues	$ 71,763	$ 78,304
Income	$ 26,321	$ 28,275

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.

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, 2016, 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, 2016 and 2015 were comprised as follows:

	2016	2015
	(In Thousands)	
Distribution plant	$ 1,346,084	$ 1,252,676
Transmission plant	758,955	680,261
Software	107,174	102,542
Land	54,813	59,806
Building and improvements	193,637	193,947
Other plant	155,079	152,063
Total property, plant & equipment	2,615,742	2,441,295
Less accumulated depreciation	537,736	539,289
	2,078,006	1,902,006
Construction work in progress	119,879	187,212
Net property, plant & equipment	$ 2,197,885	$ 2,089,218

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, 2016 and 2015 included the following:

	Remaining Period	December 31, 2016	December 31, 2015
		(In Thousands)	
Regulatory Assets:			
Unamortized redemption costs	5 to 17 years	8,907	9,697
Pension and other post-retirement benefit plans	(a)	236,688	181,030
Unfunded future income taxes	(b)	179,204	179,187
Contracts for differences	(c)	75,284	67,705
Excess generation service charge	(d)	1,536	-
Deferred transmission expense	(e)	8,465	10,425
Other	(f)	33,005	28,348
Total regulatory assets		543,089	476,392
Less current portion of regulatory assets		33,462	44,469
Regulatory Assets, Net		$ 509,627	$ 431,923
Regulatory Liabilities:			
Accumulated deferred investment tax credits	28 years	$ 14,738	$ 10,156
Rate credits	N/A	-	9,359
Excess generation service charge	(d)	-	20,895
Middletown/Norwalk local transmission network service collections	34 years	19,682	20,255
Pension and other post-retirement benefit plans	(a)	10,177	6,537
Asset removal costs	(f)	67,019	63,272
Deferred income taxes	(b)	171,757	146,878
Contracts for differences	(c)	-	739
Other	(e)	11,224	9,086
Total regulatory liabilities		294,597	287,177
Less current portion of regulatory liabilities		720	10,079
Regulatory Liabilities, Net		$ 293,877	$ 277,098

(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 3 - 10 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 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.

(e) Regulatory asset or liability which defers transmission income or expense and fluctuates based upon actual revenues and revenue requirements.

(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 as of December 31, 2016 includes decoupling ($2.3 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, 2016 and 2015 totaled $1.7 million, 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 May 2014 the Financial Accounting Standards Board (FASB) issued an amendment concerning the recognition of revenue from contracts with customers and related required disclosures. The amendment replaces existing revenue guidance, including most industry-specific guidance, and will use a five-step model for recognizing and measuring revenue from contracts with customers. The core principle is for an entity to recognize revenue to represent the transfer of goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. Required disclosures include information about the nature, amount, timing, and uncertainty of revenues and the related cash flows. In August 2015, the FASB issued an accounting standards update that defers by one year the original effective date of the revenue standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption permitted. UI does not plan to early adopt. Entities may apply the amendment retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Company will apply the modified retrospective method. UI is currently evaluating how our adoption of the amendments will affect our results of operations, financial position, cash flows, and disclosures. UI is considering the effects of the amendments on our ability to recognize revenue for certain contracts where collectability is in question and our accounting for contributions in aid of construction. In addition, the amendments will require us to capitalize, rather than expense, any costs to acquire new contracts. The FASB has issued various additional accounting standards updates, with the same deferred effective date, as follows: in March 2016 to amend and clarify the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, in April 2016 to address implementation questions on identifying performance obligations and accounting for licenses of intellectual property. UI does not expect significant effects as a result of those updates. In May 2016 the FASB issued a final update concerning narrow-scope improvements and practical expedients. UI is currently evaluating the effects of that update.

In May 2015 the FASB issued Accounting Standards Update (ASU) 2015-07 “Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)” which affects 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 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. UI’s adoption of the amendments in 2016 did not affect its results of operations, financial position, or cash flows.

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 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 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. UI does not expect our adoption of the guidance to materially affect its 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. The updated guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal year, and early application is permitted. UI is currently evaluating the effect that adopting this new accounting guidance will have on its financial statements.

In November 2016, the FASB issued Accounting Standards Update (ASU) 2016-18, “Statement of Cash Flows: Restricted Cash” to address existing diversity in the classification and presentation of changes in restricted cash on the statement of cash flows. The amendment requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The amendment does not provide a definition of restricted cash or restricted cash equivalents. The amendment is effective for entities that are not public entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years, with early adoption permitted. The amendment should be applied using a retrospective transition method to each period presented. As permitted, UI has early adopted the amendment as of the beginning of the fourth quarter of 2016 and has applied it retrospectively to all periods presented. Accordingly, the changes in restricted cash and restricted cash equivalents, presented previously in other assets of operating activities, were included in cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows, which increased by an immaterial amount and had no change in net cash provided by operating activities in the consolidated statements of cash flow, for the year ended December 31, 2016.

(B) CAPITALIZATION

Common Stock

UI had 100 shares of common stock, no par value, outstanding at December 31, 2016 and 2015.

Long-term debt

As of December 31,		**2016**		**2015**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured debt	2017-2045	$ 803,500	2.98%-6.61%	$ 803,500	2.98%-6.61%
Unsecured pollution control notes –					
Variable	2033	-	-	64,460	0.57%
Unamortized debt (costs) premium, net		(4,786)		(5,223)	
Total Debt		**$ 798,714**		**$ 862,737**	
Less: debt due within one year, included in current liabilities		70,000		-	
Total Non-current Debt		**$ 728,714**		**$ 862,737**	

The fair value of UI’s long-term debt was $895.5 as of December 31, 2016, 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:

	2017	2018	2019	2020	2021	2022 & thereafter	Total
				(In Thousands)			
Maturities	$ 70,000	$ 100,000	$ 31,000	$ 50,000	$ -	$ 552,500	$ 803,500

On December 27, 2016, UI purchased $64.5 million of its outstanding auction rate bonds. The bonds are in a five-year multiannual mode with a put date of December 27, 2021 at an interest rate of 2.85%. The timing of UI's plans to remarket these bonds in 2017 is dependent upon market conditions.

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 non-current 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 which were included in regulatory liabilities on the balance sheet as of December 31, 2015 and subsequently credited to customer bills in the first quarter of 2016. Also among the commitments made were $7.0 million in contributions to a clean energy fund and disaster relief included in accrued liabilities in the accompanying balance sheets as of December 31, 2016 and 2015. 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 included a distribution rate freeze to January 1, 2017 for UI. See "Rates" below for further discussion regarding UI distribution rates. 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.

In December 2016, PURA approved distribution rate schedules for UI for three years that became effective January 1, 2017 and which, among other things, provides for $57 million of cumulative distribution rate increases, an allowed ROE of 9.10% based on 50% equity, continued UI's existing earnings sharing mechanism whereby UI is required to return to customers 50% of any distribution earnings over the allowed ROE in a calendar year, continued the existing decoupling mechanism (under which the actual energy delivery revenues are compared on a periodic basis with the authorized delivery revenues and the difference accrued, for refund to or recovery from customers, as applicable), and approved the continuation of the requested storm reserve.

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 one year from the applicable bid day.

UI has wholesale power supply agreements in place for its entire standard service load for the first half of 2017, 80% of its standard service load for the second half of 2017, and 20% of its standard service load for the first half of 2018. 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, 2016, UI would have had to post an aggregate of approximately $12.8 million in collateral. UI would have been and remains able to provide that collateral.

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 have been phasing 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.

Through UI's renewable connections program UI is developing 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 9.10%) 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 statute, on February 7, 2017, UI entered into a master agreement with the Connecticut Green Bank to procure Connecticut Class I RECs produced by residential solar installations in 15 year tranches, with a final tranche to commence no later than 2022. UI's contractual obligation is to procure 20% of RECs produced by about 255 MW of residential solar installations. Connecticut statutes provides that the net 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.

Transmission

PURA decisions do not affect the revenue requirements determination for UI's transmission business, including the applicable ROE. UI'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. For 2016, UI's overall allowed weighted-average ROE for its transmission business was 11.29%. 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.

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 FPA, the FERC instituted proceedings because it found that ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential. The FERC stated that ISO-NE's Tariff lacks adequate transparency and challenge procedures with regard to the formula rates for ISO-NE Participating Transmission Owners, including UI. The FERC also found that the current Regional Network Service, or RNS and Local Network Service, or LNS, formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful as the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates. A settlement judge has been appointed and a settlement conference has convened. We are unable to predict the outcome of this proceeding at this time

On September 30, 2011, several New England state attorneys general, state regulatory commissions, consumer advocates, consumer groups, municipal parties and other parties collectively filed a complaint (Complaint I) with the FERC pursuant to sections 206 and 306 of the Federal Power Act. The filing parties seek an order from the FERC reducing the 11.14% base return on equity used in calculating formula rates for transmission service under the ISO-New England Open Access Transmission Tariff (OATT) to 9.2%. CMP and UI are New England Transmission Owners (NETOs) with assets and service rates that are governed by the OATT and will thereby be affected by any FERC order resulting from the filed complaint.

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

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

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

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

UI reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 final decision in Complaint I. The total reserve associated with Complaints I, II and III is $4.4 million as of December 31, 2016. If adopted as final, the impact of the initial decision would be an additional aggregate reserve for Complaints II and III of $4.3 million, which is based upon currently available information for these proceedings. UI cannot predict the outcome of the Complaint II and III proceedings.

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

New England East-West Solution

Pursuant to an agreement with CL&P (the Agreement), UI had 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 was fully energized 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 placed assets in service, it transferred title to certain NEEWS transmission assets to UI in proportion to UI's investments, but CL&P continues 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 had the option to make quarterly deposits to CL&P in exchange for ownership of specific NEEWS transmission assets as they were placed in service. UI had 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. Deposits associated with NEEWS were recorded as assets at the time the deposits were made and they were reported in the 'Other' line item within the Deferred Charges and Other Assets section of the balance sheet. When title to the assets was transferred to UI, the amount of the corresponding deposit was 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, 2016, 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.

Equity Investment in Peaking Generation

UI is party to a 50-50 joint venture with 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, 2017 through December 31, 2017 of $28.85 million and $35.67 million for GenConn Devon and GenConn Middletown, respectively. PURA has ruled previously that GenConn's project capital costs incurred were prudently incurred and are included in the 2017 approved revenue requirements.

(D) SHORT-TERM CREDIT ARRANGEMENTS

On April 5, 2016, Avangrid, Inc. and its subsidiaries, including UI, entered into a new credit facility agreement with a syndicate of banks (Avangrid Credit Facility) which replaced the UIL Holdings Credit Facility.

Under the Avangrid Credit Facility, UI has a maximum sublimit of $250 million. Additionally, under the AVANGRID Credit Facility, each of the borrowers, including UI, will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 10.0 to 17.5 basis points. The maturity date for the Avangrid Credit Facility is April 5, 2021. As of December 31, 2016 UI does not have any outstanding borrowings under the Avangrid Credit Facility. As of December 31, 2015, UI did not have any borrowings outstanding under the UIL Holdings Credit Facility.

(E) INCOME TAXES

	2016	2015
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ 486	$ 10,437
State	6,184	(2,074)
Total current	6,670	8,363
Deferred		
Federal	39,590	13,005
State	(4,909)	733
Total deferred	34,681	13,738
Investment tax credits	(532)	(248)
Total income tax expense	$ 40,819	$ 21,853

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:

	2016	2015
	(In Thousands)	
Book income before income taxes	$ 125,174	$ 79,117
Computed tax at federal statutory rate	$ 43,811	$ 27,691
Increases (reductions) resulting from:		
Plant Flow- thru differences	(187)	(1,369)
State income taxes, net of federal income tax benefits	829	(871)
Allowance for equity funds used during construction	(2,178)	(2,275)
ITC taken into income	(532)	(248)
Other items, net	(924)	(1,075)
Total income tax expense	$ 40,819	$ 21,853
Effective income tax rates	32.6%	27.6%

The significant portion of UI's income tax expense, including deferred taxes, is recovered through its regulated 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.

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 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, filed or will file a consolidated federal tax return with Avangrid, Inc. 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 are paid for their losses and other tax attributes generated when utilized. Also pursuant to the tax allocation agreement, UI settles its current tax liability or benefit each year directly with Avangrid, Inc.

As of December 31, 2016 and 2015, UI does not have any gross income tax reserves for uncertain tax positions.

The following table summarizes UI's tax years that remain subject to examination as of December 31, 2016:

Jurisdiction	*Tax years*
Federal	2013 - 2016
Connecticut	2013 - 2016

The following table summarizes UI's deferred income tax assets and liabilities as of December 31, 2016 and 2015.

	2016	**2015**
	(In Thousands)	
Deferred income tax assets:		
Post-retirement benefits	$ 101,141	$ 72,422
Merger settlement agreement	15,115	18,938
Investment tax credit carryforward	11,198	6,085
Other	54,962	38,149
	182,416	135,594
Deferred income tax liabilities:		
Plant basis and accelerated depreciation timing differences	$ 545,421	$ 498,788
Investment in GenConn	52,758	54,184
Other	28,396	21,068
	626,575	574,040
Total net deferred income tax assets (liabilities)	$ (444,159)	$ (438,446)

As of December 31, 2016 UI had $4.2 million of state tax credit carryforwards. As of December 31, 2015, UI did not have any state tax credit carryforwards.

(F) PENSION AND OTHER BENEFITS

Defined Benefit Plans (the Plans)

Pension Plans

The UI pension plan covers the majority of employees of UI and UIL corporate. The plan provides benefits under a traditional defined benefit formula and was closed to newly-hired employees in 2005. UI also has 2 non-qualified supplemental pension plan for certain employees.

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. The healthcare plans are contributory and participants' contributions are adjusted annually. For Medicare eligible non-union retirees, UI provides a subsidy through a Health Reimbursement Account (HRA) for retirees to purchase coverage on the individual market. Medicare eligible union retirees have the option of receiving a subsidy through an HRA or paying contributions and participating in company-sponsored retiree health plans.

Plan Assets

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.

UI's asset allocation policy is the most important consideration in achieving the objective of superior investment returns while minimizing risk. UI has a target asset allocation policy within allowable ranges for its pension benefits plan assets within broad categories of asset classes. The 2017 target asset allocations are approximately as follows: 54% equity securities, 27% fixed income investments, 10% bonds, 5% real estate investments and 4% treasury securities. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The 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, 2016 and 2015. Plan assets and obligations have been measured as of December 31, 2016 and 2015.

	Pension Benefits		Other Post-Retirement Benefits	
	2016	2015	2016	2015
		(In Thousands)		
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 492,821	$ 521,572	$ 65,990	$ 80,596
Service cost	6,311	7,818	1,026	1,158
Interest cost	22,873	22,168	3,148	3,436
Participant contributions	-	-	621	1,223
Actuarial (gain) loss	78,924	(28,853)	(2,643)	(16,883)
Benefits paid (including expenses)	(31,376)	(29,884)	(2,623)	(3,540)
Benefit obligation at end of year	$ 569,553	$ 492,821	$ 65,519	$ 65,990
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 339,185	$ 369,116	$ 23,503	$ 24,952
Actual return on plan assets	25,406	(7,312)	2,561	38
Employer contributions	15,029	7,265	-	-
Participant contributions	-	-	621	1,223
Benefits paid (including expenses)	(31,376)	(29,884)	(2,102)	(2,710)
Fair value of plan assets at end of year	$ 348,244	$ 339,185	$ 24,583	$ 23,503
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 221,309	$ 153,636	$ 40,936	$ 42,487
Amounts Recognized in the Balance Sheet consist of:				
Non-current liabilities	$ 221,309	$ 153,636	$ 40,936	$ 42,487
Amounts Recognized as a Regulatory Asset consist of:				
Prior service cost	(10)	(15)	(10,278)	(11,805)
Net (gain) loss	236,676	181,044	104	5,268
Total recognized as a regulatory asset	$ 236,666	$ 181,029	$ (10,174)	$ (6,537)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 569,553	$ 492,821	N/A	N/A
Accumulated benefit obligation	$ 518,934	$ 448,614	N/A	N/A
Fair value of plan assets	$ 348,244	$ 339,185	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	4.24%	4.95%	N/A	N/A
Discount rate (Non-Qualified Plans)	4.24%	4.90%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	4.24%	4.90%
Average wage increase	3.80%	3.80%	N/A	N/A
Health care trend rate (current year – pre/post-65)	N/A	N/A	6.75%/6.00%	7.00%
Health care trend rate (2026/2024 – pre/post-65)	N/A	N/A	4.50%/4.50%	5.00%

N/A – not applicable

UI is allowed to defer as regulatory assets or regulatory liabilities items that would have otherwise been recorded in accumulated OCI pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2016 and 2015 are shown above.

The discount rate is the rate at which the benefit obligations could presently be effectively settled. The discount rates were determined by developing yield curves derived from a portfolio of high grade noncallable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.

The components of net periodic benefit cost are:

	For the Year Ended December 31,			
	Pension Benefits		Other Post-Retirement Benefits	
	2016	2015	2016	2015
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 6,311	$ 7,818	$ 1,026	$ 1,158
Interest cost	22,873	22,168	3,148	3,436
Expected return on plan assets	(25,742)	(28,758)	(1,673)	(1,850)
Amortization of prior service costs	(5)	(5)	(1,527)	50
Amortization of actuarial (gain) loss	23,627	17,887	1,633	1,066
Net periodic benefit cost	$ 27,064	$ 19,110	$ 2,607	$ 3,860
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 79,258	$ 7,217	$ (3,531)	$ (3,257)
Current year prior service cost	-	-	-	(11,815)
Amortization of prior service costs	5	5	1,527	(50)
Amortization of actuarial (gain) loss	(23,627)	(17,887)	(1,633)	(1,065)
Total recognized as regulatory asset (liability)	$ 55,636	$ (10,665)	$ (3,637)	$ (16,187)
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 82,700	$ 8,445	$ (1,030)	$ (12,327)
Estimated Amortizations from Regulatory Assets into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of prior service cost	(5)	(5)	(1,538)	598
Amortization of net (gain) loss	25,218	17,673	14	(1,527)
Total estimated amortizations	$ 25,213	$ 17,668	$ (1,524)	$ (929)
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.24%	4.20%-4.30%	4.24%	4.30%
Average wage increase	3.80%	3.80%	N/A	N/A
Return on plan assets	7.75%	8.00%	7.75%	8.00%
Health care trend rate (current year – pre/post-65)	N/A	N/A	7.00%/9.00%	7.00%
Health care trend rate (2026/2024 – pre/post-65)	N/A	N/A	4.50%/4.50%	5.00%

N/A – not applicable

UI utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. Prior service costs for both the pension and other postretirement benefits plans are amortized on a straight-line basis over the average remaining service period of participants expected to receive benefits. Unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans are amortized over the lesser of the average remaining service period or 10 years. For pension benefits, 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. For other postretirement benefits, there is no such allowance for a variance in capturing the amortization of unrecognized gains and losses.

The expected long-term rate of return on plan assets assumption was developed 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. The analysis considered current capital market conditions and projected conditions. UI amortizes unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the PURA.

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	$ 375	$ (307)
Accumulated post-retirement benefit obligation	$ 5,664	$ (4,693)

Contributions

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 $10.3 million in 2017. Such contribution levels will be adjusted, if necessary, based on actuarial calculations.

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)	
2017	$ 35,034	$ 3,714
2018	$ 37,233	$ 3,713
2019	$ 34,525	$ 3,755
2020	$ 34,373	$ 3,886
2021	$ 36,367	$ 3,943
2022-2026	$ 179,275	$ 20,714

Defined Contribution Retirement Plans/401(k)

UI employees are eligible to participate in the UIL Holdings Corporation 401(k) 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 in various investment alternatives offered to employees. The matching expense for each of 2016 and 2015 was $2.5 million.

(G) RELATED PARTY TRANSACTIONS

During the years ended December 31, 2016 and 2015, UI received cash distributions from GenConn. See Note (A) Business Organization and Statement of Accounting Policies – Equity Investments.

A Director of Avangrid, Inc., the parent company of UI's parent company, 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, 2016 and 2015 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, 2016, UI recorded inter-company expenses of $45.5 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, 2016 and 2015, the Balance Sheet reflects inter-company receivables, included in other accounts receivable of $5.9 million and $9.8 million, respectively, and inter-company payables, included in accounts payable, of $13.9 million and $19.3million, respectively.

Dividends/Capital Contributions

In 2016 and 2015, 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 year ended December 31, 2016, UI did not accrue dividends to UIL Holdings. For the year ended December 31, 2015 UI accrued dividends to UIL Holdings of $59.7 million.

(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:

Year	UI
2017	2,622,493
2018	2,630,660
2019	2,215,806
2020	2,177,667
2021-after	72,655,428
	82,302,054

Rental payments charged to operating expenses in 2016 and 2015 totaled $3.2 million and $3.3 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, 2016. 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.

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 issued its decision on March 25, 2016 awarding Connecticut Yankee $32.6 million. On July 18, 2016, the notice of appeal period expired and the Phase III trial award became final. On October 14, 2016, Connecticut Yankee received the DOE's payment of the damage award. UI’s 9.5% ownership share resulted in a receipt of approximately $1.7 million in December 2016 which will be refunded to customers and approximately $1.4 million which was used to fund the decommissioning trust fund

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

English Station

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. This proceeding had been stayed in 2014 pending resolution of other proceedings before the Connecticut Department of Energy and Environmental Protection, or DEEP, concerning the English Station site. In December 2016, the court administratively closed the file without prejudice to reopen upon the filing of a motion to reopen by any party. 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. This lawsuit had been stayed in May 2014 pending mediation. Due to lack of activity in the case, the court terminated the stay and scheduled a status conference on or before August 1, 2017.

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. Mediation of the matter began in the fourth quarter of 2013 and concluded unsuccessfully in April 2015. This proceeding was stayed while DEEP and UI continue to work through the remediation process pursuant to the consent order described below. A status report was filed with the court in December 2016 and the next status report is due in May 2017.

On August 4, 2016, DEEP issued the consent order that, subject to its terms and conditions, requires UI to investigate and remediate certain environmental conditions within the perimeter of the English Station site. Under the consent order, to the extent that the cost of this investigation and remediation is less than $30 million, UI is required to remit to the State of Connecticut the difference between such cost and $30 million, to be applied to 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. However, UI is obligated to comply with the terms of the consent order even if the cost of such compliance exceeds $30 million. Under the terms of the consent order, 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.

In connection with the consent order, on August 4, 2016, DEEP also issued a consent order to Evergreen Power, Asnat, and certain related parties that provides UI access to investigate and remediate the English Station site consistent with the terms of the August 2016 consent order. UI has initiated its process to investigate and remediate the environmental conditions within the perimeter of the English Station site pursuant to the consent order.

Other

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.

(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, 2016 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, 2016		(In Thousands)		
Assets:				
Derivative assets	$ -	$ -	$ 19,416	$ 19,416
Supplemental retirement benefit trust life insurance policies	-	9,646	-	9,646
	-	9,646	19,416	29,062
Liabilities:				
Derivative liabilities	-	-	94,700	94,700
	-	-	94,700	94,700
Net fair value assets/(liabilities), December 31, 2016	$ -	$ 9,646	$ (75,284)	$ (65,638)
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
	-	-	96,230	96,230
Net fair value assets/(liabilities), December 31, 2015	$ -	$ 9,544	$ (66,966)	$ (57,422)

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, 2016 or December 31, 2015 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, 2016	Range at December 31, 2015
Contracts for differences	Risk of non-performance	0.68% - 0.81%	0.00% - 0.88%
	Discount rate	1.47% - 2.45%	1.31% - 2.27%
	Forward pricing ($ per MW)	$3.15 - $9.55	$3.15 - $11.19

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, 2016 and December 31, 2015 in the active markets for the various funds within which the assets are held.

Non-current debt is carried at cost on the balance sheet. The fair value of non-current 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, 2016 and 2015.

	Year Ended December 31, 2016 (In Thousands)
Net derivative assets/(liabilities), December 31, 2015	$ (66,966)
Unrealized gains and (losses), net	(8,318)
Net derivative assets/(liabilities), December 31, 2016	$ (75,284)
Change in unrealized gains (losses), net relating to net derivative assets/(liabilities), still held as of December 31, 2016	$ (8,318)

	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)

The following tables set forth the fair values of UI's pension and OPEB assets as of December 31, 2016 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, 2016		(In Thousands)		
Pension assets				
Mutual funds	$ -	$ 348,244	$ -	$ 348,244
	-	348,244	-	348,244
OPEB assets				
Mutual funds	24,583	-	-	24,583
	24,583	-	-	24,583
Fair value of plan assets, December 31, 2016	$ 24,583	$ 348,244	$ -	$ 372,827
December 31, 2015				
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

The determination of fair value 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".

CONNECTICUT NATURAL GAS CORPORATION

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2016 AND 2015

TABLE OF CONTENTS

Ernst & Young LLP
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Report of Independent Auditors

To the Board of Directors of Connecticut Natural Gas Corporation

We have audited the accompanying financial statements of Connecticut Natural Gas Corporation, which comprise the balance sheet as of December 31, 2016, and the related statements of income, comprehensive income, changes in shareholder's equity and cash flows for the year 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 audit. We conducted our audit in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, 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 Connecticut Natural Gas Corporation at December 31, 2016, and the results of its operations and its cash flows for the year then ended in conformity with U.S. generally accepted accounting principles.

Report of Other Auditors on December 31, 2015 Financial Statements

The financial statements of Connecticut Natural Gas Corporation for the year ended December 31, 2015, were audited by other auditors who expressed an unmodified opinion on those statements on April 4, 2016.

Ernst + Young LLP

April 7, 2017

CONNECTICUT NATURAL GAS CORPORATION
STATEMENT OF INCOME
(In Thousands)

	Year Ended December 31, 2016	Year Ended December 31, 2015
Operating Revenues	$ 322,838	$ 306,846
Operating Expenses		
Operation		
Natural gas purchased	140,830	151,227
Operation and maintenance	83,698	84,145
Depreciation and amortization	31,634	29,821
Taxes - other than income taxes	23,984	22,219
Total Operating Expenses	280,146	287,412
Operating Income	42,692	19,434
Other Income and (Deductions), net		
Other income	1,663	1,688
Other (deductions)	(586)	(449)
Total Other Income and (Deductions), net	1,077	1,239
Interest Charges, net		
Interest on long-term debt	8,741	8,741
Other interest, net	176	416
	8,917	9,157
Amortization of debt expense and redemption premiums	429	93
Total Interest Charges, net	9,346	9,250
Income Before Income Taxes	34,423	11,423
Income Taxes (Note E)	11,550	2,402
Net Income	22,873	9,021
Less:		
Preferred Stock Dividends of		
Subsidiary, Noncontrolling Interests	27	27
Net Income attributable to Connecticut Natural Gas Corporation	$ 22,846	$ 8,994

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

	Year Ended December 31, 2016	Year Ended December 31, 2015
Net Income	$ 22,873	$ 9,021
Other Comprehensive Income (Loss), net of income taxes		
Changes in unrealized gains(losses) related to pension and other post-retirement benefit plans	(128)	128
Total Other Comprehensive Income (Loss), net of income taxes	(128)	128
Comprehensive Income	22,745	9,149
Less:		
Preferred Stock Dividends of Subsidiary, Noncontrolling Interests	27	27
Comprehensive Income	$ 22,718	$ 9,122

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, 2016	Year Ended December 31, 2015
Cash Flows From Operating Activities		
Net Income	$ 22,873	$ 9,021
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	32,063	29,913
Deferred income taxes	6,081	(3,659)
Uncollectible expense	4,839	7,240
Pension expense	5,449	1,174
Regulatory assets/liabilities amortization	2,198	2,222
Regulatory assets/liabilities carrying cost	306	540
Other non-cash items, net	(1,171)	(3,252)
Changes in:		
Accounts receivable, net	(11,557)	8,122
Unbilled revenues	(7,623)	4,498
Natural gas in storage	6,089	10,790
Prepayments	(340)	58
Accounts payable	14,320	(19,539)
Interest accrued	(159)	(34)
Taxes accrued/refundable, net	1,417	5,490
Accrued pension	(3,900)	(3,001)
Accrued other post-employment benefits	(965)	(1,533)
Accrued liabilities	794	691
Regulatory assets/liabilities	(15,960)	18,896
Other assets	(191)	(374)
Other liabilities	(141)	(62)
Total Adjustments	31,549	58,180
Net Cash provided by Operating Activities	54,422	67,201
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(65,091)	(61,913)
Net Cash (used in) Investing Activities	(65,091)	(61,913)
Cash Flows from Financing Activities		
Payment of common stock dividend	-	(17,500)
Payments on long-term debt	(10,000)	-
Intercompany payable	18,775	8,000
Other	(227)	(27)
Net Cash provided by (used in) Financing Activities	8,548	(9,527)
Unrestricted Cash and Temporary Cash Investments:		
Net change for the period	(2,121)	(4,239)
Balance at beginning of period	2,835	7,074
Balance at end of period	$ 714	$ 2,835
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 8,670	$ 8,524
Income taxes	$ -	$ 725
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 10,423	$ 5,840

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

CONNECTICUT NATURAL GAS CORPORATION
BALANCE SHEET
December 31, 2016 and 2015

ASSETS
(In Thousands)

	2016	2015
Current Assets		
Unrestricted cash and temporary cash investments	$ 714	$ 2,835
Accounts receivable less allowance of $1,400 and $1,800, respectively	57,522	50,404
Unbilled revenues	24,527	16,904
Current regulatory assets (Note A)	14,461	17,090
Natural gas in storage, at average cost	22,748	28,837
Materials and supplies, at average cost	1,663	1,395
Prepayments	1,303	963
Other	200	175
Total Current Assets	123,138	118,603
Other investments	1,375	1,527
Total Property, Plant and Equipment	857,533	794,780
Less accumulated depreciation	280,731	265,758
	576,802	529,022
Construction work in progress	23,348	19,286
Net Property, Plant and Equipment	600,150	548,308
Regulatory Assets (Note A)	160,209	142,180
Deferred Charges and Other Assets		
Unamortized debt issuance expenses	170	125
Goodwill (Note A)	79,341	79,341
Other	-	230
Total Deferred Charges and Other Assets	79,511	79,696
Total Assets	$ 964,383	$ 890,314

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

CONNECTICUT NATURAL GAS CORPORATION
BALANCE SHEET
December 31, 2016 and 2015

LIABILITIES AND CAPITALIZATION
(In Thousands)

	2016	2015
Current Liabilities		
Current portion of long-term debt (Note B)	$ 20,310	$ 11,527
Accounts payable	60,140	41,236
Accrued liabilities	13,106	12,312
Current regulatory liabilities (Note A)	11,471	18,764
Interest accrued	1,905	2,064
Intercompany payable	26,775	8,000
Taxes accrued	9,037	7,595
Total Current Liabilities	142,744	101,498
Deferred Income Taxes (Note E)	40,474	45,370
Regulatory Liabilities (Note A)	195,993	192,774
Other Non-current Liabilities		
Pension accrued (Note F)	88,376	56,368
Other post-retirement benefits accrued (Note F)	12,689	12,061
Other	6,841	7,200
Total Other Non-current Liabilities	107,906	75,629
Capitalization (Note B)		
Long-term debt	109,243	129,738
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)	19,173	(3,673)
Accumulated other comprehensive income (loss)	(27)	101
Net Common Stock Equity	367,683	344,965
Total Capitalization	477,266	475,043
Total Liabilities and Capitalization	$ 964,383	$ 890,314

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, 2016 and 2015
(Thousands of Dollars)

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
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
Net income				22,873		22,873
Other comprehensive income, net of income taxes					(128)	(128)
Payment of preferred stock dividend				(27)		(27)
Balance as of December 31, 2016	10,634,436	$ 33,233	$ 315,304	$ 19,173	$ (27)	$ 367,683

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. CNG is regulated by the Connecticut Public Utilities Regulatory Authority (PURA). 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.

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 uncollectible expense, pension expense, regulatory activity, net, regulatory assets/liabilities amortization and regulatory assets/liabilities carrying costs that were reported as such in the Statement of Cash Flows in previous periods have been reclassified to conform to the current presentation. Such reclassifications had no impact on the 2015 "Net Cash provided by Operating Activities." Certain amounts related to regulatory assets and deferred tax liabilities that were reported as such in the Balance Sheet in previous periods have been reclassified to conform to the current presentation. Changes in the current presentation are 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 the impact to the prior period Statement of Cash Flows and Balance Sheet of the adjustments noted above.

December 31, 2015 (in thousands)	As previously filed	Reclassifications	As currently reported
Consolidated Statement of Cash Flows			
Adjustments to reconcile net income to net cash provided by operating activities:			
Uncollectible expense	$ -	$ 7,240	$ 7,240
Pension expense	7,368	(6,194)	1,174
Accrued pension	(9,232)	6,231	(3,001)
Accrued other post-employment benefits	(1,496)	(37)	(1,533)
Regulatory activity, net	21,658	(21,658)	-
Regulatory assets/liabilities amortization	-	2,222	2,222
Regulatory assets/liabilities carrying costs	-	540	540
Changes in:			
Accounts receivable, net	15,362	(7,240)	8,122
Regulatory assets/liabilities	-	18,896	18,896
Consolidated Balance Sheet			
Regulatory Assets	107,515	34,665	142,180
Total Assets	855,649	34,665	890,314
Deferred Income Taxes	10,705	34,665	45,370
Total Liabilities and Capitalization	855,649	34,665	890,314

CNG has evaluated subsequent events through the date its financial statements were available to be issued, April 7, 2017.

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, net 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 2016 and 2015 were 8.10% and 7.81%, respectively.

Accounts receivable and allowance for bad debt

CNG records accounts receivable at amounts billed to customers. The allowance for bad debts is established by using both historical average loss percentages to project future losses, and a specific allowance is established for known credit issues. Amounts are written off when CNG believes that a receivable will not be recovered.

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 non-current liabilities.

ARO activity for 2016 and 2015 is as follows:

	2016	2015
	(In Thousands)	
Balance as of January 1	$ 6,737	$ 6,847
Liabilities settled during the year	(375)	(466)
Accretion	354	356
Balance as of December 31	$ 6,716	$ 6,737

Depreciation

Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis using composite rates based on the estimated service lives of the various classes of assets. For utility plant other than software, service lives are determined by independent depreciation consultants 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 2016 and 2015 were approximately 3.8% and 3.9%, respectively, of the original cost of depreciable property.

Goodwill

Goodwill 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 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, CNG has the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary, or 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 CNG bypasses step zero or performs the qualitative assessment but determines 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.

CNG's step zero qualitative assessment involves evaluating key events and circumstances that could affect its fair value, 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 CNG.

CNG's step one impairment testing, and step two if required, includes various assumptions, primarily the discount rate, which is based on an estimate of CNG's marginal, weighted average cost of capital, and forecasted cash flows. CNG tests the reasonableness of the conclusions of step one impairment testing using a range of discount rates and a range of assumptions for long term cash flows.

CNG conducted a quantitative analysis (step one) in 2016 and, based on the results, determined that the estimated fair value of CNG was in excess of its carrying value. No events or circumstances occurred subsequent to the performance of the step one impairment test 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, 2016, 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, 2016 and 2015.

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, 2016 and 2015 were comprised as follows:

	2016	2015
	(In Thousands)	
Gas distribution plant	$ 768,706	$ 721,769
Software	4,361	4,720
Land	1,618	1,618
Building and improvements	29,803	29,570
Other plant	53,045	37,103
Total property, plant & equipment	857,533	794,780
Less accumulated depreciation	280,731	265,758
	576,802	529,022
Construction work in progress	23,348	19,286
Net property, plant & equipment	$ 600,150	$ 548,308

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, 2016 and 2015 included the following:

	Remaining Period		December 31, 2016		December 31, 2015
			(In Thousands)		
Regulatory Assets:					
Pension and other post-retirement benefit plans	(a)	$	123,781	$	96,601
Hardship programs	(b)		8,264		8,761
Debt premium	1 to 21 years		246		1,773
Deferred income taxes	(c)		21,749		34,665
Unfunded future income taxes	(c)		11,987		10,175
Deferred purchased gas	(f)		4,641		3,099
Other	(d)		4,002		4,196
Total regulatory assets			174,670		159,270
Less current portion of regulatory assets			14,461		17,090
Regulatory Assets, Net		$	160,209	$	142,180
Regulatory Liabilities:					
Pension and other post-retirement benefit plans	(a)	$	4,217	$	5,490
Asset removal costs	(d)		164,776		154,574
Asset retirement obligation	(e)		8,176		7,702
Rate credits	2 to 11 years		12,500		18,225
Non-firm margin sharing credits	7 years		6,829		4,696
Decoupling	(g)		7,625		15,010
Other	(d)		3,341		5,841
Total regulatory liabilities			207,464		211,538
Less current portion of regulatory liabilities			11,471		18,764
Regulatory Liabilities, Net		$	195,993	$	192,774

(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 2017. 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 May 2014 the Financial Accounting Standards Board (FASB) issued an amendment concerning the recognition of revenue from contracts with customers and related required disclosures. The amendment replaces existing revenue guidance, including most industry-specific guidance, and will use a five-step model for recognizing and measuring revenue from contracts with customers. The core principle is for an entity to recognize revenue to represent the transfer of goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. Required disclosures include information about the nature, amount, timing, and uncertainty of revenues and the related cash flows. In August 2015, the FASB issued an accounting standards update that defers by one year the original effective date of the revenue standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption permitted. CNG does not plan to early adopt. Entities may apply the amendment retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Company will apply the modified retrospective method. CNG is currently evaluating how our adoption of the amendments will affect our results of operations, financial position, cash flows, and disclosures. CNG is considering the effects of the amendments on our ability to recognize revenue for certain contracts where collectability is in question and our accounting for contributions in aid of construction. In addition, the amendments will require us to capitalize, rather than expense, any costs to acquire new contracts. The FASB has issued various additional accounting standards updates, with the same deferred effective date, as follows: in March 2016 to amend and clarify the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, in April 2016 to address implementation questions on identifying performance obligations and accounting for licenses of intellectual property. CNG does not expect significant effects as a result of those updates. In May 2016 the FASB issued a final update concerning narrow-scope improvements and practical expedients. CNG is currently evaluating the effects of that update.

In May 2015 the FASB issued Accounting Standards Update (ASU) 2015-07 “Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)” which affects 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 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. CNG’s adoption of the amendments in 2016 did not affect its results of operations, financial position, or cash flows.

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.

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 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. CNG does not expect our adoption of the guidance to materially affect its 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. The updated guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal year, and early application is permitted. CNG is currently evaluating the effect that adopting this new accounting guidance will have on its 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, 2016 and 2015.

Preferred Stock of Subsidiaries, Noncontrolling Interests

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, 2016, there were 108,706 shares issued and outstanding with a value of approximately $0.3 million.

Long-Term Debt

As of December 31,		**2016**		**2015**	
(In Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured debt	2017-2043	$ 130,000	4.30%-8.96%	$ 140,000	4.30%-9.10%
Unamortized debt (costs) premium, net		(447)		1,265	
Total Debt		**129,553**		**141,265**	
Less: debt due within one year, included in current liabilities		20,310		11,527	
Total Long-Term Debt		**$ 109,243**		**$ 129,738**	`

The fair value of CNG's long-term debt was $151.7 million as of December 31, 2016, 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.

In November 2016, CNG repaid, upon maturity, the outstanding balance of its 9.10% Medium Term Note, Series A, in the aggregate amount of $10 million.

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

	2017	**2018**	**2019**	**2020**	**2021 & Thereafter**	**Total**
				(In Thousands)		
Maturities:	$ 20,000	$ -	$ -	$ -	$ 110,000	$ 130,000

(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 approval was 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. During 2016, $5.7 million of rate credits representing a one-time credit, were credited to customer bills in the first quarter of 2016. The remaining $12.5 million will be credited to CNG customers evenly over a ten-year period beginning in 2018.

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 allowed return on equity established by PURA is 9.18%. CNG is required to return to customers 50% of any earnings over the allowed ROE in a calendar year by means of an earnings sharing mechanism. CNG also has two separate ratemaking mechanisms that reconcile actual revenue requirements related to CNG's cast iron and bare steel replacement program and system expansion. Additionally, CNG has a purchased gas adjustment clause, approved by PURA, which enables reasonably incurred cost of gas purchases to be passed 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. 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.

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, 2016 are as follows:

		(In Thousands)
2017	$	71,322
2018		62,140
2019		47,999
2020		41,802
2021		37,173
2022-after		190,463
	$	450,899

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

On April 5, 2016, Avangrid, Inc. and its subsidiaries, including CNG, entered into a new credit facility agreement with a syndicate of banks (Avangrid Credit Facility) which replaced the UIL Holdings Credit Facility.

Under the Avangrid Credit Facility, CNG has a maximum sublimit of $150 million. Additionally, under the Avangrid Credit Facility, each of the borrowers, including CNG, will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 10.0 to 17.5 basis points. The maturity date for the Avangrid Credit Facility is April 5, 2021. As of December 31, 2016 CNG does not have any outstanding borrowings under the Avangrid Credit Facility. As of December 31, 2015, CNG did not have any borrowings outstanding under the UIL Holdings Credit Facility.

(E) INCOME TAXES

	Year Ended December 31, 2016	Year Ended December 31, 2015
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ 2,099	$ 5,215
State	3,370	846
Total current	5,469	6,061
Deferred		
Federal	9,883	(591)
State	(3,802)	(3,068)
Total deferred	6,081	(3,659)
Total income tax expense	$ 11,550	$ 2,402

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, 2016	Year Ended December 31, 2015
	(In Thousands)	
Book income before income taxes	$ 34,423	$ 11,423
Computed tax at federal statutory rate	$ 12,048	$ 3,998
Increases (reductions) resulting from:		
State income taxes, net of federal income tax benefits	(281)	(1,444)
Other	(217)	(152)
Total income tax expense	$ 11,550	$ 2,402
Effective income tax rates	33.6%	21.0%

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 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. 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. Also pursuant to the tax allocation agreement, CNG settles its current tax liability or benefit each year directly with Avangrid, Inc.

The following table summarizes CNG's tax years that remain subject to examination as of December 31, 2016:

Jurisdiction	*Tax years*
Federal	2013 - 2016
Connecticut	2013 - 2016

The following table summarizes CNG's deferred tax assets and liabilities as of December 31, 2016 and 2015:

	2016	**2015**
	(In Thousands)	
Deferred income tax assets:		
Post-retirement benefits	$ 38,670	$ 25,232
CT credit carryforward	3,742	1,197
Other	-	6,941
	$ 42,412	$ 33,370
Deferred income tax liabilities:		
Plant basis and accelerated depreciation timing differences	$ 76,059	$ 73,628
Goodwill	4,283	3,588
Other	2,544	1,524
	$ 82,886	$ 78,740
Total deferred income tax assets (liabilities), net	$ (40,474)	$ (45,370)

As of December 31, 2016 and 2015, CNG had state tax credit carry forwards of $3.7 million and $1.2 million, respectively, each of which will begin to expire in 2020.

(F) PENSION AND OTHER BENEFITS

Defined Benefit Plans (the Plans)

Pension Plans

CNG has multiple qualified pension plans covering a majority of their union and management employees. CNG also has non-qualified supplemental pension plans for certain retirees. The qualified pension plans provide benefits under a traditional defined benefit formula or cash balance formula depending on date of hire. Neither of these formulas are offered to new employees hired on or after specified dates.

Employees not participating in a defined benefit plan are eligible to participate in an enhanced 401(k) plan.

Other Postretirement Benefits Plans

CNG also has plans providing other postretirement benefits for a majority of its employees. These benefits consist primarily of health care, prescription drug and life insurance benefits, for retired employees and their dependents. For Medicare eligible non-union retirees, CNG provides a subsidy through a Health Reimbursement Account (HRA) for retirees to purchase coverage on the individual market. Medicare eligible union retirees have the option of receiving a subsidy through an HRA or paying contributions and participating in company-sponsored retiree health plans.

Plan Assets

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.

CNG’s asset allocation policy is the most important consideration in achieving the objective of superior investment returns while minimizing risk. CNG has a target asset allocation policy within allowable ranges for its pension benefits plan assets within broad categories of asset classes. The 2017 target asset allocations are approximately as follows: 54% equity securities, 27% fixed income investments, 10% bonds, 5% real estate investments and 4% treasury securities. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

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, 2016 and 2015. Plan assets and obligations have been measured as of December 31, 2016 and 2015.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2016	Year Ended December 31, 2015
Change in Benefit Obligation:		(In Thousands)		
Benefit obligation at beginning of year	$ 237,975	$ 253,965	$ 21,779	$ 22,970
Service cost	4,074	4,136	224	233
Interest cost	11,212	10,876	971	939
Participant contributions	-	-	1,496	314
Actuarial (gain) loss	33,560	(20,733)	742	(1,124)
Benefits paid (including expenses)	(15,852)	(10,269)	(2,536)	(1,553)
Benefit obligation at end of year	$ 270,969	$ 237,975	$ 22,676	$ 21,779
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 181,608	$ 192,941	$ 9,718	$ 9,580
Actual return on plan assets	12,895	(4,064)	631	(156)
Employer contributions	3,942	3,000	-	-
Participant contributions	-	-	1,496	314
Benefits paid (including expenses)	(15,852)	(10,270)	(1,514)	(20)
Fair value of plan assets at end of year	$ 182,593	$ 181,607	$ 10,331	$ 9,718
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 88,376	$ 56,368	$ 12,345	$ 12,061
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 88,376	$ 56,368	$ 12,345	$ 12,061
Amounts Recognized as a Regulatory Asset (Liability) consist of:				
Prior service cost	$ 42	$ 65	$ 1,059	$ 1,306
Net (gain) loss	47,845	16,412	(1,674)	(2,318)
Total recognized as a regulatory asset (liability)	$ 47,887	$ 16,477	$ (615)	$ (1,012)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 270,969	$ 237,976	N/A	N/A
Accumulated benefit obligation	$ 240,160	$ 216,449	N/A	N/A
Fair value of plan assets	$ 182,593	$ 181,607	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	4.24%	4.95%	N/A	N/A
Discount rate (Non-Qualified Plans)	4.24%	4.90%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	4.24%	4.90%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year – pre/post-65)	N/A	N/A	6.75%/8.50%	7.00%
Health care trend rate (2026/2028 – pre/post-65)	N/A	N/A	4.50%/4.50%	5.00%

N/A – not applicable

CNG is allowed to defer as regulatory assets or regulatory liabilities items that would have otherwise been recorded in accumulated OCI pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2016 and 2015 are shown above.

The discount rate is the rate at which the benefit obligations could presently be effectively settled. The discount rates were determined by developing yield curves derived from a portfolio of high grade noncallable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.

The components of net periodic benefit cost are:

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2016	Year Ended December 31, 2015
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 4,074	$ 4,136	$ 224	$ 233
Interest cost	11,212	10,876	971	939
Expected return on plan assets	(13,845)	(15,161)	(477)	(486)
Amortization of prior service costs	23	26	247	104
Amortization of actuarial (gain) loss	3,076	600	(56)	(93)
Net periodic benefit cost	4,540	477	909	697
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 34,509	$ (1,507)	$ 588	$ (1,485)
Amortization of current year prior service costs	-	-	-	1,003
Amortization of prior service costs	(23)	(26)	(247)	(104)
Amortization of actuarial (gain) loss	(3,076)	(600)	56	93
Total recognized as regulatory asset (liability)	$ 31,410	$ (2,133)	$ 397	$ (493)
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 35,950	$ (1,656)	$ 1,306	$ 204
Estimated Amortizations from Regulatory Assets (Liabilities) into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of prior service cost	$ 22	$ 23	$ 247	$ (232)
Amortization of net (gain) loss	3,446	573	(167)	247
Total estimated amortizations	$ 3,468	$ 596	$ 80	$ 15
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.24%	4.20%-4.30%	4.24%	4.20%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.75%	8.00%	5.37%	5.56%
Health care trend rate (current year – pre/post-65)	N/A	N/A	7.00%/9.00%	7.00%
Health care trend rate (2026/2028 – pre/post-65)	N/A	N/A	4.50%/4.50%	5.00%

N/A – not applicable

CNG utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. Prior service costs for both the pension and other postretirement benefits plans are amortized on a straight-line basis over the average remaining service period of participants expected to receive benefits. Unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans are amortized over the lesser of the average remaining service period or 10 years. For pension benefits, 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. For other postretirement benefits, there is no such allowance for a variance in capturing the amortization of unrecognized gains and losses.

The expected long-term rate of return on plan assets assumption was developed 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. The analysis considered current capital market conditions and projected conditions. CNG amortizes unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the PURA.

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	$	8	$	(7)
Accumulated post-retirement benefit obligation	$	29	$	(25)

Contributions

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 $1.6 million in 2017. Such contribution levels will be adjusted, if necessary, based on actuarial calculations.

Estimated Future Benefit Payments

Expected benefit payments and Medicare Prescription Drug Improvement and Modernization Act of 2003 subsidy receipts reflecting future service as of December 31, 2016 consisted of:

Year	Pension Benefits		Other Post-Retirement Benefits		Medicare Act Subsidy	
	(In Thousands)					
2017	$	11,125	$	2,067	$	196
2018	$	11,406	$	2,036	$	203
2019	$	11,820	$	1,867	$	210
2020	$	12,246	$	1,833	$	214
2021	$	12,695	$	1,791	$	221
2022-2026	$	72,011	$	8,349	$	1,131

Defined Contribution Retirement Plans/401(k)

CNG non-union employees are eligible to participate in the UIL Holdings Corporation 401(k) 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 in various investment alternatives offered to employees. The matching expense for 2016 and 2015 was $1.2 million, and $1.1 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, 2016, CNG recorded inter-company expenses of $10.2 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, 2016 and 2015, the Balance Sheet reflects inter-company receivables, included in accounts receivable of $1.5 million and $1.7 million, respectively, and inter-company payables, included in accounts payable of $6.6 million and $7.5 million, respectively.

Dividends/Capital Contributions

For the year ended December 31, 2016 CNG did not accrue any dividends to CTG and for year ended December 31, 2015, CNG accrued dividends to CTG of $17.5 million.

(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)	
2017	$	587
2018		488
2019		387
2020		384
2021-after		258
	$	2,104

(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, 2016 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, 2016, 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, 2016 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
	(In Thousands)			
December 31, 2016				
Noncurrent investments	$ 1,375	$ -	$ -	$ 1,375
Total fair value assets, December 31, 2016	$ 1,375	$ -	$ -	$ 1,375
December 31, 2015				
Noncurrent investments	$ 1,527	$ -	$ -	$ 1,527
Total fair value assets, December 31, 2015	$ 1,527	$ -	$ -	$ 1,527

The following tables set forth the fair values of CNG's pension and OPEB assets as of December 31, 2016 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, 2016		(In Thousands)		
Pension assets				
Mutual funds	$ -	$ 182,593	$ -	$ 182,593
	-	182,593	-	182,593
OPEB assets				
Mutual funds	3,062	7,269	-	10,331
Fair value of plan assets, December 31, 2016	$ 3,062	$ 189,862	$ -	$ 192,924
December 31, 2015				
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

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 period ended December 31, 2015.

	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	$ -

THE SOUTHERN CONNECTICUT GAS COMPANY

AUDITED CONSOLIDATED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2016 AND 2015

TABLE OF CONTENTS

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Report of Independent Auditors

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, which comprise the consolidated balance sheet as of December 31, 2016, and the related consolidated statements of income, comprehensive income, changes in shareholder's equity and cash flows for the year then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

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

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

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

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Southern Connecticut Gas Company at December 31, 2016, and the consolidated results of its operations and its cash flows for the year then ended in conformity with U.S. generally accepted accounting principles.

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Report of Other Auditors on December 31, 2015 Financial Statements

The consolidated financial statements of The Southern Connecticut Gas Company for the year ended December 31, 2015, were audited by other auditors who expressed an unmodified opinion on those statements on April 4, 2016.

Ernst & Young LLP

April 27, 2017

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

	Year Ended December 31, 2016	Year Ended December 31, 2015
Operating Revenues	$ 335,886	$ 314,939
Operating Expenses		
Operation		
Natural gas purchased	145,298	136,823
Operation and maintenance	88,290	94,264
Depreciation and amortization	20,420	23,563
Taxes - other than income taxes	24,968	23,502
Total Operating Expenses	278,976	278,152
Operating Income	56,910	36,787
Other Income and (Deductions), net		
Other income	1,393	5,182
Other (deductions)	(931)	(755)
Total Other Income and (Deductions), net	462	4,427
Interest Charges, net		
Interest on long-term debt	13,374	13,374
Other interest, net	180	(37)
	13,554	13,337
Amortization of debt expense and redemption premiums	513	306
Total Interest Charges, net	14,067	13,643
Income Before Income Taxes	43,305	27,571
Income Taxes (Note E)	15,378	8,575
Net Income	$ 27,927	$ 18,996

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

	Year Ended December 31, 2016	Year Ended December 31, 2015
Net Income	$ 27,927	$ 18,996
Other Comprehensive Income (Loss), net of income taxes		
Changes in unrealized gains(losses) related to pension and other post-retirement benefit plans	222	(124)
Total Other Comprehensive Income (Loss), net of income taxes	222	(124)
Comprehensive Income	$ 28,149	$ 18,872

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, 2016	Year Ended December 31, 2015
Cash Flows From Operating Activities		
Net income	$ 27,927	$ 18,996
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	20,933	23,869
Deferred income taxes	7,863	9,153
Pension expense	4,341	423
Uncollectable expense	5,850	7,125
Environmental liabilities	-	49,000
Regulatory assets/liabilities amortization	13,367	13,657
Regulatory assets/liabilities carrying costs	86	205
Other non-cash items, net	(290)	507
Changes in:		
Accounts receivable, net	(10,920)	(113)
Unbilled revenues	(5,603)	6,505
Natural gas in storage	5,621	10,757
Prepayments	(253)	259
Accounts payable	13,258	(8,635)
Taxes accrued/refundable, net	16,014	(6,267)
Accrued liabilities	1,252	1,221
Accrued pension	(3,878)	(5,883)
Accrued other post-employment benefits	(630)	(1,751)
Regulatory assets/liabilities	(4,759)	(49,208)
Other assets	2,951	(2,979)
Other liabilities	(1,308)	(747)
Total Adjustments	63,895	47,098
Net Cash provided by Operating Activities	91,822	66,094
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(54,432)	(64,576)
Intercompany receivable	(2,880)	-
Net Cash used in Investing Activities	(57,312)	(64,576)
Cash Flows from Financing Activities		
Payment of common stock dividend	-	(26,000)
Payment of noncontrolling interest dividend	(3,500)	-
Intercompany payable	(36,962)	31,000
Other	(200)	-
Net Cash used in Financing Activities	(40,662)	5,000
Unrestricted Cash and Temporary Cash Investments:		
Net change for the period	(6,152)	6,518
Balance at beginning of period	6,946	428
Balance at end of period	$ 794	$ 6,946
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 12,802	$ 12,499
Income taxes	$ -	$ 840
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 5,601	$ 8,169

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, 2016 and 2015

ASSETS
(In Thousands)

	2016	2015
Current Assets		
Unrestricted cash and temporary cash investments	$ 794	$ 6,946
Accounts receivable less allowance of $1,300 and $1,800, respectively	59,251	53,681
Unbilled revenues	21,408	15,805
Current regulatory assets (Note A)	22,886	27,272
Natural gas in storage, at average cost	26,489	32,109
Materials and supplies, at average cost	2,115	2,311
Refundable taxes	9,012	10,793
Prepayments	776	523
Intercompany receivable	2,880	-
Other	202	3,005
Total Current Assets	145,813	152,445
Other investments	9,657	9,645
Total Property, Plant and Equipment	889,871	833,145
Less accumulated depreciation	221,864	205,176
	668,007	627,969
Construction work in progress	7,425	13,102
Net Property, Plant and Equipment (Note A)	675,432	641,071
Regulatory Assets (Note A)	153,415	148,203
Deferred Charges and Other Assets		
Unamortized debt issuance expenses	170	125
Goodwill (Note A)	134,931	134,931
Total Deferred Charges and Other Assets	135,101	135,056
Total Assets	$ 1,119,418	$ 1,086,420

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, 2016 and 2015

LIABILITIES AND CAPITALIZATION
(In Thousands)

	2016	2015
Current Liabilities		
Current portion of long-term debt (Note B)	$ 2,517	$ 2,517
Accounts payable	52,208	41,516
Accrued liabilities	17,400	16,148
Current regulatory liabilities (Note A)	2,759	7,929
Interest accrued	2,819	2,271
Taxes accrued	17,920	3,687
Intercompany payable	9,038	46,000
Total Current Liabilities	104,661	120,068
Deferred Income Taxes (Note E)	42,366	36,639
Regulatory Liabilities (Note A)	173,115	170,205
Other Noncurrent Liabilities		
Pension accrued (Note F)	61,277	42,173
Other post-retirement benefits accrued (Note F)	16,213	15,913
Environmental liabilities	46,916	49,000
Other	13,482	13,350
Total Other Noncurrent Liabilities	137,888	120,436
Capitalization		
Long-term debt (Note B)	222,523	224,856
Noncontrolling interest (Note A)	16,869	20,369
Common Stock Equity (Note B)		
Common stock	18,761	18,761
Paid-in capital	369,737	369,737
Retained earnings	33,641	5,714
Accumulated other comprehensive income (loss)	(143)	(365)
Net Common Stock Equity	421,996	393,847
Total Capitalization	661,388	639,072
Total Liabilities and Capitalization	$ 1,119,418	$ 1,086,420

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, 2016 and 2015
(Thousands of Dollars)

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
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
Net income				27,927		27,927
Other comprehensive loss, net of income taxes				-	222	222
Balance as of December 31, 2016	1,407,072	$ 18,761	$ 369,737	$ 33,641	$ (143)	$ 421,996

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

THE SOUTHERN CONNECTICUT GAS COMPANY

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. SCG is regulated by the Connecticut Public Utilities Regulatory Authority (PURA). 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.

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 uncollectible expense, pension, regulatory activity, net, regulatory assets/liabilities amortization and regulatory assets/liabilities carrying costs that were reported as such in the Consolidated Statement of Cash Flows in previous periods have been reclassified to conform to the current presentation. Such reclassifications had no impact on the 2015 "Net Cash provided by Operating Activities." Certain amounts related to regulatory assets and deferred tax liabilities that were reported as such in the Consolidated Balance Sheet in previous periods have been reclassified to conform to the current presentation. Changes in the current presentation are 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 the impact to the prior period Consolidated Statement of Cash Flows and Consolidated Balance Sheet of the adjustments noted above.

December 31, 2015 (in thousands)	As previously filed	Reclassifications	As currently reported
Consolidated Statement of Cash Flows			
Adjustments to reconcile net income to net cash provided by operating activities:			
Uncollectible expense	$ -	$ 7,125	$ 7,125
Pension expense	5,376	(4,953)	423
Accrued pension	(10,503)	4,620	(5,883)
Accrued other post-employment benefits	(2,372)	621	(1,751)
Regulatory activity, net	(35,058)	35,058	-
Regulatory assets/liabilities amortization	-	13,657	13,657
Regulatory assets/liabilities carrying costs	-	205	205
Changes in:			
Accounts receivable, net	7,012	(7,125)	(113)
Regulatory assets/liabilities	-	(49,208)	(49,208)
Consolidated Balance Sheet			
Regulatory Assets	146,440	1,763	148,203
Total Assets	1,084,657	1,763	1,086,420
Deferred Income Taxes	34,876	1,763	36,639
Total Liabilities and Capitalization	1,084,657	1,763	1,086,420

SCG has evaluated subsequent events through the date its financial statements were available to be issued, April 27, 2017.

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 $31.5 million and income of $2.5 million as of and for the year ended December 31, 2016. Intercompany operating revenues and natural gas purchased expenses of $12.6 million and intercompany receivables and payables of $1 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.

The liabilities recognized as a result of combining the above VIEs do not necessarily represent additional claims on SCG's general assets outside of the VIEs; rather they represent claims against the specific assets of the combined VIEs. Conversely, assets recognized as a result of combining these VIEs do not necessarily represent additional assets that could be used to satisfy claims against SCG's general assets. The total combined VIE assets and liabilities reflected on SCG's consolidated balance sheets are as follows:

	December 31, 2016	December 31, 2015
	(In Thousands)	
Assets:		
Current assets	$ 10,595	$ 11,346
Long-term assets	13,451	12,849
Total Assets	$ 24,046	$ 24,195
Liabilities		
Current liabilities	$ 1,545	$ 700
Long-term liabilities	-	-
Total Liabilities	$ 1,545	$ 700

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, net 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 2016 and 2015 were 0.55% and 8.40%, respectively.

Accounts receivable and allowance for bad debt

SCG records accounts receivable at amounts billed to customers. The allowance for bad debts is established by using both historical average loss percentages to project future losses, and a specific allowance is established for known credit issues. Amounts are written off when SCG believes that a receivable will not be recovered.

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 non-current liabilities.

ARO activity for 2016 and 2015 is as follows:

	2016	2015
	(In Thousands)	
Balance as of January 1	$ 11,727	$ 11,568
Liabilities settled during the year	(433)	(448)
Accretion	616	607
Balance as of December 31	$ 11,910	$ 11,727

Depreciation

Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis using composite rates based on the estimated service lives of the various classes of assets. For utility plant other than software, service lives are determined by independent depreciation consultants 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 2016 and 2015 were approximately 2.4% and 3.0%, 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 2016, SCG entered into weather insurance contracts for the winter period of November 1, 2016 through April 30, 2017. If temperatures are warmer than normal, SCG will receive payments up to a maximum of $3 million. As of December 31, 2016, the intrinsic value of the contract was $0.2 million since the variation from normal weather through December 31, 2016 reached the prescribed levels stated in the contract.

In September 2015, SCG entered into weather insurance contracts for the winter period of November 1, 2015 through April 30, 2016. According to the terms of the contract, because temperatures were warmer than normal for the contract period, SCG received a payment of $3 million in May 2016. As of December 31, 2015, the intrinsic value of the contract was $3 million since the variation from normal weather through December 31, 2015 reached the prescribed levels stated in the contract.

Goodwill

Goodwill 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 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, SCG has the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary, or 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 SCG bypasses step zero or performs 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.

SCG's step zero qualitative assessment involves evaluating key events and circumstances that could affect its fair value, 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 SCG.

SCG's step one impairment testing, and step two if required, includes various assumptions, primarily the discount rate, which is based on an estimate of SCG's marginal, weighted average cost of capital, and forecasted cash flows. SCG tests the reasonableness of the conclusions of step one impairment testing using a range of discount rates and a range of assumptions for long term cash flows.

SCG conducted a quantitative analysis (step one) in 2016 and, based on the results, determined that the estimated fair value of SCG was in excess of its carrying value. No events or circumstances occurred subsequent to the performance of the step one impairment test 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, 2016, 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, 2016 and 2015.

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, 2016 and 2015 were comprised as follows:

	2016	2015
	(In Thousands)	
Gas distribution plant	$ 806,592	$ 744,367
Software	2,019	2,315
Land	3,748	3,748
Building and improvements	25,448	23,519
VIE	17,844	17,333
Other plant	34,220	41,863
Total property, plant & equipment	889,871	833,145
Less accumulated depreciation	221,864	205,176
	668,007	627,969
Construction work in progress	7,425	13,102
Net property, plant & equipment	$ 675,432	$ 641,071

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, 2016 and 2015 included the following:

	Remaining Period	December 31, 2016	December 31, 2015
		(In Thousands)	
Regulatory Assets:			
Pension and other post-retirement benefit plans	(a)	$ 96,391	$ 79,350
Hardship programs	(b)	7,442	13,830
Deferred purchased gas	(c)	2,376	9,181
Environmental remediation costs	(g)	50,518	50,662
Debt premium	2 to 21 years	14,164	16,681
Deferred income taxes	(d)	-	1,763
Other	(e)	5,410	4,008
Total regulatory assets		176,301	175,475
Less current portion of regulatory assets		22,886	27,272
Regulatory Assets, Net		$ 153,415	$ 148,203
Regulatory Liabilities:			
Pension and other post-retirement benefit plans	(a)	3,618	4,637
Asset removal costs	(e)	97,086	95,811
Rate Credits	2 to 11 years	7,500	12,416
Unfunded future income taxes	(d)	26,742	26,587
Low income program	(f)	37,011	31,062
Non-firm margin sharing credits	7 years	1,761	4,027
Deferred income taxes	(d)	218	-
Other	(e)	1,938	3,594
Total regulatory liabilities		175,874	178,134
Less current portion of regulatory liabilities		2,759	7,929
Regulatory Liabilities, Net		$ 173,115	$ 170,205

(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 May 2014 the Financial Accounting Standards Board (FASB) issued an amendment concerning the recognition of revenue from contracts with customers and related required disclosures. The amendment replaces existing revenue guidance, including most industry-specific guidance, and will use a five-step model for recognizing and measuring revenue from contracts with customers. The core principle is for an entity to recognize revenue to represent the transfer of goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. Required disclosures include information about the nature, amount, timing, and uncertainty of revenues and the related cash flows. In August 2015, the FASB issued an accounting standards update that defers by one year the original effective date of the revenue standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption permitted. SCG does not plan to early adopt. Entities may apply the amendment retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Company will apply the modified retrospective method. SCG is currently evaluating how our adoption of the amendments will affect our results of operations, financial position, cash flows, and disclosures. SCG is considering the effects of the amendments on our ability to recognize revenue for certain contracts where collectability is in question and our accounting for contributions in aid of construction. In addition, the amendments will require us to capitalize, rather than expense, any costs to acquire new contracts. The FASB has issued various additional accounting standards updates, with the same deferred effective date, as follows: in March 2016 to amend and clarify the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, in April 2016 to address implementation questions on identifying performance obligations and accounting for licenses of intellectual property. SCG does not expect significant effects as a result of those updates. In May 2016 the FASB issued a final update concerning narrow-scope improvements and practical expedients. SCG is currently evaluating the effects of that update.

In May 2015 the FASB issued Accounting Standards Update (ASU) 2015-07 “Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)” which affects 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 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. SCG's adoption of the amendments in 2016 did not affect its results of operations, financial position, or cash flows.

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 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 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. SCG does not expect our adoption of the guidance to materially affect its 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. The updated guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal year, and early application is permitted. SCG is currently evaluating the effect that adopting this new accounting guidance will have on its 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, 2016 and 2015.

Long-Term Debt

As of December 31,		2016		2015	
(Millions)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
First mortgage bonds [(a)]	2018-2041	$ 214,000	3.88% -7.95%	$ 214,000	3.88%-7.95%
Unamortized debt (costs) premium, net		11,040		13,373	
Total Debt		**225,040**		**227,373**	
Less: debt due within one year, included in current liabilities		2,517		2,517	
Total Long-term Debt		**$ 222,523**		**$ 224,856**	

(a) The first mortgages bonds are secured by a first mortgage lien on substantially all of SCG's properties.

The fair value of SCG's long-term debt was $259.6 million as of December 31, 2016, 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:

	2017	2018	2019	2020	2021 & 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. During 2016, $5 million of rate credits representing a one-time credit were credited to customer bills in the first quarter of 2016. The remaining $7.5 million will be credited to SCG customers evenly over a ten-year period beginning in 2018.

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 allowed return on equity established by PURA is 9.36%. Additionally, SCG has a purchased gas adjustment clause, approved by PURA, which enables reasonably incurred cost of gas purchases to be passed 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.

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, 2016 are as follows:

	(In Thousands)
2017	$ 77,316
2018	69,923
2019	59,222
2020	52,943
2021	41,310
2022-after	173,317
	$ 474,031

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

On April 5, 2016, Avangrid, Inc. and its subsidiaries, including CNG, entered into a new credit facility agreement with a syndicate of banks (Avangrid Credit Facility) which replaced the UIL Holdings Credit Facility.

Under the Avangrid Credit Facility, SCG has a maximum sublimit of $150 million. Additionally, under the Avangrid Credit Facility, each of the borrowers, including SCG, will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 10.0 to 17.5 basis points. The maturity date for the Avangrid Credit Facility is April 5, 2021. As of December 31, 2016 SCG does not have any outstanding borrowings under the Avangrid Credit Facility. As of December 31, 2015, SCG did not have any borrowings outstanding under the UIL Holdings Credit Facility.

(E) INCOME TAXES

	Year Ended December 31, 2016	Year Ended December 31, 2015
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ 5,521	$ 911
State	1,994	(1,489)
Total current	7,515	(578)
Deferred		
Federal	8,262	8,373
State	(399)	780
Total deferred	7,863	9,153
Total Income tax expense	$ 15,378	$ 8,575

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, 2016	Year Ended December 31, 2015
	(In Thousands)	
Book income before income taxes	$ 43,305	$ 27,571
Computed tax at federal statutory rate	$ 15,157	$ 9,650
Increases (reductions) resulting from:		
Removal costs	(1,019)	(740)
Uncollectible reserves and programs	992	992
State taxes, net of federal income tax benefits	1,037	(461)
Variable interest entity	(876)	(846)
Other items, net	87	(20)
Total income tax expense	$ 15,378	$ 8,575
Effective income tax rates	35.5%	31.1%

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 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. 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. Also pursuant to the tax allocation agreement, SCG settles its current tax liability or benefit each year directly with Avangrid, Inc.

As of December 31, 2016 and 2015, SCG did not have any gross income tax reserves for uncertain tax positions.

The following table summarizes SCG's tax years that remain subject to examination as of December 31, 2016:

Jurisdiction	*Tax years*
Federal	2013 - 2016
Connecticut	2013 - 2016

The following table summarizes SCG's deferred tax assets and liabilities as of December 31, 2016 and 2015:

	2016	**2015**
	(In Thousands)	
Deferred income tax assets:		
Post-retirement benefits	$ 28,246	$ 19,582
Environmental Asset	19,423	19,539
CT credit carryover	6,573	3,081
Debt premium	5,714	6,651
Net operating loss carry forward	6,827	6,827
Other	11,500	13,135
	$ 78,283	$ 68,815
Deferred income tax liabilities:		
Plant basis and accelerated depreciation timing differences	$ 93,364	$ 82,718
Goodwill	16,349	13,697
Other	10,936	9,039
	$ 120,649	$ 105,454
Total deferred income tax assets (liabilities), net	$ (42,366)	$ (36,639)

As of December 31, 2016 and 2015, SCG had a state tax credit carry forward of $6.6 million that will begin to expire in 2018 and a federal net operating loss carry forward of $19.5 million that will begin to expire in 2032.

(F) PENSION AND OTHER BENEFITS

Defined Benefit Plans (the Plans)

Pension Plans

SCG has two qualified pension plans covering substantially all of their union and management employees. SCG also has non-qualified supplemental pension plans for certain retirees. The qualified pension plans provide benefits under traditional defined benefit formulas or, for those hired on or after specified dates, cash balance formulas. Neither of these formulas are offered to new employees. New employees participate in an enhanced 401(k) plan.

Other Postretirement Benefits Plans

SCG also has plans providing other postretirement benefits for a majority of its employees. These benefits consist primarily of health care, prescription drug and life insurance benefits, for retired employees and their dependents. Effective January 1, 2016, pre-Medicare eligible union retirees are eligible to participate in a multiemployer retiree welfare plan to which SCG provides a subsidy through a Voluntary Employee Benefit Association Trust. For Medicare eligible non-union retirees, SCG provides a subsidy through a Health Reimbursement Account (HRA) for retirees to purchase coverage on the individual market. Medicare eligible union retirees have the option of receiving a subsidy through an HRA or paying contributions and participating in company-sponsored retiree health plans.

Plan Assets

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.

SCG’s asset allocation policy is the most important consideration in achieving the objective of superior investment returns while minimizing risk. CNG has a target asset allocation policy within allowable ranges for its pension benefits plan assets within broad categories of asset classes. The 2017 target asset allocations are approximately as follows: 54% equity securities, 27% fixed income investments, 10% bonds, 5% real estate investments and 4% treasury securities. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

THE SOUTHERN CONNECTICUT GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2016 and 2015. Plan assets and obligations have been measured as of December 31, 2016 and 2015.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2016	Year Ended December 31, 2015
Change in Benefit Obligation:		(In Thousands)		
Benefit obligation at beginning of year	$ 160,946	$ 166,866	$ 21,691	$ 22,910
Service cost	1,797	1,850	177	180
Interest cost	7,387	7,070	986	934
Plan participants' contributions	-	-	980	-
Actuarial (gain) loss	22,454	(6,082)	69	(342)
Benefits paid (including expenses)	(13,131)	(8,758)	(2,002)	(1,991)
Benefit obligation at end of year	$ 179,453	$ 160,946	$ 21,901	$ 21,691
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 118,773	$ 124,370	$ 5,778	$ 6,167
Actual return on plan assets	8,571	(2,721)	303	(149)
Plan participants' contributions	-	-	980	-
Employer contributions	3,963	5,881	(2,002)	-
Benefits paid (including expenses)	(13,131)	(8,757)	629	(240)
Fair value of plan assets at end of year	$ 118,176	$ 118,773	$ 5,688	$ 5,778
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 61,277	$ 42,173	$ 16,213	$ 15,913
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 61,277	$ 42,173	$ 16,213	$ 15,913
Amounts Recognized as a Regulatory Asset (Liability) consist of:				
Prior service cost	$ 2,430	$ -	$ 1,644	$ 2,133
Net (gain) loss	36,788	19,371	(3,041)	(3,339)
Total recognized as a regulatory asset (liability)	$ 39,218	$ 19,371	$ (1,397)	$ (1,206)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 179,453	$ 160,946	N/A	N/A
Accumulated benefit obligation	$ 168,584	$ 151,861	N/A	N/A
Fair value of plan assets	$ 118,176	$ 118,773	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	4.24%	4.95%	N/A	N/A
Discount rate (Non-Qualified Plans)	4.24%	4.90%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	4.24%	4.90%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year – pre/post-65)	N/A	N/A	6.75%/8.00%	7.00%
Health care trend rate (2026/2028 – pre/post-65)	N/A	N/A	4.50%/4.50%	5.00%

N/A – not applicable

SCG is allowed to defer as regulatory assets or regulatory liabilities items that would have otherwise been recorded in accumulated OCI pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2016 and 2015 are shown above.

The discount rate is the rate at which the benefit obligations could presently be effectively settled. The discount rates were determined by developing yield curves derived from a portfolio of high grade noncallable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.

The components of net periodic benefit cost are:

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2016	Year Ended December 31, 2015
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 1,797	$ 1,850	$ 177	$ 180
Interest cost	7,387	7,070	986	934
Expected return on plan assets	(9,038)	(9,867)	(380)	(425)
Amortization of prior service cost	759	-	489	145
Amortization of actuarial (gain) loss	2,316	803	(152)	(267)
Net periodic benefit cost	$ 3,221	$ (144)	$ 1,120	$ 567
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 22,922	$ 3,317	$ 147	$ (1,349)
Amortization of current year prior service (credit)/costs	-	3,190	-	1,581
Amortization of prior service cost	(759)	-	(489)	(145)
Amortization of actuarial (gain) loss	(2,316)	(803)	152	267
Total recognized as regulatory asset (liability)	$ 19,847	$ 5,704	$ (190)	$ 354
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 23,068	$ 5,560	$ 930	$ 921
Estimated Amortizations from Regulatory Assets (Liabilities) into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of prior service (cost) credit	$ 759	$ 759	N/A	N/A
Amortization of net (gain) loss	2,792	1,055	N/A	N/A
Total estimated amortizations	$ 3,551	$ 1,814	N/A	N/A
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.24%	4.20-4.30%	4.24%	4.20%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.75%	8.00%	7.75%	8.00%
Health care trend rate (current year – pre/post-65)	N/A	N/A	7.00%/9.00%	7.00%
Health care trend rate (2026/2028 – pre/post-65)	N/A	N/A	4.50%/4.50%	5.00%

N/A – not applicable

SCG utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. Prior service costs for both the pension and other postretirement benefits plans are amortized on a straight-line basis over the average remaining service period of participants expected to receive benefits. Unrecognized actuarial gains and losses related to the pension and other postretirement benefits plans are amortized over the lesser of the average remaining service period or 10 years. For pension benefits, 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. For other postretirement benefits, there is no such allowance for a variance in capturing the amortization of unrecognized gains and losses.

The expected long-term rate of return on plan assets assumption was developed 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. The analysis considered current capital market conditions and projected conditions. SCG amortizes unrecognized actuarial gains and losses over ten years from the time they are incurred as required by the PURA.

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	$	63	$	(50)
Accumulated post-retirement benefit obligation	$	1,076	$	(878)

Contributions

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 $0.6 million in 2017. Such contribution levels will be adjusted, if necessary, based on actuarial calculations.

Estimated Future Benefit Payments

Expected benefit payments and Medicare Prescription Drug Improvement and Modernization Act of 2003 subsidy receipts reflecting future service as of December 31, 2016 consisted of:

Year	Pension Benefits		Other Post-Retirement Benefits		Medicare Act Subsidy	
			(In Thousands)			
2017	$	9,154	$	1,787	$	93
2018	$	9,451	$	1,668	$	99
2019	$	9,846	$	1,643	$	101
2020	$	10,097	$	1,573	$	106
2021	$	10,378	$	1,554	$	108
2022-2025	$	55,873	$	7,954	$	1,131

Defined Contribution Retirement Plans/401(k)

SCG employees are eligible to participate in the UIL Holdings Corporation 401(k) 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 in various investment alternatives offered to employees. The matching expense for 2016 and 2015 was $0.8 million and $0.7 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, 2016, SCG recorded inter-company expenses of $12.2 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, 2016 and 2015, the Consolidated Balance Sheet reflects inter-company receivables, included in accounts receivable of $2.1 million and $1.6 million, respectively, and inter-company payables, included in accounts payable of $6.2 million and $7.3 million, respectively.

Dividends/Capital Contributions

For the year ended December 31, 2016, SCG did not accrue any dividends to UIL Holdings. For the year ended December 31, 2015, SCG accrued $26 million in dividends to UIL Holdings.

(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)	
2017	$	72
2018		72
2019		72
2020		72
2021-after		48
	$	336

(I) 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, 2016, 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, 2016, UIL Holdings has determined that remediation of the properties in Bridgeport 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. 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, 2016 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
	(In Thousands)			
December 31, 2016				
Noncurrent investments	$ 9,657	$ -	$ -	$ 9,657
Total fair value assets, December 31, 2016	$ 9,657	$ -	$ -	$ 9,657
December 31, 2015				
Noncurrent investments	$ 9,644	$ -	$ -	$ 9,644
Total fair value assets, December 31, 2015	$ 9,644	$ -	$ -	$ 9,644

The following tables set forth the fair values of SCG's pension and OPEB assets as of December 31, 2016 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, 2016		(In Thousands)		
Mutual funds	$ -	$ 118,176	$ -	$ 118,176
OPEB assets				
Mutual funds	5,688	-	-	5,688
Fair value of plan assets, December 31, 2016	$ 5,688	$ 118,176	$ -	$ 123,864
December 31, 2015				
Pension assets				
Mutual 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

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 BERKSHIRE GAS COMPANY

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2016 AND 2015

TABLE OF CONTENTS

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Report of Independent Auditors

To the Board of Directors of the Berkshire Gas Company

We have audited the accompanying financial statements of the Berkshire Gas Company, which comprise the balance sheet as of December 31, 2016, and the related statements of income, comprehensive income, changes in shareholder's equity and cash flows for the year 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 audit. We conducted our audit in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, 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 the Berkshire Gas Company at December 31, 2016, and the results of its operations and its cash flows for the year then ended in conformity with U.S. generally accepted accounting principles.

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Report of Other Auditors on December 31, 2015 Financial Statements

The financial statements of the Berkshire Gas Company for the year ended December 31, 2015, were audited by other auditors who expressed an unmodified opinion on those statements on April 12, 2016.

Ernst & Young LLP

April 26, 2017

THE BERKSHIRE GAS COMPANY
STATEMENT OF INCOME
(In Thousands)

	Year Ended December 31, 2016	Year Ended December 31, 2015
Operating Revenues	$ 69,493	$ 73,198
Operating Expenses		
Operation		
Natural gas purchased	22,324	27,303
Operation and maintenance	26,682	28,752
Depreciation and amortization	7,356	7,137
Taxes - other than income taxes	3,467	3,231
Total Operating Expenses	59,829	66,423
Operating Income	9,664	6,775
Other Income and (Deductions), net		
Other income	416	1,477
Other (deductions)	(93)	(81)
Total Other Income and (Deductions), net	323	1,396
Interest Charges, net		
Interest on long-term debt	3,245	3,358
Other interest, net	(26)	(42)
	3,219	3,316
Amortization of debt expense and redemption premiums	127	124
Total Interest Charges, net	3,346	3,440
Income Before Income Taxes	6,641	4,731
Income Taxes (Note E)	2,580	1,693
Net Income	$ 4,061	$ 3,038

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

	Year Ended December 31, 2016	Year Ended December 31, 2015
Net Income	$ 4,061	$ 3,038
Other Comprehensive Income (Loss)	11	(9)
Comprehensive Income	$ 4,072	$ 3,029

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, 2016	Year Ended December 31, 2015
Cash Flows From Operating Activities		
Net income	$ 4,061	$ 3,038
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	7,483	7,261
Deferred income taxes	1,500	(1,481)
Uncollectible expense	641	452
Pension expense	1,908	285
Regulatory assets/liabilities amortization	1,742	2,229
Other non-cash items, net	(434)	(323)
Changes in:		
Accounts receivable, net	(903)	3,343
Unbilled revenues	(1,369)	1,513
Natural gas in storage	446	1,591
Accounts payable	1,756	(3,829)
Taxes accrued/refundable, net	(7,173)	(1,644)
Accrued liabilities	(870)	1,010
Accrued pension	(921)	(168)
Accrued other post-retirement benefits	(51)	(127)
Regulatory assets/liabilities	(2,005)	8,264
Other assets	856	(918)
Other liabilities	133	(1,422)
Total Adjustments	2,739	16,036
Net Cash provided by Operating Activities	6,800	19,074
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(16,448)	(16,003)
Net Cash used in Investing Activities	(16,448)	(16,003)
Cash Flows from Financing Activities		
Payments on non-current debt	(1,455)	(1,455)
Payment of common stock dividend	(7,500)	(5,400)
Intercompany payable	15,764	-
Other	(33)	-
Net Cash used in Financing Activities	6,776	(6,855)
Unrestricted Cash and Temporary Cash Investments:		
Net change for the period	(2,872)	(3,784)
Balance at beginning of period	2,950	6,734
Balance at end of period	$ 78	$ 2,950
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 3,205	$ 3,316
Income taxes	$ -	$ 700
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 800	$ 755

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

THE BERKSHIRE GAS COMPANY
BALANCE SHEET
December 31, 2016 and 2015

ASSETS
(In Thousands)

	2016	2015
Current Assets		
Unrestricted cash and temporary cash investments	$ 78	$ 2,950
Accounts receivable less allowance of $1,717 and $1,303, respectively	9,347	8,618
Unbilled revenues	5,372	4,003
Current regulatory assets (Note A)	7,149	3,960
Natural gas in storage, at average cost	1,898	2,344
Materials and supplies, at average cost	764	825
Other	2,041	2,812
Total Current Assets	26,649	25,512
Other investments	709	855
Total Property, Plant and Equipment	222,525	204,691
Less accumulated depreciation	72,618	68,546
	149,907	136,145
Construction work in progress	3,407	6,405
Net Property, Plant and Equipment (Note A)	153,314	142,550
Regulatory Assets (Note A)	35,409	33,878
Deferred Charges and Other Assets		
Unamortized debt issuance expenses	28	23
Goodwill (Note A)	51,933	51,933
Other	-	22
Total Deferred Charges and Other Assets	51,961	51,978
Total Assets	$ 268,042	$ 254,773

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

THE BERKSHIRE GAS COMPANY
BALANCE SHEET
December 31, 2016 and 2015

LIABILITIES AND CAPITALIZATION
(In Thousands)

	2016	2015
Current Liabilities		
Current portion of long-term debt (Note B)	$ 2,393	$ 2,393
Accounts payable	9,019	7,219
Accrued liabilities	3,649	4,519
Interest accrued	848	853
Intercompany payable	15,764	-
Current regulatory liabilities	2,312	-
Taxes accrued	81	7,254
Total Current Liabilities	34,066	22,238
Deferred Income Taxes (Note E)	24,591	24,537
Regulatory Liabilities (Note A)	36,347	36,009
Other Noncurrent Liabilities		
Pension accrued (Note F)	16,313	10,758
Other post-retirement benefits accrued (Note F)	2,890	1,792
Environmental remediation costs	2,950	2,600
Other	4,540	4,774
Total Other Noncurrent Liabilities	26,693	19,924
Commitments and Contingencies (Note I)		
Capitalization (Note B)		
Long-term debt	40,300	42,592
Common Stock Equity		
Common stock	-	-
Paid-in capital	106,095	106,095
Retained earnings	(42)	3,397
Accumulated other comprehensive income (loss)	(8)	(19)
Net Common Stock Equity	106,045	109,473
Total Capitalization	146,345	152,065
Total Liabilities and Capitalization	$ 268,042	$ 254,773

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, 2016 and 2015
(Thousands of Dollars)

	Common Stock		Paid-in	Retained	Accumulated Other Comprehensive	
	Shares	Amount	Capital	Earnings	Income (Loss)	Total
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
Net income				4,061		4,061
Other comprehensive income, net of deferred income taxes					11	11
Payment of common stock dividend				(7,500)		(7,500)
Balance as of December 31, 2016	100	$ -	$ 106,095	$ (42)	$ (8)	$ 106,045

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. Berkshire is regulated by the Massachusetts Department of Public Utilities (DPU) as it relates to utility service. 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.

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.

Certain amounts related to uncollectible expense, pension expense, regulatory activity, net, accrued pension, accrued other post-retirement benefits, regulatory assets/liabilities amortization and other liabilities that were reported as such in the Statement of Cash Flows in previous periods have been reclassified to conform to the current presentation. Such reclassifications had no impact on the 2015 "Net Cash provided by Operating Activities." Certain amounts related to regulatory liabilities and deferred tax liabilities that were reported as such in the Balance Sheet in previous periods have been reclassified to conform to the current presentation. Changes in the current presentation are 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 BERKSHIRE GAS COMPANY

NOTES TO FINANCIAL STATEMENTS

The following table summarizes the impact to the prior period Statement of Cash Flows and Balance Sheet of the adjustments noted above.

December 31, 2015 (in thousands)	As previously filed	Reclassifications	As currently reported
Consolidated Statement of Cash Flows			
Adjustments to reconcile net income to net cash provided by operating activities:			
Uncollectible expense	$ -	$ 452	$ 452
Pension expense	1,308	(1,023)	285
Regulatory activity, net	10,493	(10,493)	-
Regulatory assets/liabilities amortization	-	2,229	2,229
Changes in:			
Accounts receivable, net	3,795	(452)	3,343
Accrued pension	(1,368)	1,200	(168)
Accrued other post-employment benefits	-	(127)	(127)
Other liabilities	(1,372)	(50)	(1,422)
Regulatory assets/liabilities	-	8,264	8,264
Consolidated Balance Sheet			
Regulatory Liabilities	34,780	1,229	36,009
Deferred Income Taxes	25,766	(1,229)	24,537

Berkshire has evaluated subsequent events through the date its financial statements were available to be issued, April 26, 2017.

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, net 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 2016 and 2015 was 9.72% and 11.90%, respectively.

Depreciation

Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis using composite rates based on the estimated service lives of the various classes of assets. For utility plant other than software, service lives are determined by independent depreciation consultants 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 2016 and 2015 were approximately 3.4% and 3.3%, 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 2016, Berkshire entered into a weather insurance contract for the winter period of November 1, 2016 through April 30, 2017. If temperatures are warmer than normal, Berkshire will receive payments up to a maximum of $1 million. The contract had no intrinsic value at December 31, 2016 since the variation from normal weather through December 31, 2016 had not reached the prescribed levels stated in the contract.

In September 2015, Berkshire entered into a weather insurance contract for the winter period of November 1, 2015 through April 30, 2016. According to the terms of the contract, because temperatures were warmer than normal for the contract period, Berkshire received a payment of $1 million in May 2016. As of December 31, 2015, the contract had an intrinsic value of $1 million since the variation from normal weather through December 31, 2015 reached the prescribed levels stated in the contract. \

Goodwill

Goodwill 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 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, Berkshire has the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary, or 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 Berkshire bypasses step zero or performs 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.

Berkshire’s step zero qualitative assessment involves evaluating key events and circumstances that could affect its fair value, 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 Berkshire.

Berkshire’s step one impairment testing, and step two if required, includes various assumptions, primarily the discount rate, which is based on an estimate of Berkshire’s marginal, weighted average cost of capital, and forecasted cash flows. Berkshire tests the reasonableness of the conclusions of the step one impairment testing using a range of discount rates and a range of assumptions for long term cash flows.

Berkshire conducted a quantitative analysis (step one) in 2016 and, based on the results, determined that the estimated fair value of Berkshire was in excess of its carrying value. No events or circumstances occurred subsequent to the performance of the step one impairment test 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, 2016, 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, 2016 and 2015 were comprised as follows:

	2016	2015
	(In Thousands)	
Gas distribution plant	$ 180,290	$ 172,017
Land	2,286	2,286
Buildings and improvements	20,424	15,135
Other plant	19,525	15,253
Total property, plant & equipment	222,525	204,691
Less accumulated depreciation	72,618	68,546
	149,907	136,145
Construction work in progress	3,407	6,405
Net property, plant & equipment	$ 153,314	$ 142,550

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, 2016 and 2015 included the following:

	Remaining Period	December 31, 2016	December 31, 2015
		(In Thousands)	
Regulatory Assets:			
Pension plans	(a)	$ 24,334	$ 19,322
Environmental Remediation Costs	7 years	8,465	9,273
Debt premium	3 to 5 years	3,031	3,967
Deferred purchased gas	(b)	3,330	46
Unfunded future income taxes	(c)	767	858
Other	(d)	2,631	4,372
Total regulatory assets		42,558	37,838
Less current portion of regulatory assets		7,149	3,960
Regulatory Assets, Net		$ 35,409	$ 33,878
Regulatory Liabilities:			
Rate credits	0 to 2 years	$ 3,328	$ 4,000
Asset removal costs	(d)	32,074	30,360
Deferred income taxes	(c)	2,622	1,229
Other	(d)	635	420
Total regulatory liabilities		38,659	36,009
Less current portion of regulatory liabilities		2,312	-
Regulatory Liabilities, Net		$ 36,347	$ 36,009

(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 May 2014 the Financial Accounting Standards Board (FASB) issued an amendment concerning the recognition of revenue from contracts with customers and related required disclosures. The amendment replaces existing revenue guidance, including most industry-specific guidance, and will use a five-step model for recognizing and measuring revenue from contracts with customers. The core principle is for an entity to recognize revenue to represent the transfer of goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. Required disclosures include information about the nature, amount, timing, and uncertainty of revenues and the related cash flows. In August 2015, the FASB issued an accounting standards update that defers by one year the original effective date of the revenue standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption permitted. Berkshire does not plan to early adopt. Entities may apply the amendment retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Company will apply the modified retrospective method. Berkshire is currently evaluating how our adoption of the amendments will affect our results of operations, financial position, cash flows, and disclosures. Berkshire is considering the effects of the amendments on our ability to recognize revenue for certain contracts where collectability is in question and our accounting for contributions in aid of construction. In addition, the amendments will require us to capitalize, rather than expense, any costs to acquire new contracts. The FASB has issued various additional accounting standards updates, with the same deferred effective date, as follows: in March 2016 to amend and clarify the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, in April 2016 to address implementation questions on identifying performance obligations and accounting for licenses of intellectual property. Berkshire does not expect significant effects as a result of those updates. In May 2016 the FASB issued a final update concerning narrow-scope improvements and practical expedients. Berkshire is currently evaluating the effects of that update.

In May 2015 the FASB issued Accounting Standards Update (ASU) 2015-07 “Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)” which affects 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 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. BGC’s adoption of the amendments in 2016 did not affect its results of operations, financial position, or cash flows.

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 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 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. Berkshire does not expect our adoption of the guidance to materially affect its 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. The updated guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal year, and early application is permitted. Berkshire is currently evaluating the effect that adopting this new accounting guidance will have on its financial statements.

B) CAPITALIZATION

Common Stock

Berkshire had 100 shares of its common stock, $2.50 par value, outstanding as of December 31, 2016 and 2015.

Long-Term Debt

As of December 31,		**2016**		**2015**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
First mortgage bonds [(a)]	2019	$ 10,000	10.06%	$ 10,000	10.06%
Senior unsecured notes	2020-2043	30,272	5.33%-9.60%	31,727	5.33%-9.60%
Unamortized debt (costs) premium, net		2,421		3,258	
Total Debt		**42,693**		**44,985**	
Less: debt due within one year, included in current liabilities		2,393		2,393	
Total Non-current Debt		**$ 40,300**		**$ 42,592**	

(a) The first mortgages bonds are secured by a first mortgage lien on substantially all of Berkshire's properties.

The fair value of Berkshire's long-term debt was $47.8 million as of December 31, 2016, 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:

	2017	2018	2019	2020	2021 & Thereafter	Total
			(In Thousands)			
Maturities:	$ 1,455	$ 1,455	$ 11,455	$ 9,455	$ 16,452	$ 40,272

(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. DPU approval was obtained upon commitments made by UIL Holdings and Avangrid, Inc. that included $4.0 million in rate credits to Berkshire customers, to be spread over the 2016 – 2017 and 2017 – 2018 heating seasons. Such rate credits are 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. As discussed above, 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 to be in effect prior to June 1, 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 the reasonably incurred cost of gas purchases to be passed 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.

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, 2016 are as follows:

		(In Thousands)
2017	$	12,552
2018		9,243
2019		8,164
2020		2,941
2021		2,598
2022-after		23,781
	$	59,279

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

On April 5, 2016, Avangrid, Inc. and its subsidiaries, including Berkshire, entered into a new credit facility agreement with a syndicate of banks (Avangrid Credit Facility) which replaced the UIL Holdings Credit Facility.

Under the Avangrid Credit Facility, Berkshire has a maximum sublimit of $25 million. Additionally, under the Avangrid Credit Facility, each of the borrowers, including Berkshire, will pay an annual facility fee that is dependent on their credit rating. The facility fees will range from 10.0 to 17.5 basis points. The maturity date for the Avangrid Credit Facility is April 5, 2021. As of December 31, 2016 Berkshire does not have any outstanding borrowings under the Avangrid Credit Facility. As of December 31, 2015, Berkshire did not have any borrowings outstanding under the UIL Holdings Credit Facility.

(E) INCOME TAXES

	Year Ended December 31, 2016	Year Ended December 31, 2015
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions:		
Current		
Federal	$ 613	$ 2,466
State	508	754
Total current	1,121	3,220
Deferred		
Federal	1,488	(1,088)
State	12	(393)
Total deferred	1,500	(1,481)
Investment tax credits	(41)	(46)
Total income tax expense	$ 2,580	$ 1,693

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, 2016	Year Ended December 31, 2015
	(In Thousands)	
Book income before income taxes	$ 6,641	$ 4,731
Computed tax at federal statutory rate	$ 2,324	$ 1,656
Increases (reductions) resulting from:		
State income taxes, net of federal income tax benefits	338	235
Other items, net	(82)	(198)
Total income tax expense	$ 2,580	$ 1,693
Effective income tax rates	38.8%	35.8%

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 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, filed or will file a consolidated federal tax return with Avangrid, Inc. 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 are paid for their losses and other tax attributes generated when utilized. Also pursuant to the tax allocation agreement, BGC settles its current tax liability or benefit each year directly with Avangrid, Inc.

As of December 31, 2016 and 2015, Berkshire did not have any gross income tax reserves for uncertain tax positions.

The following table summarizes Berkshire's tax years that remain subject to examination as of December 31, 2016:

Jurisdiction	*Tax years*
Federal	2013 - 2016
Massachusetts	2013 – 2016

The following table summarizes Berkshire's deferred tax assets and liabilities as of December 31, 2016 and 2015:

	2016	**2015**
	(In Thousands)	
Deferred income tax assets:		
Post-retirement benefits	$ 5,894	$ 3,653
Environmental	1,341	1,186
Other	9,413	10,092
	$ 16,648	$ 14,931
Deferred income tax liabilities:		
Plant basis and accelerated depreciation timing differences	$ 38,489	$ 38,025
Deferred natural gas costs	1,989	1,338
Other	761	105
	$ 41,239	$ 39,468
Total net deferred income tax assets (liabilities)	$ (24,591)	$ (24,537)

(F) PENSION AND OTHER BENEFITS

Defined Benefit Plans (the Plans)

Pension Plans

Berkshire has multiple qualified pension plans covering substantially all of their union and management employees. The Plans provide benefits under a traditional defined benefit formula or a cash balance formula depending on date of hire. Neither of these formulas plans are offered to new employees hired on or after specified dates.

Employees not participating in a defined benefit plan are eligible to participate in an enhanced 401(k) plan.

Other Post-Retirement Plans

Berkshire provides other post-retirement benefits for certain employees. These benefits consist primarily of health care prescription drug and life insurance benefits for retired employees and their dependents.

Plan Assets

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.

Berkshire's asset allocation policy is the most important consideration in achieving the objective of superior investment returns while minimizing risk. Berkshire has a target asset allocation policy within allowable ranges for its pension benefits plan assets within broad categories of asset classes. The 2017 target asset allocations for the Berkshire Gas Company Pension Plan are approximately as follows: 54% equity securities, 27% fixed income investments, 10% bonds, 5% real estate investments and 4% treasury securities. The 2017 target asset allocations for the Berkshire Gas Company Pension Plan for Union Employees are approximately as follows: 41% equity securities, 34% fixed income investments, 14% bonds, 5% real estate investments and 6% treasury securities. Systematic rebalancing within the target ranges increases the probability that the annualized return on the investments will be enhanced, while realizing lower overall risk, should any asset categories drift outside their specified ranges.

The 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, 2016 and 2015. Plan assets and obligations have been measured as of December 31, 2016 and 2015.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2016	Year Ended December 31, 2015
Change in Benefit Obligation:		(In Thousands)		
Benefit obligation at beginning of year	$ 43,898	$ 46,454	$ 1,792	$ 1,743
Service cost	551	616	-	-
Interest cost	2,075	1,973	81	65
Participant contributions	-	-	11	-
Actuarial (gain) loss	5,772	(3,812)	1,159	112
Benefits paid (including expenses)	(2,408)	(1,333)	(153)	(128)
Benefit obligation at end of year	$ 49,888	$ 43,898	$ 2,890	$ 1,792
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 33,140	$ 35,598	$ -	$ -
Actual return on plan assets	1,923	(1,295)	-	-
Participant contributions	-	-	11	-
Employer contributions	920	170	142	128
Benefits paid (including expenses)	(2,408)	(1,333)	(153)	(128)
Fair value of plan assets at end of year	$ 33,575	$ 33,140	$ -	$ -
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 16,313	$ 10,758	$ 2,890	$ 1,792
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 16,313	$ 10,758	$ 2,890	$ 1,792
Amounts Recognized as a Regulatory Asset (Liability) consist of:				
Prior service cost	$ 382	$ 550	$ -	$ -
Net (gain) loss	$ 9,118	$ 3,233	-	-
Total recognized as a regulatory asset (liability)	$ 9,500	$ 3,783	$ -	$ -
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 49,888	$ 42,228	N/A	N/A
Accumulated benefit obligation	$ 44,103	$ 38,297	N/A	N/A
Fair value of plan assets	$ 33,575	$ 33,141	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Pension Benefits)	4.24%	4.95%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	4.24%	4.45%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year– pre/post-65)	N/A	N/A	6.75%/8.50%	7.00%
Health care trend rate (2026/2028 – pre/post-65)	N/A	N/A	4.50%/4.50%	5.00%

N/A – Not applicable

Berkshire is allowed to defer as regulatory assets or regulatory liabilities items that would have otherwise been recorded in accumulated OCI pursuant to the accounting requirements concerning defined benefit pension and other postretirement plans. Amounts recognized as regulatory assets or regulatory liabilities for the years ended December 31, 2016 and 2015 are shown above.

The discount rate is the rate at which the benefit obligations could presently be effectively settled. The discount rates were determined by developing yield curves derived from a portfolio of high grade noncallable bonds with yields that closely match the duration of the expected cash flows of our benefit obligations.
The components of net periodic benefit cost are:

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2016	Year Ended December 31, 2015
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 551	$ 616	$ -	$ -
Interest cost	2,075	1,972	81	65
Expected return on plan assets	(2,532)	(2,690)	-	-
Amortization of actuarial (gain) loss	496	41	1,068	112
Amortization of prior service cost	169	169	-	-
Net periodic benefit cost	$ 759	$ 108	$ 1,149	$ 177
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 6,381	$ 172	$ 1,068	$ 112
Amortization of prior service cost	(169)	(169)	-	-
Amortization of Actuarial (gain) loss	(496)	(41)	(1,068)	(112)
Total recognized as regulatory asset (liability)	$ 5,716	$ (38)	$ -	$ -
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 6,475	$ 70	$ 1,149	$ 177
Estimated Amortizations from Regulatory Assets (Liabilities) into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of transition obligation	$ -	$ -	$ -	$ -
Amortization of prior service cost	169	169	-	-
Amortization of net (gain) loss	713	115	-	-
Total estimated amortizations	$ 882	$ 284	$ -	$ -
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.24%	4.30%	4.45%	3.95%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.75%	7.75 - 8.00%	N/A	N/A
Health care trend rate (current year)	N/A	N/A	7.00%	7.00%
Health care trend rate (2019)	N/A	N/A	5.00%	5.00%

N/A – Not applicable

Berkshire utilizes an alternative method to amortize prior service costs and unrecognized gains and losses. Prior service costs for the Plans are amortized on a straight-line basis over the average remaining service period of participants expected to receive benefits. Unrecognized actuarial gains and losses related to the Plans are amortized over 10 years as required by the DPU. 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 expected long-term rate of return on plan assets assumption was developed 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. The analysis considered current capital market conditions and projected conditions.

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	$	13	$	(10)
Accumulated post-retirement benefit obligation	$	196	$	(175)

Contributions

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 does not expect to make a pension contribution in 2017. Such contribution levels will be adjusted, if necessary, based on actuarial calculations.

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)			
2017	$	2,063	$	180
2018	$	2,193	$	206
2019	$	2,304	$	228
2020	$	2,466	$	234
2021	$	2,619	$	235
2022-2026	$	14,824	$	1,239

Defined Contribution Retirement Plans/401(k)

Berkshire non-union employees are eligible to participate in UIL Holdings Corporation 401(k) 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 in various investment alternatives offered to employees. The matching expense for 2016 and 2015 was $0.4 million and $0.3 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, 2016, 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, 2016 and 2015, the Balance Sheet reflects inter-company payables, included in accounts payable of $0.6 million and $0.5 million, respectively, and inter-company receivables, included in accounts receivable of $0.3 million and $0.2 million, respectively.

Dividends/Capital Contributions

For the years ended December 31, 2016 and 2015, Berkshire accrued dividends to UIL Holdings of $7.5 million and $5.4 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)	
2017	$	94
2018		-
2019		-
2020		-
2021-after		-
	$	94

(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, 2016 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 $0.4 million and have recorded a liability and offsetting regulatory asset for such expenses as of December 31, 2016. 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, 2016, we had accrued approximately $2.8 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, 2016 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**
		(In Thousands)		
December 31, 2016				
Noncurrent investments	$ 709	$ -	$ -	$ 709
Total fair value assets, December 31, 2016	$ 709	$ -	$ -	$ 709
December 31, 2015				
Noncurrent investments	$ 855	$ -	$ -	$ 855
Total fair value assets, December 31, 2015	$ 855	$ -	$ -	$ 855

The following tables set forth the fair values of Berkshire's pension assets as of December 31, 2016 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, 2016		**(In Thousands)**		
Pension assets				
Mutual funds	$ -	$ 33,575	$ -	$ 33,575
Fair value of plan assets, December 31, 2016	$ -	$ 33,575	$ -	$ 33,575
December 31, 2015				
Pension assets				
Mutual funds	$ -	$ 33,140	$ -	$ 33,140
Fair value of plan assets, December 31, 2015	$ -	$ 33,140	$ -	$ 33,140

The determination of fair value of the Level 2 co-mingled mutual funds was 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.

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

Central Maine Power Company
and Subsidiaries

Index

Page(s)

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

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Report of Independent Auditors

To the Shareholders and Board of Directors
Central Maine Power Company

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

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

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

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

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

Opinion

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

Ernst & Young LLP

March 31, 2017

Central Maine Power Company and Subsidiaries
Consolidated Statements of Income

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

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Comprehensive Income

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

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

Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets

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

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

Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets

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

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Cash Flows

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

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

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

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

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

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Notes to Consolidated Financial Statements

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(a) Revenue from contracts with customers

In May 2014 the FASB issued ASC 606, Revenue from Contracts with Customers (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The core principle is for an entity to recognize revenue to represent the transfer of goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers. The original effective date for public entities was for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. In August 2015 the FASB issued an accounting standards update that defers by one year the original effective date of the revenue standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption as of the original effective date permitted. We do not plan to early adopt. Entities may apply the amendment retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). We will apply the modified retrospective method. We are currently evaluating how our adoption of the amendments will affect our results of operations, financial position, cash flows, and disclosures. We are considering the effects of the amendments on our ability to recognize revenue for certain contracts for our regulated utilities where collectability is in question and our accounting for contributions in aid of construction for our regulated utilities. In addition, the amendments will require us to capitalize, rather than expense, any costs to acquire new contracts. Some revenue arrangements, such as alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on our consolidated financial statements. The FASB has issued various additional accounting standards updates, with the same deferred effective date, as follows: in March 2016 to amend and clarify the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, in April 2016 to address implementation questions on identifying performance obligations and accounting for licenses of intellectual property. We do not expect significant effects as a result of those updates. In May 2016 the FASB issued a final update concerning narrow-scope improvements and practical expedients. We are currently evaluating the effects of that update.

(b) Fair value measurement disclosures for certain investments

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

Notes to Consolidated Financial Statements

(c) Simplifying the measurement of inventory

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

(d) Classifying and measuring financial instruments

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

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

(e) Leases

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

(f) Derivative contract novations

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

(g) Improvements to employee share-based payment accounting

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

(h) Measurement of credit losses on financial instruments

The FASB issued an accounting standards update in June 2016 that requires more timely recording of credit losses on loans and other financial instruments. The amendments affect entities that hold financial assets and net investment in leases that are not accounted for at fair value through net income (loans, debt securities, trade receivables, net investments in leases, off-balance-sheet credit exposures, etc.). They require an entity to present a financial asset (or group of financial assets) that is measured at amortized cost basis at the net amount expected to be collected. The allowance for credit losses is a valuation account that is deducted from the amortized cost basis of the financial asset(s) to present the net carrying value at the amount expected to be collected on the financial asset. The income statement reflects the measurement of credit losses for newly recognized financial assets, as well as the expected increases or decreases of expected credit losses that have taken place during the period. The measurement of expected credit losses is based on relevant information about past events, including historical experience, current conditions, and reasonable and supportable forecasts that affect the collectibility of the reported amount. An entity must use judgment in determining the relevant information and estimation methods appropriate in its circumstances. The amendments are effective for public entities that are SEC filers for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, with early adoption permitted. Entities are to apply the amendments on a modified retrospective basis for most instruments. We expect our adoption will not materially affect our results of operations, financial position, and cash flows.

(i) Certain classifications in the statement of cash flows

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

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

The FASB issued the amendment in November 2016 to address existing diversity in the classification and presentation of changes in restricted cash on the statement of cash flows. The amendment requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The amendment does not provide a definition of restricted cash or restricted cash equivalents. The amendment is effective for public entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. The amendment should be applied using a retrospective transition method to each period presented. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2016 and have applied it retrospectively to all periods presented. The adoption of the amendment did not have any impact on the consolidated statements of cash flows for the year ended December 31, 2015 as we did not have restricted cash as of the beginning and end of 2015.

Other Income and Other Deductions:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Note 2. Industry Regulation

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

Transmission - FERC ROE Proceeding

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

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

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

CMP Distribution Rate Stipulation and New Renewable Source Generation

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

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

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

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

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

Minimum Equity Requirements for Regulated Subsidiaries

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

Note 3. Regulatory Assets and Liabilities

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

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

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

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

Notes to Consolidated Financial Statements

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

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

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

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

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

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

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

Notes to Consolidated Financial Statements

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

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

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

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

Note 4. Goodwill

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

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

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

Notes to Consolidated Financial Statements

Note 5. Income Taxes

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

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

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

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

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

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

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

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

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

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

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

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

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

Note 6. Long-term Debt

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

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

(a) The first mortgages bonds are secured by a first mortgage lien on substantially all of Net Utility Plant In Service.
(b) Chester SVC Partnership notes are secured by the assets of this partnership.

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

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

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

Note 7. Bank Loans and Other Borrowings

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

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

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

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

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

Notes to Consolidated Financial Statements

Note 8. Redeemable Preferred Stock

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

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

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

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

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

Note 9. Commitments and Contingencies

CMP Transmission - ROE Complaint

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

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

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

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

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

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

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

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

Yankee Nuclear Spent Fuel Disposal Claim

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

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

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

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

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

Power purchase contracts including nonutility generator

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

Note 10. Environmental Liability

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

Waste sites

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

We have recorded an estimated liability of $2.3 million at December 31, 2016, related to four additional sites where we believe it is probable that we will incur remediation costs and/or monitoring costs, although we have not been notified that we are among the potentially responsible parties or are regulated under State Resource Conservation and Recovery Act (RCRA) program. It is reasonably possible the ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate these sites ranges from $2.7 million to $8.9 million as of December 31, 2016. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Manufactured gas plants

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

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

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

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

Note 11. Accounting for Derivative Instruments and Hedging Activities

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

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

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

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

Notes to Consolidated Financial Statements

The effect of hedging instruments on OCI and income was:

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

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

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

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

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

Notes to Consolidated Financial Statements

Assets and liabilities measured at fair value on a recurring basis

		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)				
2016				
Assets				
Noncurrent investments available for sale	**$698**	**$698**	**$-**	**$-**
Total	**$698**	**$698**	**$-**	**$-**
Liabilities				
Derivatives	**$164**	**$-**	**$-**	**$164**
Total	**$164**	**$-**	**$-**	**$164**
2015				
Assets				
Noncurrent investments available for sale	$415	$415	$-	$-
Total	$415	$415	$-	$-
Liabilities				
Derivatives	$935	$-	$-	$935
Total	$935	$-	$-	$935

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

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

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

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

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

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

Notes to Consolidated Financial Statements

Note 13. Accumulated Other Comprehensive Loss

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

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

Note 14. Retirement Benefits

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

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

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

***Obligations and funded status*:**

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

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

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

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

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

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

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

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

Notes to Consolidated Financial Statements

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

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

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

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

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2017	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	**$15,918**	**$2,833**
Estimated prior service cost (credit)	**$6**	**$(2,013)**

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

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

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

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

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

Assumed health care cost trend rates to determine benefit obligations at December 31,	2016	2015
Health care cost trend rate (pre 65/post 65)	**7.00%9.00%**	7.00%/9.00%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	**4.50%**	4.50%
Year that the rate reaches the ultimate trend rate	**2026/2028**	2026

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Note 15. Subsequent events

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

New York State Electric & Gas Corporation

Financial Statements

For the Years Ended December 31, 2016 and 2015

New York State Electric & Gas Corporation

Index

Page(s)

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

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Report of Independent Auditors

To the Shareholders and Board of Directors
of 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, 2016 and 2015, 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, 2016 and 2015, 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 12, 2017

New York State Electric & Gas Corporation
Statements of Income

Year Ended December 31,	2016	2015
(Thousands)		
Operating Revenues		
Electric	**$1,223,115**	$ 1,293,601
Natural gas	**315,975**	318,339
Total Operating Revenues	**1,539,090**	1,611,940
Operating Expenses		
Electricity purchased	**348,733**	409,154
Natural gas purchased	**78,868**	101,095
Operations and maintenance	**596,237**	607,724
Depreciation and amortization	**112,936**	140,896
Other taxes	**141,356**	136,342
Total Operating Expenses	**1,278,130**	1,395,211
Operating Income	**260,960**	216,729
Other Income	**12,301**	32,995
Other Deductions	**(1,608)**	(1,696)
Interest Charges, Net	**(60,542)**	(83,331)
Income Before Income Tax	**211,111**	164,697
Income Tax Expense	**92,224**	66,375
Net Income	**$118,887**	$98,322

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,	2016	2015
(Thousands)		
Net Income	**$118,887**	$98,322
Other Comprehensive Income, Net of Tax		
Amortization of pension for nonqualified plans	**39**	1,601
Unrealized gain (loss) on derivatives qualified as hedges:		
Unrealized gain (loss) during period on derivatives qualified as hedges	**105**	(799)
Reclassification adjustment for loss included in net income	**627**	1,022
Reclassification adjustment for loss on settled cash flow treasury hedges	**64**	380
Net unrealized gain on derivatives qualified as hedges	**796**	603
Other Comprehensive Income, Net of Tax	**835**	2,204
Comprehensive Income	**$119,722**	$100,526

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

New York State Electric & Gas Corporation
Balance Sheets

December 31,	2016	2015
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	**$3,646**	$3,408
Accounts receivable and unbilled revenues, net	**246,902**	215,172
Accounts receivable from affiliates	**13,246**	10,981
Fuel and natural gas in storage, at average cost	**11,751**	13,336
Materials and supplies	**16,490**	14,758
Broker margin accounts	**11,968**	24,001
Prepaid property taxes	**35,224**	34,819
Other current assets	**41,284**	10,224
Regulatory assets	**121,697**	70,395
Total Current Assets	**502,208**	397,094
Utility Plant at original cost	**5,248,018**	4,950,776
Less accumulated depreciation	**(2,043,588)**	(1,981,015)
Net Utility Plant in Service	**3,204,430**	2,969,761
Construction work in progress	**252,044**	323,565
Total Utility Plant	**3,456,474**	3,293,326
Other Property and Investments	**10,385**	10,402
Regulatory and Other Assets		
Regulatory assets	**1,045,706**	1,249,977
Other	**215**	-
Total Regulatory and Other Assets	**1,045,921**	1,249,977
Total Assets	**$5,014,988**	$4,950,799

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

New York State Electric & Gas Corporation
Balance Sheets

December 31,	2016	2015
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	**$219,325**	$100,417
Notes payable to affiliates	**5,900**	340,845
Accounts payable and accrued liabilities	**205,771**	128,087
Accounts payable to affiliates	**74,310**	73,379
Interest accrued	**8,381**	7,296
Taxes accrued	**1,209**	21,491
Derivative liabilities	**145**	981
Environmental remediation costs	**27,151**	27,805
Customer deposits	**13,230**	13,193
Regulatory liabilities	**108,139**	45,926
Other	**66,599**	58,732
Total Current Liabilities	**730,160**	818,152
Regulatory and Other Liabilities		
Regulatory liabilities	**710,101**	782,659
Deferred income taxes regulatory	**138,973**	195,403
Other non-current liabilities		
Deferred income taxes	**745,538**	644,485
Other postretirement benefits	**263,172**	330,835
Asset retirement obligation	**14,478**	14,902
Environmental remediation costs	**135,118**	140,176
Other	**43,352**	31,761
Total Regulatory and Other Liabilities	**2,050,732**	2,140,221
Long-term debt	**1,041,815**	844,908
Total Liabilities	**3,822,707**	3,803,281
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, 2016 and 2015)	**430,057**	430,057
Capital in excess of par value	**268,405**	268,364
Retained earnings	**494,777**	450,890
Accumulated other comprehensive loss	**(958)**	(1,793)
Total Common Stock Equity	**1,192,281**	1,147,518
Total Liabilities and Equity	**$5,014,988**	$4,950,799

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,	2016	2015
(Thousands)		
Operating Activities		
Net income	**$118,887**	$98,322
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**112,936**	140,896
Amortization of regulatory assets and liabilities	**4,977**	90,154
Deferred taxes	**59,848**	(31,905)
Carrying cost of regulatory assets and liabilities	**4,328**	14,382
Other non-cash items	**(11,484)**	(16,407)
Pension expense	**62,434**	64,345
Changes in assets and liabilities		
Accounts receivable and unbilled revenues, net	**(28,657)**	29,652
Inventories	**(147)**	8,562
Accounts payable and accrued liabilities	**71,500**	41,807
Taxes accrued	**(20,283)**	19,931
Other assets and other liabilities	**(7,190)**	(159,367)
Changes in regulatory assets and liabilities	**(18,391)**	68,229
Net Cash Provided by Operating activities	**348,758**	368,601
Investing Activities		
Utility plant additions	**(316,664)**	(275,415)
Contributions in aid of construction	**40,208**	13,244
Proceeds from sale of property, plant and equipment	**43,836**	-
Other investments	**17**	67
Net Cash Used in Investing activities	**(232,603)**	(262,104)
Financing Activities		
Non-current debt issuance	**493,160**	200,000
Repayments of non-current debt	**(197,117)**	(132,025)
Repayments of capital leases	**(2,046)**	(997)
Notes payable to affiliates	**(334,914)**	(77,210)
Dividends on common stock	**(75,000)**	(100,000)
Net Cash Used in Financing Activities	**(115,917)**	(110,232)
Net Increase (Decrease) in Cash and Cash Equivalents	**238**	(3,735)
Cash and Cash Equivalents, Beginning of Year	**3,408**	7,143
Cash and Cash Equivalents, End of Year	**$3,646**	$3,408

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 Loss	Total
Balance, January 1, 2015	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
Net income				**$118,887**		**118,887**
Other comprehensive income, net of tax					**835**	**835**
Comprehensive income						**119,722**
Stock-based compensation			**41**			**41**
Cash dividends paid				**(75,000)**		**(75,000)**
Balance, December 31, 2016	**64,508**	**$430,057**	**$268,405**	**$494,777**	**$(958)**	**$1,192,281**

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

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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 890,000 electricity and 264,800 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.(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 laws of the Kingdom of Spain. Networks was formed on November 20, 2013, when AGR was reorganized to become the parent company of Networks. Networks is a public utility sub-holding company operating under the Public Utility Holding Company Act of 2005 with operations in New York, Maine, Connecticut and Massachusetts. The wholly owned subsidiaries and the operating utility companies of Networks include: CMP Group - Central Maine Power Company (CMP), RGS - New York State Electric & Gas Corporation (NYSEG), Rochester Gas and Electric Corporation (RG&E), Maine Natural Gas Company (MNG), The United Illuminating Company (UI), The Southern Connecticut Gas Company (SCG), Connecticut Natural Gas Corporation (CNG) and The Berkshire Gas Company (BGC). UI is also a party to a joint venture with certain affiliates of NRG Energy, Inc. (NRG affiliates) pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly owned subsidiary, GenConn Energy LLC (collectively with GCE Holding LLC, GenConn) operates peaking generation plants in Devon, Connecticut (GenConn Devon) and Middletown, Connecticut (GenConn Middletown).

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

***Accounts receivable*:** Accounts receivable at December 31 include unbilled revenues of $85 million for 2016 and $64 million for 2015, and are shown net of an allowance for doubtful accounts at December 31 of $23 million for 2016 and $26 million for 2015. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $9 million in 2016 and $20 million in 2015.

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 $15 million in 2016 and $17 million in 2015. DPA receivable balances at December 31 were $24 million in 2016 and $28 million in 2015.

***Asset retirement obligations*:** We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability 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 $14 million for 2016 and $15 million for 2015. 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.

Notes to Financial Statements

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

Supplemental Disclosure of Cash Flows Information	**2016**	**2015**
(Thousands)		
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	**$40,074**	$37,874
Income taxes, paid net	**$84,291**	$65,220

Interest capitalized was $2 million in 2016 and in $3.6 million in 2015. Of the $84 million income tax, substantially all 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 2.1% of average depreciable property for 2016 and 2.7% for 2015. We amortize our capitalized software cost which is included in common plant, using the straight line method, based on useful lives of 7 to 18 years. Capitalized software costs of approximately $175 million as of December 31, 2016 and $170 million as of December 31, 2015. Depreciation expense was $107 million in 2016 and $131 million in 2015. Amortization of capitalized software was $6 million in 2016 and $10 million in 2015.

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 accumulated depreciation.

Plant	**Estimated useful life range (years)**	**2016**	**2015**
(thousands)			
Electric	29-75	**$3,780,012**	$3,597,722
Natural Gas	25-75	**945,787**	905,491
Common	7-75	**522,219**	447,563
Total plant		**$5,248,018**	$4,950,776

Electric plant includes capital leases of $33 million in 2016 and $10 million in 2015. Accumulated depreciation related to these leases was $3.3 million in 2016 and $2.4 million in 2015.

Environmental remediation liability**:** In recording our liabilities for environmental remediation costs the amount of liability for a site is the best estimate, when determinable; otherwise it is based on the minimum liability or the lower end of the range when there is a range of estimated losses. Our environmental liabilities are recorded on an undiscounted basis. Our environmental liability accruals are expected to be paid through the year 2043.

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 statement of cash flow 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 (CIAC), that is, the grant amount is credited to the cost of the related property, plant and equipment. In accounting for government grants related to operating and maintenance costs, we recognize amounts receivable as compensation for expenses already incurred in the statements of income in the period in which the expenses are incurred.

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

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

New Accounting Standards and Interpretations

(a) Revenue from contracts with customers

In May 2014 the FASB issued ASC 606, Revenue from Contracts with Customers (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The core principle is for an entity to recognize revenue to represent the transfer of goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers. The original effective date for public entities was for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. In August 2015 the FASB issued an accounting standards update that defers by one year the original effective date of the revenue standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption as of the original effective date permitted. We do not plan to early adopt. Entities may apply the amendment retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). We will apply the modified retrospective method. We are currently evaluating how our adoption of the amendments will affect our results of operations, financial position, cash flows, and disclosures. We are considering the effects of the amendments on our ability to recognize revenue for certain contracts for our regulated utilities where collectability is in question and our accounting for contributions in aid of construction for our regulated utilities. In addition, the amendments will require us to capitalize, rather than expense, any costs to acquire new contracts. Some revenue arrangements, such as alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on our financial statements. The FASB has issued various additional accounting standards updates, with the same deferred effective date, as follows: in March 2016 to amend and clarify the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, in April 2016 to address implementation questions on identifying performance obligations and accounting for licenses of intellectual property. We do not expect significant effects as a result of those updates. In May 2016 the FASB issued a final update concerning narrow-scope improvements and practical expedients. We are currently evaluating the effects of that update.

(b) Fair value measurement disclosures for certain investments

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

(c) Simplifying the measurement of inventory

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

(d) Classifying and measuring financial instruments

In January 2016 the FASB issued final guidance on the classification and measurement of financial instruments. The new guidance requires that all equity investments in unconsolidated entities (other than those accounted for using the equity method of accounting) to be measured at fair value through earnings. There will no longer be an available-for-sale classification (changes in fair value reported in other comprehensive income) for equity securities with readily determinable fair values. For equity investments without readily determinable fair values, the cost method is also eliminated. However, entities (other than those following “specialized” accounting models, such as investment companies and broker-dealers) are able to elect to record equity investments without readily determinable fair values at cost, less impairment, and plus or minus subsequent adjustments for observable price changes. Changes in the basis of these equity investments will be reported in current earnings. That election only applies to equity investments that do not qualify for the NAV practical expedient. When the fair value option has been elected for financial liabilities, changes in fair value due to instrument-specific credit risk will be recognized separately in other comprehensive income. The accumulated gains and losses due to those changes will be reclassified from accumulated other comprehensive income to earnings if the financial liability is settled before maturity. Public entities are required to use the exit price notion when measuring the fair value of financial instruments measured at amortized cost for disclosure purposes. In addition, the new guidance requires financial assets and financial liabilities to be presented separately in the notes to the financial statements, grouped by measurement category (e.g., fair value, amortized cost, lower of cost or market) and form of financial asset (e.g., loans, securities). The classification and measurement guidance is effective for public entities in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. An entity will record a cumulative-effect adjustment to beginning retained earnings as of the beginning of the first reporting period in which the guidance is adopted, with two exceptions. The amendments related to equity investments without readily determinable fair values (including disclosure requirements) will be effective prospectively. The requirement to use the exit price notion to measure the fair value of financial instruments for disclosure purposes will also be applied prospectively. We expect our adoption of the guidance will not materially affect our results of operations, financial position, or cash flows.

(e) Leases

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

(f) Derivative contract novations

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

(g) Improvements to employee share-based payment accounting

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

(h) Measurement of credit losses on financial instruments

The FASB issued an accounting standards update in June 2016 that requires more timely recording of credit losses on loans and other financial instruments. The amendments affect entities that hold financial assets and net investment in leases that are not accounted for at fair value through net income (loans, debt securities, trade receivables, net investments in leases, off-balance-sheet credit exposures, etc.). They require an entity to present a financial asset (or group of financial assets) that is measured at amortized cost basis at the net amount expected to be collected. The allowance for credit losses is a valuation account that is deducted from the amortized cost basis of the financial asset(s) to present the net carrying value at the amount expected to be collected on the financial asset. The income statement reflects the measurement of credit losses for newly recognized financial assets, as well as the expected increases or decreases of expected credit losses that have taken place during the period. The measurement of expected credit losses is based on relevant information about past events, including historical experience, current conditions, and reasonable and supportable forecasts that affect the collectability of the reported amount. An entity must use judgment in determining the relevant information and estimation methods appropriate in its circumstances. The amendments are effective for public entities that are SEC filers for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, with early adoption permitted. Entities are to apply the amendments on a modified retrospective basis for most instruments. We expect our adoption will not materially affect our results of operations, financial position, and cash flows.

(i) Certain classifications in the statement of cash flows

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

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

The FASB issued the amendment in November 2016 to address existing diversity in the classification and presentation of changes in restricted cash on the statement of cash flows. The amendment requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The amendment does not provide a definition of restricted cash or restricted cash equivalents. The amendment is effective for public entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. The amendment should be applied using a retrospective transition method to each period presented. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2016 and have applied it retrospectively to all periods presented. The adoption of the amendment did not have any impact on the statements of cash flows for the year ended December 31, 2015 as we did not have restricted cash as of the beginning and end of 2015.

Other Income and Other Deductions:

Year Ended December 31,	2016	2015
(Thousands)		
Interest and dividend income	**$50**	$1,001
Carrying costs on regulatory assets	**11,039**	23,265
Allowance for funds used during construction	**521**	7,162
Gain on sale of property	**457**	1,457
Miscellaneous	**234**	110
Total other income	**$12,301**	$32,995
Civic donations	**$(1,224)**	($720)
Miscellaneous	**(384)**	(976)
Total other deductions	**$(1,608)**	$(1,696)

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

***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 Company 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 operating and capital services provided to NYSEG by AGR and its affiliates was approximately $82 million for 2016 and $75 million for 2015 and charge for services provided by NYSEG to AGR and its subsidiaries were approximately $11 million for 2016 and $16 million for 2015. 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. The balance in accounts payable to affiliates of $74 million at December 31, 2016 and $73 million at December 31, 2015 is mostly payable to Avangrid Service Company.

Networks holds an approximate 20% ownership interest in the regulated New York TransCo. Through New York TransCo, Networks has formed a partnership with Central Hudson Gas and Electric Corporation, Consolidated Edison, Inc., National Grid, plc and Orange and Rockland Utilities, Inc. to develop a portfolio of interconnected transmission lines and substations to fulfill the objectives of the New York energy highway initiative, which is a proposal to install up to 3,200 MW of new electric generation and transmission capacity in order to deliver more power generated from upstate New York power plants to downstate New York. In 2016 NYSEG received approximately $67 million from New York TransCo in the form of $43 million for assets constructed and transferred to the New York TransCo, $22 million in contributions in aid of construction and approximately $2 million in advanced lease payments for a 99 year lease of land and attachment rights. As of December 31, 2016 the pending amount receivable from New York TransCo was $11 million.

***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 receivable balance due from AGR is $31.7 million at December 31, 2016. The aggregate amount of the intercompany income tax payable balance due to AGR was $20.3 million at December 31, 2015.

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

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

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.

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; (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 75% 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 rate plan for electric and natural gas service provided by NYSEG effective from August 26, 2010 through December 31, 2013. These rate plans contained continuation provisions beyond 2013 if NYSEG did not request new rates to go into effect and the current base rates would stay in place. The rates stayed effective until May 1, 2016, at which time a newly approved rate plan became effective.

Notes to Financial Statements

The 2010 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.

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 moderates 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, NYSEG and the 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, which was approved on June 15, 2016, balanced 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 benefits including: acceleration of the company's 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, NYSEG Gas, RG&E Electric and RG&E Gas is 9.00%. The equity ratio for each company is 48%. The Proposal includes an ESM applicable to each company. The customer share of earnings would increase at higher ROE levels, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first rate year. Earnings sharing is based on the lower of actual equity of 50%. Earnings thresholds increase in subsequent rate 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 (SAIFI) and the customer average interruption duration index (CAIDI). 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 with 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 Distribution Automation upgrades and Advanced Metering Infrastructure (AMI) implementation for customers on circuits in the Ithaca region. Other 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 the 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 Revenue Decoupling Mechanisms (RDMs) on a total revenue per class basis and the gas RDMs on a revenue per customer basis.

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 and its related proceedings have and will continue to propose regulatory changes that are intended to promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar and wider deployment of distributed energy resources, such as micro grids, on-site power supplies and storage.

REV is also intended to promote greater use of advanced energy management products to enhance demand elasticity and efficiencies. Track 1 of this initiative involves a collaborative process to examine the role of distribution utilities in enabling market based deployment of distributed energy resources to promote load management and greater system efficiency, including peak load reductions. NYSEG is participating in the initiative with other New York utilities and are providing their unique perspective. The NYPSC issued a 2015 order in Track 1, which acknowledges the utilities' role as a Distribution System Platform (DSP) provider, and required the utilities to file an initial Distribution System Implementation Plan (DSIP) by June 30, 2016. The companies filed the DSIP, which also included information regarding the potential deployment of Automated Metering Infrastructure (AMI) across its entire service territory. The companies, in December 2016, filed a petition to the NYPSC requesting approval for cost recovery associated with the full deployment of AMI, and a collaborative and settlement process began in 2017 and is expected to continue throughout 2017.

Other 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 Standard, Value of DER and Net Energy Metering, Demand Response Tariffs, and Community Choice Aggregation. As part of the Clean Energy Standard proceeding, all electric utilities were ordered to begin payments to NYSERDA for Renewable Energy Credits and Zero Emissions Credits beginning in 2017.

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. A Track 2 order was issued in May, 2016, and includes guidance related to the potential for Earnings Adjustment Mechanisms (EAMs), Platform Service Revenues, innovative rate designs, and data utilization and security. The companies, in December 2016, filed a proposal for the implementation of EAMs in the areas of System Efficiency, Energy Efficiency, Interconnections, and Clean Air. A collaborative process to review the companies' petition began in the first quarter of 2017 and is expected to continue through the summer 2017.

Minimum Equity Requirements for Regulated Subsidiaries

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

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric 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

$646 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.

On June 15, 2016, the NYPSC approved the Proposal in connection with a three-year rate plan for electric and gas service at NYSEG effective May 1, 2016. Following the approval of the proposal most of these items related to NYSEG are amortized over a five-year period, except the portion of storm costs to be recovered over ten years, and plant related tax items which are amortized over the life of associated plant. Annual amortization expense for NYSEG is approximately $16.5 million per rate year.

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

December 31,	**2016**	**2015**
(Thousands)		
Current		
Environmental remediation costs	**$5,705**	$22,498
Merchant function charge	**1,068**	5,066
Electric supply reconciliation	**8,609**	381
Property tax	**9,766**	**-**
Revenue decoupling mechanism	**10,904**	-
Pension and other post- retirement benefits cost deferrals	**21,770**	7,530
Unamortized loss on re-acquired debt	**2,037**	2,037
Storm cost	**40,129**	-
Low income programs	**2,953**	-
Hedges losses	**6,061**	25,563
Supplemental assessment surcharge	**2,638**	4,276
Other	**10,057**	3,044
Total current regulatory assets	**$121,697**	$70,395
Other long-term		
Federal tax depreciation normalization adjustment	**$73,511**	$72,951
Asset retirement obligation	**14,463**	14,889
Property tax deferrals	**32,546**	45,044
Pension and other post-retirement benefits cost deferrals	**99,649**	121,301
Merger capital expenditure	**6,991**	10,486
Low income programs	**14,446**	18,115
Unamortized loss on re-acquired debt	**14,084**	16,121
Pension and other postretirement benefits	**492,378**	618,598
Environmental remediation costs	**86,663**	67,886
Storm costs	**184,133**	246,933
Other	**26,842**	17,653
Total long-term regulatory assets	**$1,045,706**	$1,249,977

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. 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 total deferral, including carrying costs was $224 million at December 31, 2016 and $247 million at December 31, 2015. Pursuant to the approved Proposal, NYSEG will recover $139 million of the balance over five years for non-super-storms and the super-storm balance of $123 million over 10 years.

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.

Asset retirement obligations (ARO) represents the differences in timing of the recognition of costs associated with our AROs and the collection of such amounts through rates. This amount is being amortized at the related depreciation and accretion amounts of the underlying liability.

Deferred property taxes represents the customer portion of the difference between actual expense for property taxes and the amount provided for in rates. The New York (NY) amount is being amortized over a five year period following the approval of the proposal by the NYPSC

Other includes unamortized losses on re-acquired debt, unfunded future income taxes and deferred property taxes.

Notes to Financial Statements

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

December 31, (Thousands)	2016	2015
Current		
Energy efficiency portfolio standard	**$20,128**	$12,597
Non-by passable charges	**21,819**	-
Gas supply charge and deferred natural gas cost	**5,913**	5,064
Carrying costs on deferred income tax depreciation	**18,107**	-
Pension and other postretirement benefits cost deferral	**13,601**	-
New York State tax rate change	**2,685**	-
Economic development	**3,487**	-
Theoretical reserve flow thru impact	**5,367**	-
Electric supply reconciliation	**-**	6,661
Reliability support services	**3,163**	15,968
Revenue decoupling mechanism	**-**	3,805
Other	**13,869**	1,831
Total current regulatory liabilities	**$108,139**	$45,926
Long-term		
Carrying costs on deferred income tax bonus depreciation	**$39,117**	$60,263
Economic development	**16,097**	19,307
Merger capital expenditure	**4,533**	6,800
Positive benefit adjustment	**8,949**	13,423
Variable rate debt	**13,228**	17,265
Unfunded future income taxes	**-**	1,700
New York State tax rate change	**4,414**	13,378
Other taxes	**37,527**	56,537
Pension and other postretirement benefits	**10,582**	11,398
Pension and other postretirement benefits cost deferral	**46,848**	63,054
Accrued removal obligation	**493,105**	487,710
Other	**35,701**	31,824
Total non-current regulatory liabilities	**710,101**	782,659
Deferred income taxes regulatory	**138,973**	195,403
Total long-term regulatory liabilities	**$849,074**	$978,062

Reliability support services (Cayuga) represents the difference between actual expenses for reliability support services and the amount provided for in rates. This will be refunded to customers within the next year.

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

Energy efficiency portfolio standard represents the difference between revenue billed to customers through an energy efficiency charge and the costs of our energy efficiency programs as approved by the state authorities. This may be refunded to customers within the next year.

Accrued removal obligations represent the differences between asset removal costs recorded 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 five years following the approval of the proposal by the NYPSC.

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. They also represent 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 is being used to moderate increases in rates. The amortization period is five years following the approval of the proposal by the NYPSC and included in the Ginna RSSA settlement.

Theoretical reserve flow thru impact represents the differences from the rate allowance for applicable federal and state flow through impacts related to the excess depreciation reserve amortization. It also represents the carrying cost on the differences. The amortization period is five years following the approval of the proposal by the NYPSC.

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 refunded to ratepayers. The amortization period is five years following the approval of the proposal by the NYPSC.

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 five years following the approval of the proposal by the NYPSC.

New York state tax rate change represents excess funded accumulated deferred income tax balance caused by the 2014 New York state tax rate change from 7.1% to 6.5%. The amortization period is five years following the approval of the proposal by the NYPSC.

Other includes 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 (benefit) expense for the years ended December 31, 2016 and 2015 consisted of:

Year Ended December 31,	**2016**	**2015**
(Thousands)		
Current		
Federal	**$22,866**	$83,907
State	**9,510**	14,373
Current taxes charged to expense	**32,376**	98,280
Deferred		
Federal	**51,992**	(28,550)
State	**8,366**	(2,845)
Deferred taxes charged to expense (benefit)	**60,358**	(31,395)
Investment tax credit adjustments	**(510)**	(510)
Total Income Tax Expense	**$92,224**	$66,375

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, 2016 and 2015 consisted of:

Year Ended December 31,	2016	2015
(Thousands)		
Tax expense at statutory rate	**$73,889**	$57,644
Depreciation and amortization not normalized	**6,951**	4,802
Allowance for funds used during construction	**-**	(3,755)
Investment tax credit amortization	**(510)**	(510)
Tax return and related adjustments	**545**	437
State taxes net of federal benefit	**11,619**	7,493
Other, net	**(270)**	264
Total Income Tax Expense	**$92,224**	$66,375

Income tax expense for the year ended December 31, 2016 was $18.3 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, (net of federal benefit) and out-of-period adjustments partially offset by depreciation not normalized and investment tax credits. This resulted in an effective tax rate of 43.7%. 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%.

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

December 31,	2016	2015
(Thousands)		
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	**$754,086**	$690,450
Storm Costs	**88,930**	97,822
Accumulated deferred investment tax credits	**14,658**	15,168
Pension and other postretirement benefits	**107,269**	158,053
Environmental	**(27,978)**	(31,498)
Positive benefits adjustments merger order	**(4,616)**	(5,318)
Other	**(47,838)**	(84,789)
Non-current Deferred Income Tax Liabilities	**884,511**	839,888
Add: Valuation allowance	-	-
Total Non-current Deferred Income Tax Liabilities	**884,511**	839,888
Less amounts classified as regulatory liabilities		
Non-current deferred income taxes	**138,973**	195,403
Non-current Deferred Income Tax Liabilities	**$745,538**	$644,485
Deferred tax assets	**$80,432**	$121,605
Deferred tax liabilities	**964,943**	961,493
Net Accumulated Deferred Income Tax Liabilities	**$884,511**	$839,888

We have no federal or state net operating losses or tax credit carryforwards.

Notes to Financial Statements

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

Year Ended December 31,	**2016**	2015
(Thousands)		
Balance as of January 1	**$5,937**	$8,480
Reduction for tax positions related to prior years	**11,057**	-
Reduction for tax positions related to settlements with taxing authorities	**-**	(2,543)
Balance as of December 31	**$16,994**	$5,937

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 $1.6 million as of December 31, 2016 and $1.6 million as of December 31, 2015. If recognized, $(1.8) million of the total gross unrecognized tax benefits would affect the effective tax rate. Gross unrecognized tax benefits increased by $11.1 million in 2016 due to tax positions related to prior years.

On December 29, 2014, the Joint Committee on Taxation approved the examination of AGR and its subsidiaries, which includes 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.

Note 5. Long-term Debt

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

As of December 31,	**2016**			**2015**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured debt	2017-2042	$1,050,000	3.24%-6.15%	$ 650,000	3.24%-6.15%
Unsecured pollution control notes – fixed	2020	200,000	2.00%-2.375%	200,000	2.00%-2.375%
Unsecured pollution control notes – Variable	-	-	-	96,850	1.18%
Obligations under capital leases	2017-2036	28,375		7,813	
Unamortized debt issuance costs and discount		(17,235)		(9,338)	
Total Debt		**$1,261,140**		**$ 945,325**	
Less: debt due within one year, included in current liabilities		219,325		100,417	
Total Non-current Debt		**$1,041,815**		**$ 844,908**	

In November 2016, NYSEG issued $500 million in aggregate principal amount of 3.25% notes maturing in 2026. The proceeds of the offering were used to reduce balances owed to Avangrid under an intercompany revolving demand note agreement, to refinance $100 million of NYSEG debt that matured on December 15, 2016, and to repurchase, at par value, $96 million of outstanding auction rate securities on December 19, 2016.

Notes to Financial Statements

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

2017	2018	2019	2020	2021
$219,325	$1,607	$1,618	$201,304	$394

Note 6. Bank Loans and Other Borrowings

NYSEG had a total of $6 million short-term debt outstanding at December 31, 2016 and $341 million of short-term debt outstanding at December 31, 2015. NYSEG funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility) and a bank provided credit facility to which NYSEG is a party (the AGR Credit Facility), each of which are described below.

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

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There was $6 million and $341 million outstanding under this agreement as of December 31, 2016 and December 31, 2015, respectively.

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

In the AGR Credit 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 0.52 to 1.00 at December 31, 2016. We are not in default as of December 31, 2016.

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

Note 7. Preferred Stock Redeemable Solely at the Option of the Company

At December 31, 2016, 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

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 the current rate plan, September 1, 2010 through August 31, 2011. The Staff's preliminary findings indicated adjustments to deferred balances primarily associated with storm costs and the treatment of certain incentive compensation costs for purposes of the 2011 ACF. The Staff's findings approximate $8.2 million of adjustments to deferral balances and customer earnings sharing accruals. NYSEG reviewed the Staff's adjustments and work papers and provided a response in early 2013. NYSEG disagreed with certain Staff conclusions and as a result recorded a $2.4 million reserve in December 2012 in anticipation of settling the Staff issues. In the Proposal approved by the NYPSC (Note 3) the parties agreed that in full and final resolution of all years through 2012, and in full and final resolution of storm-related deferrals through 2014, the companies will add $1.9 million to the customer share of earnings sharing. Staff indicated in December 2016 that it had completed its review 2013 and 2014 compliance filings and no issues were identified.

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 $37.8 million and $25.5 million for the years ended December 31, 2016 and 2015. We estimate our expenses will be approximately $19 million in 2017.

Purchase power and natural gas 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 $83 million for NUG power in 2016 and $91 million in 2015. We estimate that our power purchases will total $86 million in 2017, $71 million in 2018, $48 million in 2019, $37 million 2020, $27 million in 2021 and $64 million thereafter.

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.

Waste sites

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 $6 million as of December 31, 2016, related to the 12 sites. We have paid remediation costs related to the 12 sites, and do not expect to incur additional liability than the amount recorded. The ultimate cost to remediate the sites may be significantly more than the accrued amount. Our estimate for costs to remediate these sites ranges from $5.2 million to $6.4 million as of December 31, 2016. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. Any cost will be flowed through to NYSEG ratepayers.

Manufactured gas plants

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 38 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 $135 million to $256 million at December 31, 2016. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $157 million at December 31, 2016, and $162 million at December 31, 2015. We recorded a corresponding regulatory asset, net of insurance recoveries and the amount collected from FirstEnergy described below, because we expect to recover the net costs in rates.

Our environmental liability accruals have been established on an undiscounted basis. We have received insurance settlements which we accounted for as reductions to our related regulatory asset.

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. Any cost or recovery will be flowed through to NYSEG ratepayers.

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 Indemnity 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. On March 31, 2017, the District Court granted motions filed by Century Indemnity and One Beacon dismissing all of NYSEG's claims against both defendants on the grounds of late notice. NYSEG is reviewing the court's decision and order to determine whether to appeal. We cannot predict the outcome of this matter.

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, 2016 and 2015, the loss recognized in regulatory assets for electricity derivatives was $7.9 million and $25.1 million, respectively. For the year ended December 31, the amount reclassified from regulatory assets/liabilities into income, which is included in electricity purchased, was loss of $48.9 million and $34.6 million for 2016 and for 2015, respectively.

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, 2016 and 2015, the amount recognized in regulatory assets for natural gas hedges was a gain of $1.2 million and a loss of $0.6 million, respectively. For the years ended December 31, 2016 and 2015, the loss reclassified from regulatory assets into income, which is included in natural gas purchased, was $0.2 million and $3 million, respectively.

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, 2016			
2017	**2,620,550**	**1,610,000**	**1,182,600**
2018	**1,355,750**	**270,000**	**-**
As of December 31, 2015			
2016	3,274,750	820,000	1,302,100
2017	1,399,800	320,000	636,000

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2016 and 2015, respectively, consisted of:

December 31, 2016	Derivative Assets - Current	Derivative Assets - Noncurrent	Derivative Liabilities - Current	Derivative Liabilities - Noncurrent
(In thousands)				`
Not designated as hedging instruments				
Derivative assets	$6,443	$3,806	$5,355	$3,705
Derivative liabilities	(5,355)	(3,705)	(11,416)	(5,497)
	1,088	101	(6,061)	(1,792)
Designated as hedging instruments				
Derivative assets	16	-	16	-
Derivative liabilities	(16)	-	(161)	-
	-	-	(145)	-
Total derivatives before offset of cash collateral	1,088	101	(6,206)	(1,792)
Cash collateral receivable	-	-	6,061	1,792
Total derivatives as presented in the balance sheet	$1,088	$101	$(145)	$-

December 31, 2015	Derivative Assets - Current	Derivative Assets - Noncurrent	Derivative Liabilities - Current	Derivative Liabilities - Noncurrent
(In thousands)				`
Not designated as hedging instruments				
Derivative assets	$2,344	$4,109	$2,344	$4,109
Derivative liabilities	(2,344)	(4,109)	(27,907)	(4,285)
	-	-	(25,563)	(176)
Designated as hedging instruments				
Derivative assets	-	-	-	-
Derivative liabilities	-	-	(981)	(369)
	-	-	(981)	(369)
Total derivatives before offset of cash collateral	-	-	(26,544)	(545)
Cash collateral receivable (payable)	-	-	25,563	176
Total derivatives as presented in the balance sheet	$-	$-	$(981)	$(369)

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)			
2016			
Interest rate contracts	$-	Interest expense	**$(105)**
Commodity contracts:	**$174**	Other operating expenses	**$(1,031)**
Total	**$174**		**$(1,136)**
2015			
Interest rate contracts	$-	Interest expense	$(629)
Commodity contracts:	$(1,323)	Other operating expenses	$(1,692)
Total	$(1,323)		$(2,321)

The amounts in AOCI related to previously settled forward starting swaps, and accumulated amortization, as of December 31, 2016, is a net loss of $0.7 million as compared to a net loss of $0.8 million for 2015. For the year ended December 31, 2016, we recorded $0.1 million in net derivative losses related to discontinue cash flow hedges. We will amortize approximately $0.1 million of discontinued cash flow hedges in 2017.

As of December 31, 2016, $0.1 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 12 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions. There was no ineffective portion of hedge recognized during the year ended December 31, 2016.

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.

Notes to Financial Statements

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, 2016, is $6.8 million for which we have posted collateral.

Note 11. Fair Value of Financial Instruments and Fair Value Measurements

The estimated fair value of debt amounted to $1,311 million and $990 million as of December 31, 2016 and 2015, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2, except for unsecured pollution controls notes-variable, with a fair value of $89 million as of December 31, 2015, 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. There were no unsecured pollution control notes-variable at December 31, 2016.

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	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Netting**	**Total**
(Thousands)					
2016					
Assets					
Noncurrent investments available for sale, primarily money market funds	**$10,385**	**$-**	**$-**	**$-**	**$10,385**
Derivatives					
Commodity contracts:					
Electricity	**9,060**	**-**	**-**	**(9,060)**	**-**
Natural Gas	**1,189**	**-**	**-**	**-**	**1,189**
Other	**-**	**-**	**16**	**(16)**	**-**
Total	**$20,634**	**$-**	**$16**	**$(9,076)**	**$11,574**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	**$(16,914)**	**$-**	**-**	**$16,914**	**-**
Natural gas	**-**	**-**	**-**	**-**	**-**
Other	**-**	**-**	**(161)**	**16**	**(145)**
Total	**$(16,914)**	**$-**	**$(161)**	**$16,930**	**$(145)**

Notes to Financial Statements

Description	(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)

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

Valuation techniques: We measure the fair value of our noncurrent investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments 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,	**2016**	2015
(Thousands)		
Beginning balance	**$1,350**	$1,719
Total gains (losses) (realized/unrealized)		
Included in earnings	**(1,031)**	(1,692)
Included in other comprehensive income	**(174)**	1,323
Ending balance	**$145**	$1,350

The gains and losses included in earnings for the periods above are reported in Operations and maintenance of the statements of income.

Note 12. Accumulated Other Comprehensive Loss

	Balance January 1, 2015	**2015 Change**	**Balance December 31, 2015**	**2016 Change**	**Balance December 31, 2016**
(Thousands)					
Amortization of pension cost for nonqualified plans, net of income tax expense of $1,033 for 2015 and $25 for 2016	$(2,111)	$1,601	$(510)	$39	$(471)
Unrealized (loss) gain on derivatives qualified as hedges:		-		-	
Unrealized (loss) gain during period on derivatives qualified as hedges, net of income tax expense(benefit) of $(524) for 2015 and $69 for 2016		(799)		105	
Reclassification adjustment for loss included in net income, net of income tax expense $671 for 2015 and $404 for 2016		1,022		627	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $249 for 2015 and $41 for 2016		380		64	
Net unrealized gain (loss) on derivatives qualified as hedges	(1,886)	603	(1,283)	796	(487)
Accumulated Other Comprehensive Loss	$(3,997)	$2,204	$(1,793)	$835	$(958)

Note 13. Retirement Benefits

We have funded noncontributory defined benefit pension plans that cover all of the eligible employees. For most employees, generally those hired before 2002, the plans provide defined benefits based on years of service and final average salary. Employees hired in 2002 or later are covered under a cash balance plan or formula where their 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 $5.6 million for 2016 and $3.6 million for 2015

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

Obligations and funded status:	**Pension Benefits**		**Postretirement Benefits**	
	2016	**2015**	**2016**	**2015**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	**$1,593,364**	$1,666,545	**$192,181**	$208,254
Service cost	**18,075**	21,603	**2,414**	2,890
Interest cost	**63,528**	61,692	**7,610**	7,654
Plan participants' contributions	**-**	-	**2,967**	2,645
Amendments	**-**	-	**-**	(913)
Actuarial (gain)/loss	**(63,187)**	(63,172)	**(1,446)**	(14,695)
Special termination benefits	**-**	342	**-**	-
Benefits paid	**(80,327)**	(93,646)	**(17,638)**	(13,658)
Federal subsidy on benefits paid	**-**	-	**5**	4
Benefit obligation at December 31	**$1,531,453**	$1,593,364	**$186,093**	$192,181
Change in plan assets				
Fair value of plan assets at January 1	**$1,368,903**	$1,472,953	**$85,807**	$89,078
Actual return on plan assets	**82,203**	(10,404)	**4,789**	(3,271)
Employer & plan participants' contributions	-	-	**17,633**	13,654
Federal subsidy on benefits paid	-	-	**5**	4
Benefits paid	**(80,327)**	(93,646)	**(24,639)**	(13,658)
Fair value of plan assets at December 31	**$1,370,779**	$1,368,903	**$83,595**	$85,807
Funded status	**$(160,674)**	$(224,461)	**$(102,498)**	$(106,374)

Amounts recognized in the balance sheet December 31,	**Pension Benefits 2016**	**2015**	**Postretirement Benefits 2016**	**2015**
(Thousands)				
Noncurrent liabilities	**$(160,674)**	$(224,461)	**$(102,498)**	$(106,374)
	$(160,674)	$(224,461)	**$(102,498)**	$(106,374)

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.

Notes to Financial Statements

Amounts recognized as regulatory assets or regulatory liabilities consist of:

	Pension Benefits		Postretirement Benefits	
December 31,	2016	2015	2016	2015
(Thousands)				
Net loss	**$485,608**	$610,459	**$14,382**	$19,162
Prior service cost (credit)	**$6,769**	$8,138	**$(24,963)**	$(30,560)

Our accumulated benefit obligation for all defined benefit pension plans was $1.5 billion for December 31, 2016 and 2015.

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

December 31,	2016	2015
(Thousands)		
Projected benefit obligation	**$1,531,453**	**$1,593,363**
Accumulated benefit obligation	**$1,460,980**	**$1,511,557**
Fair value of plan assets	**$1,370,779**	**$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,	2016	2015	2016	2015
(Thousands)				
Net periodic benefit cost				
Service cost	**$18,075**	$21,603	**$2,414**	$2,890
Interest cost	**63,528**	61,692	**7,610**	7,654
Expected return on plan assets	**(103,767)**	(108,661)	**(3,861)**	(4,454)
Amortization of prior service cost (credit)	**1,369**	2,401	**(5,597)**	(5,394)
Amortization of net loss	**83,229**	86,967	**2,407**	3,108
Special termination benefit charge		343	**-**	-
Net periodic benefit cost	**$62,434**	$64,345	**$2,973**	$3,804
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss (gain)	**$(41,623)**	$55,893	**$(2,373)**	$(6,969)
Amortization of net (loss)	**(83,229)**	(86,967)	**(2,407)**	(3,108)
Amortization of prior service (cost) credit	**(1,369)**	(2,401)	**5,597**	5,394
Current year prior service (credit) cost	**-**	-	**-**	(914)
Total recognized in regulatory assets and regulatory liabilities	**$(126,221)**	$(33,475)	**$817**	$(5,597)
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$(63,787)**	$30,870	**$3,790**	$(1,793)

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, 2017	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	$84,732	$3,320
Estimated prior service cost (credit)	$1,201	$(5,597)

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

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits 2016	Pension Benefits 2015	Postretirement Benefits 2016	Postretirement Benefits 2015
Discount rate	**4.12%**	4.10%	**4.12%**	4.10%
Rate of compensation increase	**3.90%**	3.90%	**N/A**	N/A

The discount rate is the rate at which the benefit obligations could presently be effectively settled. We determined the discount rate 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 2016	Pension Benefits 2015	Postretirement Benefits 2016	Postretirement Benefits 2015
Discount rate	**4.10%**	3.80%	**4.10**	3.80
Expected long-term return on plan assets	**7.40%**	7.50%	**-**	-
Expected long-term return on plan assets - nontaxable trust	**-**	-	**7.00%**	7.50%
Expected long-term return on plan assets - taxable trust	**-**	-	**4.5%**	5.00%
Rate of compensation increase	**3.90%**	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,	2016	2015
Health care cost trend rate (pre 65/post 65)	**7.00%/9.00%**	7.50%/ 9.00%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	**4.50%**	4.50%
Year that the rate reaches the ultimate trend rate	**2026/2028**	2026

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

	1% Increase	1% Decrease
(Thousands)		
Effect on total of service and interest cost	$34	$(34)
Effect on postretirement benefit obligation	$393	$(398)

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 in 2017.

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

(Thousands)	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
2017	$89,035	$12,983	-
2018	$91,919	$13,103	-
2019	$94,444	$13,317	-
2020	$96,782	$13,406	-
2021	$98,675	$13,538	-
2022-2026	$507,936	$65,955	-

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

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

Notes to Financial Statements

The fair values of Networks' pension benefits plan assets at December 31, 2016 and 2015, by asset category are shown in the following table. NYSEG's share of the total consolidated assets is approximately 52% for 2016 and 2015:

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

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

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

measurement being classified as Level 3 if those inputs are significant to the overall fair value measurement.

- Real estate investments – based on a discounted cash flow approach that includes the projected future rental receipts, expenses and residual values because the highest and best use of the real estate from a market participant view is as rental property.
- Other investments, principally annuity and fixed income - Level 1: at the closing price reported in the active market in which the individual investment is traded. Level 2: based on yields currently available on comparable securities of issuers with similar credit ratings. Level 3: when quoted prices are not available for identical or similar instruments, under a discounted cash flows approach that maximizes observable inputs such as current yields of similar instruments but includes adjustments for certain risks that may not be observable such as credit and liquidity risks.

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

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

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

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

The fair value of other postretirement benefits plan assets, by asset category, as of December 31, 2016 consisted and 2015 are shown in the following table. NYSEG's share of the total assets is approximately 52% for 2016 and 54% for 2015:

		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)				
2016				
Money market funds	**$5,786**	**$3,582**	**$2,204**	**$-**
Mutual funds, fixed	**40,856**	**38,496**	**2,360**	**-**
Government & corporate bonds	**1,651**	**-**	**1,651**	**-**
Mutual funds, equity	**71,031**	**41,687**	**29,344**	**-**
Common stocks	**22,896**	**22,896**	**-**	**-**
Mutual funds, other	**17,868**	**9,961**	**7,907**	**-**
Total assets measured at fair value	**$160,088**	**$116,622**	**$43,466**	**$-**
2015				
Money market funds	$4,163	$4,163	$-	$-
Mutual funds, fixed	35,438	35,438	-	-
Government & corporate bonds	1,703	-	$1,703	-
Mutual funds, equity	45,679	45,679	-	-
Common stocks	22,939	22,793	-	146
Mutual funds, other	50,518	43,400	7,118	-
Total assets measured at fair value	$160,440	$151,473	$8,821	$146

Valuation Techniques

We value our postretirement benefits plan assets as follows:

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

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

Note 14. Subsequent events

The company has performed a review of subsequent events through April 12, 2017, which is the date these financial statements were available to be issued, and no subsequent events have occurred from January 1, 2017 through such date.

Rochester Gas and Electric Corporation

Financial Statements

For the Years Ended December 31, 2016 and 2015

Rochester Gas and Electric Corporation

Index

Page(s)

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

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Report of Independent Auditors

To the Shareholders and Board of Directors
of 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, 2016 and 2015, 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 Rochester Gas and Electric Corporation at December 31, 2016 and 2015, 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 12, 2017

Rochester Gas and Electric Corporation
Statements of Income

Year Ended December 31,	2016	2015
(Thousands)		
Operating Revenues		
Electric	**$787,421**	$657,073
Natural gas	**253,159**	269,996
Total Operating Revenues	**1,040,580**	927,069
Operating Expenses		
Electricity purchased and fuel used in generation	**109,578**	117,068
Natural gas purchased	**70,562**	89,213
Operations and maintenance	**366,940**	386,290
Depreciation and amortization	**75,900**	74,050
Other taxes	**110,944**	119,421
Total Operating Expenses	**733,924**	786,042
Operating Income	**306,656**	141,027
Other Income	**14,657**	12,421
Other Deductions	**(1,325)**	(1,614)
Interest Charges, Net	**(55,529)**	(78,665)
Income Before Tax	**264,459**	73,169
Income Tax Expense	**183,801**	35,704
Net Income	**$80,658**	$37,465

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

Rochester Gas and Electric Corporation
Statements of Comprehensive Income

Year ended December 31,	2016	2015
(Thousands)		
Net Income	**$80,658**	$37,465
Other Comprehensive Income, Net of Tax		
Net unrealized holding income on investments	**6**	17
Amortization of pension for nonqualified plans	**257**	632
Unrealized gain on derivatives qualified as hedges:		
Unrealized gain (loss) during period on derivatives qualified as hedges	**3**	(255)
Reclassification adjustment for loss included in net income	**220**	346
Reclassification adjustment for loss on settled cash flow treasury hedges	**3,505**	3,483
Net unrealized gain on derivatives qualified as hedges	**3,728**	3,574
Other Comprehensive Income, net of income taxes	**3,991**	4,223
Comprehensive Income	**$84,649**	$41,688

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

Rochester Gas and Electric Corporation
Balance Sheets

December 31,	2016	2015
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	**$9**	$1,136
Accounts receivable and unbilled revenues, net	**147,337**	139,282
Accounts receivable from affiliates	**4,743**	5,007
Natural gas in storage	**6,170**	5,891
Materials and supplies	**10,173**	10,382
Broker margin accounts	**3,417**	10,570
Income tax receivable	**39,932**	11,002
Prepaid property taxes	**35,056**	30,516
Other current assets	**6,500**	5,321
Regulatory assets	**63,117**	32,980
Total Current Assets	**316,454**	252,087
Utility plant, at original cost	**3,088,882**	2,904,955
Less accumulated depreciation	**(905,434)**	(854,747)
Net Utility Plant in Service	**2,183,448**	2,050,208
Construction work in progress	**395,665**	329,307
Total Utility Plant in Service	**2,579,113**	2,379,515
Other Property and Investments	**3,764**	4,745
Regulatory and Other Assets		
Regulatory assets	**513,712**	508,381
Other	**438**	365
Total Regulatory and Other Assets	**514,150**	508,746
Total Assets	**$3,413,481**	$3,145,093

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

Rochester Gas and Electric Corporation
Balance Sheets

December 31,	2016	2015
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Notes payable to affiliates	**$249,167**	$69,717
Notes payable	**784**	-
Current portion of long term debt	**529**	39,873
Accounts payable and accrued liabilities	**206,446**	144,698
Accounts payable to affiliates	**38,306**	47,643
Interest accrued	**11,948**	13,155
Taxes accrued	**1,920**	1,835
Environmental remediation costs	**5,269**	4,745
Other	**37,068**	36,941
Regulatory liabilities	**29,733**	18,558
Total Current Liabilities	**581,170**	377,165
Regulatory and Other Liabilities		
Regulatory liabilities	**430,336**	433,100
Deferred income taxes regulatory	**51,876**	14,547
Other Non-current Liabilities		
Deferred income taxes	**434,937**	399,063
Nuclear plant obligations	**122,579**	122,258
Pension and other postretirement benefits	**180,078**	187,542
Asset retirement obligations	**3,004**	8,388
Environmental remediation costs	**133,463**	133,513
Other	**25,620**	53,181
Total Regulatory and Other Liabilities	**1,381,893**	1,351,592
Long-term debt	**664,424**	665,066
Total Liabilities	**2,627,487**	2,393,823
Commitments and Contingencies		
Equity		
Common stock ($5 par value, 50,000 shares authorized, 38,886 shares outstanding at December 31, 2016 and 2015	**194,429**	194,429
Capital in excess of par value	**530,018**	529,943
Retained earnings	**221,591**	190,933
Accumulated other comprehensive loss	**(42,806)**	(46,797)
Treasury stock, at cost (4,379 shares at December 31, 2016 and 2015)	**(117,238)**	(117,238)
Total Equity	**785,994**	751,270
Total Liabilities and Equity	**$3,413,481**	$3,145,093

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

Rochester Gas and Electric Corporation
Statements of Cash Flows

Year Ended December 31,	2016	2015
(Thousands)		
Operating Activities		
Net income	**$80,658**	$37,465
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**75,900**	74,050
Amortization of regulatory assets and liabilities	**12,109**	25,784
Carrying cost of regulatory assets and liabilities	**7,891**	25,532
Other non-cash items	**(14,552)**	(10,242)
Deferred taxes	**186,984**	23,354
Pension expense	**21,082**	20,762
Changes in operating assets and liabilities		
Accounts receivable and unbilled revenues, net	**(7,792)**	15,970
Inventory	**(70)**	13,914
Accounts payable and accrued liabilities	**40,786**	114,472
Taxes accrued	**84**	(1,559)
Other assets and other liabilities	**(153,182)**	(31,401)
Changes in regulatory assets and liabilities	**(97,209)**	(41,840)
Net Cash Provided by Operating Activities	**152,689**	266,261
Investing Activities		
Utility plant additions	**(253,261)**	(191,075)
Government grants	**-**	16,479
Contributions in aid of construction	**4,473**	8,657
Proceeds from sale of property, plant and equipment	**4,900**	-
Other investments	**981**	1,282
Net Cash Used in Investing Activities	**(242,907)**	(164,657)
Financing Activities		
Dividends on common stock	**(50,000)**	-
Notes payable and capital leases	**(509)**	(1,259)
Repayment of non-current debt	**(39,850)**	-
Notes payable to affiliates	**179,450**	(100,020)
Net Cash Provided by (Used in) Financing Activities	**89,091**	(101,279)
Net (Decrease) Increase in Cash and Cash Equivalents	**(1,127)**	325
Cash and Cash Equivalents, Beginning of Year	**1,136**	811
Cash and Cash Equivalents, End of Year	**$9**	$1,136

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, 2015	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
Net income				**80,658**			**80,658**
Other comprehensive income, net of tax					**3,991**		**3,991**
							84,649
Stock-based compensation			**75**				**75**
Common stock dividends				**(50,000)**			**(50,000)**
Balance, December 31, 2016	**38,886**	**$194,429**	**$530,018**	**$221,591**	**$(42,806)**	**$(117,238)**	**$785,994**

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 (RG&E, 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. RG&E generates electricity from hydroelectric stations. RG&E serves approximately 376,126 electricity and 310,662 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).

RG&E is a subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc. (AGR) formerly Iberdrola USA, Inc. which is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain. Networks was formed on November 20, 2013, when AGR was reorganized to become the parent company of Networks. Networks is a public utility sub-holding company operating under the Public Utility Holding Company Act of 2005 with operations in New York, Maine, Connecticut and Massachusetts. The wholly owned subsidiaries and the operating utility companies of Networks include: CMP Group - Central Maine Power Company (CMP), RGS - New York State Electric & Gas Corporation (NYSEG), Rochester Gas and Electric Corporation (RG&E), Maine Natural Gas Company (MNG), The United Illuminating Company (UI), The Southern Connecticut Gas Company (SCG), Connecticut Natural Gas Corporation (CNG) and The Berkshire Gas Company (BGC). UI is also a party to a joint venture with certain affiliates of NRG Energy, Inc. (NRG affiliates) pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly owned subsidiary, GenConn Energy LLC (collectively with GCE Holding LLC, GenConn) operates peaking generation plants in Devon, Connecticut (GenConn Devon) and Middletown, Connecticut (GenConn Middletown).

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

Accounts receivable: Accounts receivable at December 31 include unbilled revenues of $53 million in 2016 and $44 million in 2015, and are shown net of an allowance for doubtful accounts at December 31 of $22 million for 2016 and $25 million for 2015. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $10 million in 2016 and $20 million in 2015.

Unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer class and delivery loss factors. Changes in those assumptions could significantly affect the 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 $14 million in 2016 and $16 million in 2015. DPA receivable balances at December 31 were: $21 million in 2016 and $24 million in 2015.

***Asset retirement obligations*: ** We record the fair value of the liability for an asset retirement obligation (ARO) and a conditional ARO in the period in which it is incurred and capitalize the cost by increasing the carrying amount of the related long-lived asset. We adjust the liability 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 $3 million for 2016 and $8 million for 2015. 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, 2016 and 2015.

Year ended December 31,	**2016**	**2015**
(Thousands)		
ARO, beginning of year	**$8,388**	$22,725
Liabilities settled during the year	**(5,550)**	(14,534)
Accretion expense	**166**	197
ARO, end of year	**$3,004**	$8,388

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. Restricted cash represents cash legally set aside for a specified purpose or as part of an agreement with a third party. As of both December 31, 2016 and 2015, we did not have restricted cash.

Supplemental Disclosure of Cash Flows Information

	2016	2015
(Thousands)		
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	**$37,400**	**$40,110**
Income taxes paid, net	**$25,747**	**$25,219**

Interest capitalized was $10 million in 2016 and $7 million in 2015. Of the $26 million income tax, substantially all 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 in 2016 and 2015. We amortize our capitalized software cost which is included in common plant, using the straight line method, based on useful lives of 7 to 18 years. Capitalized software costs at December 31 were approximately $113 million for 2016 and $110 million for 2015. Depreciation expense was $73 million in 2016 and $69 million in 2015. Amortization of capitalized software was $3 million in 2016 and $5 million in 2015.

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 accumulated depreciation.

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

Plant	Estimated useful life range (years)	2016	2015
(Thousands)			
Electric	29-90	**$1,976,667**	**$1,856,532**
Natural Gas	30-80	**793,583**	**761,135**
Common	7-60	**318,632**	**287,288**
Total Property, Plant and Equipment		**$3,088,882**	**$2,904,955**

Electric plant includes capital leases of $13.7 million in 2016 and $14 million in 2015. Accumulated depreciation related to these leases was $2.5 million in 2016 and $1.6 million in 2015.

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

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 RG&E may file a voluntary bankruptcy petition.

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

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

New Accounting Standards and Interpretations

(a) Revenue from contracts with customers

In May 2014 the FASB issued ASC 606, Revenue from Contracts with Customers (ASC 606), replacing the existing accounting standard and industry specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The core principle is for an entity to recognize revenue to represent the transfer of goods or services to customers in amounts that reflect the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard also requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers. The original effective date for public entities was for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. In August 2015 the FASB issued an accounting standards update that defers by one year the original effective date of the revenue standard for all entities. Thus, the standard is now effective for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption as of the original effective date permitted. We do not plan to early adopt. Entities may apply the amendment retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). We will apply the modified retrospective method. We are currently evaluating how our adoption of the amendments will affect our results of operations, financial position, cash flows, and disclosures. We are considering the effects of the amendments on our ability to recognize revenue for certain contracts for our regulated utilities where collectability is in question and our accounting for contributions in aid of construction for our regulated utilities. In addition, the amendments will require us to capitalize, rather than expense, any costs to acquire new contracts. Some revenue arrangements, such as alternative revenue programs, are expected to be excluded from the scope of ASC 606 and therefore, be accounted for and presented separately from revenues under ASC 606 on our financial statements. The FASB has issued various additional accounting standards updates, with the same deferred effective date, as follows: in March 2016 to amend and clarify the implementation guidance on principal versus agent considerations for reporting revenue gross rather than net, in April 2016 to address implementation questions on identifying performance obligations and accounting for licenses of intellectual property. We do not expect significant effects as a result of those updates. In May 2016 the FASB issued a final update concerning narrow-scope improvements and practical expedients. We are currently evaluating the effects of that update.

(b) Fair value measurement disclosures for certain investments

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

(c) Simplifying the measurement of inventory

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

(d) Classifying and measuring financial instruments

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

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

(e) Leases

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

(f) Derivative contract novations

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

(g) Improvements to employee share-based payment accounting

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

(h) Measurement of credit losses on financial instruments

The FASB issued an accounting standards update in June 2016 that requires more timely recording of credit losses on loans and other financial instruments. The amendments affect entities that hold financial assets and net investment in leases that are not accounted for at fair value through net income (loans, debt securities, trade receivables, net investments in leases, off-balance-sheet credit exposures, etc.). They require an entity to present a financial asset (or group of financial assets) that is measured at amortized cost basis at the net amount expected to be collected. The allowance for credit losses is a valuation account that is deducted from the amortized cost basis of the financial asset(s) to present the net carrying value at the amount expected to be collected on the financial asset. The income statement reflects the measurement of credit losses for newly recognized financial assets, as well as the expected increases or decreases of expected credit losses that have taken place during the period. The measurement of expected credit losses is based on relevant information about past events, including historical experience, current conditions, and reasonable and supportable forecasts that affect the collectability of the reported amount. An entity must use judgment in determining the relevant information and estimation methods appropriate in its circumstances. The amendments are effective for public entities that are SEC filers for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, with early adoption permitted. Entities are to apply the amendments on a modified retrospective basis for most instruments. We expect our adoption will not materially affect our results of operations, financial position, and cash flows.

(i) Certain classifications in the statement of cash flows

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

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

The FASB issued the amendment in November 2016 to address existing diversity in the classification and presentation of changes in restricted cash on the statement of cash flows.

The amendment requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The amendment does not provide a definition of restricted cash or restricted cash equivalents. The amendment is effective for public entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, with early adoption permitted. The amendment should be applied using a retrospective transition method to each period presented. As permitted, we have early adopted the amendment as of the beginning of the fourth quarter of 2016 and have applied it retrospectively to all periods presented. The adoption of the amendment did not have any impact on the statements of cash flows for the year ended December 31, 2015 as we did not have restricted cash as of the beginning and end of 2015.

Other Income and Other Deductions:

Year Ended December 31,	**2016**	**2015**
(Thousands)		
Interest and dividend income	**$25**	$222
Allowance for funds used during construction	**11,549**	7,672
Gain on sale of property	**427**	174
Carrying costs on regulatory assets	**2,404**	4,281
Miscellaneous	**252**	73
Total other income	**$14,657**	$12,422
Miscellaneous	**$(1,325)**	$(1,614)
Total other deductions	**$(1,325)**	$(1,614)

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

***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 borrow from AGR, the parent of Networks, through intercompany revolving credit agreements, including RG&E. For RG&E the intercompany revolving credit agreements provide access to supplemental liquidity. See Note 6 for further detail on the credit facility with AGR.

Avangrid Service Company provides some administrative and management services to

Networks operating utilities, including RG&E, 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 RG&E by AGR and its affiliates were approximately $49 million in 2016 and $47 million for 2015 and charge for services provided by RG&E to AGR and its subsidiaries were approximately $11 million in 2016 and $7 million for 2015. 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 $38 million at December 31, 2016, $36 million is payable to Avangrid Service Company, and of $48 million at December 31, 2015, $35 million were payable to Avangrid Service Company and $10 million to NYSEG.

AGR, on behalf of RG&E, 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.

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

RG&E'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 RG&E. 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, RG&E 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 was $39.9 million and $11 million at December 31, 2016 and 2015, respectively.

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

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

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 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 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) 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 41% of the company's employees are covered by a collective bargaining agreement. RG&E has no agreements which will expire within the coming year.

Note 2. Industry Regulation

Electricity and Natural Gas Distribution

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 are 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 reflects 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 New York Public Service Commission (NYPSC) approved a new rate plan for electric and natural gas service provided by NYSEG and RG&E effective from August 26, 2010 through December 31, 2013. The rate plan contained continuation provisions beyond 2013 if RG&E did not request new rates to go into effect and the current base rates would stay in place. The rates stayed effective until May 1, 2016, at which time a newly approved rate plan became effective.

The 2010 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 RG&E fails 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 RG&E fails to meet the targets.

The 2010 rate plan's established revenue decoupling mechanism (RDM) is 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.

On September 1, 2012, RG&E began amortizing $5.3 million per year of its $105 million theoretical excess depreciation reserve. The amortization amounts reflect a twenty year amortization period. Theoretical excess depreciation is the difference between actual accumulated depreciation taken to date and a theoretical reserve. The actual accumulated depreciation is the result of depreciation rates allowed in prior rate orders based on estimates of useful lives and net salvage values as determined in those cases. The theoretical reserve is the amount that would have accumulated if the depreciation rates in the new rate plan had been in place for the entire useful lives of the affected assets. Differences between the actual reserve and the theoretical reserve are normal aspects of utility ratemaking. The usual treatment is to flow any excess or deficiency back as an adjustment to depreciation expense over the remaining life of the property. However, in accordance with the new rate plan, RG&E moderates 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, RG&E filed electric and gas rate cases with the NYPSC. We requested a rate increase for RG&E gas. RG&E electric proposed a rate decrease.

On February 19, 2016, RG&E and other signatory parties filed a Joint Proposal (Proposal) with the NYPSC for a three-year rate plan for electric and gas service at NYSEG and RG&E commencing May 1, 2016. The Proposal, which was approved by the NYPSC on June 15, 2016, balanced the varied interests of the signatory parties including but not limited to maintaining the companies' credit quality and mitigating the rate impacts to customers. The Proposal reflects many customer benefits including: acceleration of the companies' natural gas leak prone main replacement programs and increased funding for 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	$3.0	0.7%	$21.6	5.0%	$25.9	5.7%
Gas	$8.8	5.2%	$7.7	4.4%	$9.5	5.2%

The allowed rate of return on common equity for RG&E Electric and RG&E Gas is 9.00%. The equity ratio for each company is 48%. The Proposal includes an ESM applicable to each company. The customer share of earnings would increase at higher ROE levels, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% of ROE, respectively, in the first rate year. Earnings sharing is based on the lower of actual equity of 50%. Earnings thresholds increase in subsequent rate years.

The Proposal continues reserve accounting for qualifying Major Storms ($2.5 million annually for RG&E Electric). Incremental maintenance costs incurred to restore service in qualifying divisions will be chargeable to the Major Storm Reserve provided they meet certain thresholds.

The Proposal maintains RG&E's current electric reliability performance measures (and associated potential negative revenue adjustments for failing to meet established performance levels) which include the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI). 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 RG&E's bill reduction and arrears forgiveness Low Income Programs with increased funding levels included in the Proposal. Reforming the Energy Vision

(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, the Company will implement the 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.

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 and its related proceedings have and will continue to propose 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. RG&E is participating in the initiative with other New York utilities and are providing their unique perspective. The NYPSC issued a 2015 order in Track 1, which acknowledges the utilities' role as a Distribution System Platform (DSP) provider, and required the utilities to file an initial Distribution System Implementation Plan (DSIP) by June 30, 2016. The companies filed the DSIP, which also included information regarding the potential deployment of Automated Metering Infrastructure (AMI) across its entire service territory. The companies, in December 2016, filed a petition to the NYPSC requesting approval for cost recovery associated with the full deployment of AMI, and a collaborative and settlement process began in 2017 and is expected to continue throughout 2017.

Other 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 Standard, Value of DER and Net Energy Metering, Demand Response Tariffs, and Community Choice Aggregation. As part of the Clean Energy Standard proceeding, all electric utilities were ordered to begin payments to NYSERDA for Renewable Energy Credits and Zero Emissions Credits beginning in 2017.

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. A Track 2 order was issued in May, 2016, and includes guidance related to the potential for Earnings Adjustment Mechanisms (EAMs), Platform Service

Revenues, innovative rate designs, and data utilization and security. The companies, in December 2016, filed a proposal for the implementation of EAMs in the areas of System Efficiency, Energy Efficiency, Interconnections, and Clean Air. A collaborative process to review the companies' petition began in the first quarter of 2017 and is expected to continue through the summer 2017.

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 in 2015 and 2018. In July, 2014, GNPP filed a petition requesting that the NYPSC initiate a proceeding to examine a proposal 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 a Reliability Support Services Agreement (RSSA)." As such, the NYPSC ordered RG&E and GNPP to negotiate an RSSA.

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

On October 21, 2015, RG&E, 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. RG&E shall make monthly payments to Ginna in the amount of $15.4 million. RG&E will be entitled to 70% of revenues from Ginna's sales into the NYISO energy and capacity markets, while Ginna will be entitled to 30% of such revenues. The signatory parties recommend that the NYPSC authorize RG&E to implement a rate surcharge effective January 1, 2016, to recover amounts paid to Ginna pursuant to the RSSA. RG&E's payment obligation to Ginna did not begin until the rate surcharge was in effect and FERC issued an order authorizing the FERC Settlement agreement in the Settlement Docket. RG&E will use deferred rate credit amounts (regulatory liabilities) to offset the full amount of the Deferred Collection Amount (including carrying costs), plus credit amounts to offset all RSSA costs that exceed $2.3 million per month, not to exceed a total use of credits in the amount of $110 million, applicable through June 30, 2017. To the extent that the available credits are insufficient to satisfy the final payment from RG&E to Ginna then the RSSA surcharge would continue past March 31, 2017, to recover up to $2.3 million per month until the final payment has been recovered by RG&E from ratepayers. In the month following the expiration of the term on March 31, 2017, Ginna shall prepare and issue an invoice to RG&E for, and RG&E shall pay to Ginna, a one-time payment in the amount of $11.5 million, which will be recovered from ratepayers. If Ginna continues to deliver energy to the NYISO transmission system or makes available capacity to the NYISO markets after seventy-five days following March 31, 2017, Ginna shall pay RG&E a capital recovery balance in eight quarterly installments as long as Ginna is continuing to deliver energy or making available capacity throughout this period. The estimated capital recovery balance that is expected to be in place on March 31, 2017 is $20.1 million and will accrue interest unless amounts are prepaid by Ginna. The capital recovery balance will be refunded to ratepayers, to the extent collected, which is based on the term of the delivery of energy or capacity being made available by Ginna. 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.

Minimum Equity Requirements for Regulated Subsidiaries

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

Note 3. Regulatory Assets and Liabilities

Pursuant to the requirements concerning accounting for regulated operations we capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric 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 $243 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.

On June 15, 2016, the NYPSC approved the proposal in connection with a three-year rate plan for electric and gas service at RG&E effective May 1, 2016. Following the approval of the Proposal RG&E’s plant related tax items are amortized over the life of associated plant, and unfunded deferred taxes being amortized over a period of fifty years. A majority of the other items related to RG&E, which net to a regulatory liability, remains deferred and will not be amortized until future proceedings or will be used to recover costs of the Ginna RSSA. Following the approval of the proposal by the NYPSC, unfunded future income taxes were adjusted for the amount of $123 million to reflect the change from a flow through to normalization method, which has been recorded as an increase to income tax expense and an offsetting increase to revenue, during the year ended December 31, 2016. The amounts will be collected over a period of fifty years.

Notes to Financial Statements

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

December 31, (Thousands)	2016	2015
Current		
Revenue decoupling mechanism	**$4,172**	$6,493
Temporary supplemental assessment charge	**1,721**	2,269
Decommissioning	**6,471**	-
Reliability support services	**27,000**	-
Electric supply reconciliation	**4,152**	-
Hedge losses	**3,781**	11,167
Environmental remediation costs	**6,363**	11,111
Other	**9,457**	1,940
Total short term regulatory assets	**$63,117**	$32,980
Long-Term		
Asset retirement obligation	**3,108**	8,061
Unamortized losses on re-acquired debt	**5,012**	5,385
Decommissioning	**14,334**	7,442
Pension and other postretirement benefits cost deferrals	**34,310**	29,700
Federal tax depreciation normalization adjustment	**75,888**	74,482
Environmental remediation costs	**95,946**	98,826
Pension and other postretirement benefits	**115,469**	141,296
Unfunded future income taxes	**123,807**	128,371
Reliability support services	**28,783**	-
Other	**17,055**	14,818
Total long-term regulatory assets	**$513,712**	$508,381

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, 2016 and 2015 consisted of:

December 31, (Thousands)	**2016**	**2015**
Current		
Energy efficiency programs	**$24,798**	$20,318
Gas supply charge and deferred natural gas costs	**-**	1,140
Carrying Costs on deferred income tax bonus depreciation	**2,499**	-
Merchant function charge	**-**	(2,579)
Other	**2,436**	(321)
Total short term regulatory liabilities	**$29,733**	$18,558
Long-Term		
Asset gain sale account	**10,851**	10,616
Earnings sharing	**7,511**	6,791
Economic development	**18,796**	16,632
Merger capital expense	**10,000**	10,000
Other taxes	**6,967**	11,227
Deferred transmission congestion contracts	**17,009**	14,430
Post term amortizations	**546**	22,268
Net plant reconciliation	**9,690**	9,690
Spent nuclear fuel interest	**-**	14,155
Accrued removal obligations	**184,622**	178,242
Positive benefit adjustment	**32,639**	37,505
Deferred property taxes	**18,870**	14,605
Carrying costs on deferred income tax bonus depreciation	**55,770**	55,480
Variable rate debt	**15,063**	14,684
Low income programs	**5,891**	5,583
Other	**36,111**	11,192
Total other long term regulatory liabilities	**430,336**	433,100
Deferred income taxes regulatory	**51,876**	14,547
Total long term regulatory liabilities	**$482,212**	$447,647

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 recorded 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 five years following the approval of the proposal by the NYPSC.

Economic development represents the economic development program which enables RG&E 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

RG&E varies in any rate year from the level provided for in rates, the difference is refunded to ratepayers. The amortization period is five years following the approval of the proposal by the NYPSC.

Merger capital expense target customer credit account was created as a result of RG&E not meeting certain capital expenditure requirements established in the order approving the purchase of Energy East by Iberdrola. The amortization period is five years following the approval of the proposal by the NYPSC.

Positive benefit adjustment resulted from Iberdrola's 2008 acquisition of Energy East. This is being used to moderate increases in rates. The amortization period is five years following the approval of the proposal by the NYPSC and included in the Ginna RSSA settlement.

Post term amortization represents the revenue requirement associated with certain expired joint proposal amortization items. The amortization period is five years following the approval of the proposal by the NYPSC.

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, 2016 and 2015 consisted of:

Year Ended December 31,	**2016**	**2015**
(Thousands)		
Current		
Federal	**$(3,604)**	$11,923
State	**421**	427
Current taxes charged to (benefit) expense	**(3,183)**	12,350
Deferred		
Federal	**170,525**	14,917
State	**16,459**	8,437
Deferred taxes charged to expense	**186,984**	23,354
Total Income Tax Expense	**$183,801**	$35,704

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

Year Ended December 31,	**2016**	**2015**
(Thousands)		
Tax expense at federal statutory rate	**$92,561**	$25,609
Depreciation and amortization not normalized	**69,129**	8,734
Allowance for funds used during construction not normalized	**-**	(5,074)
State taxes, net of federal benefit	**10,972**	5,762
Tax return and audit adjustments	**(121)**	(191)
Other, net	**11,260**	864
Total Income Tax Expense	**$183,801**	$35,704

Income tax expense for the year ended December 31, 2016 was $91.2 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to depreciation not normalized and state taxes (net of federal benefit). This resulted in an effective tax rate of 69.5%. 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%.

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

As of December 31, (Thousands)	2016	2015
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	**$534,869**	$496,139
Unfunded future income taxes	**49,637**	50,854
Derivative asset	**(28,125)**	(30,701)
Non-cash return – bonus depreciation	**(23,122)**	(21,979)
Pension and other postretirement benefits	**(14,684)**	(6,126)
Positive benefits adjustments merger order	**(12,949)**	(14,857)
Other	**(18,813)**	(59,720)
Total Non-current Deferred Income Tax Liabilities	**$486,813**	$413,610
Less amounts classified as regulatory liabilities		
Non-current deferred income taxes	**51,876**	14,547
Non-current Deferred Income Tax Liabilities	**$434,937**	$399,063
Deferred tax assets	**$97,693**	$133,383
Deferred tax liabilities	**584,506**	546,993
Net Accumulated Deferred Income Tax Liabilities	**$486,813**	$413,610

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, 2016 and 2015 consisted of:

Year Ended December 31, (Thousands)	2016	2015
Balance as of January 1	**$492**	$ 2,358
Reduction for tax positions related to prior years	**2,413**	-
Reductions for tax position related to settlements with taxing authorities	**-**	(1,866)
Balance as of December 31	**$2,905**	$492

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, 2016 and $0.1 million as of December 31, 2015. Gross unrecognized tax benefits decreased by $2.4 million in 2016 due to tax positions related to prior years.

On December 29, 2014, the Joint Committee on Taxation approved the examination of AGR and its subsidiaries, which includes RG&E, 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.

Note 5. Long-term Debt

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

As of December 31,		2016		2015	
(Thousands)	Maturity Dates	Balances	Interest Rates	Balances	Interest Rates
First mortgage bonds [(a)]	2019-2033	$ 600,000	4.10%-8.00%	$ 600,000	4.10%-8.00%
Secured pollution control notes – fixed	2016	-	-	39,850	4.75%-5.00%
Unsecured pollution control notes - variable	2032	62,150	1.32%	62,150	0.195%
Obligations under capital leases	2017-2023	11,172		12,451	
Unamortized debt issuance costs and discount		(8,369)		(9,512)	
Total Debt		**$ 664,953**		**$ 704,939**	
Less: debt due within one year, included in current liabilities		529		39,873	
Total Non-current Debt		**$ 664,424**		**$ 665,066**	

(a) 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.

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

2017	2018	2019	2020	2021
$529	$1,434	$151,519	$1,609	$126,704

We have no financial debt covenant requirements related to our long-term debt at December 31, 2016 and 2015.

Note 6. Bank Loans and Other Borrowings

RG&E had a total of $249 million short-term debt outstanding at December 31, 2016 and $70 million of short-term debt outstanding at December 31, 2015. RG&E funds short-term liquidity needs through an agreement among Avangrid's regulated utility subsidiaries (the Virtual Money Pool Agreement), a bi-lateral intercompany credit agreement with Avangrid (the Bi-Lateral Intercompany Facility) and a bank provided credit facility to which RG&E is a party (the AGR Credit Facility), each of which are described below.

The Virtual Money Pool Agreement is an agreement among the investment grade-rated, regulated utility subsidiaries of Avangrid under which the parties to this agreement may lend to or borrow from each other. This Agreement allows Avangrid to optimize cash resources within the regulated utility companies which are prohibited by regulation from lending to unregulated affiliates. The interest rate on transactions under this agreement is the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. RG&E has a lending/borrowing limit of $100 million under this agreement. There was $32 million outstanding under this agreement as of December 31, 2016. The amount outstanding as of December 31, 2015 pursuant to the prior year agreement was $23 million.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $500 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There was $217 million and $47 million outstanding under this agreement as of December 31, 2016 and December 31, 2015, respectively.

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

In the AGR Credit 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 0.52 to 1.00 at December 31, 2016. We are not in default as of December 31, 2016.

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

Note 7. Commitments and Contingencies

NYPSC Staff Review of Earnings Sharing Calculations and Other Regulatory Deferrals

In December 2012, the NYPSC Staff (Staff) informed RG&E 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 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 $1.6 million of adjustments to deferral balances and customer earnings sharing accruals. RG&E reviewed the Staff's adjustments and work papers and provided a response in early 2013. RG&E disagreed with certain Staff conclusions and as a result recorded a $1 million reserve in December 2012 in anticipation of settling the Staff issues. In the Proposal approved by the NYPSC (Note 2) the parties agreed that in full and final resolution of all years through 2012, and in full and final resolution of storm-related deferrals through 2014, the companies will add $0.6 million to the customer share of earnings sharing. Staff indicated in December 2016 that it had completed its review 2013 and 2014 compliance filings and no issues were identified.

Leases

On October 21, 2015, RG&E, GNPP and multiple intervenors filed a Joint Proposal with the regulator for approval of the modified RSS Agreement for the continued operation of the Ginna Facility through March 2017. RG&E shall make monthly payments to GNPP in the amount of $15.4 million. RG&E 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. The net expense incurred under this operating lease was $114.9 million and $79.9 million for the years ended December 31, 2016 and 2015, respectively. We estimate our expenses will be approximately $58 million in 2017.

Purchase power and natural gas contracts, including nonutility generators:

RG&E 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, RG&E 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.

RG&E 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 $48 million for purchase power and natural gas contracts including nonutility generators in 2016 and in 2015. We estimate that our power purchases will total $49 million in 2017, $42 million in 2018, $29 million in 2019, $22 million in 2020, $18 million in 2021 and $85 million thereafter.

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.

Waste sites

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 nine waste sites. The nine sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the nine 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 $155 thousand at December 31, 2016, related to the nine sites. We have recorded an estimated liability of $4.1 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. Our estimate for costs to remediate these sites ranges from $4.2 million to $6.2 million as of December 31, 2016. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to us. Any cost will be flowed through to RG&E ratepayers.

Manufactured gas plants

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 $86 million to $208 million at December 31, 2016. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $134.4 million at December 31, 2016, and at December 31, 2015. We recorded a corresponding regulatory asset, net of insurance recoveries, because we expect to recover the net costs in rates.

Our environmental liabilities are recorded on an undiscounted basis 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, 2016 and 2015, the loss recognized in regulatory assets was $4.5 million and $8.7 million, respectively, 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 $17.8 million and $12.3 million for 2016 and for 2015, respectively.

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, 2016 and 2015 the amount recognized in regulatory assets for natural gas hedges was a gain $2.4 million and a loss of $2.4 million, respectively. For the years ended December 31, 2016 and 2015 the loss reclassified from regulatory assets into income, which is included in natural gas purchased, was $1.7 million and $3.3 million, respectively.

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, 2016			
2017	**1,224,350**	**3,180,000**	**439,400**
2018	**438,000**	**690,000**	**-**
As of December 31, 2015			
2016	1,232,750	3,030,000	447,500
2017	758,600	600,000	234,000

Notes to Financial Statements

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2016 and 2015, respectively, consisted of:

December 31, 2016	Derivative Assets - Current	Derivative Assets - Noncurrent	Derivative Liabilities - Current	Derivative Liabilities - Noncurrent
(In thousands)				`
Not designated as hedging instruments				
Derivative assets	$3,545	$1,173	$1,436	$920
Derivative liabilities	(1,437)	(920)	(5,217)	(1,623)
	2,108	253	(3,781)	(703)
Designated as hedging instruments				
Derivative assets	3	-	3	-
Derivative liabilities	(3)	-	(49)	-
	-	-	(46)	-
Total derivatives before offset of cash collateral	2,108	253	(3,827)	(703)
Cash collateral receivable (payable)	-	-	3,781	703
Total derivatives as presented in the balance sheet	$2,108	$253	$(46)	$-

December 31, 2015	Derivative Assets – Current	Derivative Assets - Noncurrent	Derivative Liabilities - Current	Derivative Liabilities - Noncurrent
(In thousands)				`
Not designated as hedging instruments				
Derivative assets	$916	$2,137	$916	$1,957
Derivative liabilities	(916)	(1,957)	(12,083)	(2,052)
	-	180	(11,167)	(95)
Designated as hedging instruments				
Derivative assets	-	-	-	-
Derivative liabilities	-	-	(273)	(140)
	-	-	(273)	(140)
Total derivatives before offset of cash collateral	-	180	(11,440)	(235)
Cash collateral receivable (payable)	-	-	11,167	95
Total derivatives as presented in the balance sheet	$-	$180	$(273)	$(140)

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)			
2016			
Interest rate contracts	**$-**	Interest expense	**$(5,768)**
Commodity contracts	**5**	Other operating expenses	**(362)**
Total	**$5**		**$(6,130)**
2015			
Interest rate contracts	$-	Interest expense	$(5,768)
Commodity contracts	(423)	Other operating expenses	(573)
Total	$(423)		$(6,341)

The amount in AOCI related to previously settled forward starting interest rate swaps and accumulated amortization, at December 31 is a net loss of $68.2 million for 2016 as compared to a net loss of $74 million for 2015. For the year ended December 31, 2016, 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 2017.

As of December 31, 2016, $5 thousand 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 12 months, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted energy transactions. There was no ineffective portion of hedge recognized during the year ended December 31, 2016.

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.

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, 2016, is $4.5 million for which we have posted collateral.

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

The estimated fair value of debt amounted to $830 million as of December 31, 2016 and $863 million as of December 31, 2015. 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 $61 million and $56 million as of December 31, 2016 and as of December 31, 2015, respectively, 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.

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	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Netting**	**Total**
(Thousands)					
2016					
Assets					
Noncurrent investments primarily money market funds	**$3,764**	**$-**	**$-**	**$-**	**$3,764**
Derivatives					
Commodity contracts:					
Electricity	**2,356**	**-**	**-**	**(2,356)**	**-**
Gas	**2,361**	**-**	**-**	**-**	**2,361**
Other	**-**	**-**	**3**	**(3)**	**-**
Total	**$8,481**	**$-**	**$3**	**(2,359)**	**$6,125**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	**(6,840)**	**-**	**-**	**6,840**	**-**
Natural gas	**-**	**-**	**(49)**	**3**	**(46)**
Other					
Total	**$(6,840)**	**$-**	**$(49)**	**$6,843**	**$(46)**

Description	(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)

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2016. 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 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,	**2016**	2015
(Thousands)		
Beginning balance	**$413**	$563
Total gain (loss) (realized/unrealized)		
Included in earnings	**(362)**	(573)
Included in other comprehensive income	**(5)**	423
Ending balance	**$46**	$413

The gains and losses included in earnings for the periods above are reported in Operations and maintenance of the statements of income.

Note 11. Accumulated Other Comprehensive Loss

	Balance January 1, 2015	2015 Change	Balance December 31, 2015	2016 Change	Balance December 31, 2016
(Thousands)					
Net unrealized holding gain on investments, net of income tax expense of $11 for 2015 and $4 for 2016	$16	$17	$33	**$6**	**$39**
Amortization of pension cost for nonqualified plans, net of income tax expense of $417 for 2015 and $166 for 2016	(2,530)	632	(1,898)	**257**	**(1,641)**
Unrealized (loss) gain on derivatives qualified as hedges:					
Unrealized (loss) gain during period on derivatives qualified as hedges, net of income tax (benefit) expense of $(168) for 2015 and $2 for 2016		(255)		**3**	
Reclassification adjustment for loss included in net income, net of income tax expense of $228 for 2015 and $142 for 2016		346		**220**	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $2,285 for 2015 and $2,263 for 2016		3,483		**3,505**	
Net unrealized (loss) gain on derivatives qualified as hedges	(48,506)	3,574	(44,932)	**3,728**	**(41,204)**
Accumulated Other Comprehensive Loss	$(51,020)	$4,223	$(46,797)	**$3,991**	**$(42,806)**

Note 12. Retirement Benefits

We have funded noncontributory defined benefit pension plans that cover the eligible employees. For most employees, generally those hired before 2002, the plans provide defined benefits based on years of service and final average salary. Employees hired in 2002 or later are covered under a cash balance plan or formula where their 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 2016 and in 2015.

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

***Obligations and funded status*:**

	Pension Benefits		Postretirement Benefits	
	2016	**2015**	**2016**	**2015**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	**$437,294**	$473,472	**$79,551**	$85,635
Service cost	**5,729**	5,323	**377**	451
Interest cost	**17,075**	17,189	**3,155**	3,152
Plan amendments	**-**	-	**-**	-
Plan participants' contributions	**-**	-	**333**	354
Actuarial loss (gain)	**(6,132)**	(21,211)	**(1,711)**	(5,656)
Special termination benefits	**-**	435	**-**	-
Benefits paid	**(36,434)**	(37,914)	**(5,361)**	(4,385)
Benefit obligation at December 31	**$417,532**	$437,294	**$76,344**	$79,551
Change in plan assets				
Fair value of plan assets at January 1	**$323,878**	$366,360	**-**	-
Actual return on plan assets	**20,213**	(4,568)	**-**	-
Employer and plan participants' contributions	**716**	-	**5,361**	$4,385
Benefits paid	**(36,433)**	(37,914)	**(5,361)**	(4,385)
Fair value of plan assets at December 31	**$308,374**	$323,878	**$-**	$-
Funded status at December 31	**$(109,158)**	$(113,416)	**$(76,344)**	$(79,551)

Amounts recognized in the balance sheet	**Pension Benefits**		**Postretirement Benefits**	
December 31,	**2016**	**2015**	**2016**	**2015**
(Thousands)				
Other current liabilities	**$-**	$-	**$(5,424)**	$(5,274)
Noncurrent liability	**$(109,158)**	$(113,416)	**(70,920)**	(74,277)
Total	**$(109,158)**	$(113,416)	**$(76,344)**	$(79,551)

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 2016	2015	Postretirement Benefits 2016	2015
(Thousands)				
Net loss	**$115,350**	$139,122	**$3,691**	$ 6,304
Prior service cost (credit)	**$625**	$1,477	**$(4,198)**	$(5,607)

Our accumulated benefit obligation for all defined benefit pension plans was $389 million and $406 million at December 31, 2015.

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

December 31	2016	2015
(Thousands)		
Projected benefit obligation	**$417,532**	$437,294
Accumulated benefit obligation	**$388,507**	$405,659
Fair value of plan assets	**$308,374**	$323,878

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

	Pension Benefits		Postretirement Benefits	
Years ended December 31,	**2016**	**2015**	**2016**	**2015**
(Thousands)				
Net periodic benefit cost				
Service cost	**$5,729**	$5,322	**$377**	$451
Interest cost	**17,075**	17,189	**3,155**	3,152
Expected return on plan assets	**(23,800)**	(26,010)	**-**	-
Amortization of prior service cost (credit)	**851**	1,140	**(1,409)**	(1,409)
Amortization of net loss	**21,227**	22,686	**902**	148
Special termination benefit charge	**-**	435	**-**	-
Net periodic benefit cost	**$21,082**	$20,762	**$3,025**	$2,342
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	**$(2,545)**	$9,368	**$(1,711)**	$(5,657)
Amortization of net (loss) gain	**(21,227)**	(22,686)	**(902)**	(148)
Amortization of prior service (cost) credit	**(851)**	(1,140)	**1,409**	1,409
Total recognized in regulatory assets and regulatory liabilities	**(24,623)**	(14,458)	**(1,204)**	(4,396)
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$(3,541)**	$6,304	**$1,821**	$(2,054)

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

Amounts expected to be amortized from regulatory assets or regulatory liabilities into net periodic benefit cost for the fiscal year ending December 31, 2017	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	$22,883	$566
Estimated prior service cost (credit)	$403	$(1,409)

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

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits 2016	Pension Benefits 2015	Postretirement Benefits 2016	Postretirement Benefits 2015
Discount rate	**4.12%**	4.10%	**4.12%**	4.10%
Rate of compensation increase	**4.00%**	4.00%	**N/A**	N/A

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

Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31,	Pension Benefits 2016	Pension Benefits 2015	Postretirement Benefits 2016	Postretirement Benefits 2015
Discount rate	**4.10%**	3.80%	**4.10%**	3.80%
Expected long-term return on plan assets	**7.40%**	7.50%	**N/A**	N/A
Rate of compensation increase	**4.00%**	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,	2016	2015
Health care cost trend rate (pre 65/post 65)	**7.00% /9.00%**	7.00%/9.00%
Rate to which cost trend rate is assumed to decline (the ultimate trend rate)	**4.50%**	4.50%
Year that the rate reaches the ultimate trend rate	**2026/2028**	2026

The assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans. Due to the RG&E retirees having moved into a different program, it is no longer sensitive to medical trend changes. The company is limited to a specific dollar amount and will not change in the future.

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 $6.1 million to our pension benefit plans in 2017.

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

	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
(Thousands)			
2017	$43,615	$5,272	-
2018	$42,796	$5,285	-
2019	$41,373	$5,281	-
2020	$40,593	$5,269	-
2021	$39,716	$5,252	-
2022 - 2026	$169,411	$33,361	-

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

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

The fair values of Network's pension benefits plan assets at December 31, 2016 and 2015, by asset category are shown in the following table. RG&E's share of the total consolidated assets is approximately 12% for 2016 and 2015.

Notes to Financial Statements

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

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

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

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

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

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

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

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

Note 13. Subsequent events

The company has performed a review of subsequent events through April 12, 2017, which is the date these financial statements were available to be issued, and no subsequent events have occurred from January 1, 2017 through such date.