The Narragansett Electric Company

Financial Statements

For the years ended March 31, 2018, 2017, and 2016

THE NARRAGANSETT ELECTRIC COMPANY

FINANCIAL STATEMENTS

FOR THE TWELVE MONTHS ENDED

MARCH 31, 2018

I hereby certify that I am Vice-President, NE Controller of The Narragansett Electric Company and that the enclosed financial statements for the twelve months ended March 31, 2018, have been prepared in accordance with generally accepted accounting principles, and are, in my opinion, correct, subject to year-end audit adjustments and footnote disclosure.

Christopher McCusker, Vice-President, NE Controller

Date 7/19/18

THE NARRAGANSETT ELECTRIC COMPANY

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Narragansett Electric Company

We have audited the accompanying financial statements of The Narragansett Electric Company (the "Company"), which comprise the balance sheet and statement of capitalization as of March 31, 2018, and the related statements of income, comprehensive income, cash flows and changes in shareholders' equity 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 accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

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

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

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of The Narragansett Electric Company as of March 31, 2018, and the results of its operations and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Predecessor Auditors' Opinion on 2017 and 2016 Financial Statements

The financial statements of the Company as of and for each of the two years ended March 31, 2017, were audited by other auditors, whose report, dated July 14, 2017, expressed an unmodified opinion on those statements.

Deloitte & Touche LLP

July 19, 2018

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF INCOME
(in thousands of dollars)

	Years Ended March 31,		
	2018	2017	2016
Operating revenues:			
Electric services	**$ 1,012,378**	$ 892,452	$ 944,547
Gas distribution	**432,647**	370,902	361,702
Operating revenues	**1,445,025**	1,263,354	1,306,249
Operating expenses:			
Purchased electricity	**359,726**	302,210	372,846
Purchased gas	**180,576**	132,919	139,547
Operations and maintenance	**474,341**	418,499	385,873
Depreciation	**105,686**	103,923	96,914
Other taxes	**132,057**	120,461	118,776
Total operating expenses	**1,252,386**	1,078,012	1,113,956
Operating income	**192,639**	185,342	192,293
Other income and (deductions):			
Interest on long-term debt	**(43,247)**	(43,758)	(43,963)
Other interest, including affiliate interest	**(3,619)**	(3,199)	(1,680)
Loss on sale of assets	**-**	(2,468)	-
Other (deductions) income, net	**(213)**	749	1,512
Total other deductions, net	**(47,079)**	(48,676)	(44,131)
Income before income taxes	**145,560**	136,666	148,162
Income tax expense	**22,249**	48,524	53,004
Net income	**$ 123,311**	$ 88,142	$ 95,158

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

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF COMPREHENSIVE INCOME
(in thousands of dollars)

	Years Ended March 31,		
	2018	2017	2016
Net income	**$ 123,311**	$ 88,142	$ 95,158
Other comprehensive income, net of taxes:			
Unrealized gains (losses) on securities	**26**	110	(62)
Change in pension and other postretirement obligations	**99**	(4)	9
Unrealized gains on hedges	**228**	471	494
Total other comprehensive income	**353**	577	441
Comprehensive income	**$ 123,664**	$ 88,719	$ 95,599
Related tax (expense) benefit:			
Unrealized (gains) losses on securities	**$ (38)**	$ (60)	$ 34
Change in pension and other postretirement obligations	**(29)**	2	(5)
Unrealized gains on hedges	**(93)**	(254)	(266)
Total tax expense	**$ (160)**	$ (312)	$ (237)

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

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(in thousands of dollars)

	Years Ended March 31,		
	2018	2017	2016
Operating activities:			
Net income	**$ 123,311**	$ 88,142	$ 95,158
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	**105,686**	103,923	96,914
Regulatory amortizations	**235**	714	706
Provision for deferred income taxes	**41,290**	27,470	45,818
Bad debt expense	**19,136**	14,105	8,480
Amortization of debt discount and issuance costs	**293**	293	294
Net postretirement benefits (contributions) expense	**(19,904)**	3,886	(10,559)
Net environmental remediation payments	**(2,946)**	(4,889)	(3,058)
Changes in operating assets and liabilities:			
Accounts receivable and other receivable, net, and unbilled revenues	**(66,457)**	(35,989)	74,882
Inventory	**(1,604)**	4,330	(2,662)
Regulatory assets and liabilities, net	**(64,143)**	97,822	39,235
Derivative instruments	**7,364**	(23,469)	(6,897)
Prepaid and accrued taxes	**5,094**	5,418	(3,490)
Accounts payable and other liabilities	**73,334**	19,284	(46,330)
Other, net	**(30,543)**	(1,827)	(9,144)
Net cash provided by operating activities	**190,146**	299,213	279,347
Investing activities:			
Capital expenditures	**(269,344)**	(295,621)	(278,050)
Proceeds from restricted cash	**7,834**	58,044	73,370
Payments on restricted cash	**(7,357)**	(43,887)	(43,985)
Cost of removal	**(21,033)**	(17,883)	(17,959)
Other	**(517)**	1,250	376
Net cash used in investing activities	**(290,417)**	(298,097)	(266,248)
Financing activities:			
Preferred stock dividends	**(110)**	(110)	(110)
Payments on long-term debt	**(1,375)**	(1,375)	(1,375)
Intercompany money pool and affiliated receivables/payables, net	**100,339**	(6,238)	(16,514)
Net cash provided by (used in) financing activities	**98,854**	(7,723)	(17,999)
Net decrease in cash and cash equivalents	**(1,417)**	(6,607)	(4,900)
Cash and cash equivalents, beginning of year	**7,803**	14,410	19,310
Cash and cash equivalents, end of year	**$ 6,386**	$ 7,803	$ 14,410
Supplemental disclosures:			
Interest paid	**$ (44,492)**	(42,574)	(42,683)
Income taxes (paid) refunded	**(2,624)**	63	71
Significant non-cash items:			
Capital-related accruals	**18,987**	15,775	26,990
Parent tax loss allocation	**3,047**	-	-
Share based compensation	**2**	31	25

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

THE NARRAGANSETT ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31, 2018	March 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 6,386**	$ 7,803
Restricted cash and special deposits	**479**	956
Accounts receivable	**251,985**	212,572
Allowance for doubtful accounts	**(25,617)**	(25,192)
Accounts receivable from affiliates	**22,221**	6,354
Unbilled revenues	**66,150**	57,817
Inventory	**23,390**	24,216
Regulatory assets	**87,297**	52,446
Derivative instruments	**731**	6,189
Prepaid taxes	**13,246**	9,821
Other	**3,362**	1,805
Total current assets	**449,630**	354,787
Property, plant and equipment, net	**2,984,346**	2,785,811
Other non-current assets:		
Regulatory assets	**492,361**	464,135
Goodwill	**724,810**	724,810
Derivative instruments	**10**	167
Other	**37,166**	13,905
Total other non-current assets	**1,254,347**	1,203,017
Total assets	**$ 4,688,323**	$ 4,343,615

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

THE NARRAGANSETT ELECTRIC COMPANY
BALANCE SHEETS
(in thousands of dollars)

	March 31, 2018	March 31, 2017
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 170,458**	$ 124,895
Accounts payable to affiliates	**14,430**	80,085
Current portion of long-term debt	**15,839**	1,375
Taxes accrued	**34,534**	29,624
Customer deposits	**10,627**	12,514
Interest accrued	**5,417**	5,434
Regulatory liabilities	**109,484**	106,788
Intercompany money pool	**307,520**	125,659
Derivative instruments	**1,971**	392
Renewable energy certificate obligations	**5,746**	11,841
Other	**29,640**	20,701
Total current liabilities	**705,666**	519,308
Other non-current liabilities:		
Regulatory liabilities	**553,343**	245,856
Asset retirement obligations	**9,472**	10,150
Deferred income tax liabilities, net	**324,161**	538,229
Postretirement benefits	**83,234**	121,799
Environmental remediation costs	**137,677**	135,529
Derivative instruments	**1,394**	1,224
Other	**15,467**	25,230
Other tax liabilities	**562**	-
Total other non-current liabilities	**1,125,310**	1,078,017
Capitalization:		
Shareholders' equity	**2,030,903**	1,904,300
Long-term debt	**826,444**	841,990
Total capitalization	**2,857,347**	2,746,290
Total liabilities and capitalization	**$ 4,688,323**	$ 4,343,615

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

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF CAPITALIZATION
(in thousands of dollars)

			March 31,	
			2018	2017
Total shareholders' equity			**$ 2,030,903**	$ 1,904,300
Long-term debt:	Interest Rate	Maturity Date		
Unsecured notes:				
Senior Note	4.53%	March 15, 2020	**250,000**	250,000
Senior Note	5.64%	March 15, 2040	**300,000**	300,000
Senior Note	4.17%	December 10, 2042	**250,000**	250,000
			800,000	800,000
First Mortgage Bonds ("FMB"):				
FMB Series S	6.82%	April 1, 2018	**14,464**	14,464
FMB Series N	9.63%	May 30, 2020	**10,000**	10,000
FMB Series O	8.46%	September 30, 2022	**12,500**	12,500
FMB Series P	8.09%	September 30, 2022	**3,125**	3,750
FMB Series R	7.50%	December 15, 2025	**6,000**	6,750
			46,089	47,464
Total debt			**846,089**	847,464
Unamortized debt discount			**(2,076)**	(2,301)
Unamortized debt issuance costs			**(1,730)**	(1,798)
Current portion of long-term debt			**15,839**	1,375
Long-term debt			**826,444**	841,990
Total capitalization			**$ 2,857,347**	**$ 2,746,290**

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

THE NARRAGANSETT ELECTRIC COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(in thousands of dollars)

				Accumulated Other Comprehensive Income (Loss)					
	Common Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance as of March 31, 2015	$ 56,624	$ 2,454	$ 1,354,952	$ 857	$ 1,197	$ (4,166)	$ (2,112)	$ 308,228	$ 1,720,146
Net income	-	-	-	-	-	-	-	95,158	95,158
Other comprehensive income (loss):									
Unrealized losses on securities, net of $34 tax benefit	-	-	-	(62)	-	-	(62)	-	(62)
Change in pension and other postretirement obligations, net of $5 tax expense	-	-	-	-	9	-	9	-	9
Unrealized gains on hedges, net of $266 tax expense	-	-	-	-	-	494	494	-	494
Total comprehensive income									95,599
Share based compensation	-	-	25	-	-	-	-	-	25
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Balance as of March 31, 2016	$ 56,624	$ 2,454	$ 1,354,977	$ 795	$ 1,206	$ (3,672)	$ (1,671)	$ 403,276	$ 1,815,660
Net income	-	-	-	-			-	88,142	88,142
Other comprehensive income (loss):									
Unrealized gains on securities, net of $60 tax expense	-	-	-	110	-	-	110	-	110
Change in pension and other postretirement obligations, net of $2 tax benefit	-	-	-	-	(4)	-	(4)	-	(4)
Unrealized gains on hedges, net of $254 tax expense	-	-	-	-	-	471	471	-	471
Total comprehensive income									88,719
Share based compensation	-	-	31	-	-	-	-	-	31
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Balance as of March 31, 2017	$ 56,624	$ 2,454	$ 1,355,008	$ 905	$ 1,202	$ (3,201)	$ (1,094)	$ 491,308	1,904,300
Net income	-	-	-	-			-	123,311	123,311
Other comprehensive income:									
Unrealized gains on securities, net of $38 tax expense	-	-	-	26	-	-	26	-	26
Change in pension and other postretirement obligations, net of $29 tax expense	-	-	-	-	99	-	99	-	99
Unrealized gains on hedges, net of $93 tax expense	-	-	-	-	-	228	228	-	228
Total comprehensive income									123,664
Parent tax loss allocation	-	-	3,047	-	-	-	-	-	3,047
Share based compensation	-	-	2	-	-	-	-	-	2
Preferred stock dividends	-	-	-	-	-	-	-	(110)	(110)
Balance as of March 31, 2018	$ 56,624	$ 2,454	$ 1,358,057	$ 931	$ 1,301	$ (2,973)	$ (741)	$ 614,509	$ 2,030,903

The Company had 1,132,487 shares of common stock authorized, issued and outstanding, with a par value of $50 per share and 49,089 shares of cumulative preferred stock authorized, issued and outstanding, with a par value of $50 per share at March 31, 2018 and 2017.

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

THE NARRAGANSETT ELECTRIC COMPANY
NOTES TO THE FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

The Narragansett Electric Company ("the Company") is a retail distribution company providing electric service to approximately 502,000 customers and gas service to approximately 270,000 customers in 38 cities and towns in Rhode Island. The Company's service area covers substantially all of Rhode Island.

The Company is a wholly-owned subsidiary of National Grid USA ("NGUSA" or the "Parent"), a public utility holding company with regulated subsidiaries engaged in the generation of electricity and the transmission, distribution, and sale of both natural gas and electricity. NGUSA is a direct wholly-owned subsidiary of National Grid North America Inc. ("NGNA") and an indirect wholly-owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales.

The accompanying financial statements are prepared in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"), including the accounting principles for rate-regulated entities. The financial statements reflect the ratemaking practices of the applicable regulatory authorities.

The Company has evaluated subsequent events and transactions through July 19, 2018, the date of issuance of these financial statements, and concluded that there were no events or transactions that require adjustment to, or disclosure in, the financial statements as of and for the year ended March 31, 2018.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

In preparing financial statements that conform to U.S. GAAP, the Company must make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses, and the disclosure of contingent assets and liabilities included in the financial statements. Actual results could differ from those estimates.

Regulatory Accounting

The Federal Energy Regulatory Commission ("FERC"), the Rhode Island Public Utilities Commission ("RIPUC"), and the Rhode Island Division of Public Utilities and Carriers ("Division") regulate the rates the Company charges its customers. In certain cases, the rate actions of the FERC and RIPUC can result in accounting that differs from non-regulated companies. In these cases, the Company defers costs (as regulatory assets) or recognizes obligations (as regulatory liabilities) if it is probable that such amounts will be recovered from, or refunded to, customers through future rates. Regulatory assets and liabilities are reflected on the balance sheet consistent with the treatment of the related costs in the ratemaking process.

Revenue Recognition

Revenues are recognized for energy service provided on a monthly billing cycle basis. The Company records unbilled revenues for the estimated amount of services rendered from the time meters were last read to the end of the accounting period.

As approved by the RIPUC, the Company is allowed to pass through commodity-related costs to customers and also bills for approved rate adjustment mechanisms. In addition, the Company has an electric revenue decoupling mechanism ("RDM") which requires the Company to adjust its base rates annually to reflect the over or under recovery of the Company's targeted base distribution revenues from the prior fiscal year. Further, the Company has a gas RDM, which requires the Company to adjust its base rates annually to reflect the over or under recovery of the Company's allowed revenue per customer for the year.

Other Taxes

The Company collects taxes and fees from customers such as sales taxes, other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. The Company accounts for taxes that are imposed on customers (such as sales taxes) on a net basis (excluded from revenues).

The Company's policy is to accrue for property taxes on a calendar year basis, taking into account the assessment period. The Company had accrued for property taxes of $18.0 million and $17.7 million at March 31, 2018 and 2017, respectively.

Income Taxes

Federal income taxes have been computed utilizing the asset and liability approach that requires the recognition of deferred tax assets and liabilities for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. Deferred income taxes also reflect the tax effect of net operating losses, capital losses, and general business credit carryforwards. The Company assesses the available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that the Company will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount.

The effects of tax positions are recognized in the financial statements when it is more likely than not that the position taken, or expected to be taken, in a tax return will be sustained upon examination by taxing authorities based on the technical merits of the position. The financial effect of changes in tax laws or rates is accounted for in the period of enactment. Deferred investment tax credits are amortized over the useful life of the underlying property.

NGNA files consolidated federal tax returns including all of the activities of its subsidiaries. Each subsidiary determines its tax provision based on the separate return method, modified by a benefits-for-loss allocation pursuant to a tax sharing agreement between NGNA and its subsidiaries. The benefit of consolidated tax losses and credits are allocated to the NGNA subsidiaries giving rise to such benefits in determining each subsidiary's tax expense in the year that the loss or credit arises. In a year that a consolidated loss or credit carryforward is utilized, the tax benefit utilized in consolidation is paid proportionately to the subsidiaries that gave rise to the benefit regardless of whether that subsidiary would have utilized the benefit. The tax sharing agreement also requires NGNA to allocate its parent tax losses, excluding deductions from acquisition indebtedness, to each subsidiary in the consolidated federal tax return with taxable income. The allocation of NGNA's parent tax losses to its subsidiaries is accounted for as a capital contribution and is performed in conjunction with the annual intercompany cash settlement process following the filing of the federal tax return.

Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less. Cash and cash equivalents are carried at cost which approximates fair value.

Restricted Cash

Restricted cash consists of collateral paid to the Company's counterparties for outstanding derivative instruments. The Company had restricted cash of $0.5 million and $1.0 million at March 31, 2018 and 2017, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

The Company recognizes an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is determined based on a variety of factors including, for each type of receivable, applying an estimated reserve percentage to each aging category, taking into account historical collection and write-off experience, and management's assessment of collectability from individual customers, as appropriate. The collectability of receivables is continuously assessed and, if circumstances change, the allowance is adjusted accordingly. Receivable balances are written off against the allowance for doubtful accounts when the accounts are disconnected and/or terminated and the balances are deemed to be uncollectible.

Inventory

Inventory is composed of materials and supplies as well as gas in storage. Materials and supplies are stated at weighted average cost, which represents net realizable value, and are expensed or capitalized as used. The Company's policy is to write-off obsolete inventory; there were no material write-offs of obsolete inventory for the years ended March 31, 2018, 2017, or 2016.

Gas in storage is stated at weighted average cost and the related cost is recognized when delivered to customers. Existing rate orders allow the Company to pass directly through to customers the cost of gas purchased, along with any applicable authorized delivery surcharge adjustments. Gas costs passed through to customers are subject to regulatory approvals and are reported periodically to the RIPUC.

The Company had materials and supplies of $11.8 million and $10.2 million, purchased renewable energy certificates ("RECs") of $5.1 million and $7.5 million, and gas in storage of $6.5 million and $6.5 million at March 31, 2018 and 2017, respectively. (See Renewable Energy Certificates below for more information on RECs).

Derivative Instruments

Commodity Derivative Instruments – Regulated Accounting

The Company uses various derivative instruments to manage commodity price risk. All derivative instruments, except those that qualify for the normal purchase normal sale exception, are recorded on the balance sheet at their fair value. All commodity costs, including the impact of derivative instruments, are passed on to customers through the Company's commodity rate adjustment mechanisms. Therefore, gains or losses on the settlement of these contracts are initially deferred and then refunded to, or collected from, customers consistent with regulatory requirements.

The Company has certain non-trading instruments for the physical purchase of electricity that qualify for the normal purchase normal sale exception and are accounted for upon settlement. If the Company were to determine that a contract no longer qualifies for the normal purchase normal sale exception, then the Company would recognize the fair value of the contract in accordance with the regulatory accounting described above.

The Company's accounting policy is to not offset fair value amounts recognized for derivative instruments and related cash collateral receivable or payable with the same counterparty under a master netting agreement, but rather to record and present the fair value of the derivative instrument on a gross basis, with related cash collateral recorded within restricted cash and special deposits on the balance sheet.

Commodity Derivative Instruments – Non-Regulated Accounting

The Company also uses derivative instruments related to storage optimization, such as gas purchase and swaps contracts to maximize the value of its storage and transportation assets and to reduce the cash flow variability associated with forecasted purchases and sales of various gas related commodities. The gains and losses on these contracts are shared between the Company and its customers. The Company does not apply regulatory accounting treatment on these contracts since this optimization program is not done solely on behalf of rate payers. All such derivative instruments are accounted for at fair value on the balance sheet with all changes in fair value reported in the accompanying statements of income.

Renewable Energy Certificate Obligations

RECs are stated at cost and are used to measure compliance with renewable energy standards. RECs are held primarily for consumption. At March 31, 2018 and 2017 the Company recorded purchased RECs of $5.1 million and $7.5 million within inventory and a compliance liability based on retail electricity sales of $5.7 million and $11.8 million.

Power Purchase Agreements

The Company enters into power purchase agreements to procure commodity to serve its electric service customers. The Company evaluates whether such agreements are leases, derivative instruments, or executory contracts. Power purchase agreements that do not qualify as leases or derivative instruments are accounted for as executory contracts and are, therefore, recognized as the electricity is purchased. In making its determination of the accounting for power purchase agreements, the Company considers many factors, including: the source of the electricity; the level of output from any specified facility that the Company is taking under the contract; the involvement, if any, that the Company has in operating the specified facility; and the pricing mechanisms in the contract.

Natural Gas Long-Term Arrangements

The Company enters into long-term gas contracts to procure commodity to serve its gas customers. Those contracts include Asset Management Agreements, Baseload, and Peaking gas contracts. Similar to the power purchase agreements noted above, the Company evaluates whether such agreements are derivative instruments or executory contracts and applies the appropriate accounting treatment.

Fair Value Measurements

The Company measures derivative instruments and available-for-sale securities at fair value. 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 at the measurement date. The following is the fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access as of the reporting date;
- Level 2: inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data; and
- Level 3: unobservable inputs, such as internally-developed forward curves and pricing models for the asset or liability due to little or no market activity for the asset or liability with low correlation to observable market inputs.

The asset or liability's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. The Company uses valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

Property, Plant and Equipment

Property, plant and equipment is stated at original cost. The cost of repairs and maintenance is charged to expense and the cost of renewals and betterments that extend the useful life of property, plant and equipment is capitalized. The capitalized cost of additions to property, plant and equipment includes costs such as direct material, labor and benefits, and an allowance for funds used during construction ("AFUDC").

Depreciation is computed over the estimated useful life of the asset using the composite straight-line method. Depreciation studies are conducted periodically to update the composite rates and are approved by the FERC and RIPUC. The average composite rates for the years ended March 31, 2018, 2017, and 2016 are as follows:

	Electric			Gas		
	Years Ended March 31,			Years Ended March 31,		
	2018	2017	2016	**2018**	2017	2016
Composite rates	**2.9%**	2.9%	3.0%	**3.4%**	3.2%	3.2%

Depreciation expense includes a component for estimated future cost of removal, which is recovered through rates charged to customers. Any difference in cumulative costs recovered and costs incurred is recognized as a regulatory liability. When property, plant and equipment is retired, the original cost, less salvage, is charged to accumulated depreciation, and the related cost of removal is removed from the associated regulatory liability. The Company had cumulative costs recovered in excess of costs incurred of $217.0 million and $206.7 million at March 31, 2018 and 2017, respectively.

Allowance for Funds Used During Construction

The Company records AFUDC, which represents the debt and equity costs of financing the construction of new property, plant and equipment. AFUDC equity is reported in the accompanying statements of income as non-cash income in other income, net and AFUDC debt is reported as a non-cash offset to other interest, including affiliate interest. After construction is completed, the Company is permitted to recover these costs through their inclusion in rate base and corresponding depreciation expense. The Company recorded AFUDC related to equity of $0.1 million, and $(0.1) million, and $(0.8) million reflecting adjustments to plant balances for the years ended 2018, 2017 and 2016; AFUDC related to debt was $1.4 million, $1.0 million, and $0.2 million for the years ended March 31, 2018, 2017, and 2016, respectively. The average AFUDC rates for the years ended March 31, 2018, 2017, and 2016 were 1.7%, 1.1%, and 0.7%, respectively.

Impairment of Long-Lived Assets

The Company tests the impairment of long-lived assets annually or when events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. The recoverability of an asset is determined by comparing its carrying value to the future undiscounted cash flows that the asset is expected to generate. If the comparison indicates that the carrying value is not recoverable, an impairment loss is recognized for the excess of the carrying value over the estimated fair value. For the year ended 2018, there were no impairment losses recognized for long-lived assets. For the year ended March 31, 2017, there was $2.5 million of impairment losses recognized for long-lived assets. For the year ended 2016, there were no impairment losses recognized for long-lived assets.

Goodwill

The Company tests goodwill for impairment annually on January 1, and when events occur or circumstances change that would more likely than not reduce the fair value of the Company below its carrying amount. The Company has early adopted ASU 2017-04, “Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill impairment,” which eliminates step two from the two-step goodwill impairment test. The one-step approach requires a recoverability test performed based on the comparison of the Company’s estimated fair value with its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, then goodwill is considered not impaired. If the carrying value exceeds the estimated fair value, the Company is required to recognize an impairment charge for such excess, limited to the allocated amount of goodwill.

Historically the fair value of the Company was calculated for the annual goodwill impairment test utilizing both the income and market based approaches. The Company’s fair value was calculated utilizing the income approach. The Company believes that due to the recent rate case filing currently in process with its regulator, this approach provides the most reliable information. Based on the fair value resulting from the annual analyses performed, the Company determined that no adjustment to the goodwill carrying value was required at March 31, 2018 or 2017.

Available-For-Sale Securities

The Company provides certain executives with nonqualified retirement and deferred compensation benefits which have been partially secured through separate fund arrangements. As a result, the Company holds available-for-sale securities that include equities, municipal bonds, and corporate bonds. These investments are recorded at fair value and are included in other non-current assets on the balance sheet. Changes in the fair value of these assets are recorded within other comprehensive income.

Asset Retirement Obligations

Asset retirement obligations are recognized for legal obligations associated with the retirement of property, plant and equipment primarily associated with the Company’s distribution facilities. Asset retirement obligations are recorded at fair value in the period in which the obligation is incurred, if the fair value can be reasonably estimated. In the period in which new asset retirement obligations, or changes to the timing or amount of existing retirement obligations are recorded, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period the asset retirement obligation is accreted to its present value. The Company applies regulatory accounting guidance and both the depreciation and accretion costs associated with asset retirement obligation are recorded as increases to regulatory assets on the balance sheet. These regulatory assets represent timing differences between the recognition of costs in accordance with U.S. GAAP and costs recovered through the ratemaking process.

The following table represents the changes in the Company’s asset retirement obligations:

	Years Ended March 31,	
	2018	2017
	(in thousands of dollars)	
Balance as of the beginning of the year	**$ 10,150**	$ 10,080
Accretion expense	**385**	389
Liabilities settled	**(626)**	(319)
Balance as of the end of the year	**$ 9,909**	$ 10,150

The Company had a current portion of asset retirement obligations of $0.4 million included in other current liabilities on the balance sheet at March 31, 2018.

Employee Benefits

The Company participates with other subsidiaries in defined benefit pension plans and postretirement benefit other than pension (“PBOP”) plans for its employees, administered by NGUSA. The Company recognizes its portion of the pension and PBOP plans’ funded status on the balance sheet as a net liability or asset. The cost of providing these plans is recovered through rates; therefore, the net funded status is offset by a regulatory asset or liability. The pension and PBOP plans’ assets are commingled and allocated to measure and record pension and PBOP funded status at the year-end date. Pension and PBOP plan assets are measured at fair value, using the year-end market value of those assets.

Going Concern

Current U.S. GAAP guidance requires management to evaluate whether there is substantial doubt surrounding an entity’s ability to continue as a going concern. If management concludes that substantial doubt exists additional disclosures relating to management’s evaluation and conclusion are required. Management is not aware of any indicators giving rise to substantial doubt about the Company’s ability to continue to operate and to meet its obligations as they become due.

New and Recent Accounting Guidance

Accounting Guidance Recently Adopted

Measurement of Inventory

In July 2015, the FASB issued ASU No. 2015-11, “Simplifying the Measurement of Inventory.” The new guidance requires that inventory be measured at the lower of cost and net realizable value (other than inventory measured using “last-in, first out” and the “retail inventory method”). The application of this guidance did not have a material impact on the results of operations, cash flows, or financial position of the Company since the Company’s inventory was stated at cost upon adoption and the cost represents the net realizable value. The adoption of the guidance did not change the Company’s methodology of measuring inventory.

Employee Share-Based Payment Accounting

In March 2016, the FASB issued ASU No. 2016-09, "Improvements to Employee Share-Based Payment Accounting (Topic 718)," which simplifies several aspects of the accounting for share-based payment transactions, including the accounting for income taxes, forfeitures and statutory tax withholding requirements, as well as classification in the statement of cash flows. Most notably, entities are required to recognize all excess tax benefits and shortfalls as income tax expense or benefit in the income statement within the reporting period in which they occur. The application of this guidance did not have a material impact on the results of operations, cash flows, or financial position of the Company.

Goodwill

In January 2017, the FASB issued ASU No. 2017-04, which eliminates Step 2 from the goodwill impairment test. For the Company, the requirements of the new standard will be effective for the fiscal year ended March 31, 2022, with early adoption permitted. The Company early adopted the ASU in the year ended March 31, 2018 for its annual goodwill impairment testing. Based on the resulting fair value from the annual analyses, the Company determined that no adjustment to the goodwill carrying value was required at March 31, 2018 or 2017.

Derivatives and Hedging

In March 2016, the FASB issued ASU No. 2016-05, “Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships.” This update clarifies that a change in the counterparty to a derivative instrument that has been designated as a hedging instrument under Accounting Standards Codification (“ASC”) 815, “Derivatives and Hedging,” does not require dedesignation of that hedging relationship provided that all other hedge accounting criteria in accordance with ASC 815-20-35 through ASC 815-35-18 continue to be met. The application of this guidance did not have a material impact on the results of operations, cash flows, or financial position of the Company.

Accounting Guidance Not Yet Adopted

Derivatives and Hedging

In August 2017, the FASB issued ASU No. 2017-12, “Targeted Improvements to Accounting for Hedging Activities,” which will be effective for the fiscal year ended March 31, 2020, with early adoption permitted. The amendments in this update expand and refine hedge accounting for both financial and nonfinancial risk components and align the recognition and presentation of the effects of the hedging instrument and the hedged item in the financial statements. This update also includes changes to certain targeted improvements to ease the application of current guidance related to the assessment of hedge effectiveness. The Company is currently evaluating the impact of the new guidance on the results of its operations, cash flows, and financial position.

Pension and Postretirement Benefits

In March 2017, the FASB issued ASU No. 2017-07, “Compensation Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,” which changes certain presentation and disclosure requirements for employers that sponsor defined benefit pension and other postretirement benefit plans. The ASU requires the service cost component of the net benefit cost to be in the same line item as other compensation in operating income and the other components of net benefit cost to be presented outside of operating income on a retrospective basis. In addition, only the service cost component will be eligible for capitalization when applicable, on a prospective basis. For the Company, the requirements of the new standard will be effective for the fiscal year ended March 31, 2019, and interim periods within the reporting period, with early adoption permitted. The implementation of the ASU will not have a material impact on the net income of the Company since the Company defers the difference between actual pension costs and the amounts used to establish rates (See Note 8, “Employee Benefits” for additional details).

Statement of Cash Flows

In November 2016, the FASB issued ASU No. 2016-18, "Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)," which requires entities to show the changes in the total of cash, cash equivalents, restricted cash, and restricted cash equivalents in the statement of cash flows.

In August 2016, the FASB issued ASU No. 2016-15, "Classification of Certain Cash Receipts and Cash Payments (Topic 230)," which provides guidance about the classification of certain cash receipts and payments within the statement of cash flows, including debt prepayment or extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims and policies, and distributions received from equity method investments.

For the Company, the requirements of the new standards will be effective for the fiscal year ended March 31, 2019, and interim periods therein, with early adoption permitted. The application of this guidance is not expected to have a material impact on the results of operations, cash flows, or financial position of the Company.

Income Taxes

In October 2016, the FASB issued ASU No. 2016-16, "Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory," which eliminates the exception for all intra-entity sales of assets other than inventory. As a result, a reporting entity would recognize the tax expense from the sale of the asset in the seller’s tax jurisdiction when the transfer occurs, even though the pre-tax effects of that transaction are eliminated in consolidation. For the Company, the requirements of the new standard will be effective for the fiscal year ended March 31, 2019, and interim periods thereafter, with early adoption permitted. The application of this guidance is not expected to have a material impact on the results of operations, cash flows, or financial position of the Company.

Financial Instruments – Credit Losses

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments." The amendment replaces the incurred loss impairment methodology in current U.S. GAAP with a methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information to inform credit loss estimates. For the Company, the requirements of the new standard will be effective for the fiscal year ended March 31, 2022, and interim periods within, with early adoption permitted from the fiscal year ended March 31, 2020 and interim periods within. The Company is currently evaluating the impact of the new guidance on the presentation, results of its operations, cash flows, and financial position.

Revenue Recognition

In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606).” The underlying principle of this ASU is that an entity will recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to, in exchange for those goods or services. For the Company, the new guidance is effective for the fiscal year ended March 31, 2019, including interim periods therein, and will be adopted using a modified retrospective approach.

The FASB has issued a number of additional recent ASUs related to revenue recognition, whose effective date and transition requirements are the same as those for ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606).” In March 2016, the FASB issued ASU No. 2016-08, “Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net),” which clarifies the implementation guidance on principal versus agent considerations. In April 2016, the FASB issued ASU No. 2016-10, "Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing," which provides guidance in the new revenue standard on identifying performance obligations and accounting for licenses of intellectual property. In May 2016, the FASB issued ASU No. 2016-12, “Revenue from Contracts with Customers (ASC 606) Narrow-Scope Improvements and Practical Expedients,” providing additional clarity on various aspects of Topic 606, including a) Assessing the Collectability Criterion and Accounting for Contracts That Do Not Meet the Criteria for Step 1, b) Presentation of Sales Taxes and Other Similar Taxes Collected from Customers, c) Noncash Consideration, d) Contract Modifications at Transition, e) Completed Contracts at Transition, and f) Technical Correction. Lastly, in December 2016, the FASB issued ASU No. 2016-20, "Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers." The amendments in this update cover a variety of corrections and improvements to the Codification related to the new revenue recognition standard (ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606)”).

The Company has undertaken detailed reviews of its revenue arrangements and is in the process of finalizing its assessment of the impact of the new standard. Based on work to date, the Company does not believe that the standard will have a material impact on the presentation of the results of its operations, cash flows, or financial position. However, the Company will be required to make significant additional qualitative and quantitative financial statement disclosures under ASC 606, “Revenue from Contracts with Customers,” pertaining to its revenue earning mechanisms.

Leases

In February 2016, the FASB issued a new lease accounting standard, ASU No. 2016-02, “Leases (Topic 842).” The key objective of the new standard is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Lessees will need to recognize a right-of-use asset and a lease liability for virtually all of their leases (other than leases that meet the definition of a short-term lease). For income statement purposes, a dual model has been retained, with leases to be designated as operating leases or finance leases. Expenses will be recognized on a straight-line basis for operating leases, and a front-loaded basis for finance leases. For the Company, the new standard is effective for the fiscal year ended March 31, 2020, and interim periods thereafter, with early adoption permitted. The new standard must be adopted using a modified retrospective transition, and provides for certain practical expedients. The Company is currently evaluating the impact of the new guidance on the results of its operations, cash flows, and financial position.

Financial Instruments – Classification and Measurement

In January 2016, the FASB issued ASU No. 2016-01, “Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities.” The new guidance principally affects the accounting for equity investments and financial liabilities where the fair value option has been elected, as well as the disclosure requirements for financial instruments. For the Company, the new guidance is effective for the fiscal year ended March 31, 2019, and interim periods thereafter, with early adoption permitted for fiscal years or interim periods that have not yet been issued. The application of this guidance is not expected to have a material impact on the presentation, results of its operations, cash flows, and financial position.

Stock Compensation

In May 2017, the FASB issued ASU No. 2017-09, "Stock Compensation (Topic 718): Scope of Modification Accounting," which provides clarity on the application of modification accounting upon a change to the terms or conditions of a share-based payment award. For the Company, the requirements of the new standard will be effective for the fiscal year ended March 31, 2019, with early adoption permitted. The Company is currently evaluating the impact of the new guidance on the presentation, results of its operations, cash flows, and financial position.

3. REGULATORY ASSETS AND LIABILITIES

The Company records regulatory assets and liabilities that result from the ratemaking process. The following table presents the regulatory assets and regulatory liabilities recorded on the balance sheet:

	March 31,	
	2018	2017
	(in thousands of dollars)	
Regulatory assets:		
Current:		
Derivative instruments	**$ 2,784**	$ -
Gas costs adjustment	**35,159**	1,246
Rate adjustment mechanisms	**34,890**	37,395
Renewable energy certificates	**642**	4,307
Revenue decoupling mechanism	**13,822**	9,498
Total	**87,297**	52,446
Non-current:		
Environmental response costs	**140,002**	139,024
Postretirement benefits	**187,087**	201,626
Storm costs	**142,269**	93,764
Other	**23,003**	29,721
Total	**492,361**	464,135
Regulatory liabilities:		
Current:		
Derivative Instruments	**-**	4,525
Energy efficiency	**43,089**	39,897
Rate adjustment mechanisms	**51,106**	51,300
Revenue decoupling mechanism	**15,289**	10,839
Other	**-**	227
Total	**109,484**	106,788
Non-current:		
Cost of removal	**216,983**	206,750
Environmental response fund	**12,840**	6,916
Postretirement benefits	**14,904**	10,910
Regulatory tax liability, net	**276,728**	-
Other	**31,888**	21,280
Total	**553,343**	245,856
Net regulatory liabilities (assets)	**$ (83,169)**	$ 163,937

Cost of removal: Represents cumulative amounts collected, but not yet spent, to dispose of property, plant and equipment. This liability is discharged as removal costs are incurred.

Derivative instruments: The Company evaluates open derivative instruments for regulatory deferral by determining if they are probable of recovery from, or refund to, customers through future rates. Derivative instruments that qualify for recovery are recorded at fair value, with changes in fair value recorded as regulatory assets or regulatory liabilities in the period in which the change occurs.

Energy efficiency: Represents the difference between revenue billed to customers through the Company's energy efficiency charge and the costs of the Company's energy efficiency programs as approved by the RIPUC.

Environmental response costs: The regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at sites with which it may be associated. The Company's rate plans provide for specific rate allowances for these costs at a level of $3.1 million per year, with variances deferred for future recovery from, or return to, customers. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates. The regulatory liability represents the excess of amounts received in rates over the Company's actual site investigation and remediation costs.

Gas costs adjustment: The Company is subject to rate adjustment mechanisms for commodity costs, whereby an asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered or differences between actual revenues and targeted amounts as approved by the RIPUC. These amounts will be refunded to, or recovered from, customers over the next year.

Postretirement benefits: The regulatory asset represents the Company's deferral related to the underfunded status of its pension and PBOP plans. The regulatory liability primarily represents the excess of amounts received in rates over actual costs of the Company's pension and PBOP plans to be refunded in future periods.

Rate adjustment mechanisms: In addition to commodity costs, the Company is subject to a number of additional rate adjustment mechanisms whereby an asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered or differences between actual revenues and targeted amounts as approved by the RIPUC.

Regulatory tax liability, net: Represents over-recovered federal deferred taxes of the Company primarily as a result of regulatory flow through accounting treatment and excess federal deferred taxes as a result of the recently enacted Tax Cuts and Jobs Act ("Tax Act").

Renewable energy certificates: Represents deferred costs associated with the Company's compliance obligation with the Rhode Island Renewable Portfolio Standard ("RPS"). The RPS is legislation established to foster the development of new renewable energy sources. The regulatory asset will be recovered over the next year.

Revenue decoupling mechanism: As approved by the RIPUC, the Company has an electric RDM which allows for an annual adjustment to the Company's delivery rates as a result of the reconciliation between annual target revenue and actual billed delivery service revenue. Any difference between the annual target revenue and actual billed delivery service revenue is recorded as a regulatory asset or regulatory liability. The Company also has a gas RDM which allows for an annual adjustment to the Company's delivery rates as a result of the reconciliation between allowed revenue per customer and actual revenue per customer. Any difference between the allowed revenue per customer and the actual revenue per customer is recorded as a regulatory asset or regulatory liability.

Storm costs: The Company is allowed to recover storm costs from all retail delivery service customers. This balance reflects cost yet to be recovered. See Note 4 Rate Matters for additional information regarding recovery of storm costs.

The Company records carrying charges on regulatory balances for which cash expenditures have been made and are subject to recovery, or for which cash has been collected and is subject to refund. Carrying charges are not recorded on items for which expenditures have not yet been made.

4. RATE MATTERS

General Rate Case

On February 1, 2013, the RIPUC approved a settlement agreement among the Division, the Department of the Navy, and the Company, which provided for an increase in electric base distribution revenue of $21.5 million and an increase in gas base distribution revenue of $11.3 million based on a 9.5% allowed return on equity ("ROE") and a common equity ratio of approximately 49.1%, effective February 1, 2013. This rate agreement remained through March 31, 2018.

On June 5, 2018, the Company reached a settlement with the Division and several other intervening parties to increase distribution revenue for its electric and gas operations over the three year period commencing September 1, 2018, subject to the approval of the RIPUC. This settlement is an agreement that was reached in response to the base distribution revenue increase requests that the Company filed with the RIPUC on November 27, 2017. Pursuant to the settlement, electric distribution revenue will increase by approximately $19 million, $8 million, and $4 million, annually commencing September 1, 2018, and gas distribution revenue will increase by approximately $7 million, $6 million, and $4 million annually commencing September 1, 2018. The settlement reflects an allowed ROE rate of 9.275% based on a common equity ratio of approximately 51%.

These revenue increases are intended to fund significant systems-related investments including the replacement of several aging operational systems used in our gas business with newer integrated systems that will be shared by the Company and its gas affiliates. The settlement introduces new incentive-only Performance Incentive Mechanisms of 30 to 50 basis points to address important state policy goals around modernizing the Company's energy delivery systems and achieving clean energy targets, as well as a new electric capital efficiency mechanism that includes both incentives and penalties resulting from the Company's ability to manage annual spending in its electric Infrastructure, Safety, and Reliability ("ISR") Plan. The increases set in place for the second and third years of this rate plan may be reopened for recovery of the implementation of advanced metering and grid modernization costs.

Evidentiary hearings on the settlement are scheduled to be completed by late June 2018, with a RIPUC deliberation and ruling on the settlement to take place in mid-August 2018.

Recovery of Transmission Costs

New England Power ("NEP" a company affiliate) operates the transmission facilities of its New England affiliates as a single integrated system and reimburses the Company for the cost of its transmission facilities in Rhode Island, including a return on those facilities under NEP's Tariff No. 1. In turn, these costs are allocated among transmission customers in New England in accordance with the ISO New England Open Access Transmission Tariff ("ISO-NE OATT"). According to the FERC order, the Company is compensated for its actual monthly transmission costs with its authorized maximum ROE of 11.74% on certain transmission assets. The amounts reimbursed to the Company by NEP for the years ended March 31, 2018, 2017, and 2016 were $155.1 million, $143.0 million, and $129.3 million, respectively, which are included within the accompanying statements of income. On October 16, 2014, the FERC issued an order, Opinion No. 531-A, resetting the base ROE applicable to transmission assets under the ISO-NE OATT from 11.14% to 10.57% effective as of October 16, 2014 and establishing a maximum ROE of 11.74%. On March 3, 2015, the FERC issued an Order on Rehearing, Opinion No. 531-B, affirming the 10.57% base ROE and clarifying that the 11.74% maximum ROE applies to all individual transmission projects with ROE incentives previously granted by the FERC. On April 14, 2017, the U.S. Court of Appeals for the D.C. Circuit (Court of Appeals) vacated and remanded FERC's Opinion No. 531 (and successor orders), through which FERC had lowered the New England Transmission Owners ("NETO") return on equity from 11.14% to 10.57% and capped the total incentives at 11.74%. Due to this vacatur, on June 5, 2017, NETO made a filing with FERC to reinstate the base ROE of 11.14% effective June 6, 2017. The final resolution of procedural posture of ROE complaints is unclear at this time.

Tax Cuts and Jobs Act

On March 15, 2018 FERC initiated multiple proceedings intended to adjust FERC-jurisdictional rates to reflect the corporate tax changes as a result of the passage of the Tax Act of 2017. Of the proceedings initiated relevant to the Company is the Notice of Inquiry ("NOI") seeking comments on the effects of the Tax Cuts and Jobs Act on all Commission-jurisdiction rates. This NOI will be used by FERC to build a record on the tax issues affecting FERC jurisdictional rates and will be used to determine whether additional action is needed.

The RIPUC opened a docket to address the change in the federal corporate income tax rate and other changes resulting from the Tax Act that was signed into law in December 2017. Specifically, the RIPUC requested the Company's proposal for how it planned to reduce rates associated with the income taxes recovered from customers on the ROE investment component of revenue at the new lower income tax rate of 21% effective January 1, 2018, and how it planned to return to customers the reduction in its net deferred income tax liabilities resulting from the 14% decrease in the federal income tax rate from 35%. The Company intends to reduce its revenue requirement in its pending distribution electric and gas rate cases for the impacts of the Tax Act as appropriate.

Storm Contingency Fund

On December 29, 2016, the Company filed with the RIPUC a petition to implement a Storm Fund Replenishment Factor effective July 1, 2017 to collect approximately $84.3 million over a four-year period to be credited to the Company's Storm Contingency Fund ("Storm Fund"), to restore the Storm Fund to a positive balance. In addition, the Company also requested to extend the annual $3.0 million of supplemental base distribution rate contributions beyond the current expiration date of January 31, 2019, to coincide with the four-year replenishment period. The RI Division of Public Utilities and Carriers (Division), which is the primary intervener in Rhode Island on rate matters, filed testimony challenging the recovery of $10.6 million of the $84.3 million being sought through the Storm Fund Replenishment Factor ("SFRF"). On June 21, 2017, the RIPUC unanimously approved the Company's request to collect the $84.3 million. On April 27, 2018, the RIPUC approved the Joint Proposal Settlement Agreement which proposed a Storm Fund Deficit balance reduction of $2 million instead of $10.6 million previously challenged. The SFRF is applicable to all retail delivery service customers for effect July 1, 2017, for a four-year period. In addition, the RIPUC unanimously approved the Company's request to extend the annual $3.0 million of supplemental base distribution rate contributions to the Storm Fund, which the RIPUC authorized in the Company's last rate case, for an additional 26-month period beyond its current expiration to March 31, 2021.

New England East-West Solution ("NEEWS") Project

In September 2008, the Company, NEP and Northeast Utilities jointly filed an application with the FERC to recover financial incentives for the NEEWS project, pursuant to the FERC's Transmission Pricing Policy Order No. 679. NEEWS consists of a series of inter-related transmission upgrades identified in the New England Regional System Plan and is being undertaken to address a number of reliability problems in Connecticut, Massachusetts, and Rhode Island. The Company's share of the NEEWS-related transmission investment was approximately $575 million. The Company is fully reimbursed for its transmission revenue requirements on a monthly basis by NEP through NEP's Tariff No. 1. Effective November 18, 2008, the FERC granted (1) an incentive ROE of 12.89% (125 basis points above the approved base ROE of 11.64%), (2) 100% construction work in progress ("CWIP") in rate base, and (3) recovery of plant abandoned for reasons beyond the companies' control. As discussed in the preceding section, effective October 16, 2014, the FERC issued a series of orders establishing a maximum ROE of 11.74% that effectively caps the NEEWS incentive ROE at that level. The NEEWS upgrades were placed in service in December 2015.

5. PROPERTY, PLANT AND EQUIPMENT

The following table summarizes property, plant and equipment at cost along with accumulated depreciation and amortization:

	March 31, 2018	March 31, 2017
	(in thousands of dollars)	
Plant and machinery	**$ 3,637,419**	$ 3,451,718
Land and buildings	**118,334**	111,808
Assets in construction	**152,852**	135,537
Software and other intangibles	**20,513**	20,611
Property held for future use	**15,028**	15,028
Total property, plant and equipment	**3,944,146**	3,734,702
Accumulated depreciation and amortization	**(959,800)**	(948,891)
Property, plant and equipment, net	**$ 2,984,346**	$ 2,785,811

6. DERIVATIVE INSTRUMENTS

The Company utilizes derivative instruments to manage commodity price risk associated with its natural gas purchases. The Company's commodity risk management strategy is to reduce fluctuations in firm gas sales prices to its customers.

The Company's financial exposures are monitored and managed as an integral part of the Company's overall financial risk management policy. The Company engages in risk management activities only in commodities and financial markets where it has an exposure, and only in terms and volumes consistent with its core business.

Volumes

Volumes of outstanding commodity derivative instruments measured in dekatherms ("dths") are as follows:

	March 31, 2018	March 31, 2017
	(in thousands)	
Gas future contracts	**-**	2,600
Gas purchase contracts	**2,929**	3,318
Gas swap contracts	**34,716**	27,415
Total	**37,645**	33,333

Amounts Recognized on the Balance Sheet

	Asset Derivatives March 31, 2018	Asset Derivatives March 31, 2017		Liability Derivatives March 31, 2018	Liability Derivatives March 31, 2017
	(in thousands of dollars)			*(in thousands of dollars)*	
Current assets:			Current liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas future contracts	$ -	$ 329	Gas future contracts	$ -	$ 24
Gas purchase contracts	502	-	Gas purchase contracts	**462**	344
Gas swap contracts	171	5,643	Gas swap contracts	**1,440**	22
Contracts not subject to rate recovery:			Contracts not subject to rate recovery:		
Gas purchase contracts	**10**	10	Gas purchase contracts	**8**	-
Gas swap contracts	**48**	207	Gas swap contracts	**61**	2
	731	6,189		**1,971**	392
Other non-current assets:			Other non-current liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas future contracts	**-**	-	Gas future contracts	**-**	-
Gas swap contracts	**10**	167	Gas swap contracts	**430**	337
Gas purchase contracts	**-**	-	Gas purchase contracts	**964**	887
	10	167		**1,394**	1,224
Total	**$ 741**	$ 6,356	Total	**$ 3,365**	$ 1,616

The changes in fair value of the Company's rate recoverable contracts are offset by changes in regulatory assets and liabilities. As a result, the changes in fair value of those contracts had no impact in the accompanying statements of income. For the years ended March 31, 2018, 2017, and 2016, the Company recorded a loss of $0.2 million, a gain of $0.2 million and a loss of $0.4 million, respectively, within purchased gas in the accompanying statements of income for changes in fair value for contracts not subject to rate recovery.

Credit and Collateral

The Company is exposed to credit risk related to transactions entered into for commodity price risk management. Credit risk represents the risk of loss due to counterparty non-performance. Credit risk is managed by assessing each counterparty's credit profile and negotiating appropriate levels of collateral and credit support.

The Company enters into commodity transactions on the New York Mercantile Exchange ("NYMEX"). The NYMEX clearing houses act as the counterparty to each trade. Transactions on the NYMEX must adhere to comprehensive collateral and margining requirements. As a result, transactions on the NYMEX are significantly collateralized and have limited counterparty credit risk.

The credit policy for commodity transactions is managed and monitored by the Finance Committee to National Grid plc's Board of Directors ("Finance Committee"), which is responsible for approving risk management policies and objectives for risk assessment, control and valuation, and the monitoring and reporting of risk exposures. NGUSA's Energy Procurement Risk Management Committee ("EPRMC") is responsible for approving transaction strategies, annual supply plans, and counterparty credit approval, as well as all valuation and control procedures. The EPRMC is chaired by the Vice President of U.S. Treasury and reports to both the NGUSA Board of Directors and the Finance Committee.

The EPRMC monitors counterparty credit exposure and appropriate measures are taken to bring such exposures below the limits, including, without limitation, netting agreements, and limitations on the type and tenor of trades. The Company enters into enabling agreements that allow for payment netting with its counterparties, which reduce its exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. In instances where a counterparty's credit quality has declined, or credit exposure exceeds certain levels, the Company may limit its credit exposure by restricting new transactions with the counterparty, requiring additional collateral or credit support, and negotiating the early termination of certain agreements. Similarly, the Company may be required to post collateral to its counterparties.

The Company's credit exposure for all commodity derivative instruments, normal purchase normal sale contracts, and applicable payables and receivables, net of collateral, and instruments that are subject to master netting agreements, was a liability of $2.8 million and $5.3 million as of March 31, 2018 and 2017, respectively.

The aggregate fair value of the Company's commodity derivative instruments with credit-risk-related contingent features that were in a liability position at March 31, 2018 and 2017 was $1.7 million and $0.05 million, respectively. The Company had no collateral posted for these instruments at March 31, 2018 and 2017. The cash collateral in the table below reflects margin posted on the Gas Futures contracts with exchange brokers. If the Company's credit rating were to be downgraded by one or two levels, it would not be required to post any additional collateral. If the Company's credit rating were to be downgraded by three levels, it would have been required to post $2.2 million and $0.06 million additional collateral to its counterparties at March 31, 2018 and 2017, respectively.

Offsetting Information for Derivative Instruments Subject to Master Netting Arrangements

March 31, 2018

Gross Amounts Not Offset in the Balance Sheets

(in thousands of dollars)

ASSETS:	Gross amounts of recognized assets *A*	Gross amounts offset in the Balance Sheets *B*	Net amounts of assets presented in the Balance Sheets *C=A+B*	Financial Instruments *Da*	Cash collateral received *Db*	Net amount *E=C-D*
Derivative instruments						
Gas future contracts	$ -	$ -	$ -	$ -	$ -	$ -
Gas purchase contracts	512	-	512	-	-	512
Gas swap contracts	229	-	229	-	-	229
Total	$ 741	$ -	$ 741	$ -	$ -	$ 741

LIABILITIES:	Gross amounts of recognized liabilities *A*	Gross amounts offset in the Balance Sheets *B*	Net amounts of liabilites presented in the Balance Sheets *C=A+B*	Financial Instruments *Da*	Cash collateral paid *Db*	Net amount *E=C-D*
Derivative instruments						
Gas future contracts	$ -	$ -	$ -	$ -	$ -	$ -
Gas purchase contracts	1,434	-	1,434	-	-	1,434
Gas swap contracts	1,931	-	1,931	-	-	1,931
Total	$ 3,365	$ -	$ 3,365	$ -	$ -	$ 3,365

March 31, 2017
Gross Amounts Not Offset in the Balance Sheets
(in thousands of dollars)

ASSETS:	Gross amounts of recognized assets A	Gross amounts offset in the Balance Sheets B	Net amounts of assets presented in the Balance Sheets C=A+B	Financial Instruments Da	Cash collateral received Db	Net amount E=C-D
Derivative instruments						
Gas future contracts	$ 329	$ -	$ 329	$ -	$ 329	$ -
Gas purchase contracts	10	-	10	-	-	10
Gas swap contracts	6,016	-	6,016	-	-	6,016
Total	$ 6,355	$ -	$ 6,355	$ -	$ 329	$ 6,026

LIABILITIES:	Gross amounts of recognized liabilities A	Gross amounts offset in the Balance Sheets B	Net amounts of liabilites presented in the Balance Sheets C=A+B	Financial Instruments Da	Cash collateral paid Db	Net amount E=C-D
Derivative instruments						
Gas future contracts	$ 24	$ -	$ 24	$ -	$ 24	$ -
Gas purchase contracts	1,231	-	1,231	-	-	1,231
Gas swap contracts	361	-	361	-	-	361
Total	$ 1,616	$ -	$ 1,616	$ -	$ 24	$ 1,592

7. FAIR VALUE MEASUREMENTS

The following tables present assets and liabilities measured and recorded at fair value on the balance sheet on a recurring basis and their level within the fair value hierarchy as of March 31, 2018 and 2017:

	March 31, 2018			
	Level 1	**Level 2**	**Level 3**	**Total**
	(in thousands of dollars)			
Assets:				
Derivative instruments				
Gas future contracts	$ -	$ -	$ -	$ -
Gas purchase contracts	-	10	502	512
Gas swap contracts	-	229	-	229
Available-for-sale securities	2,614	3,591	-	6,205
Total	$ 2,614	$ 3,830	$ 502	$ 6,946
Liabilities:				
Derivative instruments				
Gas future contracts	$ -	$ -	$ -	$ -
Gas purchase contracts	-	9	1,425	1,434
Gas swap contracts	-	1,931	-	1,931
Total	-	1,940	1,425	3,365
Net (liabilities) assets	$ 2,614	$ 1,890	$ (923)	$ 3,581

	March 31, 2017							
	Level 1		Level 2		Level 3		Total	
			(in thousands of dollars)					
Assets:								
Derivative instruments								
Gas future contracts	$	329	$	-	$	-	$	329
Gas purchase contracts		-		10		-		10
Gas swap contracts		-		6,016		-		6,016
Available-for-sale securities		2,500		3,286		-		5,786
Total	$	2,829	$	9,312	$	-	$	12,141
Liabilities:								
Derivative instruments								
Gas future contracts	$	24	$	-	$	-	$	24
Gas purchase contracts		-		-		1,231		1,231
Gas swap contracts		-		361		-		361
Total		24		361		1,231		1,616
Net (liabilities) assets	$	2,805	$	8,951	$	(1,231)	$	10,525

Derivative instruments: The Company’s Level 1 fair value derivative instruments consist of active exchange-based derivative instruments (e.g. natural gas futures traded on NYMEX) valued based on quoted prices (unadjusted) in active markets for identical assets or liabilities at the measurement date.

The Company’s Level 2 fair value derivative instruments consist of over-the-counter (“OTC”) gas swaps and purchase contracts with pricing inputs obtained from the NYMEX and the Intercontinental Exchange (“ICE”), except in cases where the ICE publishes seasonal averages or where there were no transactions within the last seven days. The Company may utilize discounting based on quoted interest rate curves, including consideration of non-performance risk, and may include a liquidity reserve calculated based on bid/ask spread for the Company’s Level 2 derivative instruments. Substantially all of these price curves are observable in the marketplace throughout at least 95% of the remaining contractual quantity, or they could be constructed from market observable curves with correlation coefficients of 95% or higher.

The Company’s Level 3 fair value derivative instruments consist of OTC gas purchase contracts, which are valued based on internally-developed models. Industry-standard valuation techniques, such as the Black-Scholes pricing model, Monte Carlo simulation, and Financial Engineering Associates libraries are used for valuing such instruments. A derivative is designated Level 3 when it is valued based on a forward curve that is internally developed, extrapolated, or derived from market observable curves with correlation coefficients less than 95%, where optionality is present, or if non-economic assumptions are made.

Available-for-sale securities: Available-for-sale securities are included in other non-current assets on the balance sheet and primarily include equity and debt investments based on quoted market prices (Level 1) and municipal and corporate bonds based on quoted prices of similar traded assets in open markets (Level 2).

Changes in Level 3 Derivative Instruments

	Years Ended March 31,	
	2018	2017
	(in thousands of dollars)	
Balance as of the beginning of the year	**$ (1,231)**	$ 16
Net losses	**(126)**	**(1,454)**
Settlements:		
included in earnings	**-**	**(33)**
included in regulatory assets and liabilities	**434**	**240**
Balance as of the end of the year	**$ (923)**	$ (1,231)
The amount of total gains or losses for the year included in net income attributed to the change in unrealized gains or losses related to non-regulatory assets and liabilities at year-end	$ -	$ -

A transfer into Level 3 represents existing assets or liabilities that were previously categorized at a higher level for which the inputs became unobservable during the year. A transfer out of Level 3 represents assets and liabilities that were previously classified as Level 3 for which the inputs became observable based on the criteria discussed previously for classification in Level 2. These transfers, which are recognized at the end of each period, result from changes in the observability of forward curves from the beginning to the end of each reporting period. There were no transfers between Level 1 and Level 2, and no transfers into or out of Level 3, during the years ended March 31, 2018, 2017, or 2016.

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivative instruments valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility, and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The Company considers non-performance risk and liquidity risk in the valuation of derivative instruments categorized in Level 2 and Level 3.

Quantitative Information About Level 3 Fair Value Measurements

The following tables provide information about the Company's Level 3 valuations:

Commodity	**Level 3 Position**	**Fair Value as of March 31, 2018**			**Valuation Technique(s)**	**Significant Unobservable Input**	**Range**
		Assets	**(Liabilities)**	**Total**			
			(thousands of dollars)				
Gas	Purchase contracts	$ 502	$ (1,425)	$ (923)	Discounted Cash Flow	LNG Forward Curve	$3.96-$10.68/dth
	Total	$ 502	$ (1,425)	$ (923)			

Commodity	Level 3 Position	Fair Value as of March 31, 2017			Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)	Total			
			(thousands of dollars)				
Gas	Purchase contracts	$ -	$ (1,231)	$ (1,231)	Discounted Cash Flow	LNG Forward Curve	$9.84-$10.89/dth
	Total	$ -	$ (1,231)	$ (1,231)			

The significant unobservable inputs listed above would have a direct impact on the fair values of the Level 3 instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of the Company's gas purchase derivative instruments are forward liquefied natural gas commodity prices and gas forward curves. A relative change in commodity price at various locations underlying the open positions can result in significantly different fair value estimates.

Other Fair Value Measurements

The Company's balance sheet reflects long-term debt at amortized cost. The fair value of the Company's long-term debt was based on quoted market prices when available, or estimated using quoted market prices for similar debt. The fair value of this debt at March 31, 2018 and 2017 was $0.9 billion and $0.9 billion, respectively.

All other financial instruments on the balance sheet such as accounts receivable, accounts payable, and the intercompany money pool are stated at cost, which approximates fair value.

8. EMPLOYEE BENEFITS

The Company participates with other NGUSA subsidiaries in a qualified and non-qualified non-contributory defined benefit plan (the "Pension Plans") and PBOP plan (together with the Pension Plan (the "Plans")), covering substantially all employees.

Plan assets are maintained for all of NGUSA and its subsidiaries in commingled trusts. In respect of cost determination, plan assets are allocated to the Company based on the Company's proportionate share of the Plan's projected benefit obligation. The Plan's costs are first directly charged to the Company based on the Company's employees that participate in the Plan. Costs associated with affiliated service companies' employees are then allocated as part of the labor burden for work performed on the Company's behalf. The Company applies deferral accounting for pension and PBOP expenses associated with its regulated gas and electric operations. Any differences between actual pension costs and amounts used to establish rates are deferred and collected from, or refunded to, customers in subsequent periods. Pension and PBOP expense are included within operations and maintenance expense in the accompanying statements of income. Portions of the net periodic benefit costs disclosed below have been capitalized as a component of property, plant and equipment.

Pension Plans

The Pension Plan is a defined benefit plan which provides union employees, as well as non-union employees hired before January 1, 2011, with a retirement benefit. Supplemental non-qualified, non-contributory executive retirement programs provide additional defined pension benefits for certain executives. During the years ended March 31, 2018, 2017, and 2016, the Company made contributions of approximately $28.9 million, $13.2 million, and $20.6 million, respectively, to the qualified pension plans. The Company expects to contribute approximately $12.0 million to the qualified pension plan during the year ending March 31, 2019.

Benefit payments to Pension Plan participants for the years ended March 31, 2018, 2017, and 2016 were approximately $29.5 million, $24.0 million, and $38.5 million, respectively.

PBOP Plans

The PBOP plan provides health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must contribute to the cost of their coverage. During the years ended March 31, 2018, 2017, and 2016, the Company made contributions of approximately $9.7 million, $3.3 million, and $10.0 million, respectively, to the PBOP Plans. The Company does not expect to contribute to the PBOP Plans during the year ending March 31, 2019.

Benefit payments to PBOP plan participants for the years ended March 31, 2018, 2017, and 2016 were approximately $10.5 million, $9.9 million, and $10.3 million, respectively.

Net Periodic Benefit Costs

The Company's total pension cost for the years ended March 31, 2018, 2017, and 2016 are $9.9 million, $12.2 million, and $15.9 million, respectively.

The Company's total PBOP cost for the years ended March 31, 2018, 2017, and 2016 are $3.5 million, $6.9 million, and $7.3 million, respectively.

Amounts Recognized in AOCI and Regulatory Assets

The following tables summarize the Company's changes in actuarial gains/losses and prior service costs recognized primarily in regulatory assets as well as accumulated other comprehensive income for the years ended March 31, 2018, 2017, and 2016:

	Pension Plans		
	Years Ended March 31,		
	2018	2017	2016
		(in thousands of dollars)	
Net actuarial loss (gain)	**$ 2,080**	$ (14,509)	$ 6,095
Amortization of net actuarial loss	**(9,565)**	(10,917)	(12,212)
Amortization of prior service cost, net	**(20)**	(20)	(20)
Total	**$ (7,505)**	$ (25,446)	$ (6,137)
Included in regulatory assets	**$ (7,377)**	$ (25,453)	$ (6,123)
Included in AOCI	**(128)**	7	(14)
Total	**$ (7,505)**	$ (25,446)	$ (6,137)

	PBOP Plans		
	Years Ended March 31,		
	2018	2017	2016
	(in thousands of dollars)		
Net actuarial (gain) loss	**$ (3,869)**	$ (33,082)	$ 9,178
Amortization of net actuarial loss	**(1,730)**	(3,952)	(4,074)
Amortization of prior service cost, net	**23**	225	225
Total	**$ (5,576)**	$ (36,809)	$ 5,329
Included in regulatory assets	**$ (5,576)**	$ (36,809)	$ 5,329
Total	**$ (5,576)**	$ (36,809)	$ 5,329

Amounts Recognized in AOCI and Regulatory Assets – not yet recognized as components of net actuarial loss

The following tables summarize the Company's amounts in regulatory assets and other comprehensive income on the balance sheet that have not yet been recognized as components of net actuarial loss at March 31, 2018, 2017, and 2016:

	Pension Plans		
	Years Ended March 31,		
	2018	2017	2016
	(in thousands of dollars)		
Net actuarial loss	**155,601**	$ 163,086	$ 188,512
Prior service cost	**37**	57	77
Total	**$ 155,638**	$ 163,143	$ 188,589
Included in regulatory assets	**$ 155,502**	$ 162,879	$ 188,332
Included in AOCI	**136**	264	257
Total	**$ 155,638**	$ 163,143	$ 188,589

	PBOP Plans		
	Years Ended March 31,		
	2018	2017	2016
	(in thousands of dollars)		
Net actuarial loss	**$ 27,798**	$ 33,397	$ 70,431
Prior service cost	**(45)**	(68)	(293)
Total	**$ 27,753**	$ 33,329	$ 70,138
Included in regulatory assets	**$ 27,753**	$ 33,329	$ 70,138
Total	**$ 27,753**	$ 33,329	$ 70,138

The amount of net actuarial loss and prior service cost to be amortized from regulatory assets during the year ending March 31, 2019 for the Pension Plans is $10.1 million and $0, respectively, and net actuarial loss and prior service benefit to be amortized from regulatory assets during the year ending March 31, 2019 for the PBOP Plans is $1.7 million and $0, respectively.

Amounts Recognized on the Balance Sheet

The following table summarizes the portion of the funded status above that is recognized on the Company's balance sheet at March 31, 2018 and 2017:

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2018	2017	**2018**	2017
	(in thousands of dollars)			
Projected benefit obligation	**$ (560,190)**	$ (539,583)	**$ (223,753)**	$ (219,669)
Allocated fair value of plan assets	**534,883**	487,654	**165,530**	149,504
Total	**$ (25,307)**	$ (51,929)	**$ (58,223)**	$ (70,165)
Current liabilities	**$ (149)**	$ (146)	**$ (147)**	$ (150)
Other non-current liabilities	**(25,158)**	(51,783)	**(58,076)**	(70,015)
Total	**$ (25,307)**	$ (51,929)	**$ (58,223)**	$ (70,165)

Expected Benefit Payments

Based on current assumptions, the following benefit payments are expected subsequent to March 31, 2018 in respect of the Company:

(in thousands of dollars) **Years Ended March 31,**	**Pension Plans**	**PBOP Plans**
2019	$ 34,372	$ 10,631
2020	35,499	11,019
2021	36,643	11,481
2022	37,875	11,916
2023	39,266	12,204
2024-2028	215,888	64,652
Total	**$ 399,543**	**$ 121,903**

Assumptions Used for Employee Benefits Accounting

	Pension Plans		
	Years Ended March 31,		
	2018	2017	2016
Benefit Obligations:			
Discount rate	**4.10%**	4.30%	4.25%
Rate of compensation increase	**3.50%**	3.50%	3.50%
Expected return on plan assets	6.25%	6.50%	6.50%
Net Periodic Benefit Costs:			
Discount rate	**4.30%**	4.25%	4.10%
Rate of compensation increase	**3.50%**	3.50%	3.50%
Expected return on plan assets	**6.50%**	6.50%	6.25%

	PBOP Plans		
	Years Ended March 31,		
	2018	2017	2016
Benefit Obligations:			
Discount rate	**4.10%**	4.30%	4.25%
Rate of compensation increase	**n/a**	n/a	n/a
Expected return on plan assets	**6.25%-6.75%**	6.50%-6.75%	6.50%-6.75%
Net Periodic Benefit Costs:			
Discount rate	**4.30%**	4.25%	4.10%
Rate of compensation increase	**n/a**	n/a	n/a
Expected return on plan assets	**6.50%-6.75%**	6.50%-6.75%	6.25%-6.75%

The Company selects its discount rate assumption based upon rates of return on highly rated corporate bond yields in the marketplace as of each measurement date. Specifically, the Company uses the Hewitt AA Above Median Curve along with the expected future cash flows from the Company retirement plans to determine the weighted average discount rate assumption.

The expected rate of return for various passive asset classes is based both on analysis of historical rates of return and forward looking analysis of risk premiums and yields. Current market conditions, such as inflation and interest rates, are evaluated in connection with the setting of the long-term assumptions. A small premium is added for active management of both equity and fixed income securities. The rates of return for each asset class are then weighted in accordance with the actual asset allocation, resulting in a long-term return on asset rate for each plan.

Assumed Health Cost Trend Rate

	March 31,	
	2018	2017
Health care cost trend rate assumed for next year		
Pre 65	**7.50%**	7.00%
Post 65	**5.75%**	6.00%
Prescription	**10.25%**	10.25%
Rate to which the cost trend is assumed to decline (ultimate)	**4.50%**	4.50%
Year that rate reaches ultimate trend		
Pre 65	**2028**	2025
Post 65	**2026**	2024
Prescription	**2027**	2025

Plan Assets

NGUSA, as the Plans' sponsor, manages the benefit plan investments to minimize the long-term cost of operating the Plans, with a reasonable level of risk. Risk tolerance is determined as a result of a periodic asset/liability study which analyzes the Plans' liabilities and funded status and results in the determination of the allocation of assets across equity and fixed income securities. Equity investments are broadly diversified across U.S. and non-U.S. stocks, as well as across growth, value, and small and large capitalization stocks. Likewise, the fixed income portfolio is broadly diversified across market segments. Small investments are also approved for private equity, real estate, and infrastructure with the objective of enhancing long-term returns while improving portfolio diversification. For the PBOP Plans, since the earnings on a portion of the assets are taxable, those investments are managed to maximize after tax returns consistent with the broad asset class parameters established by the asset allocation study. Investment risk and return are reviewed by NGUSA's investment committee on a quarterly basis.

The Pension Plan is a trusted non-contributory defined benefit plan covering all eligible represented employees of the Company and eligible non-represented employees of the participating National Grid companies. The PBOP Plans are both a contributory and non-contributory, trusteed, employee life insurance and medical benefit plan sponsored by NGUSA. Life insurance and medical benefits are provided for eligible retirees, dependents, and surviving spouses of NGUSA.

The target asset allocations for the benefit plans as of March 31, 2018 and 2017 are as follows:

	Pension Plans		PBOP Union		PBOP Non-Union	
	March 31,		March 31,		March 31,	
	2018	2017	**2018**	2017	**2018**	2017
			(in thousands of dollars)			
US Equities	**20%**	20%	**34%**	34%	**45%**	45%
Global equities (including US)	**7%**	7%	**12%**	12%	**0%**	0%
Global tactical asset allocation	**10%**	10%	**17%**	17%	**0%**	0%
Non-US equities	**10%**	10%	**17%**	17%	**25%**	25%
Fixed income securities	**40%**	40%	**20%**	20%	**30%**	30%
Private equity	**5%**	5%	**0%**	0%	**0%**	0%
Real estate	**5%**	5%	**0%**	0%	**0%**	0%
Infrastructure	**3%**	3%	**0%**	0%	**0%**	0%
Total	**100%**	100%	**100%**	100%	**100%**	100%

Fair Value Measurements

The following tables provide the fair value measurements amounts for the pension and PBOP assets at the Plan level:

	March 31, 2018				
	Level 1	Level 2	Level 3	Not Categorized	Total
			(in thousands of dollars)		
Pension Assets:					
Cash and cash equivalents	$ 575	$ 15,518	$ -	$ 28,149	$ 44,242
Accounts receivable	88,162	-	-	-	88,162
Accounts payable	(133,593)	-	-	-	(133,593)
Equity	303,037	(16)	-	651,355	954,376
Fixed income securities	-	553,463	-	338,944	892,407
Preferred securities	-	5,972	-	-	5,972
Private equity	-	-	-	133,785	133,785
Real estate	-	-	-	110,551	110,551
Other	1,329	-	-	178,235	179,564
Total	**$ 259,510**	**$ 574,937**	**$ -**	**$ 1,441,019**	**$ 2,275,466**
PBOP Assets:					
Cash and cash equivalents	$ 9,111	$ 16	$ -	$ 598	$ 9,725
Accounts receivable	1,998	-	-	-	1,998
Accounts payable	(183)	-	-	-	(183)
Equity	189,026	-	-	281,678	470,704
Fixed income securities	-	165,705	-	-	165,705
Other	14,030	-	-	78,622	92,652
Total	**$ 213,982**	**$ 165,721**	**$ -**	**$ 360,898**	**$ 740,601**

	March 31, 2017				
	Level 1	Level 2	Level 3	Not Categorized	Total
			(in thousands of dollars)		
Pension Assets:					
Cash and cash equivalents	$ 1,319	$ 559	$ -	$ 32,822	$ 34,700
Accounts receivable	21,974	-	-	-	21,974
Accounts payable	(22,054)	-	-	-	(22,054)
Equity	317,258	-	-	594,349	911,607
Global tactical asset allocation	-	-	-	-	-
Fixed income securities	-	599,858	-	205,392	805,250
Preferred securities	-	3,756	-	-	3,756
Private equity	-	-	-	131,865	131,865
Real estate	-	-	-	117,692	117,692
Other	350	-	-	102,857	103,207
Total	**$ 318,847**	**$ 604,173**	**$ -**	**$ 1,184,977**	**$ 2,107,997**
PBOP Assets:					
Cash and cash equivalents	$ 11,203	$ -	$ -	$ 651	$ 11,854
Accounts receivable	1,526	-	-	-	1,526
Accounts payable	(3,483)	-	-	-	(3,483)
Equity	164,420	-	-	268,140	432,560
Fixed income securities	234	145,904	-	-	146,138
Other	13,177	-	-	74,922	88,099
Total	**$ 187,077**	**$ 145,904**	**$ -**	**$ 343,713**	**$ 676,694**

The methods used to fair value pension and PBOP assets are described below:

Cash and cash equivalents: Cash and cash equivalents that can be priced daily are classified as Level 1. Active reserve funds, reserve deposits, commercial paper, repurchase agreements, and commingled cash equivalents are classified as Level 2. Cash and cash equivalents invested in commingled money market investment funds which have Net Asset Value “NAV” pricing per fund share are excluded from the fair value hierarchy.

Accounts receivable and accounts payable: Accounts receivable and accounts payable are classified as Level 1. Such amounts are short-term and settle within a few days of the measurement date.

Equity and preferred securities: Common stocks, preferred stocks, and real estate investment trusts are valued using the official close of the primary market on which the individual securities are traded. Equity securities are primarily comprised of securities issued by public companies in domestic and foreign markets plus investments in commingled funds, which are valued on a daily basis. The Company can exchange shares of the publicly traded securities and the fair values are primarily sourced from the closing prices on stock exchanges where there is active trading, in which case they are classified as Level 1 investments. If there is less active trading, then the publicly traded securities would typically be priced using observable data, such as bid and ask prices, and these measurements are classified as Level 2 investments. Mutual funds with publicly quoted prices and active trading are classified as Level 1 investments. For investments in commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, derived from the underlying securities’ quoted prices in active markets, and they are excluded from the fair value hierarchy. Investments in commingled funds with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

Global tactical asset allocation: Assets held in global tactical asset allocation funds are managed by investment managers who use both top-down and bottom-up valuation methodologies to value asset classes, countries, industrial sectors, and individual securities in order to allocate and invest assets opportunistically. Mutual funds with publicly quoted prices and active trading are classified as Level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, and are excluded from the fair value hierarchy. Investments with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

Fixed income securities: Fixed income securities (which include corporate debt securities, municipal fixed income securities, U.S. Government and Government agency securities including government mortgage backed securities, index linked government bonds, and state and local bonds) convertible securities, and investments in securities lending collateral (which include repurchase agreements, asset backed securities, floating rate notes and time deposits) are valued with an institutional bid valuation. A bid valuation is an estimated price at which a dealer would pay for a security (typically in an institutional round lot). Oftentimes, these evaluations are based on proprietary models which pricing vendors establish for these purposes. In some cases there may be manual sources when primary vendors do not supply prices. Fixed income investments are primarily comprised of fixed income securities and fixed income commingled funds. The prices for direct investments in fixed income securities are generated on a daily basis. Prices generated from less active trading with wider bid ask prices are classified as Level 2 investments. Mutual funds with publicly quoted prices and active trading are classified as Level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, and are excluded from the fair value hierarchy. Investments in commingled funds with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

Private equity and real estate: Commingled equity funds, commingled special equity funds, limited partnerships, real estate, venture capital, and other investments are valued using evaluations (NAV per fund share) based on proprietary models, or based on the NAV. Investments in private equity and real estate funds are primarily invested in privately held real estate investment properties, trusts, and partnerships as well as equity and debt issued by public or private companies. The Company's interest in the fund or partnership is estimated based on the NAV. The Company's interest in these funds cannot be readily redeemed due to the inherent lack of liquidity and the primarily long-term nature of the underlying assets. Distribution is made through the liquidation of the underlying assets. The Company views these investments as part of a long-term investment strategy. These investments are valued by each investment manager based on the underlying assets. The funds utilize valuation techniques consistent with the market, income, and cost approaches to measure the fair value of certain real estate investments. The majority of the underlying assets are valued using significant unobservable inputs and often require significant management judgment or estimation based on the best available information. Market data includes observations of the trading multiples of public companies considered comparable to the private companies being valued. Investments in limited partnerships with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

While management believes its valuation methodologies are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the NAV as a practical expedient could result in a different fair value measurement at the reporting date.

Defined Contribution Plan

NGUSA has a defined contribution pension plan that covers substantially all employees. For the years ended March 31, 2018, 2017, and 2016, the Company recognized an expense in the accompanying statements of income of $3.1 million, $2.8 million, and $2.8 million, respectively, for matching contributions.

Other Benefits

At March 31, 2018 and 2017, the Company had accrued workers compensation, auto, and general insurance claims which have been incurred but not yet reported ("IBNR") of $2.9 million and $3.5 million, respectively. IBNR reserves have been established for claims and/or events that have transpired, but have not yet been reported to the Company for payment.

9. ACCUMULATED OTHER COMPREHENSIVE INCOME

The following table represents the changes in the Company's AOCI for the years ended March 31, 2018 and 2017:

	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total
		(in thousands of dollars)		
Balance as of March 31, 2016	**$ 795**	**$ 1,206**	**$ (3,672)**	**$ (1,671)**
Other comprehensive income before reclassifications:				
Unrecognized net actuarial loss (net of $11 tax benefit)	-	(21)	-	(21)
Gain on investment (net of $83 tax benefit)	265	-	-	265
Amounts reclassified from other comprehensive income (loss):				
Amortization of net actuarial loss (net of $9 tax expense) [1]	-	17	-	17
Amortization of treasury lock (net of $254 tax expense) [2]	-	-	471	471
Gain on investment (net of $143 tax benefit) [1]	(155)	-	-	(155)
Net current period other comprehensive income	110	(4)	471	577
Balance as of March 31, 2017	**$ 905**	**$ 1,202**	**$ (3,201)**	**$ (1,094)**
Other comprehensive income before reclassifications:				
Unrecognized net actuarial loss (net of $21 tax expense)	-	79	-	79
Gain on investment (net of $61 tax benefit)	133	-	-	133
Amounts reclassified from other comprehensive income (loss):				
Amortization of net actuarial loss (net of $8 tax expense) [1]	-	20	-	20
Amortization of treasury lock (net of $93 tax expense) [2]	-	-	228	228
Gain on investment (net of $99 tax expense) [1]	(107)	-	-	(107)
Net current period other comprehensive (loss) income	26	99	228	353
Balance as of March 31, 2018	**$ 931**	**$ 1,301**	**$ (2,973)**	**$ (741)**

(1) Amounts are reported as other income, net in the accompanying statements of income.
(2) Amounts are reported as interest on long-term debt in the accompanying statements of income.

10. CAPITALIZATION

The aggregate maturities of long-term debt for the years subsequent to March 31, 2018 are as follows:

(in thousands of dollars) Years Ending March 31,	
2019	$ 15,839
2020	251,375
2021	11,375
2022	1,375
2023	13,875
Thereafter	552,250
Total	$ 846,089

The Company's debt agreements and banking facilities contain covenants, including those relating to the periodic and timely provision of financial information by the issuing entity and financial covenants such as restrictions on the level of indebtedness. Failure to comply with these covenants, or to obtain waivers of those requirements, could in some cases trigger a right, at the lender's discretion, to require repayment of some of the Company's debt and may restrict the Company's ability to draw upon its facilities or access the capital markets. During the years ended March 31, 2018 and

2017, the Company was in compliance with all such covenants.

Debt Authorizations

Since January 12, 2015, the Company had regulatory approval from the FERC to issue up to $400 million of short-term debt. The authorization was effective for a period of two years which expired on January 11, 2017 and which has now been extended to January 10, 2019. The Company had no short-term debt outstanding to third-parties as of March 31, 2018 or 2017.

First Mortgage Bonds

At March 31, 2018, the Company had $46.1 million of FMB outstanding. Substantially all of the assets used in the gas business of the Company are subject to the lien of the mortgage indentures under which these FMB have been issued. The FMB have annual sinking fund requirements totaling approximately $1.4 million.

The Company has a maximum 70% of debt-to-capitalization covenant. Furthermore, if at any time the Company's debt exceeds 60% of the total capitalization, each holder of bonds then outstanding shall receive effective as of the first date of such occurrence, a one time, and permanent 0.20% increase in the interest rate paid by the Company on its bonds. During the years ended March 31, 2018 and 2017, the Company was in compliance with this covenant.

Dividend Restrictions

Pursuant to the preferred stock arrangement, as long as any preferred stock is outstanding, certain restrictions on payment of common stock dividends would come into effect if the common stock equity was, or by reason of payment of such dividends became, less than 25% of total capitalization. The Company was in compliance with this covenant and accordingly, the Company was not restricted as to the payment of common stock dividends under the foregoing provisions at March 31, 2018 or 2017.

Cumulative Preferred Stock

The Company has certain issues of non-participating cumulative preferred stock outstanding which can be redeemed at the option of the Company. There are no mandatory redemption provisions on the Company's cumulative preferred stock. A summary of cumulative preferred stock is as follows:

	Shares Outstanding		**Amount**		
	March 31,		**March 31,**		Call
Series	**2018**	2017	**2018**	2017	Price
	(in thousands of dollars, except per share and number of shares data)				
$50 par value - 4.50% Series	**49,089**	49,089	**$ 2,454**	$ 2,454	$ 55.000

The Company did not redeem any preferred stock during the years ended March 31, 2018, 2017, or 2016. The annual dividend requirement for cumulative preferred stock was $0.1 million for each of the years ended March 31, 2018, 2017, and 2016.

11. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,		
	2018	2017	2016
		(in thousands of dollars)	
Current federal income tax expense (benefit)	**$ (19,040)**	$ 21,054	$ 7,186
Deferred federal tax expense (benefit)	**41,351**	27,576	45,963
Amortized investment tax credits [(1)]	**(62)**	(106)	(145)
Total deferred tax expense	**41,289**	27,470	45,818
Total income tax expense	**$ 22,249**	$ 48,524	$ 53,004

(1) Investment tax credits (ITC) are accounted for using the deferral and gross up method of accounting and amortized over the depreciable life of the property giving rise to the credits.

Statutory Rate Reconciliation

The Company's effective tax rate for the years ended March 31, 2018, 2017 and 2016 are 15.2 %, 35.5% and 35.8%, respectively. The following table presents a reconciliation of income tax expense at the federal statutory tax rate of 31.55%, 35%, and 35%, respectively, to the actual tax expense:

	Years Ended March 31,		
	2018	2017	2016
		(in thousands of dollars)	
Computed tax	**$ 45,923**	$ 47,833	$ 51,856
Change in computed taxes resulting from:			
Temporary difference flowed through	**695**	834	1,075
Federal Rate Change	**(23,497)**	-	-
Other items, net	**(872)**	(143)	73
Total Changes	**(23,674)**	691	1,148
Total income tax expense	**$ 22,249**	$ 48,524	$ 53,004

The Company is included in the NGNA and subsidiaries consolidated federal income tax return. The Company has joint and several liability for any potential assessments against the consolidated group.

On December 22, 2017, the Tax Act was signed into law. The Tax Act includes significant changes to various federal tax provisions applicable to the Company, including provisions specific to regulated public utilities. The most significant changes include the reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018 and the limitation of the net operating loss deduction for net operating losses generated in tax years starting after December 31, 2017 to 80% of taxable income with an indefinite carryforward period. The Tax Act provisions related to regulated public utilities eliminate bonus depreciation for certain property acquired or placed in service after September 27, 2017 and extend the normalization requirements for ratemaking treatment of excess deferred taxes.

In accordance with ASC 740, "Income Taxes," the effect of changes in tax law are required to be recognized in the period of enactment, which for the Company is the period ended March 31, 2018. Since the Company's fiscal year end is March 31, the statutory rate applicable for the Company's fiscal year ended March 31, 2018, is a blended tax rate of 31.55%. In subsequent periods, the federal income tax rate will be 21%. In addition, ASC 740 requires deferred income tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. As a result, the Company remeasured its federal deferred income tax assets and liabilities using the newly enacted tax rate of 21%.

The Company recognized a decrease in its net deferred income tax liability in the amount of $250 million, with $23.7 million of the benefit recorded to deferred income tax expense and $226.3 million recorded as a regulatory liability, for the refund of excess income taxes to the ratepayers.

On December 22, 2017, the Securities Exchange Commission issued Staff Accounting Bulletin ("SAB") 118, which provides guidance on accounting for the effects of the Tax Act. The FASB staff subsequently issued guidance stating that private companies may apply SAB 118 to the financial statements. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act enactment date to complete the accounting under ASC 740. To the extent that a company's accounting for certain income tax effects of the Tax Act is incomplete, a company can determine a reasonable estimate for those effects and record a provisional estimate in the financial statements. If a company cannot determine a provisional amount, the company should continue to apply existing accounting guidance for income taxes based on provisions of the tax laws that were in effect immediately prior to the enactment of the Tax Act.

The Company has made a reasonable estimate for the measurement and accounting of the effects of the Tax Act which has been reflected in the March 31, 2018 financial statements based on management's interpretation of the Tax Act and information available. The items reflected as provisional amounts are related to accelerated depreciation for tax purposes of certain property placed in service after September 27, 2017, the allocation of excess deferred taxes between customers and shareholders, and certain property related temporary differences. The final impact may differ from the recorded amounts to the extent refinements are made as a result of changes in management's interpretations and assumptions, additional guidance or technical corrections that may be issued.

Deferred Tax Components

	March 31,	
	2018	2017
	(in thousands of dollars)	
Deferred tax assets:		
Environmental remediation costs	**$ 28,912**	$ 47,435
Net operating losses	**50,076**	119,984
Postretirement benefits and other employee benefits	**20,731**	47,831
Regulatory liabilities - other	**21,693**	41,932
Regulatory liabilities - taxes	**58,116**	
Other items	**11,796**	20,876
Total deferred tax assets	**191,324**	278,058
Deferred tax liabilities:		
Amortization of goodwill	**36,613**	54,767
Property related differences	**366,609**	584,330
Regulatory assets - environmental	**26,704**	46,238
Regulatory assets - postretirement benefits	**35,954**	66,071
Regulatory assets - other	**14,841**	25,649
Regulatory assets - storm costs	**30,716**	34,217
Other items	**4,031**	4,936
Total deferred tax liabilities	**515,468**	816,208
Net deferred income tax liabilities	**324,144**	538,150
Deferred investment tax credits	**17**	79
Deferred income tax liabilities, net	**$ 324,161**	$ 538,229

Net Operating Losses

The amounts and expiration dates of the Company's net operating loss carryforwards as of March 31, 2018 are as follows:

	Carryforward Amount	Expiration Period
	(in thousands of dollars)	
Federal	$ 338,575	2029-2036

As a result of the accounting for uncertain tax positions, the amount of deferred tax assets reflected in the financial statements is less than the amount of the tax effect of the federal net operating loss carryforwards reflected on the income tax returns.

The Company recognizes interest related to unrecognized tax benefits in other interest, including affiliate interest and related penalties, if applicable, in other deductions, net in the accompanying statements of income. During the years ended March 31, 2018, 2017, and 2016 the Company recorded no interest expense. No tax penalties were recognized during the years ended March 31, 2018, 2017, or 2016.

It is reasonably possible that other events will occur during the next twelve months that would cause the total amount of unrecognized tax benefits to increase or decrease. However, the Company does not believe any such increases or decreases would be material to its results of operations, financial position, or cash flows.

The Company is included in NGNA and subsidiaries' administrative appeal with the Internal Revenue Service ("IRS") related to the issues disputed in the examination cycles for the years ended August 24, 2007, March 31, 2008, and March 31, 2009. The Company is expecting to reach a settlement with the IRS in the next fiscal year. The Company does not believe that the outcome of the settlement will have a material impact to its results of operations, financial position, or cash flows. The IRS continues its examination of the next cycle which includes income tax returns for the years ended March 31, 2010 through March 31, 2012. The examination is not expected to conclude in the next fiscal year. The income tax returns for the years ended March 31, 2013 through March 31, 2018 remain subject to examination by the IRS.

The following table indicates the earliest tax year subject to examination for each major jurisdiction:

Jurisdiction	Tax Year
Federal	March 31, 2010

The Company is not subject to state income taxes since the State of Rhode Island does not impose an income tax on public utility companies.

12. ENVIRONMENTAL MATTERS

The normal ongoing operations and historic activities of the Company are subject to various federal, state, and local environmental laws and regulations. Under federal and state Superfund laws, potential liability for the historic contamination of property may be imposed on responsible parties jointly and severally, without regard to fault, even if the activities were lawful when they occurred.

The United States Environmental Protection Agency (“EPA”), the Massachusetts Department of Environmental Protection (“DEP”), and the Rhode Island Department of Environmental Management (“DEM”) have alleged that the Company is a potentially responsible party under state or federal law for the remediation of numerous sites. The Company’s most significant liabilities relate to former Manufactured Gas Plant (“MGP”) facilities formerly owned by the Blackstone Valley Gas and Electric Company and the Rhode Island gas distribution assets of New England Gas. The Company is currently investigating and remediating, as necessary, those MGP sites and certain other properties under agreements with the EPA, DEM and DEP. Expenditures incurred for the years ended March 31, 2018, 2017, and 2016 were $2.9 million, $4.9 million, and $3.1 million, respectively.

The Company estimated the remaining costs of environmental remediation activities were $137.7 million and $135.5 million at March 31, 2018 and 2017, respectively. These costs are expected to be incurred over approximately 40 years. However, remediation costs for each site may be materially higher than estimated, depending on changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered. The Company has recovered amounts from certain insurers and potentially responsible parties, and, where appropriate, the Company may seek additional recovery from other insurers and from other potentially responsible parties, but it is uncertain whether, and to what extent, such efforts will be successful.

The RIPUC has approved a settlement agreement that provides for rate recovery of remediation costs of former MGP sites and certain other hazardous waste sites located in Rhode Island. Under that agreement, qualified costs related to these sites are paid out of a special fund established as a regulatory liability on the balance sheet. Rate-recoverable contributions of approximately $3 million are added annually to the fund along with interest and any recoveries from insurance carriers and other third-parties. Accordingly, as of March 31, 2018 and 2017, the Company has recorded environmental regulatory assets of $140.0 million and $139.0 million, respectively, and environmental regulatory liabilities of $12.8 million and $6.9 million, respectively.

The Company believes that its ongoing operations, and its approach to addressing conditions at historic sites, are in substantial compliance with all applicable environmental laws. Where the Company has regulatory recovery, it believes that the obligations imposed on it because of the environmental laws will not have a material impact on its results of operations or financial position.

13. COMMITMENTS AND CONTINGENCIES

Purchase Commitments

The Company has several long-term contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment. Additionally, the Company has entered into various contracts for gas delivery, storage, and supply services. Certain of these contracts require payment of annual demand charges, which are recoverable from customers. The Company is liable for these payments regardless of the level of service required from third-parties. In addition, the Company has various capital commitments related to the construction of property, plant and equipment.

The Company's commitments under these long-term contracts for the years subsequent to March 31, 2018 are summarized in the table below:

(in thousands of dollars) Years Ending March 31,	Energy Purchases
2019	308,160
2020	97,296
2021	34,243
2022	25,229
2023	17,160
Thereafter	129,054
Total	$ 611,142

The Company purchases additional energy to meet load requirements from independent power producers, other utilities, energy merchants or the ISO-NE at market prices.

Long-term Contracts for Renewable Energy

Deepwater Agreement

The 2009 Rhode Island law required the Company to solicit proposals for a small scale renewable energy generation project of up to eight wind turbines with an aggregate nameplate capacity of up to 30 MW to benefit the Town of New Shoreham. The renewable energy generation project also included a transmission cable to be constructed between Block Island and the mainland of Rhode Island. On June 30, 2010, the Company entered into a 20-year Amended Power Purchase Agreement ("PPA") with Deepwater Wind Block Island LLC, which was approved by the RIPUC in August 2010. The wind turbines reached commercial operation on December 12, 2016 and the PPA is being accounted for as an operating lease. The Company also negotiated a Transmission Facilities Purchase Agreement ("Facilities Purchase Agreement") with Deepwater Wind Block Island Transmission, LLC ("Deepwater") to purchase from Deepwater the permits, engineering, real estate, and other site development work for construction of the undersea transmission cable (collectively, the "Transmission Facilities"). On April 2, 2014, the Division issued its Consent Decision for the Company to execute the Facilities Purchase Agreement with Deepwater. In July 2014, four agreements were filed with the FERC, in part, for approval to recover the costs associated with the transmission cable and related facilities (the "Project") that will be allocated to the Company and Block Island Power Company through transmission rates. On September 2, 2014, the FERC accepted all four agreements thus approving cost recovery for the Project, with no conditions, that will apply to the Company's costs as well as those of NEP. The agreements went into effect on September 30, 2014. On January 30, 2015, the Company closed on its purchase of the Transmission Facilities from Deepwater. The Company placed the Transmission Facilities into service on October 31, 2016.

Annual Solicitations

The 2009 Rhode Island law also requires that, beginning on July 1, 2010, the Company conduct four annual solicitations for proposals from renewable energy developers and, provided commercially reasonable proposals have been received, enter into long-term contracts for the purchase of capacity, energy, and attributes from newly developed renewable energy resources. The Company's four solicitations have resulted in four PPAs that have been approved by the RIPUC:

- First Solicitation: On July 28, 2011, the RIPUC approved a 15-year PPA with Orbit Energy Rhode Island, LLC for a 3.2 MW anaerobic digester biogas project.
- Second Solicitation: On May 11, 2012, the RIPUC approved a 15-year PPA with Black Bear Development Holdings, LLC for a 3.9 MW run-of-river hydroelectric plant located in Orono, Maine. The facility reached commercial operation on November 22, 2013.
- Third Solicitation: On October 25, 2013, the RIPUC approved a 15-year PPA with Champlain Wind, LLC for a 48 MW land-based wind project located in Carroll Plantation and Kossuth Township, Maine. The PPA was terminated on January 23, 2017 because one of the required permits for the project was rejected. The impact of this termination is that the Company will need to backfill the MW capacity from that project to meet the 90 MW minimum long-term capacity requirements under the state statute.
- Fourth Solicitation: On October 29, 2015, the RIPUC approved a 15-year PPA with Copenhagen Wind Farm, LLC for an 80 MW land-based wind project located in Denmark, New York.

As approved by the RIPUC, the Company is allowed to pass through commodity-related / purchased power costs to customers. The cost of these contracts is accounted for as part of these costs.

Legal Matters

The Company is subject to various legal proceedings arising out of the ordinary course of its business. The Company does not consider any of such proceedings to be material, individually or in the aggregate, to its business or likely to result in a material adverse effect on its results of operations, financial position, or cash flows.

14. RELATED PARTY TRANSACTIONS

Accounts Receivable from and Accounts Payable to Affiliates

NGUSA and its affiliates provide various services to the Company, including executive and administrative, customer services, financial (including accounting, auditing, risk management, tax, and treasury/finance), human resources, information technology, legal, and strategic planning, that are charged between the companies and charged to each company.

The Company records short-term receivables from, and payables to, certain of its affiliates in the ordinary course of business. The amounts receivable from, and payable to, its affiliates do not bear interest and are settled through the intercompany money pool. A summary of net outstanding accounts receivable from affiliates and accounts payable to affiliates is as follows:

	Accounts Receivable from Affiliates		Accounts Payable to Affiliates	
	March 31,		March 31,	
	2018	2017	**2018**	2017
	(in thousands of dollars)			
Massachusetts Electric Company	**$ -**	$ -	**$ -**	$ 53,278
New England Power Company	**22,221**	4,322	**-**	-
NGUSA Service Company	**-**	1,816	**12,224**	22,387
Other	**-**	216	**2,206**	4,420
Total	**$ 22,221**	$ 6,354	**$ 14,430**	$ 80,085

Advance from Affiliate

In December 2008, the Company entered into an agreement with NGUSA whereby the Company can borrow up to $250 million as deemed necessary for working capital needs. The advance is non-interest bearing. At March 31, 2018 and 2017, the Company had no outstanding advance from affiliate.

Intercompany Money Pool

The settlement of the Company’s various transactions with NGUSA and certain affiliates generally occurs via the intercompany money pool in which it participates. The Company is a participant in the Regulated Money Pool and can both borrow and invest funds. Borrowings from the Regulated Money Pool bear interest in accordance with the terms of the Regulated Money Pool Agreement. As the Company fully participates in the Regulated Money Pool rather than settling intercompany charges with cash, all changes in the intercompany money pool balance and accounts receivable from affiliates and accounts payable to affiliates balances are reflected as investing or financing activities in the accompanying statements of cash flows. In addition, for the purpose of presentation in the statements of cash flows, it is assumed all amounts settled through the intercompany money pool are constructive cash receipts and payments, and therefore are presented as such.

The Regulated Money Pool is funded by operating funds from participants. NGUSA has the ability to borrow up to $3 billion from National Grid plc for working capital needs including funding of the Regulated Money Pool, if necessary. The Company had short-term intercompany money pool borrowings of $307.5 million and $125.7 million at March 31, 2018 and 2017, respectively. The average interest rates for the intercompany money pool were 1.6%, 1.1% and 0.7% for the years ended March 31, 2018, 2017, and 2016, respectively.

Service Company Charges

The affiliated service companies of NGUSA provide certain services to the Company at their cost. The service company costs are generally allocated to associated companies through a tiered approach. First and foremost, costs are directly charged to the benefited company whenever practicable. Secondly, in cases where direct charging cannot be readily determined, costs are allocated using cost/causation principles linked to the relationship of that type of service, such as number of employees, number of customers/meters, capital expenditures, value of property owned, and total transmission and distribution expenditures. Lastly, all other costs are allocated based on a general allocator determined using a 3-point formula based on net margin, net property, plant and equipment and operations and maintenance expense.

Charges from the service companies of NGUSA, including but not limited to non-power goods and services, to the Company for the years ended March 31, 2018, 2017, and 2016 were $201.3 million, $229.9 million, and $217.8 million, respectively.