THE UNITED ILLUMINATING COMPANY

AUDITED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2017 AND 2016

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KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

The Board of Directors
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, 2017, 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 accordance 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 from material misstatement, whether due to fraud or error.

Auditors' 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 of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' 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 opinion.

Opinion

In our opinion, the 2017 financial statements referred to above present fairly, in all material respects, the financial position of The United Illuminating Company as of December 31, 2017, and the results of its operations and its cash flows for the year then ended in accordance with U.S. generally accepted accounting principles.

Other Matter

The accompanying financial statements of The United Illuminating Company as of December 31, 2016 and for the year then ended were audited by other auditors whose report thereon dated April 18, 2017, expressed an unmodified opinion on those financial statements.

KPMG LLP

New York, New York
April 13, 2018

THE UNITED ILLUMINATING COMPANY
STATEMENT OF INCOME
For the Years Ended December 31, 2017 and 2016
(In Thousands)

	2017	2016
Operating Revenues	$ 921,181	$ 866,975
Operating Expenses		
Purchased power	169,000	188,712
Operation and maintenance	376,817	358,118
Depreciation and amortization	77,491	79,138
Taxes other than income taxes	107,676	98,611
Total Operating Expenses	730,984	724,579
Operating Income	190,197	142,396
Other Income and (Expense), net		
Other income	7,447	11,626
Other (expense)	(153)	(150)
Total Other Income and (Expense), net	7,294	11,476
Interest Expense, net	41,092	41,812
Income from Equity Investments	12,720	13,114
Income Before Income Tax	169,119	125,174
Income Tax	63,936	40,819
Net Income	$ 105,183	$ 84,355

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, 2017, and 2016
(Thousands of Dollars)

	2017	2016
Cash Flows From Operating Activities		
Net income	$ 105,183	$ 84,355
Adjustments to reconcile net income		
to net cash provided by operating activities:		
Depreciation and amortization	79,306	80,557
Deferred income taxes	34,483	34,681
Uncollectible expense	19,878	17,276
Pension expense	28,824	29,671
Allowance for funds used during construction (AFUDC) - equity	(1,966)	(6,222)
Undistributed (earnings) in equity investments	(12,720)	(13,114)
Regulatory assets/liabilities amortization	1,856	(284)
Regulatory assets/liabiities carrying cost	(1,567)	(243)
Other non-cash items, net	(1,001)	(802)
Changes in:		
Accounts receivable and unbilled revenues, net	(58,033)	(17,745)
Accounts payable and accrued liabilties	24,399	10,048
Cash distribution received from GenConn	12,675	13,126
Taxes accrued and refundable	22,070	1,268
Pension and post-retirement	(10,431)	(15,567)
Regulatory assets/liabilities	(26,666)	(34,533)
Environmental liabilities	(13,433)	(3,114)
Other assets	1,212	(108)
Other liabilities	(4,708)	4,736
Total Adjustments	94,178	99,631
Net Cash provided by Operating Activities	199,361	183,986
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(163,138)	(187,529)
Cash distribution from GenConn	4,088	4,074
Notes receivable from affiliates	-	54,000
Net Cash used in Investing Activities	(159,050)	(129,455)
Cash Flows from Financing Activities		
Payment of common stock dividend	(125,000)	-
Payment of long-term debt	(70,000)	(64,460)
Line of credit borrowings	100,000	-
Notes payable to affiliates	52,400	7,197
Other	(42)	(333)
Net Cash used in Financing Activities	(42,642)	(57,596)
Cash, Restricted Cash, and Cash Equivalents:		
Net change for the period	(2,331)	(3,065)
Balance at beginning of period	4,319	7,384
Balance at end of period	$ 1,988	$ 4,319
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 42,107	$ 40,571
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 23,917	$ 11,277

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THE UNITED ILLUMINATING COMPANY
BALANCE SHEET
December 31, 2017 and 2016

ASSETS
(In Thousands)

	2017	2016
Assets		
Current Assets		
Cash and cash equivalents	$ -	$ 2,590
Accounts receivable and unbilled revenues, net	154,261	141,368
Accounts receivable from affiliates	31,623	5,961
Regulatory assets	61,328	33,462
Materials and supplies	5,507	7,197
Refundable taxes	-	22,518
Derivative assets	6,912	8,785
Prepayments and other current assets	2,982	3,020
Total Current Assets	262,613	224,901
Other Investments		
Equity investment in GenConn	102,160	106,214
Other	10,592	9,979
Total Other Investments	112,752	116,193
Property, Plant and Equipment, at cost	2,688,738	2,615,742
Less accumulated depreciation	586,088	537,736
Net Property, Plant and Equipment in Service	2,102,650	2,078,006
Construction work in progress	200,478	119,879
Total Property, Plant and Equipment	2,303,128	2,197,885
Regulatory Assets	453,920	509,627
Deferred Charges and Other Assets		
Derivative assets	4,735	10,631
Other	4,197	3,490
Total Deferred Charges and Other Assets	8,932	14,121
Total Assets	$ 3,141,345	$ 3,062,727

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Statements are an integral part of the financial statements.

THE UNITED ILLUMINATING COMPANY
BALANCE SHEET
December 31, 2017 and 2016

LIABILITIES AND CAPITALIZATION
(In Thousands)

	2017	2016
Liabilities		
Current Liabilities		
Line of credit borrowings	$ 100,000	$ -
Current portion of long-term debt	100,000	70,000
Accounts payable and accrued liabilities	113,443	104,736
Accounts payable to affiliates	25,151	4,552
Regulatory liabilities	7,058	720
Interest accrued	9,903	10,864
Taxes accrued	25,499	25,947
Notes payable to affiliates	68,900	16,500
Derivative liabilities	15,776	22,917
Other liabilities	20,383	12,650
Total Current Liabilities	486,113	268,886
Deferred Income Taxes	287,764	444,159
Regulatory Liabilities	440,618	122,120
Deferred Income Taxes Regulatory	17,762	171,757
Other Noncurrent Liabilities		
Pension and post-retirement	246,363	251,743
Derivative liabilities	63,317	71,783
Environmental remediation costs	20,664	29,897
Other	16,160	20,369
Total Other Noncurrent Liabilities	346,504	373,792
Capitalization		
Long-term debt	629,102	728,714
Common Stock Equity		
Common stock	1	1
Paid-in capital	709,230	709,230
Retained earnings	224,251	244,068
Net Common Stock Equity	933,482	953,299
Total Capitalization	1,562,584	1,682,013
Total Liabilities and Capitalization	$ 3,141,345	$ 3,062,727

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, 2017 and 2016
(Thousands of Dollars)

	Common Stock				Paid-in		Retained		
	Shares		Amount		Capital		Earnings		Total
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
Net income							105,183		105,183
Payment of common stock dividend							(125,000)		(125,000)
Balance as of December 31, 2017	100	$	1	$	709,230		224,251		933,482

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

THE UNITED ILLUMINATING COMPANY

NOTES TO FINANCIAL STATEMENTS

(A) BUSINESS ORGANIZATION AND STATEMENT OF ACCOUNTING POLICIES

The United Illuminating Company (UI) is a regulated operating electric public utility established in 1899. 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 a wholly owned subsidiary of UIL Holdings Corporation (UIL Holdings). UIL Holdings, whose primary business is ownership of its operating regulated utility businesses, is a wholly owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc., which is a 81.5% owned subsidiary of Iberdrola, S.A., a corporation organized under the law of the Kingdom of Spain.

UI is also a party to a joint venture with NRG Yield Operating LLC, a subsidiary of NRG Yield, Inc., or NYLD, which is a subsidiary of NRG Energy, Inc., or NRG, pursuant to which UI holds 50% of the membership interests in GCE Holding LLC, whose wholly owned subsidiary, GenConn Energy LLC, or GenConn, operates peaking generation plants in Devon, Connecticut, or GenConn Devon, and Middletown, Connecticut, or GenConn Middletown. In February 2018, NRG announced that it has agreed to sell its ownership stake in NYLD to Global Infrastructure Partners. This sale is expected to close during the second half of 2018 and is not expected to have an impact on GenConn.

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 reported in the Financial Statements 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. The following table summarizes the impact to the prior period Statement of Income, Statement of Cash Flows and Balance Sheet of these reclassifications.

December 31, 2016 (in thousands)	As previously filed	Reclassifications	As currently reported
Statement of Income			
Operations and maintenance	258,300	99,818	358,118
Transmission wholesale	99,818	(99,818)	-
Interest on long-term debt	43,711	(43,711)	-
Other interest, net	(3,318)	3,318	-
Amortization of debt expense and redemption premiums	1,419	(1,419)	-
Interest Expense, net	-	41,812	41,812
Statement of Cash Flows			
Changes in:			
Accounts receivable and unbilled revenue, net	(17,399)	(346)	(17,745)
Unbilled revenues	(346)	346	-
Accounts payable and accrued liabilities	7,845	2,203	10,048
Accrued liabilities	2,203	(2,203)	-
Pension and post-retirement	(15,049)	(518)	(15,567)
Accrued post-employment benefits	(518)	518	-
Environmental liabilities	-	(3,114)	(3,114)
Other liabilities	1,622	3,114	4,736
Balance Sheet			
Assets			
Current Assets			
Restricted cash	1,729	(1,729)	-
Accounts receivable and unbilled revenue, net	107,009	34,359	141,368
Accounts receivable from affiliates	-	5,961	5,961
Unbilled revenues	40,226	(40,226)	-
Prepayments and other current assets	2,976	(2,976)	-
Other assets	138	2,882	3,020
Other Investments			
Other	9,811	168	9,979
Deferred Charges and Other Assets			
Unamortized debt issuance expenses	284	(284)	-
Other long-term receivable	1,477	(1,477)	-
Other	168	3,322	3,490
Liabilities			
Current Liabilities			
Notes payable to affiliates / Intercompany payable	7,197	9,303	16,500
Accounts payable and accrued liabilities	107,096	(2,360)	104,736
Accounts payable to affiliates	-	4,552	4,552
Accrued liabilities	25,767	(25,767)	-
Other current liabilities	-	12,650	12,650
Taxes accrued	24,325	1,622	25,947
Regulatory Liabilities	293,877	(171,757)	122,120
Deferred income taxes regulatory	-	171,757	171,757
Other Noncurrent Liabilities			
Pension	221,309	30,434	251,743
Other post-retirement benefits accrued	40,936	(40,936)	-
Other	9,867	10,502	20,369

UI has evaluated subsequent events through the date its financial statements were available to be issued, April 13, 2018.

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 recognizes revenues upon delivery of electricity to its customers. In addition, UI accrues revenue pursuant to the various regulatory provisions to record regulatory assets for revenues that will be collected in the future.

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.

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 refunded in the future through the ratemaking process. UI is allowed to recover all such deferred costs and is required to refund such obligations to customers through its regulated rates. See Note (C) "Regulatory Proceedings", for a discussion of the recovery of certain deferred costs and the refund of certain obligations, as well as a discussion of the regulatory decisions that provide for such recovery and require such refunding.

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, 2017 and 2016 included the following:

	Remaining Period	December 31, 2017	December 31, 2016
		(In Thousands)	
Regulatory Assets:			
Unamortized redemption costs	4 to 16 years	$ 8,127	$ 8,907
Pension and other post-retirement benefit plans	(a)	215,560	236,688
Unfunded future income taxes	(b)	144,406	179,204
Contracts for differences	(c)	67,445	75,284
Excess generation service charge	(d)	-	1,536
Deferred transmission expense	(e)	36,673	8,465
Other	(f)	43,037	33,005
Total regulatory assets		515,248	543,089
Less current portion of regulatory assets		61,328	33,462
Regulatory Assets, Net		$ 453,920	$ 509,627
Regulatory Liabilities:			
Accumulated deferred investment tax credits	17.5 - 21 years	$ 14,032	$ 14,738
Excess generation service charge	(d)	2,388	-
Middletown/Norwalk local transmission network service collections	33 years	19,109	19,682
Pension and other post-retirement benefit plans	(a)	14,514	10,177
Asset removal costs	(f)	68,051	67,019
Deferred income taxes	(b)	17,762	171,757
Tax reform remeasurement	(g)	312,776	-
Other	(e)	16,806	11,224
Total regulatory liabilities		465,438	294,597
Less current portion of regulatory liabilities		7,058	720
Regulatory Liabilities, Net		$ 458,380	$ 293,877

(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, 2017 includes decoupling ($8.8 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.
(g) Impact of deferred tax remeasurement as a consequence of the Tax Cuts and Jobs Act of 2017 enacted by the U.S. federal government on December 22, 2017. Refundable period will be determined in future rate proceedings.

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, 2017 and 2016 were comprised as follows:

	2017	2016
	(In Thousands)	
Distribution plant	$ 1,393,065	$ 1,346,084
Transmission plant	771,480	758,955
Software	109,054	107,174
Land	54,862	54,813
Building and improvements	213,989	193,637
Other plant	146,288	155,079
Total property, plant & equipment	2,688,738	2,615,742
Less accumulated depreciation	586,088	537,736
	2,102,650	2,078,006
Construction work in progress	200,478	119,879
Net property, plant & equipment	$ 2,303,128	$ 2,197,885

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 2017 and 2016 were 3.60% and 7.65%, respectively. The portion of the allowance applicable to equity funds for 2017 and 2016 was $2.0 million and $6.2 million, 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 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 2017 and 2016 were approximately 3.0% and 3.1% 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, 2017, UI has recorded a gross derivative asset of $11.6, a regulatory asset of $67.4 million and a gross derivative liability of $79.1 million ($64.5 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, 2017 and 2016 were as follows:

	December 31, 2017	December 31, 2016
	(In Thousands)	
Gross derivative assets:		
Current Assets	$ 6,912	$ 8,785
Deferred Charges and Other Assets	$ 4,735	$ 10,631
Gross derivative liabilties:		
Current Liabilities	$ 15,776	$ 22,917
Noncurrent Liabilities	$ 63,317	$ 71,783

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, 2017 and 2016 were as follows:

	Year Ended December 31, 2017	2016
	(In Thousands)	
Regulatory Assets - Derivative liabilities	$ (7,838)	$ 7,578
Regulatory Liabilities - Derivative assets	$ -	$ 739

Equity Investments

UI is party to a 50-50 joint venture with NRG Yield Operating LLC 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 $102.2 million and $106.2 million as of December 31, 2017 and 2016, respectively. As of December 31, 2017, 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 $12.7 million and $13.1 million for the years ended December 31, 2017 and 2016, 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 $16.8 million and $17.2 million during the years ended December 31, 2017 and 2016, respectively.

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

	2017	2016
	(In Thousands)	
Current assets	$ 37,963	$ 36,283
Noncurrent assets	$ 373,576	$ 388,468
Current liabilities	$ 17,936	$ 15,907
Noncurrent liabilities	$ 189,271	$ 196,344
Operating revenues	$ 70,761	$ 71,763
Income	$ 25,357	$ 26,321

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, 2017, UI did not have any equity investments that were impaired under this standard.

Unrestricted 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 unrestricted cash and temporary cash investments.

Restricted Cash

UI's restricted cash at December 31, 2017 and 2016 totaled $2.0 million and $1.8 million, respectively, which primarily relates to electric distribution and transmission capital projects, which have been withheld by UI and will remain in place until the verification of fulfillment of contractor obligations. UI's restricted cash balances are included in prepayments and other current assets on the balance sheet.

Accounts receivable and unbilled revenues

Accounts receivable at December 31, 2017 and 2016 include unbilled revenues of $42.9 million and $40.2 million, respectively and are shown net of an allowance for doubtful accounts of $2.4 million and $2.8 million for 2017 and 2016, respectively. Accounts receivable do not bear interest, although late fees may be assessed.

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**.** Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for doubtful accounts is management's best estimate of the amount of probable credit losses in the existing accounts receivable, determined based on experience. Each month, UI reviews the allowance for doubtful accounts and past due accounts by age. When management believes that a receivable will not be recovered, the account balance is charged off 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

Materials and supplies

Materials and supplies inventories are used for construction of new facilities and repairs of existing facilities. The inventories are carried and withdrawn at lower of cost and net realizable value

Other Investments

The UI's other investments consist of noncurrent investments available for sale and life insurance policies.

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".

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.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. PURA has instituted proceedings in Connecticut to review and address the implications associated with the Tax Act on the utilities providing service in the state. UI expects the regulators in Connecticut to issue requirements in 2018 regarding how all tax benefits associated with the Tax Act will be returned to customers.

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 Yield Operating LLC. 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 Accounting Standards Codification (ASC), Topic 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. ASC 606 was further amended through various updates the FASB issued thereafter. 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 amended effective date is for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption permitted as of the original effective date of annual reporting periods beginning after December 15, 2016. Entities may apply the standard 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). UI will adopt the new standard effective January 1, 2018, and apply the modified retrospective method. Based on management's assessment to existing contracts and revenue streams, UI does not expect to record any material cumulative adjustments to retained earnings and does not expect ASC 606 to have a material impact on the amount and timing of its revenue recognition. Management has identified other changes primarily related to the presentation and disclosure of revenues. Management plans to disaggregate revenues not accounted for in scope of the new standard, as required, including alternative revenue programs.

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 the 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" 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 FASB issued an update in January 2018 to clarify the application of the new leases guidance to land easements and provide relief concerning adoption efforts for existing land easements that are not accounted for as leases under the current leases guidance. The updated guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early application is permitted. UI is currently reviewing our contracts and is 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 its financial statements. UI does not expect the adoption of the new guidance will materially affect its financial position through the recording of operating leases on the balance sheet as a right-of-use asset.

In March 2017, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2017-07 "Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost". The ASU contains amendments that require an entity to present service cost separately from the other components of net benefit cost, and to report the service cost component in the income statement line item(s) where it reports the corresponding compensation cost. An entity is to present all other components of net benefit cost outside of operating cost, if it presents that subtotal. The amendments also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of a self-constructed asset). The amendments are effective for annual and interim periods in fiscal years beginning after December 15, 2017, with early adoption permitted. UI does not plan to early adopt. An entity is required to apply the amendments retrospectively for the presentation of the service cost component and the other components of net periodic pension cost and net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension cost and net periodic postretirement benefit in assets. A practical expedient allows an entity to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in the notes to financial statements for pension and postretirement benefit plans for those periods. UI does not expect the adoption of the amendments will materially affect its results of operations, financial position, cash flows, and disclosures.

In August 2017, the FASB issued ASU 2017-12 "Derivatives and Hedging". The ASU contains targeted amendments with the objective to better align hedge accounting with an entity's risk management activities in the financial statements, and to simplify the application of hedge accounting. The amendments address concerns of financial statement preparers over difficulties with applying hedge accounting and limitations for hedging both nonfinancial and financial risks and concerns of financial statement users over how hedging activities are reported in financial statements. Changes to the hedge accounting guidance to address those concerns will: 1) expand hedge accounting for nonfinancial and financial risk components and amend measurement methodologies to more closely align hedge accounting with an entity's risk management activities; 2) eliminate the separate measurement and reporting of hedge ineffectiveness, to reduce the complexity of preparing and understanding hedge results; 3) enhance disclosures and change the presentation of hedge results to align the effects of the hedging instrument and the hedged item in order to enhance transparency, comparability, and understandability of hedge results; and 4) simplify the way assessments of hedge effectiveness may be performed to reduce the cost and complexity of applying hedge accounting. The amendments are effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted in any interim period after issuance of the amendments. UI does not expect to early adopt. For cash flow and net investment hedges existing at the date of adoption, a company must apply a cumulative-effect adjustment related to the separate measurement of ineffectiveness to accumulated other comprehensive income with a corresponding adjustment to the opening balance of retained earnings as of the beginning of the fiscal year of adoption. The amended presentation and disclosure guidance is required only prospectively. An entity may make certain elections upon adoption to allow for existing hedging relationships to transition to newly allowable alternatives. UI expects the adoption of the guidance will not materially affect its results of operations, financial position, or cash flows, but does expect the amendments will ease the administrative burden of hedge documentation requirements and assessing hedge effectiveness.

In February 2018 the FASB issued ASU 2018-02 "Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" which contains amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017 by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within accumulated other comprehensive income (AOCI) (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. The amendments are effective for all entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted. An entity has the option to apply the amendments either in the period of adoption or retrospectively to each period (or periods) in which it recognizes the effect of the change in the U.S. federal corporate income tax rate in the Tax Act. An entity is required to disclose its accounting policy election, including its policy for reclassifying material stranded tax effects in AOCI to earnings (specific identification or portfolio method). UI does not expect the adoption of the amendments will materially affect our results of operations, financial position, cash flows, and disclosures.

(B) CAPITALIZATION

Common Stock

UI had 100 shares of common stock, no par value, outstanding at December 31, 2017 and 2016.

Long-term debt

As of December 31,		**2017**		**2016**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured debt	2018-2045	$ 733,500	2.98%-6.61%	$ 803,500	2.98%-6.61%
Unamortized debt (costs) premium, net		(4,398)		(4,786)	
Total Debt		**$ 729,102**		**$ 798,714**	
Less: debt due within one year, included in current liabilities		100,000		70,000	
Total Non-current Debt		**$ 629,102**		**$ 728,714**	

The estimated fair value of debt amounted to $836.2 million and $895.5 million as of December 31, 2017 and 2016, 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 natural gas 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. 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:

	2018	2019	2020	2021	2022	2023 & thereafter	Total
				(In Thousands)			
Maturities	$ 100,000	$ 31,000	$ 50,000	$ -	$ 162,500	$ 390,000	$ 733,500

Under various debt agreements, UI is required to maintain a ratio of consolidated debt to consolidated capital of not greater than 65% (debt ratio). As of December 31, 2017, UI's debt ratio was 49%.

(C) REGULATORY PROCEEDINGS

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 annual tariff increases and an ROE of 9.10% based on a 50% equity ratio, continued UI's existing earnings sharing mechanism (ESM) pursuant to which UI and its customers share on a 50/50 basis all distribution earnings above the allowed ROE in a calendar year, continued the existing decoupling mechanism, and approved the continuation of a requested storm reserve. Any dollars due to customers from the ESM continue to be first applied against any storm regulatory asset balance (if one exists at that time) or refunded to customers through a bill credit if such storm regulatory asset balance does not exist.

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 2018, 70% of its standard service load for the second half of 2018, and 20% of its standard service load for the first half of 2019. 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 such an event had occurred as of December 31, 2017, UI would have had to post an aggregate of approximately $15.8 million in collateral.

New Renewable Source Generation

Under Connecticut law Public Act 11-80, or 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 approximately 21 years. The obligations will phase in over a six-year solicitation period, and are expected to peak at an annual commitment level of about $13.6 million per year after all selected projects are online. Upon purchase, UI accounts for the RECs as inventory. UI expects to partially mitigate the cost of these contracts through the resale of the RECs. PA 11-80 provides that the remaining costs (and any benefits) of these contracts, including any gain or loss resulting from the resale of the RECs, are fully recoverable from (or credited to) customers through electric rates.

On October 23, 2013, PURA approved UI's renewable connections program filed in accordance with PA 11-80, pursuant to which UI has developed 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 The Connecticut Light and Power Company, or 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. The cost of this program, a 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, all of which are now operational, was $41.5 million.

Pursuant to Connecticut statute, in January 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.

On May 25, 2017, UI entered into six 20-year power purchase agreements, or PPAs, totaling approximately 32 MW with developers of wind and solar generation. These PPAs originated from a three-state Clean Energy RFP, and were entered into pursuant Connecticut Public Act (PA) 13-303 which provides that the net costs of the PPAs are recoverable through electric rates. The PPAs were approved by PURA on September 13, 2017.

On June 20, 2017, UI entered into twenty-two 20-year PPAs totaling approximately 72 MW with developers of wind and solar generation. These PPAs originated from RFP issued by the Connecticut Department of Energy and Environmental Protection, or DEEP, under PA 15-107 1(b) which provides that the net costs of the PPAs are recoverable through electric rates. The PPAs were approved by PURA on September 7, 2017. One contract was terminated on October 24, 2017, resulting in UI having twenty-one remaining contracts from this solicitation totaling approximately 70 MW.

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 2017, UI's overall allowed weighted-average ROE for its transmission business was 11.32%.

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 settlement discussions are underway. UI is unable to predict the outcome of this proceeding at this time.

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, MEPCO 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 transmission return. In June 2015 the NETOs and complainants both filed an appeal in the U.S. Court of Appeals for the District of Columbia of the FERC's final order. On April 14, 2017, the Court of Appeals (the Court) vacated FERC's decision on Complaint I and remanded it to FERC. The Court held that FERC, as directed by statute, did not determine first that the existing ROE was unjust and unreasonable before determining a new ROE. The Court ruled that FERC should have first determined that the then existing 11.14% base ROE was unjust and unreasonable before selecting the 10.57% as the new base ROE. The Court also found that FERC did not provide reasoned judgment as to why 10.57%, the point ROE at the midpoint of the upper end of the zone of reasonableness, is a just and reasonable ROE. Instead, FERC had only explained in its order that the midpoint of 9.39% was not just and reasonable and a higher base ROE was warranted. On June 5, 2017, the NETOs made a filing with FERC seeking to reinstate transmission rates to the status quo ante (effect of the Court vacating order is to return the parties to the rates in effect prior to FERC Final decision) as of June 8, 2017, the date the Court decision became effective. In that filing, the NETOs stated that they will not begin billing at the higher rates until 60 days after FERC has a quorum of commissioners. On October 6, 2017, FERC issued an order rejecting the NETOs request to collect transmission revenue requirements at the higher ROE of 11.14%, pending FERC order on remand. In reaching this decision, FERC stated that it has broad remedial authority to make whatever ROE it eventually determines to be just and reasonable effective for the Complaint I refund period and prospectively from October 2014, the effective date of the Complaint I Order. Therefore FERC reasoned that the NETOs will not be harmed financially by not immediately returning to their pre-Complaint I ROE. We anticipate FERC to address the Court decision during 2018. We cannot predict the outcome of action by FERC.

On December 26, 2012, a second, ROE complaint (Complaint II) for a subsequent rate period was filed requesting the then effective ROE of 11.14% 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 then effective ROE of 11.14% 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 relating to the refund periods and going forward period were held in June 2015 on Complaints II and III before a FERC Administrative Law Judge. 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 2018.

UI reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 final decision in Complaint I. Refunds were provided to customers for Complaint I. The total reserve associated with Complaints II and III is $4.4 million as of December 31, 2017, which has not changed since 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 then existing base ROE of 10.57% be reduced to 8.61% and the ROE Cap be set at 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. In April 2017, the NETOs filed for a stay in the hearings pending FERC on the Court order described above. That request was denied by the Administrative Law Judge. On November 21, 2017, the parties submitted updates to their ROE analyses and recommendations just prior to hearings with the NETOs continuing to advocate that the existing base ROE of 10.57% should remain in effect. Hearings were held in December 2017 with an expected Initial Decision from the Administrative Law Judge in March 2018. 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.
On October 5, 2017, the NETOs filed a Motion for Dismissal of Pancaked Return on Equity Complaints in light of the decision by the Court in April 2017 that became effective on June 8, 2017. The NETOs assert that all four complaints should be dismissed because the complainants have not shown that the existing ROE of 11.14% is unjust and unreasonable as the Court decision requires. In addition, the NETOs assert that Complaints II, III and IV should also be dismissed because the Court decision implicitly found that FERC’s acceptance of Pancaked FPA Section 206 complaints was statutorily improper as Congress intended that the 15-month refund period under Section 206 applies whenever FERC does not complete its review of a complaint within the 15-month period. In the event FERC chooses not to dismiss the complaints, the NETOs request that FERC consolidate the complaints for decision as the evidentiary records are either closed or advanced enough for FERC to address the requirements of the Court decision and expeditiously issue a final order. FERC has not yet ruled on this Motion. UI cannot predict the outcome of action by FERC.

Equity Investment in Peaking Generation

UI is party to a 50-50 joint venture with NRG Yield Operating LLC 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, 2018 through December 31, 2018 of $28.8 million and $35.8 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 2018 approved revenue requirements.

(D) SHORT-TERM CREDIT ARRANGEMENTS

UI 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 UI 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. UI has a lending/borrowing limit of $100 million under this agreement. There was $24.4 million outstanding as of December 31, 2017 under this agreement. There was no balance outstanding as of December 31, 2016 under this agreement.

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 $44.5 million outstanding under this agreement as of December 31, 2017. There was $16.5 million outstanding under this agreement as of December 31, 2016.

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, 2017, UI had $100 million of outstanding borrowings under the Avangrid Credit Facility. As of December 31, 2016, UI did not have any outstanding borrowings under the Avangrid Credit Facility.

(E) INCOME TAXES

	2017	2016
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ 25,557	$ 486
State	4,602	6,184
Total current	30,159	6,670
Deferred		
Federal	32,804	39,590
State	1,679	(4,909)
Total deferred	34,483	34,681
Investment tax credits	(706)	(532)
Total income tax expense	$ 63,936	$ 40,819

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:

	2017	2016
	(In Thousands)	
Book income before income taxes	$ 169,119	$ 125,174
Computed tax at federal statutory rate	$ 59,192	$ 43,811
Increases (reductions) resulting from:		
Plant Flow- thru differences	(1,194)	(2,365)
State income taxes, net of federal income tax benefits	4,083	829
2017 Tax Act deferred tax remeasurement	4,336	-
ITC taken into income	(706)	(532)
Other items, net	(1,775)	(924)
Total income tax expense	$ 63,936	$ 40,819
Effective income tax rates	37.8%	32.6%

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. UI is 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, 2017 and 2016, UI did 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, 2017:

Jurisdiction	*Tax years*
Federal	2014 - 2017
Connecticut	2014 - 2017

The following table summarizes UI's deferred income tax assets and liabilities as of December 31, 2017 and 2016.

	2017	2016
	(In Thousands)	
Deferred income taxes:		
Property related	$ (338,812)	$ (545,421)
Unfunded future income taxes	(45,333)	(77,899)
Federal and state tax credits	3,891	1,690
Investment tax credit carryforward	11,198	11,198
Investment in GenConn	(33,066)	(52,758)
Post-retirement benefits	5,854	7,965
Merger settlement agreement	8,800	15,115
2017 Tax Act remeasurement (gross up)	82,627	-
Other	(685)	24,194
	$ (305,526)	$ (615,916)
Less Regulatory Assets (Liabilities)	(17,762)	(171,757)
Total deferred income tax assets (liabilities), net	$ (287,764)	$ (444,159)

As of December 31, 2017, UI had $2.2 million of state tax credit carryforwards. As of December 31, 2016 UI had $4.2 million of state tax credit carryforwards.

(F) PENSION AND OTHER BENEFITS

Defined Benefit Plans (the Plans)

Pension Plans

The UI pension 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 plans 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 NEPC, LLC as the investment advisor 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.

Networks' asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. Management has 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, there are established 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 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, 2017 and 2016. Plan assets and obligations have been measured as of December 31, 2017 and 2016.

	Pension Benefits		Other Post-Retirement Benefits	
	2017	2016	2017	2016
Change in Benefit Obligation:		(In Thousands)		
Benefit obligation at beginning of year	$ 569,553	$ 492,821	$ 65,519	$ 65,990
Service cost	5,750	6,311	941	1,026
Interest cost	23,414	22,873	2,700	3,148
Participant contributions	-	-	650	621
Actuarial (gain) loss	31,887	78,924	(3,882)	(2,643)
Benefits paid (including expenses)	(33,138)	(31,376)	(2,778)	(2,623)
Benefit obligation at end of year	$ 597,466	$ 569,553	$ 63,150	$ 65,519
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 348,244	$ 339,185	$ 24,583	$ 23,503
Actual return on plan assets	52,772	25,406	3,385	2,561
Employer contributions	11,334	15,029	-	-
Participant contributions	-	-	650	621
Benefits paid (including expenses)	(33,138)	(31,376)	(1,500)	(2,102)
Fair value of plan assets at end of year	$ 379,212	$ 348,244	$ 27,118	$ 24,583
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 218,254	$ 221,309	$ 36,032	$ 40,936
Amounts Recognized in the Balance Sheet consist of:				
Non-current liabilities	$ 218,254	$ 221,309	$ 36,032	$ 40,936
Amounts Recognized as a Regulatory Asset consist of:				
Prior service cost	(4)	(10)	(8,741)	(10,278)
Net (gain) loss	215,735	236,676	(5,725)	104
Total recognized as a regulatory asset	$ 215,731	$ 236,666	$(14,466)	$ (10,174)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 597,466	$ 569,553	N/A	N/A
Accumulated benefit obligation	$ 540,676	$ 518,934	N/A	N/A
Fair value of plan assets	$ 379,212	$ 348,244	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	3.80%	4.24%	N/A	N/A
Discount rate (Non-Qualified Plans)	3.80%	4.24%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	3.80%	4.24%
Average wage increase	3.80%	3.80%	N/A	N/A
Health care trend rate (current year - pre/post-65)	N/A	N/A	7.50%/5.7	6.75%/6.00%
Health care trend rate (2030/2025 - pre/post-65)	N/A	N/A	4.50%/4.5	4.50%/4.50%

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, 2017 and 2016 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	
	2017	2016	2017	2016
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 5,750	$ 6,311	$ 941	$ 1,026
Interest cost	23,414	22,873	2,700	3,148
Expected return on plan assets	(25,163)	(25,742)	(1,451)	(1,673)
Amortization of prior service costs	(5)	(5)	(1,538)	(1,527)
Amortization of actuarial (gain) loss	25,219	23,627	14	1,633
Net periodic benefit cost	$ 29,215	$ 27,064	$ 666	$ 2,607
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ 4,278	$ 79,258	$ (5,815)	$ (3,531)
Amortization of prior service costs	5	5	1,537	1,527
Amortization of actuarial (gain) loss	(25,219)	(23,627)	(14)	(1,633)
Total recognized as regulatory asset (liability)	$ (20,936)	$ 55,636	$ (4,292)	$ (3,637)
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ 8,279	$ 82,700	$ (3,626)	$ (1,030)
Estimated Amortizations from Regulatory Assets into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of prior service cost	(4)	(5)	(1,537)	(1,538)
Amortization of net (gain) loss	23,903	25,218	(744)	14
Total estimated amortizations	$ 23,899	$ 25,213	$ (2,281)	$ (1,524)
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.24%	4.24%	4.24%	4.24%
Average wage increase	3.80%	3.80%	N/A	N/A
Return on plan assets	7.50%	7.75%	6.25%	7.75%
Health care trend rate (current year - pre/post-65)	N/A	N/A	6.75%/6.00%	7.00%/9.00%
Health care trend rate (2026/2024 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

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	
Aggregate service and interest cost components	$	346	$	(284)
Accumulated post-retirement benefit obligation	$	5,560	$	(4,611)

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 $15.1 million in 2018. 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)			
2018	$	45,855	$	3,618
2019	$	33,022	$	3,670
2020	$	33,400	$	3,761
2021	$	34,052	$	3,766
2022	$	34,917	$	3,752
2023-2027	$	178,091	$	19,643

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 2017 and 2016 was $5.1 million and $4.8 million, respectively.

(G) RELATED PARTY TRANSACTIONS

During the years ended December 31, 2017 and 2016, UI received cash distributions from GenConn. See Note (A) Business Organization and Statement of Accounting Policies – Equity Investments.

A Director of Avangrid, Inc. 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, 2017 and 2016 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, 2017, UI recorded inter-company expenses of $55.9 million which consisted primarily of operation and maintenance expenses. Costs of the services that are allocated amongst UI and other of UIL Holdings' regulated subsidiaries are settled periodically by way of inter-company billings and wire transfers and are included in Accounts receivable from affiliates and Accounts payable to affiliates in the accompanying balance sheets.

Dividends/Capital Contributions

In 2017 and 2016, 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, 2017, UI accrued dividends to UIL Holdings of $125 million. For the year ended December 31, 2016, UI did not accrue dividends to UIL Holdings.

(H) LEASE OBLIGATIONS

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

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

	(In Thousands)
Year	UI
2018	$ 2,653
2019	2,248
2020	2,211
2021	2,166
2022	1,972
2022-after	68,336
	$ 79,586

Rental payments charged to operating expenses in 2017 and 2016 totaled $5.3 million and $3.2 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, 2017. 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 resolutions of other proceedings before the 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 Power and Asnat filed a subsequent lawsuit in Connecticut state court seeking among other things: (i) remediation of the English Station site; (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 for July 6, 2017. On July 5, 2017, Asnat filed a pretrial memorandum claiming damages of $10 million for “environmental remediation activities” and lost use of the property. In December 2017 Plaintiffs filed a Request for Leave to Amend Complaint and Motion to Cite-In Additional Parties, including former UIL officers and employees and other UI officers, which motion was approved in February 2018. UI cannot predict the outcome of this matter.

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. Status reports are periodically filed with the DEEP.

On August 4, 2016, DEEP issued a partial consent order (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 will remit to the State of Connecticut the difference between such cost and $30 million to be used for a public purpose as determined in the discretion of the Governor of the State of Connecticut, the Attorney General of the State of Connecticut, and the Commissioner of DEEP. 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. 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.

As of December 31, 2017 UI reserved $25 million for this matter. UI cannot predict the outcome of this matter.

Other

With respect to transmission-related property adjacent to the New Haven Harbor Generating Station, UI performed an environmental analysis that indicated remaining remediation expenses would be approximately $2.7 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 UNITED ILLUMINATING COMPANY

NOTES TO FINANCIAL STATEMENTS

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, 2017 and December 31, 2016:

	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, 2017		(In Thousands)		
Assets:				
Derivative assets	$ -	$ -	11,647	$ 11,647
Supplemental retirement benefit trust life insurance policies	-	10,416	-	10,416
	-	10,416	11,647	22,063
Liabilities:				
Derivative liabilities	-	-	79,093	79,093
	-	-	79,093	79,093
Net fair value assets/(liabilities), December 31, 2017	$ -	$ 10,416	$ (67,446)	$ (57,030)
December 31, 2016				
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)

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, 2017 or December 31, 2016 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, 2017	Range at December 31, 2016
Contracts for differences	Risk of non-performance	0.11% - 0.49%	0.68% - 0.81%
	Discount rate	1.89% - 2.40%	1.47% - 2.45%
	Forward pricing ($ per MW)	$5.30 - $9.55	$3.15 - $9.55

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 UNITED ILLUMINATING COMPANY

NOTES TO FINANCIAL STATEMENTS

The determination of the fair value of the supplemental retirement benefit trust life insurance policies was based on quoted prices as of December 31, 2017 and December 31, 2016 in the active markets for the various funds within which the assets are held.

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, 2017 and 2016.

	Year Ended December 31, 2017 (In Thousands)
Net derivative assets/(liabilities), December 31, 2016	$ (75,284)
Unrealized gains and (losses), net	7,838
Net derivative assets/(liabilities), December 31, 2017	$ (67,446)
Change in unrealized gains (losses), net relating to net derivative	$ 7,838

	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)

The following tables set forth the fair values of UI's pension and OPEB assets as of December 31, 2017 and 2016.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2017		(In Thousands)		
Pension assets				
Mutual funds	$ -	$ 379,212	$ -	$ 379,212
OPEB assets				
Mutual funds	27,118	-	-	27,118
Fair value of plan assets, December 31, 2017	$ 27,118	$ 379,212	$ -	$ 406,330
December 31, 2016				
Pension assets				
Mutual funds	$ -	$ 348,244	$ -	$ 348,244
OPEB assets				
Mutual funds	24,583	-	-	24,583
Fair value of plan assets, December 31, 2016	$ 24,583	$ 348,244	$ -	$ 372,827

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, 2017 AND 2016

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KPMG

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

The Board of Directors
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, 2017, 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 accordance 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 from material misstatement, whether due to fraud or error.

Auditors' 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 of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' 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 opinion.

Opinion

In our opinion, the 2017 financial statements referred to above present fairly, in all material respects, the financial position of the Connecticut Natural Gas Corporation as of December 31, 2017, and the results of its operations and its cash flows for the year then ended in accordance with U.S. generally accepted accounting principles.

Other Matter

The accompanying financial statements of the Connecticut Natural Gas Corporation as of December 31, 2016 and for the year then ended were audited by other auditors whose report thereon dated April 7, 2017, expressed an unmodified opinion on those financial statements.

KPMG LLP

New York, New York
April 13, 2018

CONNECTICUT NATURAL GAS CORPORATION
STATEMENT OF INCOME
(In Thousands)

	Year Ended December 31, 2017	Year Ended December 31, 2016
Operating Revenues	$ 364,314	$ 322,838
Operating Expenses		
Natural gas purchased	173,312	140,830
Operation and maintenance	103,209	83,698
Depreciation and amortization	33,369	31,634
Taxes other than income taxes	26,271	23,984
Total Operating Expenses	336,161	280,146
Operating Income	28,153	42,692
Other Income and (Expense), net		
Other income	1,008	1,663
Other (expense)	(638)	(586)
Total Other Income and (Expense), net	370	1,077
Interest Expense, net	6,964	9,346
Income Before Income Tax	21,559	34,423
Income Tax	6,517	11,550
Net Income	15,042	22,873
Less: Preferred Stock Dividends of Subsidiary, Noncontrolling Interests	34	27
Net Income attributable to Connecticut Natural Gas Corporation	$ 15,008	$ 22,846

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

	Year Ended December 31, 2017	Year Ended December 31, 2016
Net Income	$ 15,042	$ 22,873
Other Comprehensive Income, net of income tax		
Changes in unrealized gains(losses) related to pension and other post-retirement benefit plans	-	(128)
Total Other Comprehensive Income, net of income tax	15,042	22,745
Comprehensive Income		
Less: Preferred Stock Dividends of Subsidiary, Noncontrolling Interests	34	27
Comprehensive Income	$ 15,008	$ 22,718

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, 2017	Year Ended December 31, 2016
Cash Flows From Operating Activities		
Net Income	$ 15,042	$ 22,873
Adjustments to reconcile net income		
to net cash provided by operating activities:		
Depreciation and amortization	33,446	32,063
Deferred income taxes	6,592	6,081
Uncollectible expense	9,187	4,839
Pension expense	6,528	5,449
Regulatory assets/liabilities amortization	1,864	2,198
Regulatory assets/liabiities carrying cost	365	306
Other non-cash items, net	(203)	(1,171)
Changes in:		
Accounts receivable and unbilled revenues, net	(14,122)	(19,180)
Natural gas in storage	(631)	6,089
Accounts payable and accrued liabilities	4,948	15,114
Interest accrued	(643)	(159)
Taxes accrued/refundable, net	(1,505)	1,417
Accrued pension and other post-retirement	(3,345)	(4,865)
Regulatory assets/liabilities	(16,384)	(15,960)
Other assets	142	(531)
Other liabilities	830	(141)
Total Adjustments	27,069	31,549
Net Cash provided by Operating Activities	42,111	54,422
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(70,387)	(65,091)
Net Cash used in Investing Activities	(70,387)	(65,091)
Cash Flows from Financing Activities		
Payment of common stock dividend	(19,000)	-
Payment of long-term debt	(20,000)	(10,000)
Payment of preferred stock dividend	(34)	(27)
Notes payable to affiliates	67,262	18,775
Other	-	(200)
Net Cash provided by Financing Activities	28,228	8,548
Unrestricted Cash and Temporary Cash Investments:		
Net change for the period	(48)	(2,121)
Balance at beginning of period	714	2,835
Balance at end of period	$ 666	$ 714
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 6,937	$ 8,670
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 7,014	$ 8,670

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

BALANCE SHEET
December 31, 2017 and 2016

ASSETS
(In Thousands)

	2017	2016
Assets		
Current Assets		
Unrestricted cash and temporary cash investments	$ 666	$ 714
Accounts receivable and unbilled revenues, net	85,964	80,502
Accounts receivable from affiliates	1,441	1,547
Regulatory assets	19,143	14,461
Gas in storage	23,379	22,748
Materials and supplies	1,887	1,663
Prepayments and other current assets	1,138	1,503
Total Current Assets	133,618	123,138
Other Investments	1,158	1,375
Property, Plant and Equipment, at cost	892,596	857,533
Less accumulated depreciation	293,532	280,731
Net Property, Plant and Equipment in Service	599,064	576,802
Construction work in progress	48,422	23,348
Total Property, Plant and Equipment	647,486	600,150
Regulatory Assets	116,875	138,460
Deferred Income Taxes Regulatory	24,588	21,749
Deferred Charges and Other Assets		
Goodwill	79,341	79,341
Other	130	170
Total Deferred Charges and Other Assets	79,471	79,511
Total Assets	$ 1,003,196	$ 964,383

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

CONNECTICUT NATURAL GAS CORPORATION
BALANCE SHEET
December 31, 2017 and 2016

LIABILITIES AND CAPITALIZATION
(In Thousands)

	2017	2016
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 89,262	$ 22,000
Current portion of long-term debt	-	20,310
Accounts payable and accrued liabilities	65,011	62,476
Accounts payable to affiliates	10,353	11,349
Other current liabilities	4,098	3,666
Regulatory liabilities	2,880	11,471
Interest accrued	1,262	1,905
Taxes accrued	8,062	9,567
Total Current Liabilities	180,928	142,744
Deferred Income Taxes	25,547	40,474
Regulatory Liabilities	224,457	195,993
Other Noncurrent Liabilities		
Pension and other post-retirement	90,761	99,933
Asset retirement obligations	6,683	6,716
Other	1,499	1,257
Total Other Noncurrent Liabilities	98,943	107,906
Capitalization		
Long-term debt, net of unamortized premium	109,290	109,243
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	15,181	19,173
Accumulated other comprehensive income	(27)	(27)
Net Common Stock Equity	363,691	367,683
Total Capitalization	473,321	477,266
Total Liabilities and Capitalization	$ 1,003,196	$ 964,383

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, 2017 and 2016
(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, 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
Net income				15,042		15,042
Payment of commom stock dividend				(19,000)		(19,000)
Payment of preferred stock dividend				(34)		(34)
Balance as of December 31, 2017	10,634,436	$ 33,233	$ 315,304	$ 15,181	$ (27)	$ 363,691

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 177,000 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. UIL Holdings, whose primary business is ownership of its operating regulated utility businesses, is a wholly owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc., which is a 81.5% owned subsidiary of Iberdrola, S.A., a corporation organized under the law of the Kingdom of Spain.

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 reported in the Financial Statements 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. The following table summarizes the impact to the prior period Statement of Income, Statement of Cash Flows and Balance Sheet of these reclassifications.

December 31, 2016 (in thousands)	As previously filed	Reclassifications	As currently reported
Statement of Income			
Interest on long-term debt	8,741	(8,741)	-
Other interest, net	176	(176)	-
Amortization of debt expense and redemption premiums	429	(429)	-
Interest Expense, net	-	9,346	9,346
Statement of Cash Flows			
Changes in:			
Accounts receivable and unbilled revenue, net	(11,557)	(7,623)	(19,180)
Unbilled revenues	(7,623)	7,623	-
Prepayments	(340)	340	-
Accounts payable and accrued liabilities	14,320	794	15,114
Accrued liabilities	794	(794)	-
Pension and other post-retirement	(3,900)	(965)	(4,865)
Accrued other post-employment benefits	(965)	965	-
Prepayments and other current assets	(191)	(340)	(531)
Cash Flow from Financing Activities			
Payment of preferred stock dividend	-	(27)	(27)
Other	(227)	27	(200)
Balance Sheet			
Assets			
Current Assets			
Accounts receivable and unbilled revenues, net	57,522	22,980	80,502
Unbilled revenues	24,527	(24,527)	-
Accounts receivable from affiliates	-	1,547	1,547
Prepayments and other current assets	1,303	200	1,503
Other	200	(200)	-
Regulatory assets	160,209	(21,749)	138,460
Deferred income taxes regulatory	-	21,749	21,749
Liabilities			
Current Liabilities			
Notes payable to affiliates / Intercompany payable	26,775	(4,775)	22,000
Accounts payable and accrued liabilities	60,140	2,336	62,476
Accounts payable to affiliate	-	11,349	11,349
Accrued liabilities	13,106	(13,106)	-
Other current liabilities	-	3,666	3,666
Taxes accrued	9,037	530	9,567
Other Noncurrent Liabilities			
Pension	88,376	11,557	99,933
Other post-retirement benefits accrued	12,689	(12,689)	-
Asset retirement obligation	-	6,716	6,716
Other	6,841	(5,584)	1,257

CNG has evaluated subsequent events through the date its financial statements were available to be issued, April 13, 2018.

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. CNG recognizes revenues upon delivery of natural gas to its customers. In addition, CNG accrues revenue pursuant to the various regulatory provisions to record regulatory assets for revenues that will be collected in the future.

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 refunded in the future through the ratemaking process. CNG is allowed to recover all such deferred costs and is required to refund such obligations to customers through its regulated rates. See Note (C) "Regulatory Proceedings", for a discussion of the recovery of certain deferred costs and the refund of certain obligations, as well as a discussion of the regulatory decisions that provide for such recovery and require such refunding.

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.

CONNECTICUT NATURAL GAS CORPORATION

NOTES TO FINANCIAL STATEMENTS

Unless otherwise stated below, all of CNG's regulatory assets earn a return. CNG's regulatory assets and liabilities as of December 31, 2017 and 2016 included the following:

	Remaining Period	December 31, 2017	December 31, 2016
		(In Thousands)	
Regulatory Assets:			
Pension and other post-retirement benefit plans	(a)	$ 108,979	$ 123,781
Hardship programs	(b)	10,977	8,264
Debt premium	18 to 20 years	-	246
Unfunded future income taxes	(c)	-	11,987
Deferred income taxes regulatory	(c)	24,588	21,749
Deferred purchased gas	(f)	10,171	4,641
Other	(d)	5,891	4,002
Total regulatory assets		160,606	174,670
Less current portion of regulatory assets		19,143	14,461
Regulatory Assets, Net		$ 141,463	$ 160,209
Regulatory Liabilities:			
Pension and other post-retirement benefit plans	(a)	$ 5,855	$ 4,217
Asset removal costs	(d)	176,113	164,776
Asset retirement obligation	(e)	8,553	8,176
Rate credits	1 to 10 years	12,500	12,500
Unfunded future income taxes	(c)	829	-
Tax reform remeasurement	(h)	13,707	-
Non-firm margin sharing credits	10 years	5,459	6,829
Decoupling	(g)	3,843	7,625
Other	(d)	478	3,341
Total regulatory liabilities		227,337	207,464
Less current portion of regulatory liabilities		2,880	11,471
Regulatory Liabilities, Net		$ 224,457	$ 195,993

(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.
(h) Impact of deferred tax remeasurement as a consequence of the Tax Cuts and Jobs Act of 2017 enacted by the U.S. federal government on December 22, 2017. Refundable period will be determined in future rate proceedings.

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 2017 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.

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, 2017 and 2016 were comprised as follows:

	2017	2016
	(In Thousands)	
Gas distribution plant	$ 803,863	$ 768,706
Software	3,093	4,361
Land	1,618	1,618
Building and improvements	31,044	29,803
Other plant	52,978	53,045
Total property, plant & equipment	892,596	857,533
Less accumulated depreciation	293,532	280,731
	599,064	576,802
Construction work in progress	48,422	23,348
Net property, plant & equipment	$ 647,486	$ 600,150

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 2017 and 2016 were 1.33% and 8.10%, respectively. The portion of the allowance applicable to equity funds was immaterial for 2017 and $0.8 million for 2016.

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 both 2017 and 2016 were approximately 3.8% of the original cost of depreciable property.

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, 2017, CNG did not have any assets that were impaired under this standard.

Unrestricted cash and temporary cash investments

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

Accounts receivable and unbilled revenues

Accounts receivable at December 31, 2017 and 2016 include unbilled revenues of $31.1 million and $24.5 million, respectively and are shown net of an allowance for doubtful accounts of $1.3 million and $1.7 million for 2017 and 2016, respectively. Accounts receivable do not bear interest, although late fees may be assessed.

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**.** Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for doubtful accounts is management's best estimate of the amount of probable credit losses in the existing accounts receivable, determined based on experience. Each month, CNG reviews the allowance for doubtful accounts and past due accounts by age. When management believes that a receivable will not be recovered, the account balance is charged off 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

Gas in storage

Natural gas in storage 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. CNG continuously monitors the weighted-average cost of gas value to ensure it remains at, or below market value.

Materials and supplies

Materials and supplies inventories are used for construction of new facilities and repairs of existing facilities. The inventories are carried and withdrawn at lower of cost and net realizable value

Other Investments

The CNG's other investments consist of noncurrent investments available for sale.

Accrued removal obligations

CNG meets the requirements concerning accounting for regulated operations, and recognizes a regulatory liability, for the difference between removal costs collected in rates and actual costs incurred. CNG classifies those amounts as accrued removal obligations.

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 2017 and 2016 is as follows:

	2017	2016
	(In Thousands)	
Balance as of January 1	$ 6,716	$ 6,737
Liabilities settled during the year	(386)	(375)
Accretion	353	354
Balance as of December 31	$ 6,683	$ 6,716

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”.

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, 2017 and 2016.

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.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. PURA has instituted proceedings in Connecticut to review and address the implications associated with the Tax Act on the utilities providing service in the state. CNG expects the regulators in Connecticut to issue requirements in 2018 regarding how all tax benefits associated with the Tax Act will be returned to customers.

New Accounting Standards

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC), Topic 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. ASC 606 was further amended through various updates the FASB issued thereafter. 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 amended effective date is for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption permitted as of the original effective date of annual reporting periods beginning after December 15, 2016. Entities may apply the standard 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). CNG will adopt the new standard effective January 1, 2018, and apply the modified retrospective method. Based on management's assessment to existing contracts and revenue streams, CNG does not expect to record any material cumulative adjustments to retained earnings and does not expect ASC 606 to have a material impact on the amount and timing of its revenue recognition. Management has identified other changes primarily related to the presentation and disclosure of revenues. Management plans to disaggregate revenues not accounted for in scope of the new standard, as required, including alternative revenue programs.

In February 2016, the FASB issued Accounting Standards Update (ASU) 2016-02 "Leases" 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 FASB issued an update in January 2018 to clarify the application of the new leases guidance to land easements and provide relief concerning adoption efforts for existing land easements that are not accounted for as leases under the current leases guidance. The updated guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early application is permitted. CNG is currently reviewing our contracts and is 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 its financial statements. CNG does not expect the adoption of the new guidance will materially affect its financial position through the recording of operating leases on the balance sheet as a right-of-use asset.

In March 2017, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2017-07 "Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost". The ASU contains amendments that require an entity to present service cost separately from the other components of net benefit cost, and to report the service cost component in the income statement line item(s) where it reports the corresponding compensation cost. An entity is to present all other components of net benefit cost outside of operating cost, if it presents that subtotal. The amendments also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of a self-constructed asset). The amendments are effective for annual and interim periods in fiscal years beginning after December 15, 2017, with early adoption permitted. CNG does not plan to early adopt. An entity is required to apply the amendments retrospectively for the presentation of the service cost component and the other components of net periodic pension cost and net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension cost and net periodic postretirement benefit in assets. A practical expedient allows an entity to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in the notes to financial statements for pension and postretirement benefit plans for those periods. CNG does not expect the adoption of the amendments will materially affect its results of operations, financial position, cash flows, and disclosures.

In February 2018 the FASB issued ASU 2018-02 "Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" which contains amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017 by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within accumulated other comprehensive income (AOCI) (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. The amendments are effective for all entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted. An entity has the option to apply the amendments either in the period of adoption or retrospectively to each period (or periods) in which it recognizes the effect of the change in the U.S. federal corporate income tax rate in the Tax Act. An entity is required to disclose its accounting policy election, including its policy for reclassifying material stranded tax effects in AOCI to earnings (specific identification or portfolio method). CNG does not expect the adoption of the amendments will materially affect our results of operations, financial position, cash flows, and disclosures.

B) CAPITALIZATION

Common Stock

CNG had 10,634,436 shares of its common stock, $3.125 par value, outstanding as of December 31, 2017 and 2016.

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, 2017, there were 108,706 shares issued and outstanding with a value of approximately $0.3 million.

Long-Term Debt

As of December 31, (In Thousands)	Maturity Dates	2017 Balances	2017 Interest Rates	2016 Balances	2016 Interest Rates
Senior unsecured debt	2028-2043	$ 110,000	4.30%-6.66%	$ 130,000	4.30%-9.10%
Unamortized debt (costs) premium, net		(710)		(447)	
Total Debt		**109,290**		**129,553**	
Less: debt due within one year, included in current liabilities		-		20,310	
Total Non-current Debt		**$ 109,290**		**$ 109,243**	

The estimated fair value of debt amounted to $137.7 million and $151.7 million as of December 31 2017 and 2016, 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 natural gas 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. 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:

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

Under various debt agreements, CNG is required to maintain a ratio of consolidated debt to consolidated capital of not greater than 65% (debt ratio). As of December 31, 2017, CNG's debt ratio was 35%.

(C) REGULATORY PROCEEDINGS

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.

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, 2017 are as follows:

	(In Thousands)
2018	$ 78,317
2019	66,986
2020	57,750
2021	51,013
2022	46,743
2023-after	295,282
	$ 596,091

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

CNG 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 CNG 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. CNG has a lending/borrowing limit of $100 million under this agreement. There was $27.7 million outstanding as of December 31, 2017 under this agreement. There was no balance outstanding as of December 31, 2016 under this agreement.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $250 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There was $61.6 million outstanding under this agreement as of December 31, 2017 and there was $22.0 million outstanding under this agreement as of December 31, 2016.

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, 2017 and 2016, CNG did not have any outstanding borrowings under the Avangrid Credit Facility.

(E) INCOME TAXES

	Year Ended December 31, 2017	Year Ended December 31, 2016
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ (539)	$ 2,099
State	464	3,370
Total current	(75)	5,469
Deferred		
Federal	9,274	9,883
State	(2,682)	(3,802)
Total deferred	6,592	6,081
Total income tax expense	$ 6,517	$ 11,550

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, 2017	Year Ended December 31, 2016
	(In Thousands)	
Book income before income taxes	$ 21,559	$ 34,423
Computed tax at federal statutory rate	$ 7,546	$ 12,048
Increases (reductions) resulting from:		
Deferred tax adjustment for prior years	(346)	-
2017 Tax Act deferred tax remeasurement	510	-
State income taxes, net of federal income tax	(1,442)	(281)
Other items, net	249	(217)
Total income tax expense	$ 6,517	$ 11,550
Effective income tax rates	30.2%	33.6%

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. CNG is 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, 2017:

Jurisdiction	*Tax years*
Federal	2013 - 2017
Connecticut	2013 - 2017

The following table summarizes CNG's deferred tax assets and liabilities as of December 31, 2017 and 2016:

	2017	2016
	(In Thousands)	
CT credit carryforward	$ 2,558	$ 3,742
Deferred tax liability on 2017 Tax Act remeasurement	4,062	-
Property related	(5,285)	(4,416)
Unfunded future income taxes	(148)	-
Goodwill	(3,382)	(4,283)
Pension (net)	(2,898)	(7,749)
Other assets (liabilities)	4,134	(6,019)
	$ (959)	$ (18,725)
Less Regulatory Assets (Liabilities)	24,588	21,749
Total deferred income tax assets (liabilities), net	$ (25,547)	$ (40,474)

As of December 31, 2017 and 2016, CNG had state tax credit carry forwards of $2.6 million and $3.7 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. The plans are closed to new employees hired on or after specified dates.

Employees not participating in a defined benefit plan are eligible for enhanced benefits in the 401(k) plans.

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 NEPC, LLC as investment advisor 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.

Networks' asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. Management has 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, there are established 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 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, 2017 and 2016. Plan assets and obligations have been measured as of December 31, 2017 and 2016.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2017	Year Ended December 31, 2016	Year Ended December 31, 2017	Year Ended December 31, 2016
Change in Benefit Obligation:		(In Thousands)		
Benefit obligation at beginning of year	$ 270,969	$ 237,975	$ 22,676	$ 21,779
Service cost	4,441	4,074	228	224
Interest cost	11,256	11,212	922	971
Participant contributions	-	-	715	1,496
Actuarial (gain) loss	6,792	33,560	(687)	742
Benefits paid (including expenses)	(11,603)	(15,852)	(2,848)	(2,536)
Benefit obligation at end of year	$ 281,855	$ 270,969	$ 21,006	$ 22,676
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 182,593	$ 181,608	$ 10,331	$ 9,718
Actual return on plan assets	27,355	12,895	691	631
Employer contributions	1,551	3,942	-	-
Participant contributions	-	-	715	1,496
Benefits paid (including expenses)	(11,603)	(15,852)	(728)	(1,514)
Fair value of plan assets at end of year	$ 199,896	$ 182,593	$ 11,009	$ 10,331
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 81,959	$ 88,376	$ 9,997	$ 12,345
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 81,959	$ 88,376	$ 9,997	$ 12,345
Amounts Recognized as a Regulatory Asset (Liability)				
Prior service cost	$ 20	$ 42	$ 812	$ 1,059
Net (gain) loss	37,162	47,845	(2,331)	(1,674)
Total recognized as a regulatory asset (liability)	$ 37,182	$ 47,887	$ (1,519)	$ (615)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 281,855	$ 270,969	N/A	N/A
Accumulated benefit obligation	$ 253,715	$ 240,160	N/A	N/A
Fair value of plan assets	$ 199,896	$ 182,593	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	3.80%	4.24%	N/A	N/A
Discount rate (Non-Qualified Plans)	3.80%	4.24%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	3.80%	4.24%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year - pre/post-65)	N/A	N/A	7.50%/8.50%	6.75%/8.50%
Health care trend rate (2030/2028 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

N/A – not applicable

CONNECTICUT NATURAL GAS CORPORATION

NOTES TO FINANCIAL STATEMENTS

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, 2017 and 2016 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	
	Year Ended December 31, 2017	**Year Ended December 31, 2016**	**Year Ended December 31, 2017**	**Year Ended December 31, 2016**
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 4,441	$ 4,074	$ 228	$ 224
Interest cost	11,256	11,212	922	971
Expected return on plan assets	(13,326)	(13,845)	(553)	(477)
Amortization of prior service costs	22	23	247	247
Amortization of actuarial (gain) loss	3,446	3,076	(167)	(56)
Net periodic benefit cost	$ 5,839	$ 4,540	$ 677	$ 909
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ (7,237)	$ 34,509	$ (824)	$ 588
Amortization of current year prior service costs	-	-	167	-
Amortization of prior service costs	(22)	(23)	(247)	(247)
Amortization of actuarial (gain) loss	(3,446)	(3,076)	-	56
Total recognized as regulatory asset (liability)	$ (10,705)	$ 31,410	$ (904)	$ 397
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ (4,866)	$ 35,950	$ (227)	$ 1,306
Estimated Amortizations from Regulatory Assets (Liabilities) into Net Periodic Benefit Cost for the next 12 month period:				
Amortization of prior service cost	$ 20	$ 22	$ 239	$ 247
Amortization of net (gain) loss	2,318	3,446	(233)	(167)
Total estimated amortizations	$ 2,338	$ 3,468	$ 6	$ 80
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.24%	4.24%	4.24%	4.24%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.50%	7.75%	5.37%	5.37%
Health care trend rate (current year - pre/post-65)	N/A	N/A	6.75%/8.50%	7.00%/9.00%
Health care trend rate (2026/2028 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

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	$ (6)	$ 5
Accumulated post-retirement benefit obligation	$ (113)	$ 101

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 $0.7 million in 2018. 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, 2017 consisted of:

Year	Pension Benefits	Other Post-Retirement Benefits	Medicare Act Subsidy
		(In Thousands)	
2018	$ 11,740	$ 2,042	$ 220
2019	$ 12,026	$ 1,878	$ 229
2020	$ 12,275	$ 1,824	$ 235
2021	$ 12,642	$ 1,747	$ 245
2022	$ 13,006	$ 1,707	$ 253
2023-2027	$ 72,311	$ 7,693	$ 1,287

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 2017 and 2016 was $1.3 million, and $1.2 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, 2017, CNG recorded inter-company expenses of $12.7 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 and are included in Accounts receivable from affiliates and Accounts payable to affiliates in the accompanying balance sheets.

Dividends/Capital Contributions

For the year ended December 31, 2017, CNG accrued $19 million in dividends to CTG. For the year ended December 31, 2016, CNG did not accrue any dividends to CTG.

(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)
2018	$ 501
2019	399
2020	396
2021	271
2022	6
2023 - after	-
	$ 1,573

(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, 2017 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, 2017, 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, 2017 and December 31, 2016.

	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, 2017		(In Thousands)		
Noncurrent investments	$ 1,158	$ -	$ -	$ 1,158
Total fair value assets, December 31, 2017	$ 1,158	$ -	$ -	$ 1,158
December 31, 2016				
Noncurrent investments	$ 1,375	$ -	$ -	$ 1,375
Total fair value assets, December 31, 2016	$ 1,375	$ -	$ -	$ 1,375

The following tables set forth the fair values of CNG's pension and OPEB assets as of December 31, 2017 and 2016.

	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, 2017		(In Thousands)		
Pension assets				
Mutual funds	$ -	$ 199,896	$ -	$ 199,896
	-	199,896	-	199,896
OPEB assets				
Mutual funds	3,410	7,599	-	11,009
Fair value of plan assets, December 31, 2017	$ 3,410	$ 207,495	$ -	$ 210,905
December 31, 2016				
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

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, 2017 AND 2016

TABLE OF CONTENTS

KPMG

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

The Board of Directors
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, 2017, 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 accordance 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 from material misstatement, whether due to fraud or error.

Auditors' 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 of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' 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 opinion.

Opinion

In our opinion, the 2017 financial statements referred to above present fairly, in all material respects, the financial position of The Berkshire Gas Company as of December 31, 2017, and the results of its operations and its cash flows for the year then ended in accordance with U.S. generally accepted accounting principles.

KPMG LLP

New York, New York
April 13, 2018

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Report of Independent Auditors

The Board of Directors
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.

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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.

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

EY
Building a better working world

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of 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.

Other-matter

As discussed in Note A, the Company has revised its financial statements to correct a prior period error.

Ernst + Young LLP

April 26, 2017, except as to Note A, which is as of April 13, 2018

THE BERKSHIRE GAS COMPANY
STATEMENT OF INCOME
(In Thousands)

	Year Ended December 31, 2017	Year Ended December 31, 2016
Operating Revenues	$ 75,001	$ 69,493
Operating Expenses		
Natural gas purchased	26,360	22,324
Operation and maintenance	27,178	26,682
Depreciation and amortization	8,013	7,356
Taxes other than income taxes	4,036	3,467
Total Operating Expenses	65,587	59,829
Operating Income	9,414	9,664
Other Income and (Expense), net		
Other income	248	416
Other (expense)	(98)	(93)
Total Other Income and (Expense), net	150	323
Interest Expense, net	3,270	3,346
Income Before Income Tax	6,294	6,641
Income Tax	1,556	2,580
Net Income	$ 4,738	$ 4,061

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

	Year Ended December 31, 2017	Year Ended December 31, 2016
Net Income	$ 4,738	$ 4,061
Other Comprehensive Income, net of income tax	10	11
Comprehensive Income	$ 4,748	$ 4,072

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, 2017	Year Ended December 31, 2016
Cash Flows From Operating Activities		
Net income	$ 4,738	$ 4,061
Adjustments to reconcile net income		
to net cash provided by operating activities:		
Depreciation and amortization	8,121	7,483
Deferred income taxes	6,167	1,500
Uncollectible expense	524	641
Pension expense	1,260	1,908
Regulatory assets/liabilities amortization	1,543	1,742
Other non-cash items, net	130	(434)
Changes in:		
Accounts receivable and unbilled revenue, net	(1,946)	(2,272)
Natural gas in storage	10	446
Accounts payable and accrued liabilities	604	886
Taxes accrued/refundable, net	434	(7,173)
Pension accrued	(2,362)	(972)
Environmental liabilities	1,000	350
Regulatory assets/liabilities	(4,852)	(2,005)
Other assets	(1,322)	856
Other liabilities	(1,047)	(217)
Total Adjustments	8,264	2,739
Net Cash provided by Operating Activities	13,002	6,800
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(17,778)	(16,448)
Net Cash used in Investing Activities	(17,778)	(16,448)
Cash Flows from Financing Activities		
Payment of common stock dividend	-	(7,500)
Payment of long-term debt	(1,455)	(1,455)
Notes payable to affiliates	6,500	15,764
Other	-	(33)
Net Cash provided by Financing Activities	5,045	6,776
Unrestricted Cash and Temporary Cash Investments:		
Net change for the period	269	(2,872)
Balance at beginning of period	78	2,950
Balance at end of period	$ 347	$ 78
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 3,137	$ 3,205
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 797	$ 800

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

THE BERKSHIRE GAS COMPANY
BALANCE SHEET
December 31, 2017 and 2016

ASSETS
(In Thousands)

	2017	2016 revised (See Note A)
Assets		
Current Assets		
Unrestricted cash and temporary cash investments	$ 347	$ 78
Accounts receivable and unbilled revenues, net	14,592	13,203
Accounts receivable from affiliates	323	292
Regulatory assets	9,025	7,149
Gas in storage	1,888	1,898
Materials and supplies	870	764
Other current assets	1,944	728
Total Current Assets	28,989	24,112
Other Investments	2,331	2,450
Property, Plant and Equipment, at cost	239,471	222,525
Less accumulated depreciation	77,297	72,618
Net Property, Plant and Equipment in Service	162,174	149,907
Construction work in progress	2,393	3,407
Total Property, Plant and Equipment	164,567	153,314
Regulatory Assets	33,281	35,409
Deferred Income Taxes Regulatory	2,384	-
Deferred Charges and Other Assets		
Goodwill	51,933	51,933
Other	21	28
Total Deferred Charges and Other Assets	51,954	51,961
Total Assets	$ 283,506	$ 267,246

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

THE BERKSHIRE GAS COMPANY
BALANCE SHEET
December 31, 2017 and 2016

LIABILITIES AND CAPITALIZATION
(In Thousands)

	2017	2016 revised (See Note A)
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 14,800	$ 8,300
Current portion of long-term debt	2,393	2,393
Accounts payable and accrued liabilities	12,609	10,755
Accounts payable to affiliates	6,809	8,021
Other current liabilities	1,315	1,356
Interest accrued	852	848
Regulatory liabilities	2,185	2,312
Taxes accrued	451	17
Total Current Liabilities	41,414	34,002
Deferred Income Taxes	20,354	24,591
Regulatory Liabilities	48,846	33,725
Deferred Income Taxes Regulatory	-	2,622
Other Noncurrent Liabilities		
Pension	18,285	20,029
Environmental remediation costs	3,950	2,950
Other	2,585	3,714
Total Other Noncurrent Liabilities	24,820	26,693
Capitalization		
Long-term debt	38,011	40,300
Common Stock Equity		
Paid-in capital	106,095	106,095
Retained earnings	3,964	(774)
Accumulated other comprehensive income (loss)	2	(8)
Net Common Stock Equity	110,061	105,313
Total Capitalization	148,072	145,613
Total Liabilities and Capitalization	$ 283,506	$ 267,246

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, 2017 and 2016

(Thousands of Dollars)

	Common Stock			Paid-in		Retained Earnings (Accumulated		Accumulated Other Comprehensive		Total
	Shares		Amount		Capital		Deficit)		Income (Loss)	
Balance as of December 31, 2015, as previously reported	100	$	-	$	106,095	$	3,397	$	(19)	$ 109,473
Adjustment of correction of error, net of tax (See Note A)							(732)			
Balance as of December 31, 2015 (revised)	100	$	-	$	106,095	$	2,665	$	(19)	$ 108,741
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	$	(774)	$	(8)	$ 105,313
Net income							4,738			4,738
Other comprehensive income, net of deferred income taxes									10	10
Balance as of December 31, 2017	100	$	-	$	106,095	$	3,964	$	2	$ 110,061

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

(A) STATEMENT OF ACCOUNTING POLICIES

The Berkshire Gas Company (Berkshire) engages in natural gas transportation, distribution and sales operations serving approximately 40,000 customers in its service area in western Massachusetts, which includes the cities of Pittsfield, North Adams and Greenfield. 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. UIL Holdings, whose primary business is ownership of its operating regulated utility businesses, is a wholly owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc., which is a 81.5% owned subsidiary of Iberdrola, S.A., a corporation organized under the law of the Kingdom of Spain.

Accounting Records

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

Basis of Presentation

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

Berkshire has revised its previously issued Financial Statements to correct an error related to accounts receivable, refundable taxes, taxes accrued and retained earnings. Management believes that these revisions are not material to the previously issued financial statements. In addition, certain amounts reported in the Financial Statements 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. The following table summarizes the impact to the prior period Statement of Income, Statement of Cash Flows and Balance Sheet of these reclassifications.

December 31, 2016 (in thousands)	As previously filed	Errors	Reclassifications	As currently reported
Statement of Income				
Interest on long-term debt	$ 3,245	$ -	$ (3,245)	$ -
Other interest, net	(26)	-	26	-
Amortization of debt expense and redemption premiums	127	-	(127)	-
Interest Expense, net	-	-	3,346	3,346
Statement of Cash Flows				
Changes in:				
Accounts receivable and unbilled revenue, net	(903)	-	(1,369)	(2,272)
Unbilled revenues	(1,369)	-	1,369	-
Accounts payable and accrued liabilities	1,756	-	(870)	886
Accrued liabilities	(870)	-	870	-
Pension accrued	(921)	-	(51)	(972)
Accrued other post-employment benefits	(51)	-	51	-
Environmental liabilities	-	-	350	350
Other liabilities	133	-	(350)	(217)
Balance Sheet				
Assets				
Current Assets				
Accounts receivable and unbilled revenues, net	9,347	(1,224)	5,080	13,203
Unbilled revenues	5,372	-	(5,372)	-
Accounts receivable from affiliates	-	-	292	292
Prepayments and other current assets	2,041	428	(1,741)	728
Other investments	709	-	1,741	2,450
Liabilities				
Current Liabilities				
Notes payable to affiliates / Intercompany payable	15,764	-	(7,464)	8,300
Accounts payable and accrued liabilities	9,019	-	1,736	10,755
Accounts payable to affiliate	-	-	8,021	8,021
Accrued liabilities	3,649	-	(3,649)	-
Taxes accrued	81	(64)	-	17
Other current liabilities	-	-	1,356	1,356
Regulatory liabilities	36,347	-	(2,622)	33,725
Deferred income taxes regulatory	-	-	2,622	2,622
Other Noncurrent Liabilities				
Pension	16,313	-	3,716	20,029
Other post-retirement benefits accrued	2,890	-	(2,890)	-
Other	4,540	-	(826)	3,714
Capitalization				
Retained earnings	(42)	(732)	-	(774)

Berkshire has evaluated subsequent events through the date its financial statements were available to be issued, April 13, 2018.

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. Berkshire recognizes revenues upon delivery of natural gas to its customers. In addition, Berkshire accrues revenue pursuant to the various regulatory provisions to record regulatory assets for revenues that will be collected in the future.

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 refunded in the future through the ratemaking process. Berkshire is allowed to recover all such deferred costs and is required to refund such obligations to customers through its regulated rates. See Note (C) "Regulatory Proceedings", for a discussion of the recovery of certain deferred costs and the refund of certain obligations, as well as a discussion of the regulatory decisions that provide for such recovery and require such refunding.

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, 2017 and 2016 included the following:

	Remaining Period	December 31, 2017	December 31, 2016
		(In Thousands)	
Regulatory Assets:			
Pension plans	(a)	$ 22,362	$ 24,334
Environmental remediation costs	7 years	8,290	8,465
Debt premium	2 to 4 years	2,095	3,031
Deferred purchased gas	(b)	6,047	3,330
Unfunded future income taxes	(c)	622	767
Deferred income taxes regulatory	(c)	2,384	-
Other	(d)	2,890	2,631
Total regulatory assets		44,690	42,558
Less current portion of regulatory assets		9,025	7,149
Regulatory Assets, Net		$ 35,665	$ 35,409
Regulatory Liabilities:			
Rate credits	0 to 1 year	$ 1,328	$ 3,328
Asset removal costs	(d)	33,530	32,074
Tax Act remeasurement	(c)	15,410	-
Deferred income taxes regulatory	(e)	-	2,622
Other	(d)	763	635
Total regulatory liabilities		51,031	38,659
Less current portion of regulatory liabilities		2,185	2,312
Regulatory Liabilities, Net		$ 48,846	$ 36,347

(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.
(e) Impact of deferred tax remeasurement as a consequence of the Tax Cuts and Jobs Act of 2017 enacted by the U.S. federal government on December 22, 2017. Refundable period will be determined in future rate proceedings.

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 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.

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 2017 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.

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, 2017 and 2016 were comprised as follows:

	2017	2016
	(In Thousands)	
Gas distribution plant	$ 190,541	$ 180,290
Land	2,304	2,286
Buildings and improvements	26,707	20,424
Other plant	19,919	19,525
Total property, plant & equipment	239,471	222,525
Less accumulated depreciation	77,297	72,618
	162,174	149,907
Construction work in progress	2,393	3,407
Net property, plant & equipment	$ 164,567	$ 153,314

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 2017 and 2016 was 1.31% and 9.72%, respectively. The portion of the allowance applicable to equity funds was immaterial for 2017 and $0.1 million for 2016.

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 2017 and 2016 were approximately 3.5% and 3.4%, respectively, of the original cost of depreciable property.

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, 2017, Berkshire did not have any assets that were impaired under this standard.

Unrestricted cash and temporary cash investments

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

Accounts receivable and unbilled revenues

Accounts receivable at December 31, 2017 and 2016 include unbilled revenues of $6.5 million and $5.4 million, respectively and are shown net of an allowance for doubtful accounts of $1.6 million and $1.7 million for 2017 and 2016, respectively. Accounts receivable do not bear interest, although late fees may be assessed.

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. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for doubtful accounts is management's best estimate of the amount of probable credit losses in the existing accounts receivable, determined based on experience. Each month, Berkshire reviews the allowance for doubtful accounts and past due accounts by age. When management believes that a receivable will not be recovered, the account balance is charged off 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

Gas in storage

Natural gas in storage 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. Berkshire continuously monitors the weighted-average cost of gas value to ensure it remains at, or below market value.

Materials and supplies

Materials and supplies inventories are used for construction of new facilities and repairs of existing facilities. The inventories are carried and withdrawn at lower of cost and net realizable value

Other Investments

The Berkshire's other investments consist of noncurrent investments available for sale and life insurance policies.

Accrued removal obligations

Berkshire meets the requirements concerning accounting for regulated operations, and recognizes a regulatory liability, for the difference between removal costs collected in rates and actual costs incurred. Berkshire classifies those amounts as accrued removal obligations.

Pension and Other Post-Retirement Benefits

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

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.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. The DPU has instituted proceedings in Massachusetts to review and address the implications associated with the Tax Act on the utilities providing service in the state. Berkshire expects the regulators in Massachusetts to issue requirements in 2018 regarding how all tax benefits associated with the Tax Act will be returned to customers.

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 October 2017, Berkshire entered into a weather insurance contract for the winter period of November 1, 2017 through April 30, 2018. 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, 2017 since the variation from normal weather through December 31, 2017 had not reached the prescribed levels stated in the contract.

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.

New Accounting Standards

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC), Topic 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. ASC 606 was further amended through various updates the FASB issued thereafter. 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 amended effective date is for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption permitted as of the original effective date of annual reporting periods beginning after December 15, 2016. Entities may apply the standard 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). Berkshire will adopt the new standard effective January 1, 2018, and apply the modified retrospective method. Based on management's assessment to existing contracts and revenue streams, Berkshire does not expect to record any material cumulative adjustments to retained earnings and does not expect ASC 606 to have a material impact on the amount and timing of its revenue recognition. Management has identified other changes primarily related to the presentation and disclosure of revenues. Management plans to disaggregate revenues not accounted for in scope of the new standard, as required, including alternative revenue programs.

In February 2016, the FASB issued Accounting Standards Update (ASU) 2016-02 "Leases" 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 FASB issued an update in January 2018 to clarify the application of the new leases guidance to land easements and provide relief concerning adoption efforts for existing land easements that are not accounted for as leases under the current leases guidance. The updated guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early application is permitted. Berkshire is currently reviewing our contracts and is 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 its financial statements. Berkshire does not expect the adoption of the new guidance will materially affect its financial position through the recording of operating leases on the balance sheet as a right-of-use asset.

In March 2017, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2017-07 "Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost". The ASU contains amendments that require an entity to present service cost separately from the other components of net benefit cost, and to report the service cost component in the income statement line item(s) where it reports the corresponding compensation cost. An entity is to present all other components of net benefit cost outside of operating cost, if it presents that subtotal. The amendments also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of a self-constructed asset). The amendments are effective for annual and interim periods in fiscal years beginning after December 15, 2017, with early adoption permitted. BGC does not plan to early adopt. An entity is required to apply the amendments retrospectively for the presentation of the service cost component and the other components of net periodic pension cost and net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension cost and net periodic postretirement benefit in assets. A practical expedient allows an entity to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in the notes to financial statements for pension and postretirement benefit plans for those periods. Berkshire does not expect the adoption of the amendments will materially affect its results of operations, financial position, cash flows, and disclosures.

In February 2018 the FASB issued ASU 2018-02 "Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" which contains amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017 by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within accumulated other comprehensive income (AOCI) (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. The amendments are effective for all entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted. An entity has the option to apply the amendments either in the period of adoption or retrospectively to each period (or periods) in which it recognizes the effect of the change in the U.S. federal corporate income tax rate in the Tax Act. An entity is required to disclose its accounting policy election, including its policy for reclassifying material stranded tax effects in AOCI to earnings (specific identification or portfolio method). Berkshire does not expect the adoption of the amendments will materially affect our results of operations, financial position, cash flows, and disclosures.

B) CAPITALIZATION

Common Stock

Berkshire had 100 shares of its common stock, $2.50 par value, outstanding as of December 31, 2017 and 2016.

Long-Term Debt

As of December 31,		**2017**		**2016**	
(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	28,818	5.33%-9.60%	30,272	5.33%-9.60%
Unamortized debt (costs) premium, net		1,586		2,421	
Total Debt		**40,404**		**42,693**	
Less: debt due within one year, included in current liabilities		2,393		2,393	
Total Non-current Debt		**38,011**		**$ 40,300**	

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

The estimated fair value of debt amounted to $45.9 million and $47.8 million as of December 31 2017 and 2017, 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 natural gas 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.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:

	2018	2019	2020	2021	2022 & Thereafter	Total
			(In Thousands)			
Maturities:	$ 1,455	$ 11,455	$ 9,455	$ 1,453	$ 15,000	$ 38,818

Under various debt agreements, Berkshire is required to maintain the following:

- A ratio of consolidated debt to consolidated capital of not greater than 65% (debt ratio). As of December 31, 2017, such ratio was 33%.
- A ratio of consolidated funded debt to consolidated adjusted capitalization (adjusted capitalization excludes the impact of goodwill) of not greater than 65%. As of December 31, 2017, such ratio was 42%.
- A fixed charges coverage ratio of no less than 1.50 to 1.00. As of December 31, 2017, such ratio was 2.89 to 1.00.
- To maintain a tangible net worth greater than $9 million. As of December 31, 2017, BGC's tangible net worth was $57.6 million.

(C) REGULATORY PROCEEDINGS

Rates

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

Berkshire's rates are established by the DPU. Berkshire's 10-year rate plan, which was approved by the DPU and included an approved ROE of 10.5%, expired on January 31, 2012. Berkshire continues to charge the rates that were in effect at the end of the rate plan and, in accordance with the approval by the DPU of the of the 2015 merger of UIL Holdings with Avangrid, Inc., Berkshire has 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, 2017 are as follows:

	(In Thousands)
2018	$ 13,387
2019	8,164
2020	2,941
2021	2,598
2022	2,598
2023-after	21,182
	$ 50,870

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

BGC 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 BGC 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. BGC has a lending/borrowing limit of $15 million under this agreement. There was no balance outstanding as of December 31, 2017 under this agreement. There was no balance outstanding as of December 31, 2016 under this agreement.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $50 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There was $14.8 million outstanding under this agreement as of December 31, 2017 and there was $8.3 million outstanding under this agreement as of December 31, 2016.

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, 2017 and 2016, Berkshire did not have any outstanding borrowings under the Avangrid Credit Facility.

THE BERKSHIRE GAS COMPANY

NOTES TO FINANCIAL STATEMENTS

(E) INCOME TAXES

	Year Ended December 31, 2017	Year Ended December 31, 2016
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions:		
Current		
Federal	$ (3,990)	$ 613
State	(585)	508
Total current	(4,575)	1,121
Deferred		
Federal	5,064	1,488
State	1,103	12
Total deferred	6,167	1,500
Investment tax credits	(36)	(41)
Total income tax expense	$ 1,556	$ 2,580

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, 2017	Year Ended December 31, 2016
	(In Thousands)	
Book income before income taxes	$ 6,294	$ 6,641
Computed tax at federal statutory rate	$ 2,203	$ 2,324
Increases (reductions) resulting from:		
State income taxes, net of federal income tax benefits	328	338
2017 Tax Act deferred tax remeasurement	171	-
Other items, net	(1,146)	(82)
Total income tax expense	$ 1,556	$ 2,580
Effective income tax rates	24.7%	38.8%

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. Berkshire is 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, 2017 and 2016, 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, 2017:

Jurisdiction	*Tax years*
Federal	2013 - 2017
Massachusetts	2013 – 2017

The following table summarizes Berkshire's deferred tax assets and liabilities as of December 31, 2017 and 2016:

	2017	**2016**
	(In Thousands)	
Property related	$ (22,536)	$ (38,489)
Environmental	1,184	1,341
Deferred tax liability on 2017 Tax Act remeasurement	4,274	-
Federal net operating loss	300	-
Post-retirement benefits, net	(1,234)	5,894
Other assets (liabilities)	42	4,041
	$ (17,970)	$ (27,213)
Less Regulatory Assets (Liabilities)	2,384	(2,622)
Total deferred income tax assets (liabilities), net	$ (20,354)	$ (24,591)

(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. The Plans are closed to new employees hired on or after specified dates.

Employees not participating in a defined benefit plan are eligible for enhanced benefits in the 401(k) plans.

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 NEPC, LLC as the investment advisor 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.

Networks' asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. Management has 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, there are established 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 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, 2017 and 2016. Plan assets and obligations have been measured as of December 31, 2016 and 2015.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2017	Year Ended December 31, 2016	Year Ended December 31, 2017	Year Ended December 31, 2016
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation at beginning of year	$ 49,888	$ 43,898	$ 2,890	$ 1,792
Service cost	578	551	32	-
Interest cost	2,010	2,075	119	81
Participant contributions	-	-	-	11
Actuarial (gain) loss	2,123	5,772	839	1,159
Benefits paid (including expenses)	(2,008)	(2,408)	(180)	(153)
Benefit obligation at end of year	$ 52,591	$ 49,888	$ 3,700	$ 2,890
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 33,575	$ 33,140	$ -	$ -
Actual return on plan assets	4,908	1,923	-	-
Participant contributions	-	-	-	11
Employer contributions	-	920	180	142
Benefits paid (including expenses)	(1,971)	(2,408)	(180)	(153)
Fair value of plan assets at end of year	$ 36,512	$ 33,575	$ -	$ -
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 16,079	$ 16,313	$ 3,700	$ 2,890
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 16,079	$ 16,313	$ 3,700	$ 2,890
Amounts Recognized as a Regulatory Asset (Liability) consist of:				
Prior service cost	$ 213	$ 382	$ -	$ -
Net (gain) loss	$ 7,986	$ 9,118	839	-
Total recognized as a regulatory asset (liability)	$ 8,199	$ 9,500	$ 839	$ -
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 52,591	$ 49,888	N/A	N/A
Accumulated benefit obligation	$ 45,667	$ 44,103	N/A	N/A
Fair value of plan assets	$ 36,512	$ 33,575	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Pension Benefits)	3.80%	4.24%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	3.80%	4.24%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year - pre/post-65)	N/A	N/A	7.50%/8.50%	6.75%/8.50%
Health care trend rate (2030/2028 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

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, 2017 and 2016 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, 2017	Year Ended December 31, 2016	Year Ended December 31, 2017	Year Ended December 31, 2016
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 578	$ 551	$ 32	$ -
Interest cost	2,010	2,075	119	81
Expected return on plan assets	(2,366)	(2,532)	-	-
Amortization of actuarial (gain) loss	713	496	-	1,068
Amortization of prior service cost	169	169	-	-
Net periodic benefit cost	$ 1,104	$ 759	$ 151	$ 1,149
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ (419)	$ 6,381	$ 839	$ 1,068
Amortization of prior service cost	(169)	(169)	-	-
Amortization of Actuarial (gain) loss	(713)	(496)	-	(1,068)
Total recognized as regulatory asset (liability)	$ (1,301)	$ 5,716	$ 839	$ -
Total recognized in Net Periodic Benefit Costs and Regulatory Asset (Liability):				
	$ (197)	$ 6,475	$ 990	$ 1,149
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	580	713	84	-
Total estimated amortizations	$ 749	$ 882	$ 84	$ -
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.24%	4.24%	4.24%	4.45%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.00%	7.75%	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 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	$ 17	$ (15)
Accumulated post-retirement benefit obligation	$ 250	$ (224)

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 expects to make a pension contribution of approximately $0.2 million in 2018. 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)	
2018	$ 2,130	$ 243
2019	$ 2,223	$ 284
2020	$ 2,306	$ 291
2021	$ 2,450	$ 289
2022	$ 2,581	$ 317
2023-2027	$ 14,239	$ 1,608

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 union employees are eligible to participate in the Berkshire Gas Company Union 401(k) Plan. Employees may defer a portion of their 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 2017 and 2016 was $0.5 million and $0.4 million, respectively.

(G) RELATED PARTY TRANSACTIONS

Inter-company Transactions

Berkshire receives various administrative and management services from and enters into certain inter-company transactions with UIL Holdings and its subsidiaries. For the year ended December 31, 2017, Berkshire recorded inter-company expenses of $3.3 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 and are included in Accounts receivable from affiliates and Accounts payable to affiliates in the accompanying balance sheets.

Dividends/Capital Contributions

Berkshire did not accrue any dividends to UIL Holdings during 2017. For the year ended December 31, 2016, Berkshire accrued dividends to UIL Holdings of $7.5 million.

(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)	
2018	$	86
2019		7
2020		7
2021		7
2022		5
2023-after		-
	$	112

(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, 2017 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. Management estimates 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 $0.5 million and has recorded a liability and offsetting regulatory asset for such expenses as of December 31, 2017. 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, 2017, Berkshire had accrued approximately $3.8 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, 2017 and December 31, 2016.

	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, 2017	(In Thousands)			
Noncurrent investments	$ 564	$ -	$ -	$ 564
Total fair value assets, December 31, 2017	$ 564	$ -	$ -	$ 564
December 31, 2016				
Noncurrent investments	$ 709	$ -	$ -	$ 709
Total fair value assets, December 31, 2016	$ 709	$ -	$ -	$ 709

The following tables set forth the fair values of Berkshire's pension assets as of December 31, 2017 and 2016.

	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, 2017	(In Thousands)			
Pension assets				
Mutual funds	$ -	$ 36,512	$ -	$ 36,512
Fair value of plan assets, December 31, 2017	$ -	$ 36,512	$ -	$ 36,512
December 31, 2016				
Pension assets				
Mutual funds	$ -	$ 33,575	$ -	$ 33,575
Fair value of plan assets, December 31, 2016	$ -	$ 33,575	$ -	$ 33,575

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.

New York State Electric & Gas Corporation
Financial Statements
For the Years Ended December 31, 2017 and 2016

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

The Board of Directors
New York State Electric and Gas Corporation:

We have audited the accompanying financial statements of New York State Electric and Gas Corporation, which comprise the balance sheet as of December 31, 2017, and the related statements of income, comprehensive income, changes in common stock 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 accordance 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 from material misstatement, whether due to fraud or error.

Auditors' 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 of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' 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 opinion.

Opinion

In our opinion, the 2017 financial statements referred to above present fairly, in all material respects, the financial position of New York State Electric and Gas Corporation as of December 31, 2017, and the results of its operations and its cash flows for the year then ended in accordance with U.S. generally accepted accounting principles.

Other Matter

The accompanying financial statements of New York State Electric and Gas Corporation as of December 31, 2016 and for the year then ended were audited by other auditors whose report thereon dated April 12, 2017, expressed an unmodified opinion on those financial statements.

KPMG LLP

New York, New York
April 17, 2018

New York State Electric & Gas Corporation

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Financial Statements As of and for the Years Ended December 31, 2017 and 2016

New York State Electric & Gas Corporation
Statements of Income

Years Ended December 31,	2017	2016
(Thousands)		
Operating Revenues		
Electric	$1,254,670	$1,223,115
Natural gas	280,151	315,975
Total Operating Revenues	**1,534,821**	**1,539,090**
Operating Expenses		
Electricity purchased	313,978	348,733
Natural gas purchased	92,999	78,868
Operations and maintenance	621,973	596,237
Depreciation and amortization	129,023	112,936
Other taxes	144,281	141,356
Total Operating Expenses	**1,302,254**	**1,278,130**
Operating Income	**232,567**	**260,960**
Other Income	15,372	12,301
Other Deductions	(1,154)	(1,608)
Interest Charges, net	(62,999)	(60,542)
Income Before Income Tax	**183,786**	**211,111**
Income Tax Expense	78,819	92,224
Net Income	**$104,967**	**$118,887**

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

New York State Electric & Gas Corporation
Statements of Comprehensive Income

Years Ended December 31,	2017	2016
(Thousands)		
Net Income	**$104,967**	**$118,887**
Other Comprehensive Income, Net of Tax		
Amortization of pension cost for nonqualified plans	(74)	39
Unrealized gain on derivatives qualified as hedges:		
Unrealized (loss) gain during period on derivatives qualified as hedges	(164)	105
Reclassification adjustment for loss included in net income	228	627
Reclassification adjustment for loss on settled cash flow treasury hedges	63	64
Other Comprehensive Income, Net of Tax	**53**	**835**
Comprehensive Income	**$105,020**	**$119,722**

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

New York State Electric & Gas Corporation
Balance Sheets

As of December 31,	2017	2016
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$3,396	$3,646
Accounts receivable and unbilled revenues, net	268,977	246,902
Accounts receivable from affiliates	10,704	13,246
Fuel and natural gas in storage, at average cost	15,231	11,751
Materials and supplies	15,813	16,490
Broker margin accounts	13,334	11,968
Income tax receivable	41,844	31,690
Prepaid property taxes	35,779	35,224
Other current assets	6,060	9,594
Regulatory assets	113,403	121,697
Total Current Assets	**524,541**	**502,208**
Utility plant, at original cost	5,588,372	5,248,018
Less accumulated depreciation	(2,100,274)	(2,043,588)
Net Utility Plant in Service	**3,488,098**	**3,204,430**
Construction work in progress	240,657	252,044
Total Utility Plant	**3,728,755**	**3,456,474**
Other Property and Investments	10,411	10,385
Regulatory and Other Assets		
Regulatory assets	888,255	1,045,706
Deferred income taxes regulatory	30,376	-
Other	1,634	215
Total Regulatory and Other Assets	**920,265**	**1,045,921**
Total Assets	**$5,183,972**	**$5,014,988**

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

New York State Electric & Gas Corporation
Balance Sheets

As of December 31,	2017	2016
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	$322	$219,325
Notes payable	150,000	-
Notes payable to affiliates	124,643	5,900
Accounts payable and accrued liabilities	287,925	205,771
Accounts payable to affiliates	78,532	74,310
Interest accrued	5,963	8,381
Taxes accrued	1,553	1,209
Derivative liabilities	39	145
Environmental remediation costs	51,758	27,151
Customer deposits	12,532	13,230
Regulatory liabilities	78,298	108,139
Other	77,684	66,599
Total Current Liabilities	**869,249**	**730,160**
Regulatory and Other Liabilities		
Regulatory liabilities	1,190,333	710,101
Deferred income taxes regulatory	-	138,973
Other non-current liabilities		
Deferred income taxes	497,082	745,538
Other postretirement benefits	224,736	263,172
Asset retirement obligation	14,021	14,478
Environmental remediation costs	105,707	135,118
Other	44,009	43,352
Total Regulatory and Other Liabilities	**2,075,888**	**2,050,732**
Long-term debt	1,041,536	1,041,815
Total Liabilities	**3,986,673**	**3,822,707**
Commitments and Contingencies		
Common Stock Equity		
Common stock ($6.66 2/3 par value, 90,000,000 shares authorized and 64,508,477 shares outstanding at December 31, 2017 and 2016)	430,057	430,057
Capital in excess of par value	268,403	268,405
Retained earnings	499,744	494,777
Accumulated other comprehensive loss	(905)	(958)
Total Common Stock Equity	**1,197,299**	**1,192,281**
Total Liabilities and Equity	**$5,183,972**	**$5,014,988**

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

New York State Electric & Gas Corporation
Statements of Cash Flows

Years Ended December 31,	2017	2016
(Thousands)		
Cash Flow from Operating Activities		
Net income	**$104,967**	**$118,887**
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	129,023	112,936
Amortization of regulatory assets and liabilities	46,864	4,977
Carrying cost of regulatory assets and liabilities	3,269	4,328
Amortization of debt issuance costs	1,745	1,034
Deferred taxes	59,189	59,848
Pension cost	60,825	62,434
Stock-based compensation	(11)	(331)
Accretion expenses	774	797
Gain on disposal of property, plant and equipment	(1,080)	-
Other non-cash items	(21,899)	(12,984)
Changes in assets and liabilities		
Accounts receivable and unbilled revenues, net	(19,533)	(28,657)
Materials and supplies and fuel and natural gas in storage	(2,803)	(147)
Accounts payable and accrued liabilities	81,541	71,500
Accrued taxes	345	(20,283)
Taxes receivable	(21,326)	(20,518)
Other assets/liabilities	(75,777)	13,328
Regulatory assets/liabilities	57,102	(18,391)
Net Cash Provided by Operating Activities	**403,215**	**348,758**
Cash Flow from Investing Activities		
Utility plant additions	(377,859)	(316,664)
Contributions in aid of construction	24,352	40,208
Proceeds from sale of property, plant and equipment	2,352	43,836
Investments, net	(26)	17
Net Cash Used in Investing activities	**(351,181)**	**(232,603)**
Cash Flow from Financing Activities		
Non-current debt issuance	-	493,160
Repayments of non-current debt	(200,000)	(197,117)
Repayment of capital leases	(21,027)	(2,046)
Notes payable	150,000	-
Notes payable to affiliates	118,743	(334,914)
Common stock dividends	(100,000)	(75,000)
Net Cash Used in Financing Activities	**(52,284)**	**(115,917)**
Net (Decrease) Increase in Cash and Cash Equivalents	**(250)**	**238**
Cash and Cash Equivalents, Beginning of Year	**3,646**	**3,408**
Cash and Cash Equivalents, End of Year	**$3,396**	**$3,646**

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)	Number of shares (*)	Common stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stock Equity
Balance, January 1, 2016	**64,508,477**	**$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
Common stock dividends	-	-	-	(75,000)	-	(75,000)
Balance, December 31, 2016	**64,508,477**	**430,057**	**268,405**	**494,777**	**(958)**	**1,192,281**
Net income	-	-	-	104,967	-	104,967
Other comprehensive income, net of tax	-	-	-	-	53	53
Comprehensive income						105,020
Stock-based compensation	-	-	(2)	-	-	(2)
Common stock dividends	-	-	-	(100,000)	-	(100,000)
Balance, December 31, 2017	**64,508,477**	**$430,057**	**$268,403**	**$499,744**	**$(905)**	**$1,197,299**

(*) Par value of share amounts is $6.66 2/3

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

Notes to Financial Statements

Note 1. Significant Accounting Policies

Background: New York State Electric & Gas Corporation (NYSEG, the company, we, our, us) conducts regulated electricity transmission and distribution operations and regulated natural gas transportation, storage and distribution operations in upstate New York. It also generates electricity, primarily from its several hydroelectric stations. NYSEG serves approximately 894,000 electricity and 266,000 natural gas customers as of December 31, 2017 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 the Networks businesses. 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.

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). We sell electricity from owned generation to the NYISO. We purchase electricity from the NYISO to serve our customers. 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).

Notes to Financial Statements

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

***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).

***Utility Plant*:** Utility plant is accounted for at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, the estimated cost of removal or reconditioning is recorded as an asset retirement obligation (ARO) and an equal amount is added to the carrying amount of the asset.

Assets are transferred from “Construction work in progress” to “Utility Plant” when they are available for service.

Utility plant is depreciated 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 2.3% of average depreciable property for 2017 and 2.1% for 2016. We amortize our capitalized software cost which is included in other plant, using the straight line method, based on useful lives of 7 to 17 years. Capitalized software costs were approximately $184.0 million as of December 31, 2017 and $175.0 million as of December 31, 2016. Depreciation expense was $123.0 million in 2017 and $107.0 million in 2016. Amortization of capitalized software was $6.0 million in 2017 and $6.0 million in 2016.

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.

Allowance for funds used during construction (AFUDC) is a noncash item which represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of interest expense and the remainder is recorded as other income.

Our balances of major classes of utility plant and associated useful lives are shown below as of December 31.

Notes to Financial Statements

Utility Plant	Estimated useful life range (years)	2017	2016
(thousands)			
Electric	29-75	$4,022,679	$3,780,012
Natural Gas	25-75	1,002,251	945,787
Common	7-75	563,442	522,219
Total Utility Plant in Service		**5,588,372**	**5,248,018**
Total accumulated depreciation		(2,100,274)	(2,043,588)
Total Net Utility Plant in Service		**3,488,098**	**3,204,430**
Construction work in progress		240,657	252,044
Total Utility Plant		**$3,728,755**	**3,456,474**

Electric plant includes capital leases of $31.9 million in 2017 and $33.0 million in 2016. Accumulated depreciation related to these leases was $5.4 million in 2017 and $3.3 million in 2016.

Impairment of long lived assets: We evaluate property, plant, and equipment and other long lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is required to be recognized if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying amount of the long lived asset exceeds the asset's fair value. Depending on the asset, fair value may be determined by use of a discounted cash flow model.

***Fair value measurement*:** Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

***Derivatives and hedge accounting*:** Derivatives are recognized on the balance sheets at their fair value, except for certain electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that qualify for, and are elected under, the normal purchases and normal sales exception. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. Changes in the fair value of a derivative contract are recognized in earnings unless specific hedge accounting criteria are met.

Derivatives that qualify and are designated for hedge accounting are classified as cash flow hedges. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in Other Comprehensive Income (OCI) and later reclassified into earnings when the underlying transaction occurs. For all designated and qualifying hedges, we maintain formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If we determine that the derivative is no longer highly effective as a hedge, hedge accounting will be discontinued prospectively. For cash flow hedges of forecasted transactions, we estimate the future cash flows of the forecasted transactions and evaluate the probability of the occurrence and timing of such transactions. If we determine it is probable that the forecasted transaction will not occur, hedge gains and losses previously recorded in OCI are immediately recognized in earnings.

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. Changes in the fair value of electric and natural gas hedge contracts are recorded to derivative assets or liabilities with an offset to regulatory assets or regulatory liabilities.

We offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

***Cash and cash equivalents*:** 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, 2017 and 2016, we did not have restricted cash. Book overdrafts representing outstanding checks in excess of funds on deposit are classified as “Accounts payable and accrued liabilities” on the balance sheets. Changes in book overdrafts are reported in the operating activities section of the statements of cash flows.

Statements of cash flows: Supplemental disclosure of cash flow information is as follows:

	2017	2016
(Thousands)		
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	$40,861	$40,074
Income taxes paid, net	$28,261	$84,291

Of the $28.3 million income tax, substantially all was paid to AGR under the tax sharing agreement. Interest capitalized was $11.4 million in 2017 and in $2.0 million in 2016. Accrued liabilities for property, plant and equipment additions were $18.8 million in 2017 and $14.0 million in 2016.

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.

***Accounts receivable*:** Accounts receivable at December 31 include unbilled revenues of $99.6 million for 2017 and $84.6 million for 2016, and are shown net of an allowance for doubtful accounts at December 31 of $23.2 million for 2017 and $23.1 million for 2016. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $12.1 million in 2017 and $9.1 million in 2016.

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 $14.5 million in 2017 and $14.7 million in 2016. DPA receivable balances at both December 31, 2017 and 2016 were $24.0 million.

***Inventory**:* Inventory comprises fuel and natural 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 carried and withdrawn at lower of cost and net realizable value 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.

***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 $14.0 million for 2017 and $14.5 million for 2016. 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, 2017 and 2016.

Year ended December 31,	**2017**	**2016**
(Thousands)		
ARO, beginning of year	$14,478	$14,902
Liabilities settled during the year	(1,231)	(1,221)
Accretion expense	774	797
ARO, end of year	**$14,021**	**$14,478**

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.

***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 2050.

Post-employment and other employee benefits: We sponsor defined benefit pension plans that cover the majority of our employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in other comprehensive income, as management believes it is probable that such items will be recoverable through the ratemaking process. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. We use the standard amortization methodology under which amounts in excess of ten percent of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement. Our policy is to calculate the expected return on plan assets using the market related value of assets. That value is determined by recognizing the difference between actual returns and expected returns over a five year period.

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 $41.8 million at December 31, 2017. The aggregate amount of the intercompany income tax receivable payable balance due from AGR was $31.7 million at December 31, 2016.

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 balance sheets.

On December 22, 2017, the President of the United States signed into law legislation referred to as the “Tax Cuts and Jobs Act” (the “Tax Act”). The Tax Act includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of business entities, and includes specific provisions related to regulated public utilities. The most significant change that impacted the Company was the permanent reduction in the corporate federal income tax rate from 35% to 21%, which required us to measure existing net deferred tax liabilities using the lower rate in the period of enactment, resulting in an excess deferred tax liability reduction in the amount of $476.9 million that regulators will determine how and when such amounts are passed back to customers. The specific provisions in the Tax Act related to regulated public utilities generally allow for the continued deductibility of interest expense, the elimination of full expensing for tax purposes of certain property acquired after September 27, 2017, and continues certain rate normalization requirements for accelerated depreciation benefits.

The staff of the US Securities and Exchange Commission (“SEC”) has recognized the complexity of reflecting the impacts of the Tax Act, and on December 22, 2017, issued guidance in Staff Accounting Bulletin 118 (“SAB 118”) which clarifies accounting for income taxes under ASC 740 if information is not yet available or complete and provides for up to a one year period in which to complete the required analyses and accounting (“the measurement period”).

The Company has completed or has made a reasonable estimate for the measurement and accounting of certain effects of the Tax Act which have been reflected in the December 31, 2017 financial statements. The Company has reported provisional amounts for the income tax effects related to the re-measurement of our deferred tax assets and liabilities. The ultimate impact may differ (materially) from the provisional amounts, among other things, as a result of additional analysis, changes in interpretations and assumptions, the release of additional guidance by the Internal Revenue Service, Treasury Department, and other standard-setting bodies. There were no specific impacts that could not be reasonably estimated.

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.

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 NYSEG 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 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 is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities.

(a) Revenue from contracts with customers

In May 2014, the FASB issued Accounting Standards Codification (ASC), Topic 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. ASC 606 was further amended through various updates the FASB issued thereafter. 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 amended effective date for public entities is for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption permitted as of the original effective date of annual reporting periods beginning after December 15, 2016. Entities may apply the standard 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). Effective January 1, 2018, we have adopted ASC 606 and applied the modified retrospective method. Our revenues are derived primarily from tariff-based sales of electric and natural gas service to customers in New York with no defined contractual term. For such revenues, we will recognize revenues in an amount derived from the commodities delivered to customers. Based on our assessment of existing contracts and revenue streams, we do not expect ASC 606 to have a material impact on the amount and timing of our revenue recognition from the superseded revenue standard and therefore, we did not record a material cumulative adjustment to retained earnings. We have identified other changes primarily related to the presentation and disclosure of revenues. We plan to disaggregate revenues from contracts with customers in our note disclosure by the source of the commodity sold. We will also disaggregate revenues not accounted for in scope of the new standard, as required, including alternative revenue programs.

(b) 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.

(c) 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 FASB issued an update in January 2018 to clarify the application of the new leases guidance to land easements and provide relief concerning adoption efforts for existing land easements that are not accounted for as leases under current GAAP. 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 right-of-use assets, along with the corresponding liabilities.

(d) 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.

(e) Certain classifications in the statement of cash flows

The FASB issued 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 and disclosures.

(f) Simplifying the test for goodwill impairment

In January 2017 the FASB issued amendments to simplify the test for goodwill impairment, which are required for public entities and certain other entities that have goodwill reported in their financial statements. The amendments simplify the subsequent measurement of goodwill by eliminating Step 2 from the goodwill impairment test. In computing the implied fair value of goodwill under Step 2, an entity had to perform procedures to determine the fair value at the impairment testing date of its assets and liabilities (including unrecognized assets and liabilities) following the procedure that would be required in determining the fair value of assets acquired and liabilities assumed in a business combination. Under the new guidance, an entity should perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; but the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Also, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable. Certain requirements are eliminated for any reporting unit with a zero or negative carrying amount, therefore the same impairment assessment applies to all reporting units. An entity is required to disclose the amount of goodwill allocated to each reporting unit with a zero or negative carrying amount of net assets. An entity still has the option to perform the qualitative assessment for a reporting unit to determine if the quantitative impairment test is necessary. The amendments modify the concept of impairment from the condition that exists when the carrying amount of goodwill exceeds its implied fair value to the condition that exists when the carrying amount of a reporting unit exceeds its fair value. The amendments are effective for public entities for annual and interim periods in fiscal years beginning after December 15, 2019, with the amendments applied on a prospective basis. Early adoption is allowed. We expect our adoption of the amendments will not materially affect our results of operations, financial position, cash flows, and disclosures.

(g) Improving the presentation of net periodic benefit costs

In March 2017, the FASB issued amendments to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost in the financial statements. The amendments require an entity to present service cost separately from the other components of net benefit cost, and to report the service cost component in the income statement line item(s) where it reports the corresponding compensation cost. An entity is to present all other components of net benefit cost outside of operating cost. The amendments also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of a self-constructed asset). The amendments are effective for public entities for annual and interim periods in fiscal years beginning after December 15, 2017, with early adoption permitted. We do not plan to early adopt. An entity is required to apply the amendments retrospectively for the presentation of the service cost component and the other components of net periodic pension cost and net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension cost and net periodic postretirement benefit in assets. A practical expedient allows an entity to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in the notes to financial statements for pension and postretirement benefit plans for those periods. We expect our adoption of the amendments will not materially affect our results of operations, financial position, cash flows, and disclosures.

(h) Targeted improvements to accounting for hedging activities

In August 2017, the FASB issued targeted amendments with the objective to better align hedge accounting with an entity's risk management activities in the financial statements, and to simplify the application of hedge accounting. The amendments address concerns of financial statement preparers over difficulties with applying hedge accounting and limitations for hedging both nonfinancial and financial risks and concerns of financial statement users over how hedging activities are reported in financial statements. Changes to the hedge accounting guidance to address those concerns will: 1) expand hedge accounting for nonfinancial and financial risk components and amend measurement methodologies to more closely align hedge accounting with an entity's risk management activities; 2) eliminate the separate measurement and reporting of hedge ineffectiveness, to reduce the complexity of preparing and understanding hedge results; 3) enhance disclosures and change the presentation of hedge results to align the effects of the hedging instrument and the hedged item in order to enhance transparency, comparability, and understandability of hedge results; and 4) simplify the way assessments of hedge effectiveness may be performed to reduce the cost and complexity of applying hedge accounting. The amendments are effective for public entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted in any interim period after issuance of the amendments. We do not expect to early adopt. For cash flow and net investment hedges existing at the date of adoption, a company must apply a cumulative-effect adjustment related to the separate measurement of ineffectiveness to accumulated other comprehensive income (AOCI) with a corresponding adjustment to the opening balance of retained earnings as of the beginning of the fiscal year of adoption. The amended presentation and disclosure guidance is required only prospectively. An entity may make certain elections upon adoption to allow for existing hedging relationships to transition to newly allowable alternatives. We expect our adoption of the guidance will not materially affect our results of operations, financial position, or cash flows, but we expect the amendments will ease the administrative burden of hedge documentation requirements and assessing hedge effectiveness.

(i) Reclassification of certain tax effects from accumulated other comprehensive income

In February 2018 the FASB issued amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017 by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within AOCI (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. The amendments are effective for all entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted including, for public entities, adoption in any interim period for which financial statements have not been issued. An entity has the option to apply the amendments either in the period of adoption or retrospectively to each period (or periods) in which it recognizes the effect of the change in the U.S. federal corporate income tax rate in the Tax Act. An entity is required to disclose its accounting policy election, including its policy for reclassifying material stranded tax effects in AOCI to earnings (specific identification or portfolio method). We have not early adopted the amendments as of December 31, 2017. We expect our adoption of the amendments will not materially affect our results of operations, financial position, cash flows, and disclosures.

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 76% of the company's employees are covered by a collective bargaining agreement. There are no agreements which will expire within the coming year.

Note 2. Industry Regulation

Electricity and Natural Gas Distribution

Our revenues are essentially regulated, being based on tariffs established in accordance with administrative procedures set by the 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.

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 and NYSEG Gas is 9.00%. The equity ratio for each company is 48%; however, the equity ratio is set at the actual up to 50% for earnings sharing calculation purposes. The customer share of any earnings above allowed levels increases as the ROE increases, with customers receiving 50%, 75% and 90% of earnings over 9.5%, 10.0% and 10.5% ROE, respectively, in the first rate year covering the period May 1, 2016 – April 30, 2017. The earnings sharing levels increase in rate year two (May 1, 2017 – April 30, 2018) to 9.65%, 10.15% and 10.65% ROE, respectively. The earnings sharing levels further increase in rate year three (May 1, 2018 – April 30, 2019) to 9.75%, 10.25% and 10.75% ROE, respectively. The rate plans also include the implementation of a rate adjustment mechanism designed to return or collect certain defined reconciled revenues and costs, new depreciation rates, and continuation of the existing RDM for each business.

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 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 associated with this petition began in in the first quarter of 2017, was suspended in the second quarter of 2017 and resumed in the first quarter of 2018.

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 Distributed Energy Resources (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 New York State Energy Research and Development Authority (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 is ongoing.

In March, 2017, the NYPSC issued three separate REV-related orders. These orders created a series of filing requirements for NYSEG beginning in March 2017 and extending through the end of 2018. The three orders involve: 1) modifications to the electric utilities' proposed interconnection earnings adjustment mechanism framework; 2) further DSIP requirements, including filing of an updated DSIP plan by mid-2018 and implementing two energy storage projects at each company by the end of 2018; and 3) Net Energy Metering Transition including implementation of Phase One of the Value of DER. In September 2017, the NYPSC issued another order related to the Value of DER, requiring tariff filings, changes to Standard Interconnection Requirements, and planning for the implementation of automated consolidated billing.

Minimum Equity Requirements for Regulated Subsidiaries

NYSEG is 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.

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2017 Windstorm

On March 11, 2017, the New York State Department of Public Service (the Department) commenced an investigation of NYSEG's preparation for and response to the March 2017 windstorm, which affected more than 219,000 customers. The Department investigation included a comprehensive review of NYSEG's preparation for and response to the windstorm, including all aspects of the company's filed and approved emergency plan. The Department held public hearings on April 12 and 13, 2017.

On November 16, 2017, the NYPSC announced that the Department Staff had completed their investigation into the March 2017 Windstorm and the NYPSC issued an Order Instituting

Proceeding and to Show Cause. The Staff's investigation found that NYSEG violated certain parts of their emergency response plans, which makes them subject to possible financial penalties. NYSEG responded to the order in a timely manner and have entered into settlement discussions with the Department Staff. The unprecedented weather that resulted in the March 2017 windstorm posed great challenges to NYSEG's communities, employees, contractors, assisting utilities, and municipal partners who all worked tirelessly to safely restore power to all customers. NYSEG's priorities during any storm are the restoration of service to their respective customers and the safety of their communities, customers, employees and contractors. We cannot predict the outcome of this regulatory action.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. The NYPSC has instituted proceedings in New York to review and address the implications associated with the Tax Act on the utilities providing service in state of New York. We expect the regulators, including the FERC, to issue requirements in 2018 regarding how all tax benefits associated with the Tax Act will be returned to customers.

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 $579.1 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, 2017 and 2016 consisted of:

December 31,	2017	2016
(Thousands)		
Current		
Environmental remediation costs	$5,705	$5,705
Merchant function charge	-	1,068
Electric supply reconciliation	144	8,609
Property tax	9,766	9,766
Revenue decoupling mechanism	12,447	10,904
Pension and other post-retirement benefits cost deferrals	23,887	21,770
Unamortized loss on re-acquired debt	2,037	2,037
Storm cost	40,129	40,129
Low income programs	1,826	2,953
Hedges losses	1,155	6,061
Rate change levelization	8,252	-
Other	8,055	12,695
Total current regulatory assets	**$113,403**	**$121,697**
Other long-term		
Federal tax depreciation normalization adjustment	$92,988	$73,511
Asset retirement obligation	14,055	14,463
Property tax deferrals	14,370	32,546
Pension and other post-retirement benefits cost deferrals	71,949	99,649
Merger capital expenditure	1,720	6,991
Low income programs	7,487	14,446
Unamortized loss on re-acquired debt	12,047	14,084
Pension and other postretirement benefits	398,341	492,378
Environmental remediation costs	93,155	86,663
Storm costs	165,623	184,133
Other	16,520	26,842
Total long-term regulatory assets	**888,255**	**1,045,706**
Deferred income taxes regulatory	30,376	-
Total long-term regulatory assets	**$918,631**	**$1,045,706**

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.

Federal tax depreciation normalization adjustment represents the deferral of the normalization of change impacts in book lives and the pass back of theoretical reserves associated with deferred income tax.

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 $205.8 million at December 31, 2017 and $184.1 million at December 31, 2016. Pursuant to the approved Proposal, NYSEG will recover $139.0 million of the balance over five years for non-super-storms and the super-storm balance of $123.0 million over 10 years. Recovery began May 1, 2016 at the start of the most recent Joint Proposal with the Commission.

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 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 represent 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.

Rate change levelization represents NY delivery rate levelization to smooth the rate increase across the three year plan to avoid unnecessary spikes and offsetting dips in customer rates.

Other includes items such as post-term amortization.

Deferred income taxes regulatory: see Note 1.

Current and long-term regulatory liabilities at December 31, 2017 and 2016 consisted of:

December 31, (Thousands)	**2017**	**2016**
Current		
Energy efficiency portfolio standard	$15,368	$20,128
Non by-passable charges	4,515	21,819
Gas supply charge and deferred natural gas cost	3,654	5,913
Carrying costs on deferred income tax depreciation	18,107	18,107
Pension and other postretirement benefits cost deferral	13,601	13,601
New York State tax rate change	-	2,685
Economic development	3,487	3,487
Theoretical reserve flow through impact	5,367	5,367
Reliability support services	26	3,163
Debt rate reconciliation	2,825	2,825
Positive benefit adjustment	2,685	2,685
NYS excess DIT – in rates	2,676	-
Other	5,987	8,359
Total current regulatory liabilities	**$78,298**	**$108,139**
Long-term		
Carrying costs on deferred income tax bonus depreciation	$26,183	$39,117
Economic development	12,919	16,097
Merger capital expenditure	-	4,533
Positive benefit adjustment	6,264	8,949

Variable rate debt	17,295	13,228
Unfunded future income taxes	21,484	-
New York State tax rate change	1,738	4,414
Tax Act-remeasurement	476,855	-
Other taxes	-	37,527
Pension and other postretirement benefits	12,180	10,582
Pension and other postretirement benefits cost deferral	33,646	46,848
Accrued removal obligation	516,905	493,105
Other	64,864	35,701
Total non-current regulatory liabilities	**1,190,333**	**710,101**
Deferred income taxes regulatory	-	138,973
Total long-term regulatory liabilities	**$1,190,333**	**$849,074**

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.

Variable Rate Debt represents the over/under collection of costs related to variable rate debt instruments identified in the rate case. Costs include interest, commissions and fees versus amounts included in rates.

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.

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.

Tax Act - remeasurement represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The NYPSC has instituted separate proceedings to review and address the implications associated with the Tax Act on the utilities providing service in state of New York. We expect the regulators, including the FERC, to issue requirements in 2018 regarding how all tax benefits associated with the Tax Act will be returned to customers.

Other includes various items subject to reconciliation including theoretical reserve, earnings sharing provision and asset retirement obligations.

Note 4. Income Taxes

The Tax Act changes significantly the federal taxation of business entities, including among other things, a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. We have made a reasonable estimate of the effects of the Tax Act and recorded provisional amounts for the income tax effects related to the remeasurement of our deferred tax assets and liabilities and the associated regulatory liabilities established by our regulated utility companies in our financial statements as of December 31, 2017. As we complete our analysis of the Tax Act, collect and prepare necessary data, and interpret any additional guidance issued by the U.S. Treasury Department, the IRS, and other standard-setting bodies, we may make adjustments to the provisional amounts. Those adjustments may materially impact our provision for income taxes in the period in which the adjustments are made.

Current and deferred taxes charged to expense for the years ended December 31, 2017 and 2016 consisted of:

Year Ended December 31,	**2017**	**2016**
(Thousands)		
Current		
Federal	$15,456	$22,866
State	4,684	9,510
Current taxes charged to expense	**20,140**	**32,376**

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Deferred		
Federal	51,821	51,992
State	7,368	8,366
Deferred taxes charged to expense (benefit)	**59,189**	**60,358**
Investment tax credit adjustments	(510)	(510)
Total Income Tax Expense	**$78,819**	**$92,224**

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, 2017 and 2016 consisted of:

Year Ended December 31,	**2017**	**2016**
(Thousands)		
Tax expense at statutory rate	$64,325	$73,889
Impact of Depreciation Normalization	-	6,951
Investment tax credit amortization	(510)	(510)
Tax return and related adjustments	7,020	545
State taxes net of federal benefit	7,834	11,619
Other, net	150	(270)
Total Income Tax Expense	**$78,819**	**$92,224**

Income tax expense for the year ended December 31, 2017 was $14.4 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to tax return and related adjustments, and state taxes, (net of federal benefit). This resulted in an effective tax rate of 42.9%. 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 the elimination of deferred taxes on normalizing depreciation. This resulted in an effective tax rate of 43.7%.

Deferred tax assets and liabilities as of December 31, 2017 and 2016 consisted of:

December 31,	**2017**	**2016**
(Thousands)		
Non-current Deferred Income Tax Liabilities (Assets)		
Property related	$530,396	$754,086
Storm Costs	53,773	88,930
Federal And State Tax Credits	(2,665)	
Accumulated deferred investment tax credits	(510)	14,658
Pension and other postretirement benefits	28,933	107,269
Regulatory Liability related to Tax Reform	(124,626)	0
Federal And State Tax Credits	(738)	0
Environmental	(15,317)	(27,978)
Positive benefits Adjustment	0	(4,616)
Other	(2,540)	(47,838)
Total Non-current Deferred Income Tax Liabilities	**466,706**	**884,511**
Less amounts classified as regulatory liabilities		
Less non-current deferred income taxes classified as regulatory liabilities	(30,376)	138,973
Non-current Deferred Income Tax Liabilities	**$497,082**	**$745,538**
Deferred tax assets	$146,396	$80,432
Deferred tax liabilities	613,102	964,943
Net Accumulated Deferred Income Tax Liabilities	**$466,706**	**$884,511**

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

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2017 and 2016 consisted of:

Year Ended December 31,	2017	2016
(Thousands)		
Balance as of January 1	$16,994	$5,937
Increases for tax positions related to prior years	867	11,057
Balance as of December 31	**$17,861**	**$16,994**

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

Accruals for interest and penalties on tax reserves were $0.4 million as of December 31, 2017 and $1.6 million as of December 31, 2016. If recognized, $1.8 million of the total gross unrecognized tax benefits would affect the effective tax rate as a benefit. Gross unrecognized tax benefits increased by $0.9 million in 2017 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, 2017 and 2016, our long-term debt was:

As of December 31,		2017		2016	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
Senior unsecured debt	2022-2042	$ 850,000	3.24%-5.75%	$ 1,050,000	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	-	-	-		
Obligations under capital leases	2018-2030	7,348		28,375	
Unamortized debt issuance costs and discount		(15,490)		(17,235)	
Total Debt		**$1,041,858**		**$ 1,261,140**	
Less: debt due within one year, included in current liabilities		322		219,325	
Total Non-current Debt		**$1,041,536**		**$ 1,041,815**	

At December 31, 2017, long-term debt, including sinking fund obligations and capital lease payments (in thousands) that will become due during the next five years are:

2018	2019	2020	2021	2022
$322	$1,795	$201,444	$489	$75,320

Note 6. Bank Loans and Other Borrowings

NYSEG had a total of $274.6million and $6.0 million of short-term debt outstanding at December 31, 2017 and 2016, respectively. 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. NYSEG had a notes payable of $5.9 million outstanding under this agreement as of December 31, 2017 and there was no balance outstanding at 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 $118.7 million and $6.0 million outstanding under this agreement as of December 31, 2017 and December 31, 2016, 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 borrowed $150 million under this agreement as of December 31, 2017.

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 0.48 to 1.00 at December 31, 2017. We are not in default as of December 31, 2017.

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

At December 31, 2017, 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

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2017 Windstorm

On March 11, 2017, the Department commenced an investigation of NYSEG's preparation for and response to the March 2017 windstorm, which affected more than 219,000 customers. The Department investigation included a comprehensive review of NYSEG's preparation for and response to the windstorm, including all aspects of the companies' filed and approved emergency plan. The Department held public hearings on April 12 and 13, 2017.

On November 16, 2017, the NYPSC announced that the Department Staff had completed their investigation into the March 2017 Windstorm and the NYPSC issued an Order Instituting Proceeding and to Show Cause. The Staff's investigation found that RG&E and NYSEG violated certain parts of their emergency response plans, which makes them subject to possible financial penalties. NYSEG responded to the order in a timely manner and have entered into settlement discussions with the Department Staff. The unprecedented weather that resulted in the March 2017 windstorm posed great challenges to the NYSEG's communities, employees, contractors, assisting utilities, and municipal partners who all worked tirelessly to safely restore power to all customers. NYSEG's priorities during any storm are the restoration of service to their respective customers and the safety of their communities, customers, employees and contractors. We cannot predict the outcome of this regulatory action.

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 pays Cayuga a monthly fixed price and also pays for capital expenditures for specified capital projects. NYSEG is 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 $17.6 million and $37.8 million for the years ended December 31, 2017 and 2016.

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 $87.9 million for non-utility generator (NUG) power in 2017 and $83.3 million in 2016. We estimate that our power purchases will total $79.5 million in 2018, $56.6 million in 2019, $36.1 million in 2020, $25.7 million 2021, $13.6 million in 2022 and $59.0 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 Environmental Protection Agency (EPA) and the New York State Department of Environmental Conservation (NYSDEC), as appropriate, have notified us that we are among the potentially responsible parties that may be liable for costs incurred to remediate certain hazardous substances at 12 waste sites. The 12 sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the 12 sites, 11 sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites and four sites are also included on the National Priorities list. Any liability may be joint and several for certain of those sites.

We have a liability recorded of $5.4 million as of December 31, 2017, 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 $5.3 million to $5.9 million as of December 31, 2017. 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 $131.6 million to $245.9 million at December 31, 2017. 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 $152.1 million at December 31, 2017, and $156.7 million at December 31, 2016. We recorded a corresponding regulatory asset, net of insurance recoveries and the amount collected from FirstEnergy described below, because we expect to recover the net costs in rates.

Our environmental liability accruals are recorded on an undiscounted basis and are expected to be paid through the year 2050.

FirstEnergy

NYSEG sued FirstEnergy under the Comprehensive Environmental Response, Compensation, and Liability Act to recover environmental cleanup costs at sixteen former manufactured gas sites, which are included in the discussion above. In July 2011, the District Court issued a decision and order in NYSEG's favor. Based on past and future clean-up costs at the sixteen sites in dispute, FirstEnergy would be required to pay NYSEG approximately $60 million if the decision were upheld on appeal. 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.

FirstEnergy appealed the decision to the Second Circuit Court of Appeals. On September 11, 2014, the Second Circuit Court of Appeals affirmed the District Court's decision in NYSEG's favor, but modified the decision 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 manufactured gas plant (MGP) sites. Based on current projections, FirstEnergy's share is estimated at approximately $22 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 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, although this amount may change substantially depending upon the determination of various factual matters and legal issues during the case.

Century Indemnity and OneBeacon 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 filed a motion with the District Court on April 14, 2017 seeking reconsideration of the Court's decision and is researching grounds for further appeal if the reconsideration motion is denied. We cannot predict the outcome of this matter, however, any recovery will be flowed through to NYSEG ratepayers.

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.

Notes to Financial Statements

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, 2017 and 2016, the amount recognized in regulatory assets for electricity derivatives was a loss of $0.4 million and $7.9 million, respectively. For the years ended December 31, 2017 and 2016, the amount reclassified from regulatory assets/liabilities into income, which is included in electricity purchased, was a loss of $24.3 million and $48.9 million, 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, 2017 and 2016, the amount recognized in regulatory assets for natural gas hedges was a loss of $0.7 million and $1.2 million, respectively. For the years ended December 31, 2017 and 2016, the amount reclassified from regulatory assets into income, which is included in natural gas purchased, was a loss of $0.1 million and $0.2 million, respectively.

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

	Electricity Contracts	**Natural Gas Contracts**	**Other Fuel Contracts**
Year to settle	**Mwhs**	**Dths**	**Gallons**
As of December 31, 2017			
2018	2,381,125	1,580,000	1,043,400
2019	219,000	330,000	-
As of December 31, 2016			
2017	2,620,550	1,610,000	1,182,600
2018	1,355,750	270,000	-

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2017 and 2016, respectively, consisted of:

Notes to Financial Statements

December 31, 2017	Derivative Assets - Current	Derivative Assets - Noncurrent	Derivative Liabilities - Current	Derivative Liabilities - Noncurrent
(In thousands)				`
Not designated as hedging instruments				
Derivative assets	$8,859	$ 515	$ 8,859	$405
Derivative liabilities	(8,859)	(405)	(10,015)	(456)
	-	110	(1,156)	(51)
Designated as hedging instruments				
Derivative assets	36	-	36	-
Derivative liabilities	(36)	-	(75)	-
	-		(39)	-
Total derivatives before offset of cash collateral		110	(1,195)	51
Cash collateral receivable	-	-	1,156	(51)
Total derivatives as presented in the balance sheet	**$-**	**$110**	**$(39)**	**$-**

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)**	**$-**

The effect of hedging instruments on OCI and income was:

Year Ended December 31,	(Loss) Gain Recognized in OCI on Derivatives	Location of (Loss) Gain Reclassified From Accumulated OCI into Income	Loss Reclassified From Accumulated OCI into Income
Derivatives in Cash Flow Hedging Relationships	**Effective Portion**	**Effective Portion**	
(Thousands)			
2017			
Interest rate contracts	$-	Interest expense	$(105)

Commodity contracts	$(271)	Other operating expenses	$(377)
Total	**$(271)**		**$(482)**
2016			
Interest rate contracts	$-	Interest expense	$(105)
Commodity contracts	$174	Other operating expenses	$(1,031)
Total	**$174**		**$(1,136)**

The amounts in AOCI related to previously settled forward starting swaps, and accumulated amortization, as of December 31, 2017, is a net loss of $0.6 million as compared to a net loss of $0.7 million for 2016. For the year ended December 31, 2017, 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 2018.

As of December 31, 2017, $0.4 million in losses are reported in AOCI because the forecasted transaction is considered to be probable. We expect that those losses will be reclassified into earnings within the next 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, 2017.

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, 2017 is $1.2 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 $1,095 million and $1,311 million as of December 31, 2017 and 2016, 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 Financial Statements

Assets and liabilities measured at fair value on a recurring basis

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

Description **(Thousands)**	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Netting**	**Total**
2017					
Assets					
Noncurrent investments available for sale, primarily money market funds	$10,411	$-	$-	$-	$10,411
Derivatives					
Commodity contracts:					
Electricity	9,356	-	-	(9,246)	110
Natural Gas	19	-	-	(19)	-
Other	-	-	36	(36)	-
Total	**$19,786**	**$-**	**$36**	**$(9,301)**	**$10,521**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	$(9,726)	$-	-	$9,726	-
Natural gas	(744)	-	-	744	-
Other	-	-	(75)	36	(39)
Total	**$(10,470)**	**$-**	**$(75)**	**$10,506**	**$(39)**
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)**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2017 and 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.

<u>Valuation techniques</u>: We measure the fair value of our noncurrent investments available for sale using quoted market prices in active markets for identical assets and include the measurements in Level 1. The investments which are Rabbi Trusts for deferred compensation plans primarily

consist of money market funds.

We determine the fair value of our 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 our electric load obligations using derivative contracts that are settled based upon Locational Based Marginal Pricing published by the NYISO. We hedge approximately 70% of their electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value the companies' 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.
- 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,	**2017**	**2016**
(Thousands)		
Beginning balance	$145	$1,350
Total (losses) gains (realized/unrealized)		
Included in earnings	(377)	(1,031)
Included in other comprehensive income	271	(174)
Ending balance	**$39**	**$145**

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, 2016	**2016 Change**	**Balance December 31, 2016**	**2017 Change**	**Balance December 31, 2017**
(Thousands)					
Amortization of pension cost for nonqualified plans, net of income tax /(benefit) of $25 for 2016 and $(48) for 2017	$(510)	$39	$(471)	$(74)	$(545)
Unrealized gain (loss) on derivatives qualified as hedges:		-			
Unrealized gain (loss) during period on derivatives qualified as hedges, net of income tax expense (benefit) of $69 for 2016 and $(107) for 2017		105		(164)	
Reclassification adjustment for loss included in net income, net of					

income tax expense of $404 for 2016 and $150 for 2017		627		228	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $41 for 2016 and $42 for 2017		64		63	
Net unrealized gain (loss) on derivatives qualified as hedges	(1,283)	796	(487)	127	(360)
Accumulated Other Comprehensive Loss	**$(1,793)**	**$835**	**$(958)**	**$53**	**$(905)**

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 $6.0 million for 2017 and $5.6 million for 2016.

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**	
	2017	**2016**	**2017**	**2016**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$1,531,453	$1,593,364	$186,093	$192,181
Service cost	16,718	18,075	2,180	2,414
Interest cost	61,280	63,528	7,402	7,610
Plan participants' contributions	-	-	3,399	2,967
Actuarial loss/(gain)	85,229	(63,187)	(185)	(1,446)
Benefits paid	(93,111)	(80,327)	(17,793)	(17,638)
Federal subsidy on benefits paid	-	-	15	5
Benefit obligation at December 31	**$1,601,569**	**$1,531,453**	**$181,111**	**$186,093**
Change in plan assets				
Fair value of plan assets at January 1	$1,370,779	$1,368,903	$83,595	$85,807
Actual return on plan assets	196,438	82,203	7,243	4,789
Employer & plan participants' contributions	-	-	10,778	17,633
Federal subsidy on benefits paid	-	-	15	5
Benefits paid	(93,111)	(80,327)	(17,793)	(24,639)
Fair value of plan assets at December 31	**$1,474,106**	**$1,370,779**	**$83,838**	**$83,595**

Funded status	**$(127,463)**	**$(160,674)**	**$(97,273)**	**$(102,498)**

Amounts recognized in the balance sheet	**Pension Benefits**		**Postretirement Benefits**	
December 31,	**2017**	**2016**	**2017**	**2016**
(Thousands)				
Noncurrent liabilities	$(127,463)	$(160,674)	$(97,273)	$(102,498)

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,	**2017**	**2016**	**2017**	**2016**
(Thousands)				
Net loss	$392,773	$485,608	$7,186	$14,382
Prior service cost (credit)	$5,568	$6,769	$(19,367)	$(24,963)

Our accumulated benefit obligation for all defined benefit pension plans was $1.5 billion as of both December 31, 2017 and 2016. NYSEG's postretirement benefits were partially funded as of December 31, 2017 and 2016.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets for our plans as of both December 31, 2017 and 2016. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2017 and 2016.

December 31,	**2017**	**2016**
(Thousands)		
Projected benefit obligation	$1,601,569	$1,531,453
Accumulated benefit obligation	$1,531,218	$1,460,980
Fair value of plan assets	$1,474,106	$1,370,779

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

	Pension Benefits		**Postretirement Benefits**	
Years Ended December 31,	**2017**	**2016**	**2017**	**2016**
(Thousands)				
Net periodic benefit cost				
Service cost	$16,718	$18,075	$2,180	$2,414
Interest cost	61,280	63,528	7,402	7,610
Expected return on plan assets	(103,106)	(103,767)	(3,553)	(3,861)
Amortization of prior service cost (credit)	1,201	1,369	(5,596)	(5,597)
Amortization of net loss	84,732	83,229	3,320	2,407
Net periodic benefit cost	**$60,825**	**$62,434**	**$3,753**	**$2,973**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain)	$(8,103)	$(41,623)	$(3,875)	$(2,373)
Amortization of net (loss)	(84,732)	(83,229)	(3,320)	(2,407)
Amortization of prior service (cost) credit	(1,201)	(1,369)	5,596	5,597
Total recognized in regulatory assets and regulatory liabilities	**$(94,036)**	**$(126,221)**	**$(1,599)**	**$817**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$(33,211)**	**$(63,787)**	**$2,154**	**$3,790**

Notes to Financial Statements

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, 2018	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	$99,369	$3,661
Estimated prior service cost (credit)	$1,077	$(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, 2018.

Weighted-average assumptions used to determine benefit obligations at December 31,	Pension Benefits 2017	2016	Postretirement Benefits 2017	2016
Discount rate	3.63%	4.12%	3.63%	4.12%
Rate of compensation increase	3.9%	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 Years ended December 31,	Pension Benefits 2017	2016	Postretirement Benefits 2017	2016
Discount rate	4.12%	4.10%	4.12%	4.10%
Expected long-term return on plan assets	7.30%	7.40%	-	-
Expected long-term return on plan assets - nontaxable trust	-	-	6.50%	7.00%
Expected long-term return on plan assets - taxable trust	-	-	4.25%	4.50%
Rate of compensation increase	3.90%	3.90%	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,	2017	2016
Health care cost trend rate (pre 65/post 65)	6.75%/8.50%	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	2026/2028

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

(Thousands)	1% Increase	1% Decrease
Effect on total of service and interest cost	$19	$(22)
Effect on postretirement benefit obligation	$269	$(303)

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 2018.

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
2018	$91,095	$12,241	-
2019	$93,903	$12,513	-
2020	$96,526	$12,683	-
2021	$98,546	$12,865	-
2022	$100,323	$12,939	-
2023-2027	$510,093	$62,292	-

***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, 2017 and 2016, by asset category are shown in the following table. NYSEG's share of the total consolidated assets is approximately 52% for 2017 and 2016:

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)				
2017				
Cash and cash equivalents	$17,531	$-	$17,531	$-
U.S. government securities	13,338	13,338	-	-
Common stocks	129,312	129,312	-	-
Registered investment companies	105,037	105,037	-	-
Corporate bonds	447,124	-	447,124	-
Preferred stocks	4,381	299	4,082	-
Equity commingled funds	435,635	185,989	249,646	-
Other investments, principally annuity and fixed income	548,957	-	548,957	-
	$1,701,315	**$433,975**	**$1,267,340**	**$-**
Other investments measured at net asset value	1,126,017			
Total	**$2,827,332**			
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	-
Equity commingled funds	371,831	-	371,831	-
Other investments, principally annuity and fixed income	310,785	-	310,785	-
	$1,477,301	**$384,451**	**$1,092,850**	**$-**
Other investments measured at net asset value	1,157,112			
Total	**$2,634,413**			

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.
- Equity commingled funds – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.

Notes to Financial Statements

- 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.
- Other investments measured at net asset value (NAV) – alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

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 other postretirement benefits plan assets, by asset category, as of December 31, 2017 consisted and 2016 are shown in the following table. NYSEG's share of the total assets is approximately 51% for 2017 and 52% for 2016:

		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)				
2017				
Money market funds	$3,978	$3,978	$-	$-
Mutual funds, fixed	35,419	35,419	-	-
Government & corporate bonds	1,658	-	1,658	-
Mutual funds, equity	76,444	49,089	27,355	-
Common stocks	19,800	19,800	-	-
Mutual funds, other	27,172	19,573	7,599	-
Total assets measured at fair value	**$164,471**	**$127,859**	**$36,612**	**$-**

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**	$-

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.
- 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, 2017 and 2016.

Note 14. Other Income and Other Deductions

Years Ended December 31,	**2017**	**2016**
(Thousands)		
Interest and dividend income	$37	$50
Carrying costs on regulatory assets	4,809	11,039
Allowance for funds used during construction	7,315	521
Gain on sale of property	1,080	457
Miscellaneous	2,131	234
Total other income	**$15,372**	**$12,301**
Civic donations	$(1,148)	($1,224)
Miscellaneous	(6)	(384)
Total other deductions	**$(1,154)**	**$(1,608)**

Note 15. 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 $89.8 million for 2017 and $82.2 million for 2016 and charge for services provided by NYSEG to AGR and its subsidiaries were approximately $22.2 million for 2017 and $11.3 million for 2016. All charges for services are at cost. The balance in accounts payable to affiliates of $78.5 million at December 31, 2017 and $74.3 million at December 31, 2016 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. The amount receivable from New York TransCo was $6.3 million at December 31, 2017 and $10.9 million at December 31, 2016.

Note 16. Subsequent Events

The company has performed a review of subsequent events through April 17, 2018, which is the date these financial statements were available to be issued, and no subsequent events have occurred from January 1, 2018 through such date.

Rochester Gas and Electric Corporation
Financial Statements
As of and For the Years Ended December 31, 2017 and 2016

Rochester Gas and Electric Corporation

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Financial Statements As of and for the Years Ended December 31, 2017 and 2016

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

Shareholders and The Board of Directors
Rochester Gas and Electric Corporation:

We have audited the accompanying financial statements of Rochester Gas and Electric Corporation, which comprise the balance sheet as of December 31, 2017, and the related statements of income, comprehensive income, changes in common stock 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 accordance 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 from material misstatement, whether due to fraud or error.

Auditors' 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 of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' 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 opinion.

Opinion

In our opinion, the 2017 financial statements referred to above present fairly, in all material respects, the financial position of Rochester Gas and Electric Corporation as of December 31, 2017, and the results of its operations and its cash flows for the year then ended in accordance with U.S. generally accepted accounting principles.

Other Matter

The accompanying financial statements of Rochester Gas and Electric Corporation as of December 31, 2016 and for the year then ended were audited by other auditors whose report thereon dated April 12, 2017, expressed an unmodified opinion on those financial statements.

KPMG LLP

New York, New York
March 30, 2018

Rochester Gas and Electric Corporation
Statements of Income

Years Ended December 31,	2017	2016
(Thousands)		
Operating Revenues		
Electric	$588,232	$787,421
Natural gas	262,447	253,159
Total Operating Revenues	**850,679**	**1,040,580**
Operating Expenses		
Electricity purchased and fuel used in generation	102,169	109,578
Natural gas purchased	85,124	70,562
Operations and maintenance	280,310	366,940
Depreciation and amortization	71,470	75,900
Other taxes	121,243	110,944
Total Operating Expenses	**660,316**	**733,924**
Operating Income	**190,363**	**306,656**
Other Income	15,498	14,657
Other Deductions	(485)	(1,325)
Interest Charges, net	(62,642)	(55,529)
Income Before Tax	**142,734**	**264,459**
Income Tax Expense	59,505	183,801
Net Income	**$83,229**	**$80,658**

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

Rochester Gas and Electric Corporation
Statements of Comprehensive Income

Years ended December 31,	2017	2016
(Thousands)		
Net Income	**$83,229**	**$80,658**
Other Comprehensive Income, Net of Tax		
Net unrealized holding income on investments	-	6
Amortization of pension for nonqualified plans	(61)	257
Unrealized (loss) gain on derivatives qualified as hedges:		
Unrealized (loss) gain during period on derivatives qualified as hedges	(94)	3
Reclassification adjustment for loss included in net income	98	220
Reclassification adjustment for loss on settled cash flow treasury hedges	3,505	3,505
Other Comprehensive Income, Net of Tax	**3,448**	**3,991**
Comprehensive Income	**$86,677**	**$84,649**

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

Rochester Gas and Electric Corporation
Balance Sheets

As of December 31,	2017	2016
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$631	$9
Accounts receivable and unbilled revenues, net	160,303	147,337
Accounts receivable from affiliates	4,318	4,743
Notes receivable from affiliates	39,727	-
Natural gas in storage	9,302	6,170
Materials and supplies	11,005	10,173
Broker margin accounts	6,848	3,417
Income tax receivable	16,589	39,932
Prepaid property taxes	35,120	35,056
Other current assets	3,555	6,500
Regulatory assets	63,627	63,117
Total Current Assets	**351,025**	**316,454**
Utility plant, at original cost	3,423,287	3,088,882
Less accumulated depreciation	(948,638)	(905,434)
Net Utility Plant in Service	**2,474,649**	**2,183,448**
Construction work in progress	332,457	395,665
Total Utility Plant in Service	**2,807,106**	**2,579,113**
Other Property and Investments	3,781	3,764
Regulatory and Other Assets		
Regulatory assets	486,398	513,712
Deferred income taxes regulatory	25,680	-
Other	1,021	438
Total Regulatory and Other Assets	**513,099**	**514,150**
Total Assets	**$3,675,011**	**$3,413,481**

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

Rochester Gas and Electric Corporation
Balance Sheets

As of December 31,	2017	2016
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Notes payable to affiliates	$-	$249,167
Notes payable	-	784
Current portion of long term debt	1,434	529
Accounts payable and accrued liabilities	166,062	206,446
Accounts payable to affiliates	41,685	38,306
Interest accrued	12,329	11,948
Taxes accrued	1,692	1,920
Environmental remediation costs	2,435	5,269
Other	37,579	37,068
Regulatory liabilities	33,463	29,733
Total Current Liabilities	**296,679**	**581,170**
Regulatory and Other Liabilities		
Regulatory liabilities	694,751	430,336
Deferred income taxes regulatory	-	51,876
Other Non-current Liabilities		
Deferred income taxes	320,944	434,937
Nuclear plant obligations	123,622	122,579
Pension and other postretirement benefits	175,394	180,078
Asset retirement obligations	3,214	3,004
Environmental remediation costs	131,367	133,463
Other	22,501	25,620
Total Regulatory and Other Liabilities	**1,471,793**	**1,381,893**
Long-term debt	958,911	664,424
Total Liabilities	**2,727,383**	**2,627,487**
Commitments and Contingencies		
Common Stock Equity		
Common stock ($5 par value, 50,000,000 shares authorized, 38,885,813 shares outstanding at December 31, 2017 and 2016)	194,429	194,429
Capital in excess of par value	604,975	530,018
Retained earnings	304,820	221,591
Accumulated other comprehensive loss	(39,358)	(42,806)
Treasury stock, at cost (4,379,300 shares at December 31, 2017 and 2016)	(117,238)	(117,238)
Total Common Stock Equity	**947,628**	**785,994**
Total Liabilities and Equity	**$3,675,011**	**$3,413,481**

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

Rochester Gas and Electric Corporation
Statements of Cash Flows

Years Ended December 31,	2017	2016
(Thousands)		
Cash Flow from Operating Activities		
Net income	**$83,229**	**$80,658**
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	71,470	75,900
Amortization of regulatory assets and liabilities	5,515	12,109
Carrying cost of regulatory assets and liabilities	12,468	7,891
Amortization of debt issuance costs	1,251	1,128
Deferred taxes	93,981	186,984
Pension cost	22,756	21,082
Stock-based compensation	(70)	223
Accretion expenses	159	165
Gain on disposal of property, plant and equipment	(20)	-
Other non-cash items	(8,054)	(16,068)
Changes in operating assets and liabilities		
Accounts receivable and unbilled revenues, net	(12,540)	(7,792)
Materials and supplies and natural gas in storage	(3,964)	(70)
Accounts payable and accrued liabilities	(36,267)	40,786
Accrued taxes	(228)	84
Other assets/liabilities	(1,310)	(153,182)
Regulatory assets/liabilities	(10,034)	(97,209)
Net Cash Provided by Operating Activities	**218,342**	**152,689**
Cash Flow from Investing Activities		
Utility plant additions	(301,811)	(253,261)
Contributions in aid of construction	4,783	4,473
Proceeds from sale of property, plant and equipment	561	4,900
Notes receivable from affiliates	(39,727)	-
Investments, net	(17)	981
Net Cash Used in Investing Activities	**(336,211)**	**(242,907)**
Cash Flow from Financing Activities		
Capital contributions from parent	75,000	-
Repayment of capital leases	(1,354)	(509)
Proceeds from non-current note issuance, net	294,012	-
Repayments of non-current debt	-	(39,850)
Notes payable to affiliates	(249,167)	179,450
Common stock dividends	-	(50,000)
Net Cash Provided by Financing Activities	**118,491**	**89,091**
Net Increase (Decrease) in Cash and Cash Equivalents	**622**	**(1,127)**
Cash and Cash Equivalents, Beginning of Year	**9**	**1,136**
Cash and Cash Equivalents, End of Year	**$631**	**$9**

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)	Number of shares (*)	Common stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Loss	Treasury Stock	Total Common Stock Equity
Balance, January 1, 2016	**38,885,813**	**$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	**38,885,813**	**194,429**	**530,018**	**221,591**	**(42,806)**	**(117,238)**	**785,994**
Net income	-	-	-	83,229	-	-	83,229
Other comprehensive income, net of tax	-	-	-	-	3,448	-	3,448
							86,677
Capital contribution	-	-	75,000	-	-	-	75,000
Stock-based compensation	-	-	(43)	-	-	-	(43)
Balance, December 31, 2017	**38,885,813**	**$194,429**	**$604,975**	**$304,820**	**$(39,358)**	**$(117,238)**	**$947,628**

(*) Par value of share amounts is $5

The accompanying notes are an integral part of our 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 378,000 electricity and 313,000 natural gas customers as of December 31, 2017 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 the Networks businesses. 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.

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.

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

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

Utility Plant**:** Utility plant is accounted for at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, the estimated cost of removal or reconditioning is recorded as an asset retirement obligation (ARO) and an equal amount is added to the carrying amount of the asset.

Assets are transferred from “Construction work in progress” to “Utility Plant” when they are available for service.

Utility plant is depreciated 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 in 2017 and 2.5% of average depreciable property in 2016. We amortize our capitalized software cost which is included in common plant, using the straight line method, based on useful lives of 7 to 17 years. Capitalized software costs at December 31 were approximately $116 million for 2017 and $113 million for 2016. Depreciation expense was $69 million in 2017 and $73 million in 2016. Amortization of capitalized software was $2 million in 2017 and $3 million in 2016.

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.

Allowance for funds used during construction (AFUDC) is a noncash item which represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of interest expense and the remainder is recorded as other income.

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

Plant	**Estimated useful life range (years)**	**2017**	**2016**
(Thousands)			
Electric	29-90	$2,219,220	$1,976,667
Natural Gas	30-80	874,581	793,583
Common	7-60	329,486	318,632

Utility plant at original cost	**3,423,287**	**3,088,882**
Less accumulated depreciation	(948,638)	(905,434)
Net Utility Plant in Service	**2,474,649**	**2,183,448**
Construction work in progress	332,457	395,665
Total Utility Plant	**$2,807,106**	**$2,579,113**

Electric plant includes capital leases of $13.7 million in 2017 and $13.7 million in 2016. Accumulated depreciation related to these leases was $2.9 million in 2017 and $2.5 million in 2016.

Impairment of long lived assets: We evaluate property, plant, and equipment and other long lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is required to be recognized if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying amount of the long lived asset exceeds the asset's fair value. Depending on the asset, fair value may be determined by use of a discounted cash flow model.

***Fair value measurement*:** Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

Derivatives and hedge accounting**:** Derivatives are recognized on the balance sheets at their fair value, except for certain electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that qualify for, and are elected under, the normal purchases and normal sales exception. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. Changes in the fair value of a derivative contract are recognized in earnings unless specific hedge accounting criteria are met.

Derivatives that qualify and are designated for hedge accounting are classified as cash flow hedges. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in Other Comprehensive Income (OCI) and later reclassified into earnings when the underlying transaction occurs. For all designated and qualifying hedges, we maintain formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If we determine that the derivative is no longer highly effective as a hedge, hedge accounting will be discontinued prospectively. For cash flow hedges of forecasted transactions, we estimate the future cash flows of the forecasted transactions and evaluate the probability of the occurrence and timing of such transactions. If we determine it is probable that the forecasted transaction will not occur, hedge gains and losses previously recorded in OCI are immediately recognized in earnings.

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. Changes in the fair value of electric and natural gas hedge contracts are recorded to derivative assets or liabilities with an offset to regulatory assets or regulatory liabilities.

We offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement.

Cash and cash equivalents**:** 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, 2017 and 2016, we did not have restricted cash. Book overdrafts representing outstanding checks in excess of funds on deposit are classified as “Accounts payable and accrued liabilities” on the balance sheets. Changes in book overdrafts are reported in the operating activities section of the statements of cash flows.

Statements of cash flows: Supplemental disclosure of cash flow information is as follows:

(Thousands)	2017	2016
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	$29,491	$37,400
Income taxes (refunded) paid, net	$(58,091)	$25,747

Of the $58.1 million income tax refunded, substantially all was received from AGR under the tax sharing agreement. Interest capitalized was $20.5 million in 2017 and $10.0 million in 2016. Accrued liabilities for property, plant and equipment additions were $17.9 million in 2017 and $19.5 million in 2016.

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.

Accounts receivable: Accounts receivable at December 31 include unbilled revenues of $64.2 million in 2017 and $52.9 million in 2016, and are shown net of an allowance for doubtful accounts at December 31 of $23.1 million for 2017 and $22.4 million for 2016.

Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $15.4 million in 2017 and $9.9 million in 2016.

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 $14.4 million in 2017 and $14.0 million in 2016. DPA receivable balances at December 31 were $21.8 million in 2017 and $21.0 million in 2016.

Inventory: Inventory comprises natural 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. The inventories are carried and withdrawn at lower of cost and net realizable value 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.

***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 $3.2 million for 2017 and $3.0 million for 2016. 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, 2017 and 2016.

Year ended December 31,	**2017**	**2016**
(Thousands)		
ARO, beginning of year	$3,004	$8,388
Liabilities settled during the year	(228)	(5,550)
Increase to provision	279	-
Accretion expense	159	166
ARO, end of year	**$3,214**	**$3,004**

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.

***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 2046.

Post-employment and other employee benefits: We sponsor defined benefit pension plans that cover the majority of our employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in other comprehensive income, as management believes it is probable that such items will be recoverable through the ratemaking process. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. We use the standard amortization methodology under which amounts in excess of ten percent of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement. Our policy is to calculate the expected return on plan assets using the market related value of assets. That value is determined by recognizing the difference between actual returns and expected returns over a five year period.

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, RG&E 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 $16.6 million and $39.9 million at December 31, 2017 and December 31, 2016, respectively.

The Company uses 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 balance sheets.

On December 22, 2017, the President of the United States signed into law legislation referred to as the “Tax Cuts and Jobs Act” (the “Tax Act”). The Tax Act includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of business entities, and includes specific provisions related to regulated public utilities. The most significant change that impacted the Company was the permanent reduction in the corporate federal income tax rate from 35% to 21%, which required us to measure existing net deferred tax liabilities using the lower rate in the period of enactment, resulting in an excess deferred tax liability reduction in the amount of $288 million that regulators will determine how and when such amounts are passed back to customers. The specific provisions in the Tax Act related to regulated public utilities generally allow for the continued deductibility of interest expense, the elimination of full expensing for tax purposes of certain property acquired after September 27, 2017, and continues certain rate normalization requirements for accelerated depreciation benefits.

The staff of the US Securities and Exchange Commission (“SEC”) has recognized the complexity of reflecting the impacts of the Tax Act, and on December 22, 2017, issued guidance in Staff Accounting Bulletin 118 (“SAB 118”) which clarifies accounting for income taxes under ASC 740 if information is not yet available or complete and provides for up to a one year period in which to complete the required analyses and accounting (“the measurement period”).

The Company has completed or has made a reasonable estimate for the measurement and accounting of certain effects of the Tax Act which have been reflected in the December 31, 2017 financial statements. The Company has reported provisional amounts for the income tax effects related to the re-measurement of our deferred tax assets and liabilities. The ultimate impact may differ (materially) from the provisional amounts, among other things, as a result of additional analysis, changes in interpretations and assumptions, the release of additional guidance by the Internal Revenue Service, Treasury Department, and other standard-setting bodies. There were no specific impacts that could not be reasonably estimated.

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. 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.

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 is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities.

(a) Revenue from contracts with customers

In May 2014, the FASB issued Accounting Standards Codification (ASC), Topic 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. ASC 606 was further amended through various updates the FASB issued thereafter. 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 amended effective date for public entities is for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption permitted as of the original effective date of annual reporting periods beginning after December 15, 2016. Entities may apply the standard 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). Effective January 1, 2018, we have adopted ASC 606 and applied the modified retrospective method. Our revenues are derived primarily from tariff-based sales of electric and natural gas service to customers in New York with no defined contractual term. For such revenues, we will recognize revenues in an amount derived from the commodities delivered to customers. Based on our assessment of existing contracts and revenue streams, we do not expect ASC 606 to have a material impact on the amount and timing of our revenue recognition from the superseded revenue standard and therefore, we did not record a material cumulative adjustment to retained earnings. We have identified other changes primarily related to the presentation and disclosure of revenues. We plan to disaggregate revenues from contracts with customers in our note disclosure by the source of the commodity sold. We will also disaggregate revenues not accounted for in scope of the new standard, as required, including alternative revenue programs.

(b) 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.

(c) 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 FASB issued an update in January 2018 to clarify the application of the new leases guidance to land easements and provide relief concerning adoption efforts for existing land easements that are not accounted for as leases under current GAAP. 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 right-of-use assets, along with the corresponding liabilities.

(d) 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.

(e) Certain classifications in the statement of cash flows

The FASB issued 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 and disclosures.

(f) Simplifying the test for goodwill impairment

In January 2017 the FASB issued amendments to simplify the test for goodwill impairment, which are required for public entities and certain other entities that have goodwill reported in their financial statements. The amendments simplify the subsequent measurement of goodwill by eliminating Step 2 from the goodwill impairment test. In computing the implied fair value of goodwill under Step 2, an entity had to perform procedures to determine the fair value at the impairment testing date of its assets and liabilities (including unrecognized assets and liabilities) following the procedure that would be required in determining the fair value of assets acquired and liabilities assumed in a business combination. Under the new guidance, an entity should perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; but the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Also, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable. Certain requirements are eliminated for any reporting unit with a zero or negative carrying amount, therefore the same impairment assessment applies to all reporting units. An entity is required to disclose the amount of goodwill allocated to each reporting unit with a zero or negative carrying amount of net assets. An entity still has the option to perform the qualitative assessment for a reporting unit to determine if the quantitative impairment test is necessary. The amendments modify the concept of impairment from the condition that exists when the carrying amount of goodwill exceeds its implied fair value to the condition that exists when the carrying amount of a reporting unit exceeds its fair value. The amendments are effective for public entities for annual and interim periods in fiscal years beginning after December 15, 2019, with the amendments applied on a prospective basis. Early adoption is allowed. We expect our adoption of the amendments will not materially affect our results of operations, financial position, cash flows, and disclosures.

(g) Improving the presentation of net periodic benefit costs

In March 2017, the FASB issued amendments to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost in the financial statements. The amendments require an entity to present service cost separately from the other components of net benefit cost, and to report the service cost component in the income statement line item(s) where it reports the corresponding compensation cost. An entity is to present all other components of net benefit cost outside of operating cost. The amendments also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of a self-constructed asset). The amendments are effective for public entities for annual and interim periods in fiscal years beginning after December 15, 2017, with early adoption permitted. We do not plan to early adopt. An entity is required to apply the amendments retrospectively for the presentation of the service cost component and the other components of net periodic pension cost and net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension cost and net periodic postretirement benefit in assets. A practical expedient allows an entity to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in the notes to financial statements for pension and postretirement benefit plans for those periods. We expect our adoption of the amendments will not materially affect our results of operations, financial position, cash flows, and disclosures.

(h) Targeted improvements to accounting for hedging activities

In August 2017, the FASB issued targeted amendments with the objective to better align hedge accounting with an entity's risk management activities in the financial statements, and to simplify the application of hedge accounting. The amendments address concerns of financial statement preparers over difficulties with applying hedge accounting and limitations for hedging both nonfinancial and financial risks and concerns of financial statement users over how hedging activities are reported in financial statements. Changes to the hedge accounting guidance to address those concerns will: 1) expand hedge accounting for nonfinancial and financial risk components and amend measurement methodologies to more closely align hedge accounting with an entity's risk management activities; 2) eliminate the separate measurement and reporting of hedge ineffectiveness, to reduce the complexity of preparing and understanding hedge results; 3) enhance disclosures and change the presentation of hedge results to align the effects of the hedging instrument and the hedged item in order to enhance transparency, comparability, and understandability of hedge results; and 4) simplify the way assessments of hedge effectiveness may be performed to reduce the cost and complexity of applying hedge accounting. The amendments are effective for public entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted in any interim period after issuance of the amendments. We do not expect to early adopt. For cash flow and net investment hedges existing at the date of adoption, a company must apply a cumulative-effect adjustment related to the separate measurement of ineffectiveness to accumulated other comprehensive income (AOCI) with a corresponding adjustment to the opening balance of retained earnings as of the beginning of the fiscal year of adoption. The amended presentation and disclosure guidance is required only prospectively. An entity may make certain elections upon adoption to allow for existing hedging relationships to transition to newly allowable alternatives. We expect our adoption of the guidance will not materially affect our results of operations, financial position, or cash flows, but we expect the amendments will ease the administrative burden of hedge documentation requirements and assessing hedge effectiveness.

(i) Reclassification of certain tax effects from accumulated other comprehensive income

In February 2018 the FASB issued amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017 by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within AOCI (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. The amendments are effective for all entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted including, for public entities, adoption in any interim period for which financial statements have not been issued. An entity has the option to apply the amendments either in the period of adoption or retrospectively to each period (or periods) in which it recognizes the effect of the change in the U.S. federal corporate income tax rate in the Tax Act. An entity is required to disclose its accounting policy election, including its policy for reclassifying material stranded tax effects in AOCI to earnings (specific identification or portfolio method).
We have not early adopted the amendments as of December 31, 2017. We expect our adoption of the amendments will not materially affect our results of operations, financial position, cash flows, and disclosures.

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 44% 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.

RGE Rate Plans

On September 16, 2010, the NYPSC approved a new rate plan for electric and natural gas service provided by 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 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%; however, the equity ratio is set at the actual up to 50% for earnings sharing calculation purposes. The customer share of any earnings above allowed levels increases as the ROE increases, 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 covering the period May 1, 2016 – April 30, 2017. The earnings sharing levels increase in rate year two (May 1, 2017 – April 30, 2018) to 9.65%, 10.15% and 10.65% ROE, respectively. The earnings sharing levels further increase in rate year three (May 1, 2018 – April 30, 2019) to 9.75%, 10.25% and 10.75% ROE, respectively. The rate plans also include the implementation of a rate adjustment mechanism designed to return or collect certain defined reconciled revenues and costs, new depreciation rates, and continuation of the existing RDM for each business.

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 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 associated with this petition began in the first quarter of 2017, was suspended in the second quarter of 2017 and resumed in the first quarter of 2018.

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 Distributed Energy Resources (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 New York State Energy Research and Development Authority (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 is ongoing.

In March, 2017, the NYPSC issued three separate REV-related orders. These orders created a series of filing requirements for NYSEG beginning in March 2017 and extending through the end of 2018. The three orders involve: 1) modifications to the electric utilities' proposed interconnection earnings adjustment mechanism framework; 2) further DSIP requirements, including filing of an updated DSIP plan by mid-2018 and implementing two energy storage projects at RG&E and NYSEG by the end of 2018; and 3) Net Energy Metering Transition including implementation of Phase One of the Value of DER. In September 2017, the NYPSC issued another order related to the Value of DER, requiring tariff filings, changes to Standard Interconnection Requirements, and planning for the implementation of automated consolidated billing.

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2017 Windstorm

On March 11, 2017, the New York State Department of Public Service (the Department) commenced an investigation of RG&E's preparation for and response to the March 2017 windstorm, which affected more than 219,000 customers. The Department investigation included a comprehensive review of RG&E's preparation for and response to the windstorm, including all aspects of the companies' filed and approved emergency plan. The Department held public hearings on April 12 and 13, 2017.

On November 16, 2017, the NYPSC announced that the Department Staff had completed their investigation into the March 2017 Windstorm and the NYPSC issued an Order Instituting Proceeding and to Show Cause. The Staff's investigation found that RG&E violated certain parts of their emergency response plans, which makes them subject to possible financial penalties. RG&E responded to the order in a timely manner and have entered into settlement discussions with the Department Staff.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. The NYPSC has instituted proceedings in New York to review and address the implications associated with the Tax Act on the utilities providing service in state of New York. We expect the regulators, including the FERC, to issue requirements in 2018 regarding how all tax benefits associated with the Tax Act will be returned to customers.

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. On February 23, 2016, the NYPSC unanimously adopted the joint proposal, which provides for a term of the RSSA from April 1, 2015 through March 31, 2017 and RG&E monthly payments to Ginna in the amount of $15.4 million. In addition, RG&E is entitled to 70% of revenues from Ginna's sales into the NYISO energy and capacity markets, while Ginna is entitled to 30% of such revenues. The NYPSC also authorized RG&E to implement a rate surcharge effective January 1, 2016, to recover amounts paid to Ginna pursuant to the RSSA. The FERC issued an order authorizing the FERC Settlement agreement in the Settlement Docket on March 1, 2016, at which point the rate surcharge went into effect. RG&E used 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. The available credits were insufficient to satisfy the final payment amount from RG&E to Ginna, and consistent with the agreement with the NYPSC, the RSSA surcharge continues past March 31, 2017, to recover up to $2.3 million per month until the final payment has been recovered by RG&E from customers.

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 $208.0 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.

Current and long-term regulatory assets at December 31, 2017 and 2016 consisted of:

December 31,	**2017**	**2016**
(Thousands)		
Current		
Revenue decoupling mechanism	$8,249	$4,172
Temporary supplemental assessment charge	-	1,721
Decommissioning	6,471	6,471
Storm Costs	6,086	-
Reliability support services	27,000	27,000
Electric supply reconciliation	-	4,152
Hedge losses	1,658	3,781
Environmental remediation costs	6,363	6,363
Other	7,800	9,457
Total short term regulatory assets	**$63,627**	**$63,117**
Long-Term		
Asset retirement obligation	3,153	3,108
Unamortized losses on re-acquired debt	4,814	5,012
Decommissioning	8,655	14,334
Pension and other postretirement benefits cost deferrals	37,615	34,310
Federal tax depreciation normalization adjustment	50,211	75,888
Environmental remediation costs	86,288	95,946

Pension and other postretirement benefits	95,940	115,469
Unfunded future income taxes	130,336	123,807
Reliability support services	10,234	28,783
Storm Costs	49,544	-
Other	9,608	17,055
Total long-term regulatory assets	**486,398**	**513,712**
Deferred income taxes regulatory	25,680	-
Total long-term regulatory assets	**$512,078**	**$513,712**

Revenue Decoupling Mechanism represents the mechanism established to disassociate the utility's profits from its delivery/commodity sales.

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.

Decommissioning represents amounts to be collected in rates for the decommissioning of shut down plants.

Federal tax depreciation normalization adjustment represents the deferral of the normalization of change impacts in book lives and the pass back of theoretical reserves associated with Powertax deferred income tax.

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.

Reliability support services represent the deferral of costs associated with keeping units available and capable of being committed for reliability purposes as requested by the utility or the NYISO.

Storm costs are allowed in rates based on an estimate of the routine costs of service restoration.

RG&E 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.

Other includes items such as deferred purchased gas.

Deferred income taxes regulatory: see Note 1.

Current and long-term regulatory liabilities at December 31, 2017 and 2016 consisted of:

December 31, (Thousands)	**2017**	**2016**
Current		
Energy efficiency programs	$21,300	$24,798
Carrying Costs on deferred income tax bonus depreciation	8,333	2,499
Other	3,830	2,436
Total short term regulatory liabilities	**$33,463**	**$29,733**
Long-Term		
Asset gain sale account	10,851	10,851
Earnings sharing	12,483	7,511
Economic development	18,846	18,796
Merger capital expense	5,953	10,000
Other taxes	-	6,967
Deferred transmission congestion contracts	19,117	17,009
Post term amortizations	-	546
Net plant reconciliation	9,690	9,690
Accrued removal obligations	175,175	184,622
Positive benefit adjustment	32,639	32,639
Deferred property taxes	19,406	18,870
Carrying costs on deferred income tax bonus depreciation	45,769	55,770
Tax Act-remeasurement	288,190	-
Variable rate debt	16,016	15,063
Low income programs	4,466	5,891
Other	36,150	36,111
Total other long term regulatory liabilities	**694,751**	**430,336**
Deferred income taxes regulatory	-	51,876
Total long term regulatory liabilities	**$694,751**	**$482,212**

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.

Deferred transmission congestion contracts represent the deferral of the right to collect day-ahead market congestions rents going forward in time.

Positive benefit adjustment resulted from Iberdrola's 2008 acquisition of AGR (formerly Energy East Corporation). 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.

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

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.

Tax Act - remeasurement represents the impact from remeasurement of deferred income tax balances as a result of the Tax Act enacted by the U.S. federal government on December 22, 2017. Reductions in accumulated deferred income tax balances due to the reduction in the corporate income tax rates from 35% to 21% under the provisions of the Tax Act will result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers, generally through reductions in future rates. The NYPSC has instituted separate proceedings to review and address the implications associated with the Tax Act on the utilities providing service in state of New York. We expect the regulators, including the FERC, to issue requirements in 2018 regarding how all tax benefits associated with the Tax Act will be returned to customers.

Variable Rate Debt represents the over/under collection of costs related to variable rate debt instruments identified in the rate case. Costs would include interest, commissions and fees versus amounts included in rates.

Other includes asset retirement obligations, post-term obligations, New York State rate change and theoretical reserve.

Note 4. Income Taxes

The Tax Act changes significantly the federal taxation of business entities, including among other things, a federal corporate tax rate decrease from 35% to 21% for tax years beginning after December 31, 2017. We have made a reasonable estimate of the effects of the Tax Act and recorded provisional amounts for the income tax effects related to the remeasurement of our deferred tax assets and liabilities and the associated regulatory liabilities established by our regulated utility companies in our financial statements as of December 31, 2017. As we complete our analysis of the Tax Act, collect and prepare necessary data, and interpret any additional guidance issued by the U.S. Treasury Department, the IRS, and other standard-setting bodies, we may make adjustments to the provisional amounts. Those adjustments may materially impact our provision for income taxes in the period in which the adjustments are made.

Current and deferred taxes charged to expense for the years ended December 31, 2017 and 2016 consisted of:

Years Ended December 31,	2017	2016
(Thousands)		
Current		
Federal	$(37,205)	$(3,604)
State	2,729	421
Current taxes charged to (benefit)/expense	**$(34,476)**	**(3,183)**
Deferred		
Federal	86,186	170,525
State	7,795	16,459
Deferred taxes charged to expense	**93,981**	**186,984**
Total Income Tax Expense	**$59,505**	**$183,801**

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, 2017 and 2016 consisted of:

Years Ended December 31,	2017	2016
(Thousands)		
Tax expense at federal statutory rate	$49,957	$92,561
Impact of depreciation normalization	-	69,129
Tax return and audit adjustments	(19)	(121)
State taxes, net of federal benefit	6,845	10,972
Other, net	2,722	11,260
Total Income Tax Expense	**$59,505**	**$183,801**

Income tax expense for the year ended December 31, 2017 was $9.5 million higher than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, net of federal benefit. This resulted in an effective tax rate of 41.7%. 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 elimination of deferred taxes on normalizing depreciation and state taxes, (net of federal benefit). This resulted in an effective tax rate of 69.5%.

Deferred tax assets and liabilities as of December 31, 2017 and 2016 consisted of:

December 31,	2017	2016
(Thousands)		
Noncurrent Deferred Income Tax Liabilities (Assets)		
Property related	$397,810	$534,869
Unfunded FIT normalization amortization	37,794	49,637
Derivative assets	(17,257)	(28,125)
Non-cash return – bonus depreciation	(11,091)	(23,122)
Pension and other postretirement benefits	(10,288)	(14,684)
Positive benefits adjustment merger order	(8,530)	(12,949)
Regulatory liability due to “Tax Cuts and Jobs Act”	(75,318)	-
Federal and state tax credits	(1,386)	(696)
Federal and state NOLs	(2,509)	-
Other	(13,961)	(18,117)
Noncurrent Deferred Income Tax Liabilities	**295,264**	**486,813**
Less amounts classified as regulatory liabilities		
Less noncurrent deferred income taxes classified as regulatory liabilities	(25,680)	51,876
Noncurrent Deferred Income Tax Liabilities	**$320,944**	**$434,937**

Deferred tax assets	$140,340	$97,693
Deferred tax liabilities	435,604	584,506
Net Accumulated Deferred Income Tax Liabilities	**$295,264**	**$486,813**

RG&E has $1.4 million of federal and state research and development credits.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2017 and 2016 consisted of:

Years Ended December 31,	**2017**	**2016**
(Thousands)		
Balance as of January 1	$2,905	$492
Increases for tax positions related to prior years	271	2,413
Reduction for tax positions related to prior years	(650)	-
Balance as of December 31	**$2,526**	**$2,905**

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

There were no additional accruals for interest and penalties on tax reserves as of December 31, 2017 and as of December 31, 2016. Gross unrecognized tax benefits decreased $0.4 million in 2017 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, 2017 and 2016, our long-term debt was:

As of December 31,	**2017**			**2016**	
(Thousands)	**Maturity Dates**	**Balances**	**Interest Rates**	**Balances**	**Interest Rates**
First mortgage bonds [(a)]	2019-2033	$ 900,000	3.10%-8.00%	$ 600,000	4.10%-8.00%
Secured pollution control notes – fixed	2016	-	-	-	-
Unsecured pollution control notes - variable	2032	62,150	1.94%	62,150	1.32%
Obligations under capital leases	2018-2023	9,818		11,172	
Unamortized debt issuance costs and discount		(11,623)		(8,369)	
Total Debt		**$ 960,345**		**$ 664,953**	
Less: debt due within one year, included in current liabilities		1,434		529	
Total Non-current Debt		**$ 958,911**		**$ 664,424**	

(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.

On May 24, 2017, RG&E issued $300 million in aggregate principal amount of 3.10% First Mortgage Bonds maturing in 2027. Proceeds of the offering were used to reduce short-term debt, to fund capital expenditures and for general corporate purposes. Net proceeds of the offering after the price discount and issuance-related expenses were $294 million.

At December 31, 2017, long-term debt, including lease obligations (in thousands), that will become due during the next five years are:

2018	2019	2020	2021	2022
$1,434	$151,961	$1,961	$126,961	$1,961

We have no financial debt covenant requirements related to our long-term debt at December 31, 2017 and 2016.

Note 6. Bank Loans and Other Borrowings

RG&E had no short-term debt outstanding at December 31, 2017 and $249.0 million of short-term debt outstanding at December 31, 2016. 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 no debt outstanding as of December 31, 2017 under this agreement. The amount of debt outstanding as of December 31, 2016 under this agreement was $32 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 no balance outstanding under this agreement as of December 31, 2017 and there was $217 million outstanding under this agreement as of December 31, 2016.

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 both December 31, 2017 and 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 0.51 to 1.00 at December 31, 2017. We are not in default as of December 31, 2017.

Note 7. Commitments and Contingencies

New York State Department of Public Service Investigation of the Preparation for and Response to the March 2017 Windstorm

On March 11, 2017, the New York State Department of Public Service (the Department) commenced an investigation of RG&E's preparation for and response to the March 2017 windstorm, which affected more than 219,000 customers. The Department investigation included a comprehensive review of RG&E's preparation for and response to the windstorm, including all aspects of the companies' filed and approved emergency plan. The Department held public hearings on April 12 and 13, 2017.

On November 16, 2017, the NYPSC announced that the Department Staff had completed their investigation into the March 2017 Windstorm and the NYPSC issued an Order Instituting Proceeding and to Show Cause. The Staff's investigation found that RG&E violated certain parts of their emergency response plans, which makes them subject to possible financial penalties. RG&E responded to the order in a timely manner and have entered into settlement discussions with the Department Staff.

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. On February 23, 2016, the NYPSC unanimously adopted the joint proposal, which provides for a term of the RSSA from April 1, 2015, through March 31, 2017 and RG&E monthly payments to GNPP in the amount of $15.4 million. RG&E is entitled to 70% of revenues from GNPP's sales into the energy and capacity markets, while GNPP is entitled to 30% of such revenues. We account for this arrangement as an operating lease. The net expense incurred under this operating lease was $5.6 million and $114.9 million for the years ended December 31, 2017 and 2016, respectively.

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 $47.9 million for purchase power and natural gas contracts including nonutility generators in 2017 and $48.0 million in 2016. We estimate that our power purchases will total $47.9 million in 2018, $36.4 million in 2019, $21.9 million in 2020, $18.0 million in 2021, and 2022 and $58.6 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 $157.4 thousand at December 31, 2017, related to the nine sites. We have recorded an estimated liability of $4.1 million related to another seven 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 $4.3 million to $6.2 million as of December 31, 2017. 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 12 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 12 sites ranges from $81.0 million to $194.6 million at December 31, 2017. 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 $129.5 million at December 31, 2017, and $134.4 million at December 31, 2016. 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 and are expected to be paid through the year 2046.

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, 2017 and 2016, the amount recognized in regulatory assets was a gain of $0.1 million and a loss of $4.5 million, respectively, for electricity derivatives. For the years ended December 31, 2017 and 2016, the amount reclassified from regulatory assets into income, which is included in electricity purchased, was a loss of $12.5 million and $17.8 million, 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, 2017 and 2016, the amount recognized in regulatory assets for natural gas hedges was a loss of $1.8 million and a gain of $2.4 million, respectively. For the years ended December 31, 2017 and 2016 the amount reclassified from regulatory assets into income, which is included in natural gas purchased, was a loss of $0.2 million and a loss of $1.7 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, 2017			
2018	1,286,375	3,490,000	412,100
2019	-	680,000	-
As of December 31, 2016			
2017	1,224,350	3,180,000	439,400
2018	438,000	690,000	-

The offsetting of derivatives, location in the balance sheet and amounts of derivatives as of December 31, 2017 and 2016, respectively, consisted of:

December 31, 2017	Derivative Assets - Current	Derivative Assets - Noncurrent	Derivative Liabilities - Current	Derivative Liabilities - Noncurrent
(In thousands)				`
Not designated as hedging instruments				
Derivative assets	$4,271	$-	$4,129	$-
Derivative liabilities	(4,129)	-	(5,787)	(104)
	142	**-**	**(1,658)**	**(104)**
Designated as hedging instruments				
Derivative assets	8	-	8	-
Derivative liabilities	(8)	-	(49)	-
	-	**-**	**(41)**	**-**
Total derivatives before offset of cash collateral	142		(1,699)	(104)
Cash collateral receivable (payable)	-	-	1,658	104
Total derivatives as presented in the balance sheet	**$142**	**$-**	**$(41)**	**$-**

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)**	**$-**

As of both December 31, 2017 and 2016, the derivative assets and liabilities are presented within other current and non-current assets and liabilities of the balance sheet, respectively.

The effect of hedging instruments on other comprehensive income (OCI) and income was:

Year Ended December 31,	**(Loss) Gain Recognized in OCI on Derivatives**	**Location of (Loss) Gain Reclassified from Accumulated OCI into Income**	**Loss Reclassified from Accumulated OCI into Income**
Derivatives in Cash Flow Hedging Relationships	**Effective Portion**	**Effective Portion**	
(Thousands)			
2017			
Interest rate contracts	$-	Interest expense	$(5,768)
Commodity contracts	(155)	Other operating expenses	(160)
Total	**$(155)**		**$(5,928)**
2016			
Interest rate contracts	$-	Interest expense	$(5,768)
Commodity contracts	5	Other operating expenses	(362)
Total	**$5**		**$(6,130)**

The amount in AOCI related to previously settled forward starting interest rate swaps and accumulated amortization, at December 31, 2017 is a net loss of $62.5 million as compared to a net loss of $68.2 million at December 31, 2016. For the year ended December 31, 2017, 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 2018.

As of December 31, 2017, $.04 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, 2017.

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, 2017, is $1.8 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 $1,129 million as of December 31, 2017 and $830 million as of December 31, 2016. 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 $61.0 million as of both December 31, 2017 and 2016, 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)					
2017					
Assets					
Noncurrent investments primarily money market funds	$3,781	$-	$-	$-	$3,781
Derivatives					
Commodity contracts:					
Electricity	4,236	-	-	(4,094)	142
Gas	35	-	-	(35)	-
Other	-	-	8	(8)	-
Total	**$8,052**	**$-**	**$8**	**$(4,137)**	**$3,923**
Liabilities					
Derivatives					
Commodity contracts:					
Electricity	(4,094)	-	-	4,094	-
Natural gas	(1,798)	-	-	1,798	-
Other	-	-	(49)	8	(41)
Total	**$(5,892)**	**$-**	**$(49)**	**$5,900**	**$(41)**

2016					
Assets					
Noncurrent investments available for sale, primarily money market funds	$3,764	$-	$-	$-	$3,764
Derivatives					
Commodity contracts:					
Electricity	2,356	-	-	(2,356)	-
Natural 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)**

We had no transfers to or from Level 1 and 2 during the year ended December 31, 2017. 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 approximately 70% of their electric load obligations using contracts for a NYISO location where an active market exists. The forward market prices used to value the companies' open electric energy derivative contracts are based on quotes prices in active markets for identical assets or liabilities with no adjustment required and therefore we include the fair value 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,	**2017**	**2016**
(Thousands)		
Beginning balance	$46	$413
Total (losses) gains (realized/unrealized)		
Included in earnings	(160)	(362)
Included in other comprehensive income	155	5
Ending balance	**$41**	**$46**

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, 2016	2016 Change	Balance December 31, 2016	2017 Change	Balance December 31, 2017
(Thousands)					
Net unrealized holding gain on investments, net of income tax expense of $4 for 2016 and $0 for 2017	$33	$6	$39	$-	$39
Amortization of pension cost for nonqualified plans, net of tax expense (benefit) of $166 for 2016 and $(40) for 2017	(1,898)	257	(1,641)	(61)	(1,702)
Unrealized gain (loss) on derivatives qualified as hedges:					
Unrealized gain (loss) during period on derivatives qualified as hedges, net of income tax expense (benefit) of $2 for 2016 and $(61) for 2017		3		(94)	
Reclassification adjustment for loss included in net income, net of income tax expense of $142 for 2016 and $62 for 2017		220		98	
Reclassification adjustment for loss on settled cash flow treasury hedges, net of income tax expense of $2,263 for 2016 and $2,263 for 2017		3,505		3,505	
Net unrealized (loss) gain on derivatives qualified as hedges	**(44,932)**	**3,728**	**(41,204)**	**3,509**	**(37,695)**
Accumulated Other Comprehensive Loss	**$(46,797)**	**$3,991**	**$(42,806)**	**$3,448**	**$(39,358)**

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 $3.1 million in 2017 and $2.9 million in 2016.

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	
	2017	**2016**	**2017**	**2016**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$417,532	$437,294	$76,344	$79,551
Service cost	5,728	5,729	326	377
Interest cost	16,313	17,075	3,038	3,155
Plan participants' contributions		-	684	333
Actuarial loss/(gain)	20,478	(6,132)	102	(1,711)
Benefits paid	(45,762)	(36,434)	(5,069)	(5,361)
Benefit obligation at December 31	**$414,289**	**$417,532**	**$75,425**	**$76,344**
Change in plan assets				
Fair value of plan assets at January 1	$308,374	$323,878	**-**	-
Actual return on plan assets	40,236	20,213	**-**	-
Employer and plan participants' contributions	6,200	716	5,069	5,361
Benefits paid	(45,762)	(36,433)	(5,069)	(5,361)
Fair value of plan assets at December 31	**309,048**	**$308,374**	**$-**	**$-**
Funded status at December 31	**$(105,241)**	**$(109,158)**	**$(75,425)**	**$(76,344)**

Amounts recognized in the balance sheet	**Pension Benefits**		**Postretirement Benefits**	
December 31,	**2017**	**2016**	**2017**	**2016**
(Thousands)				
Other current liabilities	$-	$-	$(5,272)	$(5,424)
Pension and other postretirement benefits	(105,241)	(109,158)	(70,153)	(70,920)
Total	**$(105,241)**	**$(109,158)**	**$(75,425)**	**$(76,344)**

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,	**2017**	**2016**	**2017**	**2016**
(Thousands)				
Net loss	$95,279	$115,350	$3,228	$3,691
Prior service cost (credit)	$223	$625	$(2,789)	$(4,198)

Our accumulated benefit obligation for all defined benefit pension plans was $387.6 million at December 31, 2017 and $388.5 million at December 31, 2016.

The projected benefit obligation and the accumulated benefit obligation exceeded the fair value of pension plan assets as of both December 31, 2017 and 2016. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets as of December 31, 2017 and 2016.

December 31	2017	2016
(Thousands)		
Projected benefit obligation	$414,289	$417,532
Accumulated benefit obligation	$387,627	$388,507
Fair value of plan assets	$309,049	$308,374

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

	Pension Benefits		Postretirement Benefits	
Years Ended December 31,	**2017**	**2016**	**2017**	**2016**
(Thousands)				
Net periodic benefit cost				
Service cost	$5,728	$5,729	$326	$377
Interest cost	16,313	17,075	3,038	3,155
Expected return on plan assets	(22,571)	(23,800)	-	-
Amortization of prior service cost (credit)	403	1,140	(1,409)	(1,409)
Amortization of net loss	22,883	21,227	566	902
Net periodic benefit cost	**$22,756**	**$21,082**	**$2,521**	**$3,025**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net (gain) loss	$2,813	$(2,545)	$102	$(1,711)
Amortization of net (loss) gain	(22,883)	(21,227)	(566)	(902)
Amortization of prior service (cost) credit	(403)	(1,140)	1,409	(851)
Total recognized in regulatory assets and regulatory liabilities	(20,473)	(24,623)	945	(1,204)
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$2,283**	**$(3,541)**	**$3,466**	**$1,821**

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, 2018	Pension Benefits	Postretirement Benefits
(Thousands)		
Estimated net loss	$27,059	$1,314
Estimated prior service cost (credit)	$223	$(1,082)

We expect that no pension benefit or postretirement benefit plan assets will be returned to us during the fiscal year ending December 31, 2018.

Weighted-average assumptions used to	Pension Benefits		Postretirement Benefits	
determine benefit obligations at December 31,	**2017**	**2016**	**2017**	**2016**
Discount rate	3.63%	4.12%	3.63%	4.12%
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 years ended December 31,	Pension Benefits		Postretirement Benefits	
	2017	2016	2017	2016
Discount rate	4.12%	4.10%	4.12%	4.10%
Expected long-term return on plan assets	7.30%	7.40%	N/A	N/A
Rate of compensation increase	4.00%	4.00%	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,	2017	2016
Health care cost trend rate (pre 65/post 65)	6.75%-8.50%	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	2026/2028

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 $13.0 million to our pension benefit plans in 2018.

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)			
2018	$53,049	$5,244	-
2019	$40,417	$5,227	-
2020	$39,799	$5,204	-
2021	$38,550	$5,173	-
2022	$36,561	$5,122	-
2023 - 2027	$156,947	$24,386	-

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, 2017 and 2016, by asset category are shown in the following table. RG&E's share of the total consolidated assets is approximately 11% and 12% for 2017 and 2016, respectively.

		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)				
2017				
Cash and cash equivalents	$17,531	$-	$17,531	$-
U.S. government securities	13,338	13,338	-	-
Common stocks	129,312	129,312	-	-
Registered investment companies	105,037	105,037	-	-
Corporate bonds	447,124	-	447,124	-
Preferred stocks	4,381	299	4,082	-
Equity commingled funds	435,635	185,989	249,646	-
Other investments, principally annuity and fixed income	548,957	-	548,957	-
	$1,701,315	**$433,975**	**$1,267,340**	**$-**
Other investments measured at net asset value	1,126,017			
Total	**$2,827,332**			
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	-
Equity commingled funds	371,831		371,831	-
Other investments, principally annuity and fixed income	310,785	-	310,785	-
	$1,477,301	**$384,451**	**$1,092,850**	**$-**

Other investments measured at net asset value	1,157,112
Total	**$2,634,413**

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.
- Equity commingled funds – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- 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.
- Other investments measured at net asset value (NAV) – alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

Pension plan equity securities did not include any AGR and Iberdrola common stock as of both December 31, 2017 and 2016.

Note 13. Other Income and Other Deductions

Years Ended December 31, **(Thousands)**	**2017**	**2016**
Interest and dividend income	$528	$25
Allowance for funds used during construction	11,199	11,549
Gain on sale of property	20	427
Carrying costs on regulatory assets	3,684	2,404
Miscellaneous	67	252
Total other income	**$15,498**	**$14,657**
Miscellaneous	(485)	(1,325)
Total other deductions	**$(485)**	**$(1,325)**

Note 14. 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 $66.9 million in 2017 and $49.2 million for 2016 and the charge for services provided by RG&E to AGR and its subsidiaries were approximately $12.8 million in 2017 and $11.5 million for 2016. All charges for services are at cost. All of the charges associated with services provided are recorded as revenues to offset other operating expenses on the financial statements. Of the balance in accounts payable to affiliates of $41.6 million at December 31, 2017, $40.5 million is payable to Avangrid Service Company, and of $38.3 million at December 31, 2016, $36.5 million was payable to Avangrid Service Company.

The balance in notes receivable from affiliates of $39.7 million at December 31, 2017 is from the UIL companies and there was no balance at December 31, 2016. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 6 of these financial statements.

AGR, on behalf of RG&E, guarantees $123 million to fund the clean-up of the GNPP.

Note 15. Subsequent events

The company has performed a review of subsequent events through March 30, 2018, which is the date these financial statements were available to be issued, and no subsequent events have occurred from January 1, 2018 through such date.

Central Maine Power Company
and Subsidiaries
Consolidated Financial Statements
For the Years Ended December 31, 2017 and 2016

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Consolidated Financial Statements for the Years Ended December 31, 2017 and 2016

KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

The Shareholder and Board of Directors
Central Maine Power Company and Subsidiaries:

We have audited the accompanying consolidated financial statements of Central Maine Power Company and Subsidiaries, which comprise the consolidated balance sheet as of December 31, 2017, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for the year then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance 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 consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the 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 consolidated financial statements.

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

Opinion

In our opinion, the 2017 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Central Maine Power Company and Subsidiaries as of December 31, 2017, and the results of their operations and their cash flows for the year then ended in accordance with U.S. generally accepted accounting principles.

Other Matter

The accompanying consolidated financial statements of Central Maine Power Company and Subsidiaries as of December 31, 2016 and for the year then ended were audited by other auditors whose report thereon dated March 31, 2017, expressed an unmodified opinion on those financial statements.

KPMG LLP

New York, New York
March 30, 2018

Central Maine Power Company and Subsidiaries
Consolidated Statements of Income

Years Ended December 31,	2017	2016
(Thousands)		
Operating Revenues		
Sales and services	**$822,110**	**$833,938**
Operating Expenses		
Electricity purchased	12,846	59,201
Operations and maintenance	374,603	352,244
Depreciation and amortization	91,842	102,786
Other taxes	60,621	54,536
Total Operating Expenses	**539,912**	**568,767**
Operating Income	**282,198**	**265,171**
Other Income	11,615	6,416
Other Deductions	(821)	(1,711)
Interest Charges, net	(51,673)	(52,985)
Income Before Income Tax	**241,319**	**216,891**
Income Tax Expense	82,166	81,071
Net Income	**159,153**	**135,820**
Less: net income attributable to noncontrolling interest	1,282	409
Net Income Attributable to CMP	**157,871**	**135,411**
Net Income Available for CMP Common Stock	**$157,871**	**$135,411**

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Comprehensive Income

Years ended December 31,	2017	2016
(Thousands)		
Net Income	**$159,153**	**$135,820**
Other Comprehensive Income, Net of Tax		
Amortization of pension cost for nonqualified plans	11	75
Unrealized gain on derivatives qualified as hedges:		
Unrealized (loss) gain during period on derivatives qualified as hedges	(101)	81
Reclassification adjustment for loss included in net income	155	388
Reclassification adjustment for loss on settled cash flow treasury hedges	1,285	1,323
Other Comprehensive Income, Net of Tax	**1,350**	**1,867**
Comprehensive Income	**160,503**	**137,687**
Less:		
Comprehensive income attributable to noncontrolling interests	1,282	409
Comprehensive Income Attributable to CMP	**$159,221**	**$137,278**

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

Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2017	2016
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	$15,096	$7,968
Accounts receivable and unbilled revenues, net	171,978	161,725
Accounts receivable from affiliates	30,729	1,671
Notes receivable from affiliates	28,336	32,100
Materials and supplies	15,349	15,018
Prepayments and other current assets	63,036	79,170
Regulatory assets	12,689	18,198
Total Current Assets	**337,213**	**315,850**
Utility plant, at original cost	4,068,887	3,828,993
Less accumulated depreciation	(976,602)	(893,117)
Net Utility Plant in Service	**3,092,285**	**2,935,876**
Construction work in progress	156,247	160,459
Total Utility Plant	**3,248,532**	**3,096,335**
Other Property and Investments	1,268	1,297
Regulatory and Other Assets		
Regulatory assets	437,461	489,765
Goodwill	324,938	324,938
Other	38,544	19,027
Total Regulatory and Other Assets	**800,943**	**833,730**
Total Assets	**$4,387,956**	**$4,247,212**

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

Central Maine Power Company and Subsidiaries
Consolidated Balance Sheets

As of December 31,	2017	2016
(Thousands, except share information)		
Liabilities		
Current Liabilities		
Current portion of long-term debt	$1,452	$5,154
Notes payable to affiliates	434	-
Accounts payable and accrued liabilities	192,244	145,653
Accounts payable to affiliates	41,072	35,844
Interest accrued	17,828	17,851
Taxes accrued	2,043	3,154
Other current liabilities	55,614	54,008
Regulatory liabilities	44,182	36,801
Total Current Liabilities	**354,869**	**298,465**
Regulatory and Other Liabilities		
Regulatory liabilities	489,276	109,941
Deferred income taxes regulatory	229	149,232
Other Non-current liabilities		
Deferred income taxes	401,254	660,090
Pension and other postretirement benefits	207,997	194,716
Other	46,617	56,096
Total Regulatory and Other Liabilities	**1,145,373**	**1,170,075**
Long-term debt	1,040,859	1,042,310
Total Liabilities	**2,541,101**	**2,510,850**
Commitments and Contingencies		
Redeemable Preferred Stock	**571**	**571**
CMP Common Stock Equity		
Common stock ($5 par value, 80,000,000 shares authorized and 31,211,471 shares outstanding at December 31, 2017 and 2016)	156,057	156,057
Capital in excess of par value	764,004	764,014
Retained earnings	919,992	812,121
Accumulated other comprehensive loss	(5,297)	(6,647)
Total CMP Common Stock Equity	**1,834,756**	**1,725,545**
Noncontrolling interest	11,528	10,246
Total Equity	**1,846,284**	**1,735,791**
Total Liabilities and Equity	**$4,387,956**	**$4,247,212**

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

Central Maine Power Company and Subsidiaries
Consolidated Statements of Cash Flows

Years Ended December 31,	**2017**	**2016**
(Thousands)		
Cash Flow from Operating Activities		
Net income	**$159,153**	**$135,820**
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	91,842	102,786
Amortization of regulatory assets and liabilities	(16,892)	(17,548)
Carrying cost of regulatory assets and liabilities	(437)	942
Amortization of debt issuance costs	573	644
Deferred taxes	63,926	14,942
Pension cost	18,852	22,433
Stock-based compensation	(132)	(127)
Accretion expenses	42	40
Gain on disposal of property, plant and equipment	(138)	-
Other non-cash items	(1,704)	2,368
Changes in operating assets and liabilities		
Accounts receivable and unbilled revenues, net	(39,311)	(14,392)
Materials and supplies	(331)	810
Accounts payable and accrued liabilities	23,733	14,652
Accrued taxes	(5,963)	-
Other assets/liabilities	42,990	15,958
Regulatory assets/liabilities	(30,159)	20,912
Net Cash Provided by Operating Activities	**306,044**	**300,240**
Cash Flow from Investing Activities		
Utility plant additions	(263,465)	(220,257)
Contributions in aid of construction	14,773	25,001
Notes receivable from affiliates	3,764	(8,663)
Proceeds from sale of property, plant and equipment	1,275	284
Investments, net	29	(20)
Net Cash Used in Investing Activities	**(243,624)**	**(203,655)**
Cash Flow from Financing Activities		
Capital contributions from parent	-	50,000
Repayment of capital leases	(4,543)	(2,098)
Repayments of non-current debt	(1,183)	(41,183)
Proceeds of short term debt-affiliates	434	-
Common stock dividends	(50,000)	(100,696)
Net Cash Used in Financing Activities	**(55,292)**	**(93,977)**
Net Increase in Cash and Cash Equivalents	**7,128**	**2,608**
Cash and Cash Equivalents, Beginning of Year	**7,968**	**5,360**
Cash and Cash Equivalents, End of Year	**$15,096**	**$7,968**

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

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

	CMP Stockholder							
(Thousands, except per share amounts)	**Number of shares (*)**	**Common Stock**	**Capital in Excess of Par Value**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Total CMP Common Stock Equity**	**Non-controlling Interest**	**Total Equity**
Balances, January 1, 2016	**31,211,471**	**$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
Preferred stock dividends	-	-		(100,696)	-	(100,696)	-	(100,696)
Balances, December 31, 2016	**31,211,471**	**156,057**	**764,014**	**812,121**	**(6,647)**	**1,725,545**	**10,246**	**1,735,791**
Net income	-	-	-	157,871	-	157,871	1,282	159,153
Other comprehensive income, net of tax	-	-	-	-	1,350	1,350	-	1,350
Comprehensive income								160,503
Stock-based compensation	-	-	(10)	-	-	(10)	-	(10)
Common stock dividends	-	-	-	(50,000)	-	(50,000)	-	(50,000)
Balances, December 31, 2017	**31,211,471**	**$156,057**	**$764,004**	**$919,992**	**($5,297)**	**$1,834,756**	**$11,528**	**$1,846,284**

(*) Par value of share amounts is $5

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 624,000 customers as of December 31, 2017 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 consists of the following subsidiaries: Maine Electric Power Company, Inc. (MEPCO) is a 78.3% owned subsidiary of CMP with the remaining 21.7% owned by Emera Maine (EM) which is wholly-owned by Emera, Inc. Chester SVC Partnership (the Partnership or Chester) is a general partnership between NORVARCO, a wholly-owned subsidiary of CMP, which owns 50% interest in the Partnership and Bangor Var Co., Inc., a wholly-owned subsidiary of EM, which owns the remaining 50% interest organized on October 9, 1990 under the Maine Uniform Partnership Act.

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.

Basis of presentation: The accompanying consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP) and are presented on a consolidated basis, and therefore include the accounts of CMP and its consolidated subsidiaries. All intercompany transactions and accounts have been eliminated in all periods presented.

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

***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.

***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).

***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.

Utility Plant: Utility plant is accounted for at historical cost. In cases where we are required to dismantle installations or to recondition the site on which they are located, the estimated cost of removal or reconditioning is recorded as an asset retirement obligation (ARO) and an equal amount is added to the carrying amount of the asset.

Assets are transferred from “Construction work in progress” to “Utility Plant” when they are available for service.

Utility plant in service is depreciated 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 2017 and 2.5% for 2016. We amortize our capitalized software cost which is included in utility plant, using the straight line method, based on useful lives of 5 to 15 years. Capitalized software costs were approximately $142.9 million as of December 31, 2017 and $94.0 million as of December 31, 2016. Depreciation expense was $85.4 million in 2017 and $95.0 million in 2016. Amortization of capitalized software was $6.4 million in 2017 and $8.0 million in 2016.

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.

Allowance for funds used during construction (AFUDC) is a noncash item which represents the allowed cost of capital, including a return on equity (ROE), used to finance construction projects. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of interest expense and the remainder is recorded as other income.

Our balances of major classes of utility plant and the associated useful lives are shown below as of December 31.

Utility Plant	**Estimated useful life (years)**	**2017**	**2016**
(Thousands)			
Electric			
Transmission	4-70	$2,255,967	$2,192,851
Distribution	15-82	1,388,724	1,295,277
Vehicles	4-10	61,658	58,621
Other	27-45	362,538	282,244
Total Utility Plant in Service		**4,068,887**	**3,828,993**
Total accumulated depreciation		(976,602)	(893,117)
Total Net Utility Plant in Service		**3,092,285**	**2,935,876**
Construction work in progress		156,247	160,459
Total Utility Plant		**$3,248,532**	**$3,096,335**

Electric plant includes capital leases of $45.0 million for 2017 and $41.0 million for 2016. Accumulated depreciation related to these leases was $37.9 million for 2017 and $37.0 million in 2016.

Impairment of long lived assets: We evaluate property, plant, and equipment and other long lived assets for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is required to be recognized if the carrying amount of the asset exceeds the undiscounted future net cash flows associated with that asset.

The impairment loss to be recognized is the amount by which the carrying amount of the long lived asset exceeds the asset's fair value. Depending on the asset, fair value may be determined by use of a discounted cash flow model.

Fair value measurement: Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants as of the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place in either the principal market for the asset or liability, or, in the absence of a principal market, in the most advantageous market for the asset or liability.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset according to its highest and best use, or by selling it to another market participant that would use the asset according to its highest and best use.

We use valuation techniques that are appropriate in the circumstances and for which sufficient data is available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. All assets and liabilities for which fair value is measured or disclosed in the consolidated financial statements are categorized within the fair value hierarchy based on the transparency of input to the valuation of an asset or liability as of the measurement date.

The three input levels of the fair value hierarchy are as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability either directly or indirectly, for substantially the full term of the contract.
- Level 3 - one or more inputs to the valuation methodology are unobservable or cannot be corroborated with market data.

Categorization within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

Derivatives and hedge accounting: Derivatives are recognized on the balance sheets at their fair value, except for certain electricity commodity purchases and sales contracts for both capacity and energy (physical contracts) that qualify for, and are elected under, the normal purchases and normal sales exception. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. Changes in the fair value of a derivative contract are recognized in earnings unless specific hedge accounting criteria are met.

Derivatives that qualify and are designated for hedge accounting are classified as cash flow hedges. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in Other Comprehensive Income (OCI) and later reclassified into earnings when the underlying transaction occurs. For all designated and qualifying hedges, we maintain formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If we determine that the derivative is no longer highly effective as a hedge, hedge accounting will be discontinued prospectively. For cash flow hedges of forecasted transactions, we estimate the future cash flows of the forecasted transactions and evaluate the probability of the occurrence and timing of such transactions. If we determine it is probable that the forecasted transaction will not occur, hedge gains and losses previously recorded in OCI are immediately recognized in earnings.

Changes in conditions or the occurrence of unforeseen events could require discontinuance of the hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from OCI into earnings. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. Changes in the fair value of electric and natural gas hedge contracts are recorded to derivative assets or liabilities with an offset to regulatory assets or regulatory liabilities.

We offset fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral arising from derivative instruments executed with the same counterparty under a master netting arrangement

Cash and cash equivalents: 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, 2017 and 2016, we did not have restricted cash. Book overdrafts representing outstanding checks in excess of funds on deposit are classified as “Accounts payable and accrued liabilities” on the consolidated balance sheets. Changes in book overdrafts are reported in the operating activities section of the consolidated statements of cash flows.

Consolidated statements of cash flows: Supplemental disclosure of cash flow information is as follows:

(Thousands)	**2017**	**2016**
Cash paid during the year ended December 31:		
Interest, net of amounts capitalized	$40,611	$50,892
Income taxes paid, net	$30,059	$19,018

Interest capitalized was $10.4 million in 2017 and $1.5 million in 2016. Accrued liabilities for property, plant and equipment additions were $18.3 million in 2017 and $16.5 million in 2016.

***Accounts receivable*:** Accounts receivable at December 31 include unbilled revenues of $36.0 million for 2017 and $27.0 million for 2016, and are shown net of an allowance for doubtful accounts at December 31 of $3.8 million for 2017 and $2.9 million for 2016. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $3.8 million in 2017 and $3.9 million in 2016.

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 $1.4 million for 2017 and $1.3 million in 2016. DPA receivable balances at December 31 were $9.1 million in 2017 and $8.5 million in 2016.

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 the lower of cost and net realizable value and reported on the balance sheets 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.

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 $0.8 million for 2017 and $0.8 million for 2016. 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 within regulatory liabilities.

***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 2054.

Post-employment and other employee benefits: We sponsor defined benefit pension plans that cover the majority of our employees. We also provide health care and life insurance benefits through various postretirement plans for eligible retirees.

We evaluate our actuarial assumptions on an annual basis and consider changes based on market conditions and other factors. All of our qualified defined benefit plans are funded in amounts calculated by independent actuaries, based on actuarial assumptions proposed by management.

We account for defined benefit pension or other postretirement plans, recognizing an asset or liability for the overfunded or underfunded plan status. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. We reflect all unrecognized prior service costs and credits and unrecognized actuarial gains and losses as regulatory assets rather than in other comprehensive income, as management believes it is probable that such items will be recoverable through the ratemaking process. We use a December 31st measurement date for our benefits plans.

We amortize prior service costs for both the pension and other postretirement benefits plans on a straight-line basis over the average remaining service period of participants expected to receive benefits. We use the standard amortization methodology under which amounts in excess of ten percent of the greater of the projected benefit obligation or market related value are amortized over the plan participants' average remaining service to retirement. Our policy is to calculate the expected return on plan assets using the market related value of assets. That value is determined by recognizing the difference between actual returns and expected returns over a five year period.

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 $57.3 million and $45.5 million at December 31, 2017 and December 31, 2016, 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.

On December 22, 2017, the President of the United States signed into law legislation referred to as the “Tax Cuts and Jobs Act” (the “Tax Act”). The Tax Act includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of business entities, and includes specific provisions related to regulated public utilities. The most significant change that impacted the Company was the permanent reduction in the corporate federal income tax rate from 35% to 21%, which required us to measure existing net deferred tax liabilities using the lower rate in the period of enactment, resulting in an excess deferred tax liability reduction in the amount of $489 million that regulators will determine how and when such amounts are passed back to customers. The specific provisions in the Tax Act related to regulated public utilities generally allow for the continued deductibility of interest expense, the elimination of full expensing for tax purposes of certain property acquired after September 27, 2017, and continues certain rate normalization requirements for accelerated depreciation benefits.

The staff of the US Securities and Exchange Commission (“SEC”) has recognized the complexity of reflecting the impacts of the Tax Act, and on December 22, 2017, issued guidance in Staff Accounting Bulletin 118 (“SAB 118”) which clarifies accounting for income taxes under ASC 740 if information is not yet available or complete and provides for up to a one year period in which to complete the required analyses and accounting (“the measurement period”).

The Company has completed or has made a reasonable estimate for the measurement and accounting of certain effects of the Tax Act which have been reflected in the December 31, 2017 financial statements. The Company has reported provisional amounts for the income tax effects related to the re-measurement of our deferred tax assets and liabilities. The ultimate impact may differ (materially) from the provisional amounts, among other things, as a result of additional analysis, changes in interpretations and assumptions, the release of additional guidance by the Internal Revenue Service, Treasury Department, and other standard-setting bodies. There were no specific impacts that could not be reasonably estimated.

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.

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 is a public business entity; therefore, we adopt new accounting standards based on the effective date for public entities.

(a) Revenue from contracts with customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC), Topic 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. ASC 606 was further amended through various updates the FASB issued thereafter. 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 amended effective date for public entities is for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption permitted as of the original effective date of annual reporting periods beginning after December 15, 2016. Entities may apply the standard 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). Effective January 1, 2018, we have adopted ASC 606 and applied the modified retrospective method. Our revenues are derived primarily from tariff-based sales of electric service to customers in Maine with no defined contractual term. For such revenues, we will recognize revenues in an amount derived from the commodities delivered to customers. Based on our assessment of existing contracts and revenue streams, we do not expect ASC 606 to have a material impact on the amount and timing of our revenue recognition from the superseded revenue standard and therefore, we did not record a material cumulative adjustment to retained earnings. We have identified other changes primarily related to the presentation and disclosure of revenues. We plan to disaggregate revenues from contracts with customers in our note disclosure by the source of the commodity sold. We will also disaggregate revenues not accounted for in scope of the new standard, as required, including alternative revenue programs.

(b) 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 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 consolidated results of operations, financial position, or cash flows.

(c) 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

FASB issued an update in January 2018 to clarify the application of the new leases guidance to land easements and provide relief concerning adoption efforts for existing land easements that are not accounted for as leases under current GAAP. 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 right-of-use assets, along with the corresponding liabilities.

(d) 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 consolidated results of operations, financial position, and cash flows.

(e) Certain classifications in the statement of cash flows

The FASB issued 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 and disclosures.

(f) Simplifying the test for goodwill impairment

In January 2017 the FASB issued amendments to simplify the test for goodwill impairment, which are required for public entities and certain other entities that have goodwill reported in their financial statements. The amendments simplify the subsequent measurement of goodwill by eliminating Step 2 from the goodwill impairment test. In computing the implied fair value of goodwill under Step 2, an entity had to perform procedures to determine the fair value at the impairment testing date of its assets and liabilities (including unrecognized assets and liabilities) following the procedure that would be required in determining the fair value of assets acquired and liabilities assumed in a business combination. Under the new guidance, an entity should perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; but the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Also, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable. Certain requirements are eliminated for any reporting unit with a zero or negative carrying amount, therefore the same impairment assessment applies to all reporting units. An entity is required to disclose the amount of goodwill allocated to each reporting unit with a zero or negative carrying amount of net assets. An entity still has the option to perform the qualitative assessment for a reporting unit to determine if the quantitative impairment test is necessary. The amendments modify the concept of impairment from the condition that exists when the carrying amount of goodwill exceeds its implied fair value to the condition that exists when the carrying amount of a reporting unit exceeds its fair value. The amendments are effective for public entities for annual and interim periods in fiscal years beginning after December 15, 2019, with the amendments applied on a prospective basis. Early adoption is allowed. We expect our adoption of the amendments will not materially affect our results of operations, financial position, cash flows, and disclosures.

(g) Improving the presentation of net periodic benefit costs

In March 2017, the FASB issued amendments to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost in the financial statements. The amendments require an entity to present service cost separately from the other components of net benefit cost, and to report the service cost component in the income statement line item(s) where it reports the corresponding compensation cost. An entity is to present all other components of net benefit cost outside of operating cost. The amendments also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of a self-constructed asset). The amendments are effective for public entities for annual and interim periods in fiscal years beginning after December 15, 2017, with early adoption permitted. We do not plan to early adopt. An entity is required to apply the amendments retrospectively for the presentation of the service cost component and the other components of net periodic pension cost and net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension cost and net periodic postretirement benefit in assets. A practical expedient allows an entity to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in the notes to financial statements for pension and postretirement benefit plans for those periods. We expect our adoption of the amendments will not materially affect our consolidated results of operations, financial position, cash flows, and disclosures.

(h) Targeted improvements to accounting for hedging activities

In August 2017, the FASB issued targeted amendments with the objective to better align hedge accounting with an entity's risk management activities in the financial statements, and to simplify the application of hedge accounting. The amendments address concerns of financial statement preparers over difficulties with applying hedge accounting and limitations for hedging both nonfinancial and financial risks and concerns of financial statement users over how hedging activities are reported in financial statements. Changes to the hedge accounting guidance to address those concerns will: 1) expand hedge accounting for nonfinancial and financial risk components and amend measurement methodologies to more closely align hedge accounting with an entity's risk management activities; 2) eliminate the separate measurement and reporting of hedge ineffectiveness, to reduce the complexity of preparing and understanding hedge results; 3) enhance disclosures and change the presentation of hedge results to align the effects of the hedging instrument and the hedged item in order to enhance transparency, comparability, and understandability of hedge results; and 4) simplify the way assessments of hedge effectiveness may be performed to reduce the cost and complexity of applying hedge accounting. The amendments are effective for public entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted in any interim period after issuance of the amendments. We do not expect to early adopt. For cash flow and net investment hedges existing at the date of adoption, a company must apply a cumulative-effect adjustment related to the separate measurement of ineffectiveness to accumulated other comprehensive income (AOCI) with a corresponding adjustment to the opening balance of retained earnings as of the beginning of the fiscal year of adoption. The amended presentation and disclosure guidance is required only prospectively. An entity may make certain elections upon adoption to allow for existing hedging relationships to transition to newly allowable alternatives. We expect our adoption of the guidance will not materially affect our consolidated results of operations, financial position, or cash flows, but we expect the amendments will ease the administrative burden of hedge documentation requirements and assessing hedge effectiveness.

(i) Reclassification of certain tax effects from accumulated other comprehensive income

In February 2018 the FASB issued amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017 by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within AOCI (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. The amendments are effective for all entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted including, for public entities, adoption in any interim period for which financial statements have not been issued. An entity has the option to apply the amendments either in the period of adoption or retrospectively to each period (or periods) in which it recognizes the effect of the change in the U.S. federal corporate income tax rate in the Tax Act. An entity is required to disclose its accounting policy election, including its policy for reclassifying material stranded tax effects in AOCI to earnings (specific identification or portfolio method). We have not early adopted the amendments as of December 31, 2017. We expect our adoption of the amendments will not materially affect our consolidated results of operations, financial position, cash flows, and disclosures.

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 70% of the company's employees are covered by a collective bargaining agreement. CMP has no agreements which will expire within the coming year.

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 are applied based on the cost of providing service.

Electricity Distribution

The Maine distribution rate stipulation, the Federal Energy Regulatory Commission (FERC) Transmission Return on Equity (ROE) case, the Storm proceedings, and the Tax Act are some of the most important specific regulatory processes that currently affect CMP.

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

Energy costs that are set on the New England wholesale markets are passed on to consumers. The difference between energy costs that are budgeted and those that are actually incurred by the utilities is offset by applying compensation procedures that result in either immediate or deferred tariff adjustments. These procedures apply to certain other costs, 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.

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

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 Tier 2 (Large) storm costs that exceed a certain balance on a fifty-fifty basis, with CMP's exposure limited to $3.0 million annually. Tier 2 storms are defined as storms where the incremental restoration costs are between $3.5 million and $15.0 million.

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 July 1, 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, 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.

MPUC Investigation into the Response by Public Utilities to the October 2017 Storm

On December 19, 2017, the Commission issued a Notice of Investigation regarding utility response to the October 2017 Storm. The wind storm of October 2017 was unprecedented in the number of customers impacted and the magnitude of the damage across the entire Central Maine Power service territory. During the event, thousands of trees were broken or uprooted and many caused damage to the electrical delivery system. The vast majority of tree related damage was from trees that were located outside of the maintenance clearance zone. Damage occurred on nearly every CMP distribution circuit, resulting in more than 1,400 broken poles. CMP currently estimates that the total incremental costs are approximately $70.2 million, of which approximately $32.4 million are capital costs associated with the replacement of damaged infrastructure, including poles, cross arms, transformers and related equipment. Additionally, approximately $744,000 of the incremental amount is operations and maintenance expense for repairs to CMP transmission facilities. Accordingly, the net incremental operations and maintenance expense for restoration of the distribution system are approximately $37 million. With regard to the recovery of incremental storm restoration costs in CMP distribution rates, CMP expects that recovery will be addressed in the Company's 2018 Annual Compliance Filing proceeding pursuant to the applicable provisions of the stipulation approved by the Commission in Docket No. 2013-00168.

Tax Cuts and Jobs Act

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. The MPUC has instituted separate proceedings in Maine to review and address the implications associated with the Tax Act on the utilities providing service in Maine. We expect the regulators, including the FERC, to issue requirements in 2018 regarding how all tax benefits associated with the Tax Act will be returned to customers.

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 $208.7 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, 2017 and 2016 consisted of:

December 31,	**2017**	**2016**
(Thousands)		
Current		
Transmission revenue reconciliation mechanism	7,629	12,049
Deferred meter replacement costs	2,388	2,548
Environmental remediation costs	1,178	1,240
Other	1,494	2,361
Total current regulatory assets	**$12,689**	**$18,198**
Long-term		
Federal tax depreciation normalization adjustment	11,834	11,920
Storm costs	38,541	2,051
Unamortized losses on reacquired debt	536	722
Pension and other postretirement benefit costs	219,764	210,394
Unfunded future income taxes	136,753	230,851
Deferred meter replacement costs	29,110	31,543
Other	923	2,284
Total long-term regulatory assets	**$437,461**	**$489,765**

Transmission revenue reconciliation mechanism (“ATU”) reflects any differences in actual costs in the rate year from those used to set rates. The ATU is recovered over the subsequent June to May period. When the ATU is known we record it as a regulatory asset (regulatory liability), with an offset to revenues, and amortize it over the twelve month period as the related revenues are collected (refunded).

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.

Federal tax depreciation normalization adjustment represents the deferral of the normalization of change impacts in book lives and the pass back of theoretical reserves associated with Powertax deferred income tax.

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 $38.5 million at December 31, 2017 and $2.0 million at December 31, 2016.

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.

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

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

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

Current and long-term regulatory liabilities at December 31, 2017 and 2016 consisted of:

December 31,	2017	2016
(Thousands)		
Current		
Accrued removal obligations	$2,251	$2,251
Transmission revenue reconciliation mechanism	13,701	4,764
Yankee DOE refund	3,997	23,938
Stranded cost	17,000	238
Revenue decoupling mechanism	4,098	4,507
Other	3,135	1,103
Total current regulatory liabilities	**$44,182**	**$36,801**
Long-term		
Environmental remediation costs	2,246	3,131
Rate refund-FERC ROE proceeding	22,520	21,738
Accrued removal obligations	64,106	78,286
Scenario B revenue collection	14,617	-
Tax Act - remeasurement	385,492	-
Other	295	6,786
Total non-current regulatory liabilities	**489,276**	**109,941**
Deferred income taxes regulatory	229	149,232
Total long-term regulatory liabilities	**$489,505**	**$259,173**

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.

Yankee DOE refund: 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. CMP’s share of awards associated with Yankee is credited back to customers.

Stranded cost represents costs that resulted from government-mandated long term Purchased Power Agreement (PPA) contracts between CMP and power producers (at prices above current market rates), which must be resold to the market at the current going rate. These costs and assets became "stranded" as CMP was prohibited from owning power and was therefore forced to sell the power back at the market rate; significantly lower than the PPA price. The monthly stranded cost over/under expense compared to revenue, is recorded to be recovered in future years.

Rate refund-FERC ROE proceeding: see Note 9.

The regulatory liability associated with Scenario B represents the commission approved continuation of the December 2013 storm cost amortization for future rate treatment.

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 2017 and in 2016 as a result of our annual impairment assessment, which we performed as of October 1. For 2017 as a result of our step one testing and for 2016 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 2017 or for 2016 that required us to update the assessment.

The carrying amount of goodwill was $325.0 million at both December 31, 2017 and 2016 with no accumulated impairment losses and no changes during 2017 and 2016.

Note 5. Income Taxes

Current and deferred taxes charged to expense for the years ended December 31, 2017 and 2016 consisted of:

Years Ended December 31,	**2017**	**2016**
(Thousands)		
Current		
Federal	$17,165	$52,923
State	1,075	13,206
Current taxes charged to expense	**18,240**	**66,129**
Deferred		
Federal	53,185	9,611
State	10,741	5,331
Deferred taxes charged to expense	**63,926**	**14,942**
Total Income Tax Expense	**$82,166**	**$81,071**

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, 2017 and 2016 consisted of:

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Years Ended December 31,	2017	2016
(Thousands)		
Tax expense at federal statutory rate	$84,461	$76,033
Depreciation and amortization not normalized	(4,737)	(5,221)
Tax return and audit adjustments	(789)	(597)
Tax reform	(613)	-
State taxes, net of federal benefit	7,680	12,069
Other, net	(3,836)	(1,213)
Total Income Tax Expense	**$82,166**	**$81,071**

Income tax expense for the year ended December 31, 2017 was $2.3 million lower than it would have been at the statutory federal income tax rate of 35% due predominately to state taxes, (net of federal benefit), and depreciation and amortization not normalized, and a benefit from measurement of deferred income tax balances as a result of the Tax Act enacted on December 22, 2017, by the U.S. federal government. This resulted in an effective tax rate of 34.0%. Income tax expense for the year ended December 31, 2016 was $5.0 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 37.4%.

Deferred tax assets and liabilities as of December 31, 2017 and 2016 consisted of:

December 31,	2017	2016
(Thousands)		
Noncurrent Deferred Income Tax Liabilities (Assets)		
Property Related	$5480,634	$721,444
Unfunded Future Income Taxes	38,366	92,946
Regulatory liability due to “Tax Cuts and Jobs Act”	(108,149)	-
Derivative Assets	(1,674)	(3,365)
Federal And State Tax Credits	(9,854)	-
Federal and State NOL'S	(895)	-
Pension and other postretirement benefits	8,198	3,768
Other	(5,608)	(11,196)
Noncurrent Deferred Income Tax Liabilities	**401,018**	**803,597**
Add: Valuation allowance	465	5,725
Total Noncurrent Deferred Income Tax Liabilities	**401,483**	**809,322**
Less amounts classified as regulatory liabilities		
Noncurrent deferred income taxes	229	149,232
Noncurrent Deferred Income Tax Liabilities	**$401,254**	**$660,090**
Deferred tax assets	$126,180	$14,561
Deferred tax liabilities	527,663	823,883
Net Accumulated Deferred Income Tax Liabilities	**$401,483**	**$809,322**

CMP has $8.6 million of federal and state research and development credits offset by $0.5 million of valuation allowance.

The reconciliation of unrecognized income tax benefits for the years ended December 31, 2017, and 2016 consisted of:

Years Ended December 31,	2017	2016
(Thousands)		
Balance as of January 1	$39,794	$20,077
Increases for tax positions related to prior years	-	19,717
Reduction for tax positions related to prior years	(10,369)	-
Balance as of December 31	**$29,425**	**$39,794**

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, 2017 and as of December 31, 2016. If recognized, $1.7 million of the total gross unrecognized tax benefits would affect the effective tax rate as an expense. Gross unrecognized tax benefits decreased $10.3 million in 2017 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, 2017 and 2016, our long-term debt was:

As of December 31,		**2017**		**2016**	
(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%	140,000	5.38%-6.40%
Chester: Promissory and Senior Notes[(b)]	2020	3,359	7.05%-10.48%	4,542	7.05%-10.48%
Obligations under capital leases	2018-2036	2,881		7,424	
Unamortized debt issuance costs and discount		(3,929)		(4,502)	
Total Debt		**$1,042,311**		**$ 1,047,464**	
Less: debt due within one year, included in current liabilities		1,452		5,154	
Total Non-current Debt		**$1,040,859**		**$ 1,042,310**	

(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, 2017, long-term debt, including sinking fund obligations and capital lease payments (in thousands) that will become due during the next five years are:

2018	**2019**	**2020**	**2021**	**2022**
$1,452	$152,220	$2,024	$150,307	$125,000

We have no debt covenant requirements related to the maintenance of financial ratios in our long term debt agreements at December 31, 2017 and 2016.

Note 7. Bank Loans and Other Borrowings

CMP had no short-term debt outstanding at December 31, 2017 or December 31, 2016. 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 "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. CMP has a lending/borrowing limit of $100 million under this agreement.

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 both December 31, 2017 and 2016.

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 both December 31, 2017 and 2016.

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, 2017 and 2016, our redeemable preferred stock was:

Series	Par Value per Share	Redemption Price per Share	Shares Authorized and Outstanding[1]	Amount (Thousands) 2017	2016
CMP, 6% Noncallable	$100	-	5,713	$571	$571
Total				**$571**	**$571**

[1] At December 31, 2017 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 Contingent Liabilities

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, MEPCO 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 transmission return. In June 2015 the NETOs and complainants both filed an appeal in the U.S. Court of Appeals for the District of Columbia of the FERC's final order. On April 14, 2017, the Court of Appeals (the Court) vacated FERC's decision on Complaint I and remanded it to FERC. The Court held that FERC, as directed by statute, did not determine first that the existing ROE was unjust and unreasonable before determining a new ROE. The Court ruled that FERC should have first determined that the then existing 11.14% base ROE was unjust and unreasonable before selecting the 10.57% as the new base ROE. The Court also found that FERC did not provide reasoned judgment as to why 10.57%, the point ROE at the midpoint of the upper end of the zone of reasonableness is a just and reasonable ROE. Instead, FERC had only explained in its order that the midpoint of 9.39% was not just and reasonable and a higher base ROE was warranted. On June 5, 2017, the NETOs made a filing with FERC seeking to reinstate transmission rates to the status quo ante (effect of the Court vacating order is to return the parties to the rates in effect prior to FERC Final decision) as of June 8, 2017, the date the Court decision became effective. In that filing, the NETOs stated that they will not begin billing at the higher rates until 60 days after FERC has a quorum of commissioners. On October 6, 2017, FERC issued an order rejecting the NETOs request to collect transmission revenue requirements at the higher ROE of 11.14%, pending FERC order on remand. In reaching this decision, FERC stated that it has broad remedial authority to make whatever ROE it eventually determines to be just and reasonable effective for the Complaint I refund period and prospectively from October 2014, the effective date of the Complaint I Order. Therefore FERC reasoned that the NETOs will not be harmed financially by not immediately returning to their pre-Complaint I ROE. We anticipate FERC to address the Court decision during 2018. We cannot predict the outcome of action by FERC.

On December 26, 2012, a second ROE complaint (Complaint II) for a subsequent rate period was filed requesting the then effective ROE of 11.14% 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 then effective ROE of 11.14% 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 relating to the refund periods and going forward period were held in June 2015 on Complaints II and III before a FERC Administrative Law Judge. 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 2018.

CMP reserved for refunds for Complaints I, II and III consistent with the FERC's March 3, 2015 final decision in Complaint I. Refunds were provided to customers for Complaint I. The CMP total reserve associated with Complaints II and III is $22.5 million, as of December 31, 2017, which has not changed since December 31, 2016, except for the accrual of carrying costs. 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 then existing base ROE of 10.57% be reduced to 8.61% and the ROE Cap be set at 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.. In April 2017, the NETOs filed for a stay in the hearings pending FERC on the Court order described above. That request was denied by the Administrative Law Judge. On November 21, 2017, the parties submitted updates to their ROE analyses and recommendations just prior to hearings with the NETOs continuing to advocate that the existing base ROE of 10.57% should remain in effect. Hearings were held in December 2017 with an expected Initial Decision from the Administrative Law Judge in March 2018. 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.

On October 5, 2017, the NETOs filed a Motion for Dismissal of Pancaked Return on Equity Complaints in light of the decision by the Court in April 2017 that became effective on June 8, 2017. The NETOs assert that all four complaints should be dismissed because the complainants have not shown that the existing ROE of 11.14% is unjust and unreasonable as the Court decision requires. In addition, the NETOs assert that Complaints II, III and IV should also be dismissed because the Court decision implicitly found that FERC's acceptance of Pancaked FPA Section 206 complaints was statutorily improper as Congress intended that the 15-month refund period under Section 206 applies whenever FERC does not complete its review of a complaint within the 15-month period. In the event FERC chooses not to dismiss the complaints, the NETOs request that FERC consolidate the complaints for decision as the evidentiary records are either closed or advanced enough for FERC to address the requirements of the Court decision and expeditiously issue a final order. FERC has not yet ruled on this Motion. We cannot predict the outcome of action by FERC.

Power purchase contracts including nonutility generator

We recognized expense of approximately $12.0 million for NUG power in 2017 and $57.6 million in 2016. We estimate that our power purchases will total $16.3 million in 2018, $26.4 million in 2019, $26.5 million in 2020, $26.7 million in 2021, $26.9 million in 2022 and $305.2 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, 2017.

We have recorded an estimated liability of $2.3 million at December 31, 2017, 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, 2017. 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, 2017. 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, 2017, and 2016. 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 $(0.7) million as of December 31, 2017, and $(0.2) million as of December 31, 2016, and are included in current liabilities.

The effect of hedging instruments on OCI and income was:

Year Ended December 31,	(Loss) Gain 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)			
2017			
Interest rate contracts	$-	Interest expense	$(2,175)
Commodity contracts:			
Fleet Fuel	$(171)	Other operating expenses	(262)
Total	**$(171)**		**$(2,437)**
2016			
Interest rate contracts	$-	Interest expense	$(2,175)
Commodity contracts:			
Fleet Fuel	$133	Other operating expenses	(638)
Total	**$133**		**$(2,813)**

The amount in OCI related to previously settled interest rate hedging contracts at December 31 is a net loss of $5.8 million for 2017 and a net loss of $8.0 million for 2016. For the year ended December 31, 2017, we recorded $2.2 million in net derivative losses related to discontinued cash flow hedges. We will amortize approximately $2.2 million of discontinued cash flow hedges in 2018.

At December 31, 2017, $0.7 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, 2017.

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

The estimated fair value of debt amounted to $1,169 million and $1,144 million as of December 31, 2017 and 2016, respectively. The estimated fair value was determined, in most cases, by discounting the future cash flows at market interest rates. The interest rate curve used to make these calculations takes into account the risks associated with the electricity industry and the credit ratings of the borrowers in each case. The fair value hierarchy for the fair value of debt is considered as Level 2.

Assets and liabilities measured at fair value on a recurring basis

Description	Total	Fair Value Measurements at December 31, Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(Thousands)				
2017				
Assets				
Noncurrent investments available for sale	$623	$623	$-	$-
Total	**$623**	**$623**	**$-**	**$-**
Liabilities				
Derivatives	$73	$-	$-	$73
Total	**$73**	**$-**	**$-**	**$73**
2016				
Assets				
Noncurrent investments available for sale	$698	$698	$-	$-
Total	**$698**	**$698**	**$-**	**$-**
Liabilities				
Derivatives	$164	$-	$-	$164
Total	**$164**	**$-**	**$-**	**$164**

We had no transfers to or from Level 1 and 2 during the years ended December 31, 2017 and 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 primarily consist of money market funds.

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

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

Year ended December 31,	Fair Value Measurements Using Significant Unobservable Inputs (Level 3) Derivatives, Net 2017	2016
(Thousands)		
Beginning balance	$164	$935
Total gain or loss for the period		
Included in earnings	(262)	(638)
Included in other comprehensive income	171	(133)
Ending balance	**$73**	**$164**

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.

Note 13. Accumulated Other Comprehensive Loss

(Thousands)	Balance January 1, 2016	2016 Change	Balance December 31, 2016	2017 Change	Balance December 31, 2017
Amortization of pension cost for nonqualified plans, net of income tax expense of $48 for 2016 and $8 for 2017	$(1,959)	$75	**$(1,884)**	$11	**$(1,872)**
Unrealized (loss) gain on derivatives qualified as hedges:					
Unrealized gain (loss) during period on derivatives qualified as hedges, net of income tax expense (benefit) of $52 for 2016 and $(70) for 2017		81		(101)	
Reclassification adjustment for loss included in net income, net of income tax expense of $250 for 2016 and of $107 for 2017		388		155	
Reclassification adjustment for loss on settled cash flow treasury hedge, net of income tax expense of $852 for 2016 and $890 for 2017		1,323		1,285	
Net unrealized (loss) gain on derivatives qualified as hedges	$(6,555)	$1,792	**$(4,763)**	$1,339	**$(3,424)**
Accumulated Other Comprehensive Loss	$(8,514)	$1,867	**$(6,647)**	$1,350	**$(5,297)**

No Accumulated Other Comprehensive Loss is attributable to the non-controlling 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 $2.9 million for 2017 and $3.0 million for 2016.

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	
	2017	**2016**	**2017**	**2016**
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	$396,523	$405,281	$106,979	$113,861
Service cost	7,679	7,846	647	712
Interest cost	15,976	16,267	4,269	4,523
Plan participants' contributions	-	-	642	528
Actuarial loss (gain)	36,141	(12,059)	8,721	(5,520)
Medicare subsidies received	-	-	60	48
Benefits paid	(24,333)	(20,812)	(7,122)	(7,173)
Benefit obligation at December 31	**431,986**	**$396,523**	**$114,196**	**$106,979**
Change in plan assets				
Fair value of plan assets at January 1	$272,645	$256,948	$36,141	$35,635
Actual return on plan assets	37,492	15,773	4,158	2,117
Employer contributions	15,700	20,736	2,801	6,597
Employer and plan participants' contributions		-	642	528
Benefits paid	(24,333)	(20,812)	(7,122)	(8, 784)
Medicare subsidies received	-	-	60	48
Fair value of plan assets at December 31	**$301,503**	**$272,645**	**$36,682**	**$36,141**
Funded status at December 31	**(130,483)**	**(123,878)**	**(77,514)**	**(70,838)**

Amounts recognized in the balance sheet	Pension Benefits		Postretirement Benefits	
December 31,	**2017**	**2016**	**2017**	**2016**
(Thousands)				
Noncurrent liabilities	$(130,483)	$(123,878)	$(77,514)	$(70,838)

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,	**2017**	**2016**	**2017**	**2016**
(Thousands)				
Net loss	$182,574	$179,114	$45,878	$41,974
Prior service cost (credit)	$-	$7	$(8,688)	$(10,701)

Our accumulated benefit obligation for all defined benefit pension plans at December 31 was $394.0 million for 2017 and $359.7 million for 2016.

Our postretirement benefits were partially funded at December 31, 2017 and 2016.

The projected benefit obligation and accumulated benefit obligation exceeded the fair value of pension plan assets for our plans as of December 31, 2017 and 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,	**2017**	**2016**
(Thousands)		
Projected benefit obligation	$431,986	$396,523
Accumulated benefit obligation	$393,959	$359,747
Fair value of plan assets	$301,503	$272,645

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

	Pension Benefits		Postretirement Benefits	
Years ended December 31,	**2017**	**2016**	**2017**	**2016**
(Thousands)				
Net periodic benefit cost				
Service cost	$7,679	$7,846	$647	$712
Interest cost	15,976	16,267	4,268	4,523
Expected return on plan assets	(20,727)	(19,963)	(2,175)	(2,292)
Amortization of prior service cost (credit)	6	9	(2,013)	(2,013)
Amortization of net loss	15,918	18,274	2,833	3,579
Net periodic benefit cost	**$18,852**	**$22,433**	**$3,560**	**$4,509**
Other changes in plan assets and benefit obligations recognized in regulatory assets and regulatory liabilities				
Net loss (gain)	$19,377	$(7,870)	$6,737	$(5,345)
Amortization of net loss	(15,918)	(18,274)	(2,833)	(3,579)
Amortization of prior service (cost) credit	(6)	(9)	2,013	2,013
Total recognized in regulatory assets and regulatory liabilities	**3,453**	**(26,153)**	**5,917**	**(6,911)**
Total recognized in net periodic benefit cost and regulatory assets and regulatory liabilities	**$22,305**	**$(3,720)**	**$9,477**	**$(2,402)**

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, 2018	**Pension Benefits**	**Postretirement Benefits**
(Thousands)		
Estimated net loss	$20,245	$3,346
Estimated prior service cost (credit)	$-	$(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, 2018.

Weighted-average assumptions used to determine benefit obligations at December 31,	**Pension Benefits**		**Postretirement Benefits**	
	2017	**2016**	**2017**	**2016**
Discount rate	3.63%	4.12%	3.63%	4.12%
Rate of compensation increase	3.80%-4.20%	3.80%-4.20%	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**		**Postretirement Benefits**	
	2017	**2016**	**2017**	**2016**
Discount rate	4.12%	4.10%	4.12%	4.10%
Expected long-term return on plan assets	7.30%	7.40%	-	-
Expected long-term return on plan assets - nontaxable trust	-	-	6.50%	7. 0%

Expected long-term return on plan assets - taxable trust	-	-	4.25%	4.50%
Rate of compensation increase (Union/Non-Union	3.80%-4.20%	3.80%-4.20%	N/A	N/A

We developed our expected long-term rate of return on plan assets assumption based on a review of long-term historical returns for the major asset classes, the target asset allocations and the effect of rebalancing of plan assets discussed below. That analysis considered current capital market conditions and projected conditions. Our policy is to calculate the expected return on plan assets using the market related value of assets. We amortize unrecognized actuarial gains and losses 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,	**2017**	**2016**
Health care cost trend rate (pre 65/post 65)	6.75%/8.50%	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	2026/2028

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

	1% Increase	**1% Decrease**
(Thousands)		
Effect on total of service and interest cost	$238	$(200)
Effect on postretirement benefit obligation	$6,563	$(5,510)

Contributions: In accordance with our funding policy we make annual contributions of not less than the minimum required by applicable regulations. We expect to contribute $20.0 million to our pension benefit plans in 2018.

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)			
2018	$19,021	$7,109	$171
2019	$19,461	$7,341	$190
2020	$20,199	$7,385	$211
2021	$20,930	$7,359	$236
2022	$21,840	$7,424	$260
2023 - 2027	$120,860	$37,323	$1,660

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, 2017 and 2016, by asset category are shown in the following table. CMP's share of the total consolidated assets is approximately 11% for 2017 and 10% for 2016.

		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)				
2017				
Cash and cash equivalents	$17,531	$-	$17,531	$-
U.S. government securities	13,338	13,338	-	-
Common stocks	129,312	129,312	-	-
Registered investment companies	105,037	105,037	-	-
Corporate bonds	447,124	-	447,124	-
Preferred stocks	4,381	299	4,082	-
Equity commingled funds	435,635	185,989	249,646	-
Other investments, principally annuity and fixed income	548,957	-	548,957	-
	$1,701,315	**$433,975**	**$1,267,340**	**$-**
Other investments measured at net asset value	1,126,017			
Total	**$2,827,332**			
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	-
Equity commingled funds	371,831		371,831	-
Other investments, principally annuity and fixed income	310,785	-	310,785	-
	$1,477,301	**$384,451**	**$1,092,850**	**$-**

Other investments measured at net asset value	1,157,112
Total	**$2,634,413**

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.
- Equity commingled funds – the fair value is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.
- 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.
- Other investments measured at net asset value (NAV) – alternative investments, such as private equity and real estate oriented investments, partnership/joint ventures and hedge funds are valued using the NAV as a practical expedient.

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, 2017 and 2016, by asset category are shown in the following table. CMP's share of the total consolidated assets was approximately 22% for 2017 and 2016.

		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)				
2017				
Money market funds	$3,978	$3,978	$-	$-
Mutual funds, fixed	35,419	35,419	-	-
Government & corporate bonds	1,658	-	1,658	-
Mutual funds, equity	76,444	49,089	27,355	-
Common stocks	19,800	19,800	-	-
Mutual funds, other	27,172	19,573	7,599	-
Total assets measured at fair value	**$164,471**	**$127,859**	**$36,612**	**$-**
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**	**$43,466**	**$-**

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, 2017 and 2016.

Note 15. Other Income and Other Deductions

Years Ended December 31,	**2017**	**2016**
(Thousands)		
Gain on sale of property	$138	$1,409
Interest and dividends income	777	139
Allowance for funds used during construction	7,829	3,759
Carrying costs on regulatory assets	2,457	500
Equity earnings	46	-
Miscellaneous	368	609
Total other income	**$11,615**	**$6,416**
Donations	(617)	(500)
Miscellaneous	(204)	(1,211)
Total other deductions	**$(821)**	**$(1,711)**

Note 16. 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 (ASC) 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 $35.6 million and $35.2 million for 2017 and 2016, respectively. Charge for services provided by CMP to AGR and its subsidiaries were approximately $7.2 million for 2017 and $2.9 million for 2016. All charges for services are at cost. The balance in accounts payable to affiliates of $41.1 million at December 31, 2017 and $35.8 million at December 31, 2016 is payable to Avangrid Service Company.

The balance in accounts receivable from affiliates of $30.7 million at December 31, 2017 is from an advance payment to ASC for administrative and management services of $30.0 million and the remaining $0.7 million is for services provided to MEPCO.

The balance in notes receivable from affiliates of $28.3 million at December 31, 2017 is from the UIL companies and the balance of $32.1 million at December 31, 2016 is from RG&E. Notes receivable from affiliates relate to the Virtual Money Pool Agreement as discussed in Note 7 of these financial statements.

Of the $29.7 million paid for income taxes, substantially all was paid to AGR under the tax sharing agreement.

Note 17. Subsequent Events

The company has performed a review of subsequent events through March 30, 2018, which is the date these financial statements were available to be issued, and no subsequent events have occurred from January 1, 2018 through such date.

THE SOUTHERN CONNECTICUT GAS COMPANY

AUDITED CONSOLIDATED FINANCIAL STATEMENTS

AS OF AND FOR THE YEARS ENDED

DECEMBER 31, 2017 AND 2016

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KPMG LLP
345 Park Avenue
New York, NY 10154-0102

Independent Auditors' Report

To the Board of Directors
The Southern Connecticut Gas Company:

We have audited the accompanying consolidated financial statements of The Southern Connecticut Gas Company and its subsidiaries, which comprise the consolidated balance sheet as of December 31, 2017, 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 consolidated financial statements in accordance 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 consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the 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 consolidated financial statements.

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

Opinion

In our opinion, the 2017 consolidated financial statements referred to above present fairly, in all material respects, the financial position of The Southern Connecticut Gas Company and its subsidiaries, as of December 31, 2017, and the results of their operations and their cash flows for the year then ended in accordance with U.S. generally accepted accounting principles.

Other Matter

The accompanying consolidated financial statements of The Southern Connecticut Gas Company and its subsidiaries, as of December 31, 2016 and for the year then ended were audited by other auditors whose report thereon dated April 27, 2017, expressed an unmodified opinion on those financial statements, before the reclassification for the adjustments described in note A to the consolidated financial statements.

As part of our audit of the 2017 consolidated financial statements, we also audited the adjustments described in note A that were applied to recast the 2016 consolidated financial statements. In our opinion, such adjustments are appropriate and have been properly applied. We were not engaged to audit, review, or apply any procedures to the 2016 consolidated financial statements of The Southern Connecticut Gas Company and its subsidiaries, other than with respect to the adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2016 consolidated financial statements as a whole.

KPMG LLP

New York, New York
April 30, 2018

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

	Year Ended December 31, 2017	Year Ended December 31, 2016
Operating Revenues	$ 363,832	$ 335,886
Operating Expenses		
Natural gas purchased	169,043	145,298
Operation and maintenance	99,706	88,290
Depreciation and amortization	25,831	20,420
Taxes other than income taxes	27,547	24,968
Total Operating Expenses	322,127	278,976
Operating Income	41,705	56,910
Other Income and (Expense), net		
Other income	3,566	1,393
Other (expense)	(1,556)	(931)
Total Other Income and (Expense), net	2,010	462
Interest Expense, net	13,508	14,067
Income Before Income Tax	30,207	43,305
Income Tax	2,467	15,378
Net Income	27,740	27,927
Less: Net Income Attributable to Noncontrolling Interest	7,115	-
Net Income Attributable to The Southern Connecticut Gas Company	$ 20,625	$ 27,927

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

	Year Ended December 31, 2017	Year Ended December 31, 2016
Net Income	$ 27,740	$ 27,927
Other Comprehensive Income, net of income tax	841	222
Comprehensive Income	28,581	28,149
Less: Comprehensive Income attributable to Noncontrolling Interest	7,115	-
Comprehensive Income Attributable to The Southern Connecticut Gas Company	$ 21,466	$ 28,149

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, 2017	Year Ended December 31, 2016
Cash Flows From Operating Activities		
Net income	$ 27,740	$ 27,927
Adjustments to reconcile net income		
to net cash provided by operating activities:		
Depreciation and amortization	26,020	20,933
Uncollectible expense	8,781	5,850
Deferred income taxes	(1,862)	7,863
Pension expense	4,656	4,341
Regulatory assets/liabilities amortization	13,367	13,367
Regulatory assets/liabiities carrying cost	174	86
Other non-cash items, net	(511)	(290)
Changes in:		
Accounts receivable and unbilled revenue, net	(14,206)	(16,523)
Natural gas in storage	(1,204)	5,621
Accounts payable and accrued liabilities	13,511	14,510
Taxes accrued/refundable, net	(10,880)	16,014
Accrued pension and other post-retirement	(691)	(4,508)
Regulatory assets/liabilities	(12,997)	(4,759)
Other assets	11,893	2,698
Other liabilities	84	(1,308)
Total Adjustments	36,135	63,895
Net Cash provided by Operating Activities	63,875	91,822
Cash Flows from Investing Activities		
Plant expenditures including AFUDC debt	(54,690)	(54,432)
Notes receivable from affiliates	(1,557)	(2,880)
Net Cash used in Investing Activities	(56,247)	(57,312)
Cash Flows from Financing Activities		
Payment of common stock dividend	(27,000)	-
Payment of noncontrolling interest dividend	-	(3,500)
Notes payable to affililiates	19,200	(36,962)
Other	-	(200)
Net Cash used in Financing Activities	(7,800)	(40,662)
Unrestricted Cash and Temporary Cash Investments:		
Net change for the period	(172)	(6,152)
Balance at beginning of period	794	6,946
Balance at end of period	$ 622	$ 794
Cash paid during the period for:		
Interest (net of amount capitalized)	$ 13,515	$ 12,802
Non-cash investing activity:		
Plant expenditures included in ending accounts payable	$ 5,380	$ 5,601

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, 2017 and 2016

ASSETS
(In Thousands)

	2017	2016
Assets		
Current Assets		
Unrestricted cash and temporary cash investments	$ 622	$ 794
Accounts receivable and unbilled revenues, net	80,972	78,570
Accounts receivable from affiliates	8,992	5,541
Notes receivable from affiliates	4,437	2,880
Regulatory assets	26,240	22,886
Gas in storage	27,693	26,489
Materials and supplies	1,787	2,115
Prepayments and other current assets	1,298	9,990
Total Current Assets	152,041	149,265
Other Investments	10,584	9,657
Property, Plant and Equipment, at cost	929,416	889,871
Less accumulated depreciation	234,646	221,864
Net Property, Plant and Equipment in Service	694,770	668,007
Construction work in progress	12,323	7,425
Total Property, Plant and Equipment	707,093	675,432
Regulatory Assets	140,059	153,415
Deferred Income Taxes Regulatory	10,864	-
Deferred Charges and Other Assets		
Goodwill	134,931	134,931
Other	130	170
Total Deferred Charges and Other Assets	135,061	135,101
Total Assets	$ 1,155,702	$ 1,122,870

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, 2017 and 2016

LIABILITIES AND CAPITALIZATION
(In Thousands)

	2017	2016
Liabilities		
Current Liabilities		
Notes payable to affiliates	$ 38,898	$ 19,698
Current portion of long-term debt	52,517	2,517
Accounts payable and accrued liabilities	57,533	53,461
Accounts payable to affiliates	9,395	-
Regulatory liabilities	9,557	2,759
Other current liabilities	8,208	8,385
Interest accrued	2,201	2,819
Taxes accrued	7,594	18,474
Total Current Liabilities	185,903	108,113
Deferred Income Taxes	34,239	42,366
Regulatory Liabilities	197,090	172,897
Deferred Income Taxes Regulatory	-	218
Other Noncurrent Liabilities		
Pension and other post-retirement	59,790	70,589
Asset retirement obligations	12,089	11,910
Environmental remediation costs	46,886	46,916
Other	8,943	8,473
Total Other Noncurrent Liabilities	127,708	137,888
Capitalization		
Long-term debt, net of unamortized premium	170,316	222,523
Common Stock Equity		
Common stock	18,761	18,761
Paid-in capital	369,737	369,737
Retained earnings	27,266	33,641
Accumulated other comprehensive income (loss)	698	(143)
Net Common Stock Equity of The Southern Connecticut Gas Company	416,462	421,996
Noncontrolling interest	23,984	16,869
Total Common Stock Equity	440,446	438,865
Total Capitalization	610,762	661,388
Total Liabilities and Capitalization	$ 1,155,702	$ 1,122,870

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, 2017 and 2016

(Thousands of Dollars)

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance as of December 31, 2015	1,407,072	$ 18,761	$ 369,737	$ 5,714	$ (365)	$ 20,369	$ 414,216
Net income attributable to The Southern Connecticut Gas Company				27,927			27,927
Other comprehensive loss, net of income taxes				-	222		222
Payment of noncontrolling interest dividend						(3,500)	(3,500)
Balance as of December 31, 2016	1,407,072	$ 18,761	$ 369,737	$ 33,641	$ (143)	$ 16,869	$ 438,865
Net income attributable to The Southern Connecticut Gas Company				20,625			20,625
Net income attributable to Noncontrolling interest						7,115	7,115
Other comprehensive loss, net of income taxes					841		841
Payment of common stock dividend				(27,000)			(27,000)
Balance as of December 31, 2017	1,407,072	$ 18,761	$ 369,737	$ 27,266	$ 698	$ 23,984	$ 440,446

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 197,000 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. UIL Holdings, whose primary business is ownership of its operating regulated utility businesses, is a wholly owned subsidiary of Avangrid Networks, Inc. (Networks), which is a wholly-owned subsidiary of Avangrid, Inc., which is a 81.5% owned subsidiary of Iberdrola, S.A., a corporation organized under the law of the Kingdom of Spain.

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. All intercompany transactions and accounts have been eliminated in all periods presented.

Certain amounts reported in the Financial Statements 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. The following table summarizes the impact to the prior period Statement of Income, Statement of Cash Flows and Balance Sheet of these reclassifications.

THE SOUTHERN CONNECTICUT GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2016 (in thousands)	As previously filed	Reclassifications	As currently reported
Statement of Income			
Interest on long-term debt	13,374	(13,374)	-
Other interest, net	180	(180)	-
Amortization of debt expense and redemption premiums	513	(513)	-
Interest Expense, net	-	14,067	14,067
Statement of Cash Flows			
Changes in:			
Accounts receivable and unbilled revenue, net	(10,920)	(5,603)	(16,523)
Unbilled revenues	(5,603)	5,603	-
Accounts payable and accrued liabilities	13,258	1,252	14,510
Accrued liabilities	1,252	(1,252)	-
Pension and other post-retirement	(3,878)	(630)	(4,508)
Accrued other post-employment benefits	(630)	630	-
Prepayments	(253)	253	-
Other assets	2,951	(253)	2,698
Balance Sheet			
Assets			
Current Assets			
Accounts receivable and unbilled revenues, net	59,251	19,319	78,570
Unbilled revenues	21,408	(21,408)	-
Accounts receivable from affiliates	-	5,541	5,541
Refundable taxes	9,012	(9,012)	-
Prepayments and other current assets	776	9,214	9,990
Other	202	(202)	-
Liabilities			
Current Liabilities			
Notes payable to affiliates / Intercompany payable	9,038	10,660	19,698
Accounts payable and accrued liabilities	52,208	1,253	53,461
Accounts payable to affiliate	-	-	-
Accrued liabilities	17,400	(17,400)	-
Other current liabilities	-	8,385	8,385
Taxes accrued	17,920	554	18,474
Regulatory liabilities	173,115	(218)	172,897
Deferred income taxes regulatory	-	218	218
Other Noncurrent Liabilities			
Pension	61,277	9,312	70,589
Other post-retirement benefits accrued	16,213	(16,213)	-
Asset retirement obligation	-	11,910	11,910
Other	13,482	(5,009)	8,473

SCG has evaluated subsequent events through the date its financial statements were available to be issued, April 30, 2018.

Variable Interest Entities

CNE Peaking LLC (CNE) and Total Peaking Services LLC (TPS), both wholly owned subsidiaries of United Resources, Inc. (URI), which is a wholly owned subsidiary of UIL Holdings, owns and operates a 14.6 million gallon liquefied natural gas (LNG) storage tank operated by SCG and located on property owned by SCG in Milford, Connecticut, and certain equipment, materials and supplies used in or useful for the operation of the Tank. The Assets earn a rate of return equal to SCG's allowed rate of return. CNE and TPS 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 CNE and TPS with SCG operating the storage tank and all of the revenues at CNE and TPS being derived from SCG. As a result, CNE and TPS have been consolidated into the financial statements of SCG, which include total assets of $29.8 million and income of $7.1 million as of and for the year ended December 31, 2017. Intercompany operating revenues and natural gas purchased expenses of $11.7 million and intercompany receivables and payables of $2.3 million have been eliminated upon consolidation. The equity interests in CNE and TPS held by URI are reflected as a noncontrolling interest in the accompanying Consolidated Balance Sheet and Statement of Changes in Shareholder's Equity.

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, 2017	December 31, 2016
	(In Thousands)	
Assets:		
Current assets	$ 13,126	$ 10,595
Long-term assets	16,637	13,451
Total Assets	$ 29,763	$ 24,046
Liabilities		
Current liabilities	$ 5,779	$ 1,545
Long-term liabilities	-	-
Total Liabilities	$ 5,779	$ 1,545

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. SCG recognizes revenues upon delivery of natural gas to its customers. In addition, SCG accrues revenue pursuant to the various regulatory provisions to record regulatory assets for revenues that will be collected in the future.

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 refunded in the future through the ratemaking process. SCG is allowed to recover all such deferred costs and is required to refund such obligations to customers through its regulated rates. See

THE SOUTHERN CONNECTICUT GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note (C) "Regulatory Proceedings", for a discussion of the recovery of certain deferred costs and the refund of certain obligations, as well as a discussion of the regulatory decisions that provide for such recovery and require such refunding.

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, 2017 and 2016 included the following:

	Remaining Period	December 31, 2017	December 31, 2016
		(In Thousands)	
Regulatory Assets:			
Pension and other post-retirement benefit plans	(a)	$ 81,257	$ 96,391
Hardship programs	(b)	6,184	7,442
Deferred purchased gas	(c)	10,432	2,376
Environmental remediation costs	(g)	50,311	50,518
Debt premium	1 to 20 years	11,647	14,164
Deferred income taxes regulatory	(c)	10,864	-
Other	(e)	6,468	5,410
Total regulatory assets		177,163	176,301
Less current portion of regulatory assets		26,240	22,886
Regulatory Assets, Net		$ 150,923	$ 153,415
Regulatory Liabilities:			
Pension and other post-retirement benefit plans	(a)	4,984	3,618
Asset removal costs	(e)	98,713	97,086
Rate Credits	1 to 10 years	7,500	7,500
Unfunded future income taxes	(d)	22,471	26,742
Tax reform remeasurement	(h)	24,678	-
Low income program	(f)	43,167	37,011
Non-firm margin sharing credits	7 years	4,334	1,761
Deferred income taxes regulatory	(c)	-	218
Other	(e)	800	1,938
Total regulatory liabilities		206,647	175,874
Less current portion of regulatory liabilities		9,557	2,759
Regulatory Liabilities, Net		$ 197,090	$ 173,115

(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.
(h) Impact of deferred tax remeasurement as a consequence of the Tax Cuts and Jobs Act of 2017 enacted by the U.S. federal government on December 22, 2017. Refundable period will be determined in future rate proceedings.

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 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.

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 2017 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.

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, 2017 and 2016 were comprised as follows:

	2017	2016
	(In Thousands)	
Gas distribution plant	$ 842,063	$ 806,592
Software	2,204	2,019
Land	3,748	3,748
Building and improvements	25,725	25,448
VIE	19,911	17,844
Other plant	35,765	34,220
Total property, plant & equipment	929,416	889,871
Less accumulated depreciation	234,646	221,864
	694,770	668,007
Construction work in progress	12,323	7,425
Net property, plant & equipment	$ 707,093	$ 675,432

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 2017 and 2016 were 1.28% and 0.55%, respectively. The portion of the allowance applicable to equity funds for 2017 and 2016 was immaterial.

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 2017 and 2016 were approximately 2.8% and 2.4%, respectively, of the original cost of depreciable property.

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, 2017, SCG did not have any assets that were impaired under this standard.

Unrestricted cash and temporary cash investments

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

Accounts receivable and unbilled revenues

Accounts receivable at December 31, 2017 and 2016 include unbilled revenues of $27.7 million and $21.4 million, respectively and are shown net of an allowance for doubtful accounts of $1.0 million and $1.6 million for 2017 and 2016, respectively. Accounts receivable do not bear interest, although late fees may be assessed.

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. Changes in those assumptions could significantly affect the estimated amounts of unbilled revenues.

The allowance for doubtful accounts is management's best estimate of the amount of probable credit losses in the existing accounts receivable, determined based on experience. Each month, SCG reviews the allowance for doubtful accounts and past due accounts by age. When management believes that a receivable will not be recovered, the account balance is charged off 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

Gas in storage

Natural gas in storage 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. SCG continuously monitors the weighted-average cost of gas value to ensure it remains at, or below market value.

Materials and supplies

Materials and supplies inventories are used for construction of new facilities and repairs of existing facilities. The inventories are carried and withdrawn at lower of cost and net realizable value

Other Investments

The SCG's other investments consist of noncurrent investments available for sale, which primarily consist of money market funds.

Accrued removal obligations

SCG meets the requirements concerning accounting for regulated operations, and recognizes a regulatory liability, for the difference between removal costs collected in rates and actual costs incurred. SCG classifies those amounts as accrued removal obligations.

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.
ARO activity for 2017 and 2016 is as follows:

	2017	2016
	(In Thousands)	
Balance as of January 1	$ 11,910	$ 11,727
Liabilities settled during the year	(447)	(433)
Accretion	626	616
Balance as of December 31	$ 12,089	$ 11,910

Weather Insurance Contracts

On an annual basis, SCG has assessed 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 October of 2017, SCG entered into a weather insurance contract for the period of November 1, 2017 through December 31, 2017. If temperatures were warmer than normal, SCG would receive a payment, up to a maximum of $1.5 million; however, if temperatures were colder than normal, SCG would make a payment of up to a maximum of $1 million. As a result of PURA’s approval for a decoupling mechanism which went into effect on January 1, 2018, the contract did not extend into the 2018 portion of the heating season. The intrinsic value of the contract, which is carried on the balance sheet as a derivative liability, totaled $0.5 million at December 31, 2017, and was subsequently paid.

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.

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, 2017 and 2016.

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.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the Tax Act) was signed into law. The Tax Act contains significant changes to the federal tax structure, including among other things, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017. PURA has instituted proceedings in Connecticut to review and address the implications associated with the Tax Act on the utilities providing service in the state. SCG expects the regulators in Connecticut to issue requirements in 2018 regarding how all tax benefits associated with the Tax Act will be returned to customers.

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.

New Accounting Standards

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC), Topic 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. ASC 606 was further amended through various updates the FASB issued thereafter. 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 amended effective date is for annual reporting periods beginning after December 15, 2017, and interim periods therein, with early adoption permitted as of the original effective date of annual reporting periods beginning after December 15, 2016. Entities may apply the standard 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). SCG will adopt the new standard effective January 1, 2018, and apply the modified retrospective method. Based on management’s assessment to existing contracts and revenue streams, SCG does not expect to record any material cumulative adjustments to retained earnings and does not expect ASC 606 to have a material impact on the amount and timing of its revenue recognition. Management has identified other changes primarily related to the presentation and disclosure of revenues. Management plans to disaggregate revenues not accounted for in scope of the new standard, as required, including alternative revenue programs.

In February 2016, the FASB issued Accounting Standards Update (ASU) 2016-02 "Leases" 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 FASB issued an update in January 2018 to clarify the application of the new leases guidance to land easements and provide relief concerning adoption efforts for existing land easements that are not accounted for as leases under the current leases guidance. The updated guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early application is permitted. SCG is currently reviewing our contracts and is 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 its financial statements. SCG does not expect the adoption of the new guidance will materially affect its financial position through the recording of operating leases on the balance sheet as a right-of-use asset.

In March 2017, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2017-07 "Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost". The ASU contains amendments that require an entity to present service cost separately from the other components of net benefit cost, and to report the service cost component in the income statement line item(s) where it reports the corresponding compensation cost. An entity is to present all other components of net benefit cost outside of operating cost, if it presents that subtotal. The amendments also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of a self-constructed asset). The amendments are effective for annual and interim periods in fiscal years beginning after December 15, 2017, with early adoption permitted. SCG does not plan to early adopt. An entity is required to apply the amendments retrospectively for the presentation of the service cost component and the other components of net periodic pension cost and net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension cost and net periodic postretirement benefit in assets. A practical expedient allows an entity to retrospectively apply the amendments on adoption to net benefit costs for comparative periods by using the amounts disclosed in the notes to financial statements for pension and postretirement benefit plans for those periods. SCG does not expect the adoption of the amendments will materially affect its results of operations, financial position, cash flows, and disclosures.

In February 2018 the FASB issued ASU 2018-02 "Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" which contains amendments to address a narrow-scope financial reporting issue that arose as a consequence of the Tax Cuts and Jobs Act of 2017 (the Tax Act) enacted on December 22, 2017 by the U.S. federal government. Under current guidance, the adjustment of deferred taxes for the effect of a change in tax laws or rates is required to be included in income from continuing operations, thus the associated tax effects of items within accumulated other comprehensive income (AOCI) (referred to as stranded tax effects) do not reflect the appropriate tax rate. The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Act. As a result, the amendments eliminate the stranded tax effects resulting from the Tax Act and will improve the usefulness of information reported to financial statement users. The amendments only relate to the reclassification of the income tax effects of the Tax Act, and do not affect the underlying guidance that requires the effect of a change in tax laws or rates to be included in income from continuing operations. The amendments are effective for all entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted. An entity has the option to apply the amendments either in the period of adoption or retrospectively to each period (or periods) in which it recognizes the effect of the change in the U.S. federal corporate income tax rate in the Tax Act. An entity is required to disclose its accounting policy election, including its policy for reclassifying material stranded tax effects in AOCI to earnings (specific identification or portfolio method). SCG does not expect the adoption of the amendments will materially affect our results of operations, financial position, cash flows, and disclosures.

B) CAPITALIZATION

Common Stock

SCG had 1,407,072 shares of its common stock, $13.33 par value, outstanding as of December 31, 2017 and 2016.

Long-Term Debt

As of December 31,		2017		2016	
(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		8,833		11,040	
Total Debt		**222,833**		**225,040**	
Less: debt due within one year, included in current liabilities		52,517		2,517	
Total Long-term Debt		**$ 170,316**		**$ 222,523**	

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

The estimated fair value of debt amounted to $261.2 million and $259.6 million as of December 31 2017 and 2016, 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 natural gas 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.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:

	2018	2019	2020	2021	2022 & Thereafter	Total
			(In Thousands)			
Maturities	$ 50,000	$ -	$ -	$ 25,000	$ 139,000	$ 214,000

Under various debt agreements, SCG is required to maintain a ratio of consolidated debt to consolidated capital of not greater than 65% (debt ratio). As of December 31, 2017, SCG's debt ratio was 37%.

(C) REGULATORY PROCEEDINGS

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.

On June 30, 2017, SCG filed an application with PURA for new tariffs to become effective January 1, 2018. SCG requested a three-year rate plan for calendar years 2018, 2019 and 2020 and a proposed ROE of 9.95%. SCG also requested to implement a revenue decoupling mechanism (RDM) and Distribution Integrity Management Program, or DIMP, mechanism. On October 16, 2017, SCG, Prosecutorial Staff from PURA, and the Connecticut Office of Consumer Counsel filed an amended settlement agreement with PURA for approval, which includes among other items the implementation of an RDM, earnings sharing mechanism and the DIMP as proposed by SCG, the amortization of certain regulatory liabilities (most notably accumulated hardship deferral balances and certain accumulated deferred income taxes) and tariff increases based on an ROE of 9.25% and approximately 52% equity level. The parties also agreed on a three-year rate plan with rate increases of $1.5 million, $4.7 million and $5.0 million in 2018, 2019, and 2020, respectively. PURA approved the amended rate case settlement agreement on December 13, 2017, and new tariffs became effective on January 1, 2018. 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.

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, 2017 are as follows:

	(In Thousands)
2018	$ 78,837
2019	73,498
2020	64,721
2021	51,060
2022	39,304
2023-after	227,379
	$ 534,799

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

SCG 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 SCG 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. SCG has a lending/borrowing limit of $100 million under this agreement. There was $9.8 million outstanding as of December 31, 2017 under this agreement. There was no balance outstanding as of December 31, 2016 under this agreement.

The Bi-Lateral Intercompany Facility provides for borrowing of up to $250 million from Avangrid at the A2/P2 non-financial 30-day commercial paper rate published by the Federal Reserve. There was $29.1 million outstanding under this agreement as of December 31, 2017 and there was $19.7 million outstanding under this agreement as of December 31, 2016.

On April 5, 2016, Avangrid, Inc. and its subsidiaries, including SCG, 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, 2017 and 2016, SCG did not have any outstanding borrowings under the Avangrid Credit Facility.

(E) INCOME TAXES

	Year Ended December 31, 2017	Year Ended December 31, 2016
	(In Thousands)	
Income tax expense consists of:		
Income tax provisions (benefits):		
Current		
Federal	$ 2,647	$ 5,521
State	1,682	1,994
Total current	4,329	7,515
Deferred		
Federal	(76)	8,262
State	(1,786)	(399)
Total deferred	(1,862)	7,863
Total Income tax expense	$ 2,467	$ 15,378

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, 2017	Year Ended December 31, 2016
	(In Thousands)	
Book income before income taxes	$ 30,207	$ 43,305
Computed tax at federal statutory rate	$ 10,573	$ 15,157
Increases (reductions) resulting from:		
Removal costs	(1,000)	(1,019)
Uncollectible reserves and programs	1,158	992
State taxes, net of federal income tax benefits	(103)	1,037
2017 Tax Act deferred tax remeasurement	(3,262)	-
Variable interest entity	(519)	(876)
Other items, net	(4,380)	87
Total income tax expense	$ 2,467	$ 15,378
Effective income tax rates	8.2%	35.5%

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. SCG is 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, 2017 and 2016, 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, 2017:

Jurisdiction	*Tax years*
Federal	2013 - 2017
Connecticut	2013 - 2017

The following table summarizes SCG's deferred tax assets and liabilities as of December 31, 2017 and 2016:

`	2017	2016
	(In Thousands)	
Property related	$ (37,939)	$ (55,776)
Unfunded future income taxes	7,658	10,753
Federal and state tax credits	4,589	6,573
Deferred tax asset on 2017 Tax Act remeasurement	5,037	-
Federal and state net operating loss	4,796	6,827
Post-retirement benefits, net	(2,429)	(4,114)
Other liabilities	(5,087)	(6,847)
	$ (23,375)	$ (42,584)
Less Regulatory Assets (Liabilities)	10,864	(218)
Total deferred income tax assets (liabilities), net	$ (34,239)	$ (42,366)

As of December 31, 2017, SCG had a net state tax credit carry forward of $4.6 million and a federal net operating loss carry forward of $4.8 million that will begin to expire in 2032. As of December 31, 2016, SCG had a net state tax credit carry forward of $6.6 million and a federal net operating loss carry forward of $6.8 million.

(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. The Plans are closed to new employees. New employees are eligible for enhanced benefits in the 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 NEPC, LLC as investment advisor 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.

Networks' asset allocation policy is the most important consideration in achieving our objective of superior investment returns while minimizing risk. Management has 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, there are established 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 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, 2017 and 2016. Plan assets and obligations have been measured as of December 31, 2017 and 2016.

	Pension Benefits		Other Post-Retirement Benefits	
	Year Ended December 31, 2017	Year Ended December 31, 2016	Year Ended December 31, 2017	Year Ended December 31, 2016
Change in Benefit Obligation:	(In Thousands)			
Benefit obligation at beginning of year	$ 179,453	$ 160,946	$ 21,901	$ 21,691
Service cost	1,925	1,797	163	177
Interest cost	7,417	7,387	893	986
Plan participants' contributions	-	-	615	980
Actuarial (gain) loss	377	22,454	(1,777)	69
Benefits paid (including expenses)	(9,140)	(13,131)	(2,102)	(2,002)
Benefit obligation at end of year	$ 180,032	$ 179,453	$ 19,693	$ 21,901
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 118,176	$ 118,773	$ 5,688	$ 5,778
Actual return on plan assets	17,354	8,571	700	303
Plan participants' contributions	-	-	615	980
Employer contributions	654	3,963	1,450	(2,002)
Benefits paid (including expenses)	(9,140)	(13,131)	(2,388)	629
Fair value of plan assets at end of year	$ 127,044	$ 118,176	$ 6,065	$ 5,688
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ 52,988	$ 61,277	$ 13,628	$ 16,213
Amounts Recognized in the Consolidated Balance Sheet consist of:				
Non-current liabilities	$ 52,988	$ 61,277	$ 13,628	$ 16,213
Amounts Recognized as a Regulatory Asset (Liability) consist of:				
Prior service cost	$ 1,671	$ 2,430	$ 1,155	$ 1,644
Net (gain) loss	25,562	36,788	(4,463)	(3,041)
Total recognized as a regulatory asset (liability)	$ 27,233	$ 39,218	$ (3,308)	$ (1,397)
Information on Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:				
Projected benefit obligation	$ 180,032	$ 179,453	N/A	N/A
Accumulated benefit obligation	$ 174,171	$ 168,584	N/A	N/A
Fair value of plan assets	$ 127,044	$ 118,176	N/A	N/A
The following weighted average actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate (Qualified Plans)	3.80%	4.24%	N/A	N/A
Discount rate (Non-Qualified Plans)	3.80%	4.24%	N/A	N/A
Discount rate (Other Post-Retirement Benefits)	N/A	N/A	3.80%	4.24%
Average wage increase	3.50%	3.50%	N/A	N/A
Health care trend rate (current year pre/post-65)	N/A	N/A	7.50%/8.50%	6.75%/8.00%
Health care trend rate (2030/2028 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

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, 2017 and 2016 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, 2017	**Year Ended December 31, 2016**	**Year Ended December 31, 2017**	**Year Ended December 31, 2016**
	(In Thousands)			
Components of net periodic benefit cost:				
Service cost	$ 1,925	$ 1,797	$ 163	$ 177
Interest cost	7,417	7,387	893	986
Expected return on plan assets	(8,551)	(9,038)	(376)	(380)
Amortization of prior service cost	759	759	489	489
Amortization of actuarial (gain) loss	2,791	2,316	(392)	(152)
Net periodic benefit cost	$ 4,341	$ 3,221	$ 777	$ 1,120
Other Changes in Plan Assets and Benefit Obligations Recognized as a Regulatory Asset (Liability):				
Net (gain) loss	$ (8,424)	$ 22,922	$ (1,815)	$ 147
Amortization of current year prior service (credit)/costs	-	-	-	-
Amortization of prior service cost	(759)	(759)	(489)	(489)
Amortization of actuarial (gain) loss	(2,791)	(2,316)	392	152
Total recognized as regulatory asset (liability)	$ (11,974)	$ 19,847	$ (1,912)	$ (190)
Total recognized in net periodic benefit costs and regulatory asset (liability)	$ (7,633)	$ 23,068	$ (1,135)	$ 930
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	1,671	2,792	N/A	N/A
Total estimated amortizations	$ 2,430	$ 3,551	N/A	N/A
The following actuarial weighted average assumptions were used in calculating net periodic benefit cost:				
Discount rate	4.24%	4.24%	4.24%	4.24%
Average wage increase	3.50%	3.50%	N/A	N/A
Return on plan assets	7.50%	7.75%	7.00%	7.75%
Health care trend rate (current year - pre/post-65)	N/A	N/A	6.75%/8.50%	7.00%/9.00%
Health care trend rate (2026/2028 - pre/post-65)	N/A	N/A	4.50%/4.50%	4.50%/4.50%

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	$ 45	$ (36)
Accumulated post-retirement benefit obligation	$ 903	$ (734)

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 $2.3 million in 2018. 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, 2017 consisted of:

Year	Pension Benefits	Other Post-Retirement Benefits	Medicare Act Subsidy
		(In Thousands)	
2018	$ 9,755	$ 1,597	$ 104
2019	$ 10,028	$ 1,560	$ 106
2020	$ 10,270	$ 1,475	$ 111
2021	$ 10,391	$ 1,449	$ 113
2022	$ 10,598	$ 1,402	$ 118
2023-2027	$ 54,866	$ 6,385	$ 401

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 2017 and 2016 was $0.9 million and $0.8 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, 2017, SCG recorded inter-company expenses of $15.0 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 and are included in Accounts receivable from affiliates and Accounts payable to affiliates in the accompanying balance sheets.

Dividends/Capital Contributions

For the year ended December 31, 2017, SCG accrued $27 million in dividends to UIL Holdings. For the years ended December 31, 2016, SCG did not accrue any 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)	
2018		77
2019		72
2020		72
2021		48
2022		-
2023 - after		-
	$	269

(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, 2017 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, 2017, SCG reserved $48.7 million related to the property located in New Haven which was offset by a regulatory asset. Additionally, as of December 31, 2017, SCG 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, 2017 and December 31, 2016.

	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, 2017				
Noncurrent investments	$ 10,584	$ -	$ -	$ 10,584
Total fair value assets, December 31, 2017	$ 10,584	$ -	$ -	$ 10,584
December 31, 2016				
Noncurrent investments	$ 9,657	$ -	$ -	$ 9,657
Total fair value assets, December 31, 2016	$ 9,657	$ -	$ -	$ 9,657

The following tables set forth the fair values of SCG's pension and OPEB assets as of December 31, 2017 and 2016.

	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, 2017	(In Thousands)			
Pension assets				
Mutual funds	$ -	$ 127,044	$ -	$ 127,044
OPEB assets				
Mutual funds	6,065	-	-	6,065
Fair value of plan assets, December 31, 2017	$ 6,065	$ 127,044	$ -	$ 133,109
December 31, 2016				
Pension assets				
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

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".