National Grid USA and Subsidiaries

Consolidated Financial Statements

For the years ended March 31, 2017 and 2016

NATIONAL GRID USA AND SUBSIDIARIES

TABLE OF CONTENTS

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Report of Independent Auditors

To the Board of Directors of
National Grid USA

We have audited the accompanying consolidated financial statements of National Grid USA and its subsidiaries, which comprise the consolidated balance sheets as of March 31, 2017 and 2016, and the related consolidated statements of income, comprehensive income, cash flows, capitalization, and changes in shareholder's equity for the years then ended.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

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

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of National Grid USA and its subsidiaries as of March 31, 2017 and 2016, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

September 27, 2017

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(in millions of dollars)

	Years Ended March 31, 2017	2016
Operating revenues:		
Electric services	**$ 6,355**	$ 6,667
Gas distribution	**4,645**	4,316
Other	**21**	25
Total operating revenues	**11,021**	11,008
Operating expenses:		
Purchased electricity	**1,556**	1,948
Purchased gas	**1,531**	1,301
Operations and maintenance	**4,340**	4,314
Depreciation	**1,064**	1,006
Other taxes	**1,118**	1,099
Total operating expenses	**9,609**	9,668
Operating income	**1,412**	1,340
Other income and (deductions):		
Interest on long-term debt	**(413)**	(386)
Other interest, including affiliate interest	**(92)**	(80)
Income from equity investments	**30**	33
(Loss) gain on sale of assets	**(4)**	76
Unrealized gains on investment in Dominion Midstream Partners, LP	**15**	53
Impairment charge	**(39)**	-
Other income, net	**71**	20
Total other deductions, net	**(432)**	(284)
Income before income taxes	**980**	1,056
Income tax expense	**355**	402
Income from continuing operations	**625**	654
Loss from discontinued operations, net of taxes	**(11)**	(13)
Net income	**614**	641
Net income attributable to non-controlling interest	**(1)**	-
Dividends paid on preferred stock	**(592)**	(1,179)
Net income (loss) attributable to common shares	**$ 21**	$ (538)

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions of dollars)

	Years Ended March 31,	
	2017	2016
Net income	**$ 614**	$ 641
Other comprehensive income (loss), net of taxes:		
Unrealized gains (losses) on securities	**8**	(4)
Change in pension and other postretirement obligations	**286**	42
Unrealized gains on hedges	**-**	1
Total other comprehensive income	**294**	39
Comprehensive income	**$ 908**	$ 680
Less: comprehensive income attributable to non-controlling interest	**(1)**	-
Comprehensive income attributable to common and preferred stock	**$ 907**	$ 680
Related tax (expense) benefit:		
Unrealized (gains) losses on securities	**$ (4)**	$ 3
Change in pension and other postretirement obligations	**(197)**	(29)
Total tax expense	**$ (201)**	$ (26)

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions of dollars)

	Years Ended March 31, 2017	Years Ended March 31, 2016
Operating activities:		
Net income	**$ 614**	$ 641
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation	**1,064**	1,006
Regulatory amortizations	**98**	115
Provision for deferred income taxes	**212**	345
Bad debt expense	**152**	191
Loss (income) from equity and financial investments, net of dividends received	**(23)**	(9)
Loss (gain) on sale of assets	**4**	(76)
Unrealized gains on investment in Dominion Midstream Partners, LP	**(15)**	(53)
Impairment of non-operating assets	**39**	-
Allowance for equity funds used during construction	**(29)**	(19)
Amortization of debt discount and issuance costs	**12**	12
Net postretirement benefits (contributions) expense	**(188)**	1
Environmental remediation payments	**(118)**	(118)
Share based compensation	**27**	21
Changes in operating assets and liabilities:		
Accounts receivable, net, and unbilled revenues	**(428)**	566
Accounts receivable from/payable to affiliates, net	**14**	(36)
Inventory	**67**	(35)
Regulatory assets and liabilities, net	**459**	(3)
Derivative instruments	**(51)**	(110)
Prepaid and accrued taxes	**8**	31
Accounts payable and other liabilities	**361**	(190)
Renewable energy certificate obligations, net	**(24)**	(43)
Other, net	**(28)**	5
Net cash provided by operating activities	**2,227**	2,242
Investing activities:		
Capital expenditures	**(2,808)**	(2,572)
Proceeds from restricted cash and special deposits	**189**	329
Payments on restricted cash and special deposits	**(170)**	(232)
Cost of removal	**(222)**	(179)
Contributions in equity investments	**(102)**	(1)
Other	**(16)**	5
Net cash used in investing activities	**(3,129)**	(2,650)
Financing activities:		
Preferred stock dividends	**(592)**	(1,179)
Payments on long-term debt	**(939)**	(866)
Proceeds from long-term debt	**1,200**	1,221
Payment of debt issuance costs	**(7)**	-
Commercial paper issued (paid)	**684**	(284)
Advance from affiliate	**34**	1,979
Parent loss tax allocation	**22**	-
Payments on sale/leaseback arrangement	**(41)**	(41)
Net cash provided by financing activities	**361**	830
Net (decrease) increase in cash and cash equivalents	**(541)**	422
Net cashflow from discontinued operations - operating	**11**	12
Cash and cash equivalents, beginning of year	**884**	450
Cash and cash equivalents, end of year	**$ 354**	$ 884
Supplemental disclosures:		
Interest paid	**$ (428)**	$ (381)
Income taxes paid	**(3)**	(4)
Significant non-cash items:		
Capital-related accruals included in accounts payable	**154**	181

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	March 31,	
	2017	2016
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 354**	$ 884
Restricted cash and special deposits	**74**	93
Accounts receivable	**2,250**	2,080
Allowance for doubtful accounts	**(416)**	(406)
Accounts receivable from affiliates	**2**	28
Unbilled revenues	**508**	416
Inventory	**399**	481
Regulatory assets	**530**	712
Derivative instruments	**32**	15
Prepaid taxes	**159**	156
Other	**83**	103
Total current assets	**3,975**	4,562
Equity investments	**210**	125
Property, plant and equipment, net	**29,418**	27,464
Other non-current assets:		
Regulatory assets	**4,833**	4,846
Goodwill	**7,129**	7,129
Derivative instruments	**2**	5
Postretirement benefits asset	**293**	187
Financial investments	**757**	693
Other	**157**	141
Total other non-current assets	**13,171**	13,001
Total assets	**$ 46,774**	$ 45,152

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	March 31,	
	2017	2016
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 1,391**	$ 1,211
Accounts payable to affiliates	**32**	44
Advance from affiliate	**3,091**	3,057
Commercial paper	**982**	298
Current portion of long-term debt	**106**	940
Taxes accrued	**74**	47
Customer deposits	**115**	121
Interest accrued	**145**	120
Regulatory liabilities	**833**	569
Derivative instruments	**54**	94
Renewable energy certificate obligations	**140**	193
Payroll and benefits accruals	**296**	276
Other	**162**	148
Total current liabilities	**7,421**	7,118
Other non-current liabilities:		
Regulatory liabilities	**3,049**	3,016
Asset retirement obligations	**96**	94
Deferred income tax liabilities, net	**5,548**	4,989
Postretirement benefits	**2,358**	3,712
Environmental remediation costs	**2,002**	1,295
Derivative instruments	**44**	41
Other	**833**	932
Total other non-current liabilities	**13,930**	14,079
Commitments and contingencies (Note 13)		
Capitalization:		
Common and preferred stock	**14,264**	14,215
Retained earnings	**2,343**	2,322
Accumulated other comprehensive income (loss)	**(552)**	(846)
Common and preferred equity	**16,055**	15,691
Non-controlling interest	**21**	9
Total shareholders' equity	**16,076**	15,700
Long-term debt	**9,347**	8,255
Total capitalization	**25,423**	23,955
Total liabilities and capitalization	**$ 46,774**	$ 45,152

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
(in millions of dollars)

			March 31,	
			2017	2016
Common and preferred equity			**$ 16,055**	$ 15,691
Non-controlling interest			**21**	9
Long-term debt:	Interest Rate	Maturity Date		
Notes Payable[1]	2.72% - 9.75%	January 2016 - March 2046	**8,018**	7,328
Promissory Notes to National Grid North America Inc.	3.13% - 3.25%	June 2027 - April 2028	**209**	227
Gas Facilities Revenue Bonds	Variable	December 2020 - July 2026	**230**	230
Gas Facilities Revenue Bonds[2]	4.7% - 6.95%	April 2020 - July 2026	**-**	411
First Mortgage Bonds	6.82% - 9.63%	April 2018 - April 2028	**122**	124
State Authority Financing Bonds	Variable	June 2015 - August 2042	**919**	918
Total debt			**9,498**	9,238
Unamortized debt premium			**4**	6
Unamortized debt issuance costs			**(49)**	(49)
Current portion of long-term debt			**(106)**	(940)
Long-term debt			**9,347**	8,255
Total capitalization			**$ 25,423**	$ 23,955

(1) See Note 10, "Capitalization" under "Notes Payable" for additional details.

(2) During March 2016, The Brooklyn Union Gas Company issued Notice of Optional Redemption letters to the bond holders of the fixed interest rate gas facilities revenue bonds. The Brooklyn Union Gas Company fully repaid these bonds during April 2016 and hence these bonds are classified within current portion of long-term debt at March 31, 2016.

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(in millions of dollars)

	Common Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss): Unrealized Gain (Loss) on Available-For-Sale Securities	Accumulated Other Comprehensive Income (Loss): Pension and Other Postretirement Benefits	Accumulated Other Comprehensive Income (Loss): Hedging Activity	Accumulated Other Comprehensive Income (Loss): Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest	Total
Balance as of March 31, 2015	**$ -**	**$ 35**	**$ 14,153**	**$ 8**	**$ (890)**	**$ (3)**	**$ (885)**	**$ 2,860**	**$ 14**	**$ 16,177**
Net income	-	-	-	-			-	641	-	641
Other comprehensive income (loss):										
Unrealized losses on securities, net of $3 tax benefit	-	-	-	(4)	-	-	(4)	-	-	(4)
Change in pension and other postretirement obligations, net of $29 tax expense	-	-	-	-	42	-	42	-	-	42
Unrealized gains on hedges, net of $0 tax expense	-	-	-	-	-	1	1	-	-	1
Total comprehensive income										680
Share based compensation	-	-	21	-	-	-	-	-	-	21
Preferred stock dividends	-	-	-	-	-	-	-	(1,179)	-	(1,179)
Other equity transactions with non-controlling interest	-	-	6	-	-	-	-	-	(5)	1
Balance as of March 31, 2016	**$ -**	**$ 35**	**$ 14,180**	**$ 4**	**$ (848)**	**$ (2)**	**$ (846)**	**$ 2,322**	**$ 9**	**$ 15,700**
Net income	-	-	-	-			-	613	1	614
Other comprehensive income:										
Unrealized gains on securities, net of $4 tax expense	-	-	-	8	-	-	8	-	-	8
Change in pension and other postretirement obligations, net of $197 tax expense	-	-	-	-	286	-	286	-	-	286
Total comprehensive income										908
Parent loss tax allocation	-	-	22	-	-	-	-	-	-	22
Share based compensation	-	-	27	-	-	-	-	-	-	27
Preferred stock dividends	-	-	-	-	-	-	-	(592)	-	(592)
Other equity transactions with non-controlling interest	-	-	-	-	-	-	-	-	11	11
Balance as of March 31, 2017	**$ -**	**$ 35**	**$ 14,229**	**$ 12**	**$ (562)**	**$ (2)**	**$ (552)**	**$ 2,343**	**$ 21**	**$ 16,076**

The Company had 641 shares of common stock authorized, issued and outstanding, with a par value of $0.10 per share, 915 shares of preferred stock authorized, issued and outstanding, with a par value of $0.10 per share, and 372,641 shares of cumulative preferred stock authorized, issued and outstanding, with par values of $100 and $50 per share at March 31, 2017 and 2016.

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

NATIONAL GRID USA AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

National Grid USA ("NGUSA" or "the Company") is 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 (the "Parent"), a public limited company incorporated under the laws of England and Wales.

NGUSA has two major lines of business, "Gas Distribution" and "Electric Services," and operates various energy services and investment companies. The Company's Gas Distribution business consists of six gas distribution subsidiaries which provide gas distribution services to customers in the areas of central, northern, and eastern New York, the New York City boroughs of Brooklyn, Queens, and Staten Island, and the Long Island Counties of Nassau and Suffolk, as well as the states of Massachusetts and Rhode Island. The Company's Electric Services business primarily consists of five electric distribution subsidiaries which provide electric services to customers in the areas of eastern, central, northern, and western New York, as well as the states of Massachusetts and Rhode Island and operate electric transmission facilities in Massachusetts, New Hampshire, Rhode Island, Maine, and Vermont.

The Company's wholly-owned New England subsidiaries include: New England Power Company ("NEP"), The Narragansett Electric Company ("Narragansett"), Massachusetts Electric Company ("Massachusetts Electric"), Nantucket Electric Company ("Nantucket"), Boston Gas Company ("Boston Gas"), and Colonial Gas Company ("Colonial Gas"). The Company's wholly-owned New York subsidiaries include: Niagara Mohawk Power Corporation ("Niagara Mohawk"), National Grid Generation, LLC ("Genco"), The Brooklyn Union Gas Company ("Brooklyn Union"), and KeySpan Gas East Corporation ("KeySpan Gas East").

Genco provides energy services and supply capacity to and produce energy for the use of customers of the Long Island Power Authority ("LIPA") on Long Island, New York. The services provided to LIPA through the Power Supply Agreement ("PSA"), which was amended and restated for a maximum term of 15 years in May 2013, provide LIPA with electric generating capacity, energy conversion, and ancillary services from the Company's Long Island generating units.

Prior to December 31, 2013, the Company provided operation, maintenance and construction services, and significant administrative services relating to the Long Island electric transmission and distribution system owned by LIPA. These activities, primarily settlement of legacy contingencies, are reflected as discontinued operations in the accompanying consolidated financial statements for the years ended March 31, 2017 and 2016.

Energy Investments

The Company's Energy Investments business consists of development investments such as natural gas pipelines, as well as certain other domestic energy-related investments. The Company has a wholly-owned subsidiary, National Grid LNG LLC, which is engaged in the business of receiving, storing, and redelivering liquefied natural gas ("LNG") in liquid and gaseous states, through facilities located in Providence, Rhode Island. The Company also owns a 53.7% interest in two hydro-transmission electric companies which are consolidated into these financial statements.

The Company's consolidated financial statements also include a 26.25% interest in Millennium Pipeline Company LLC ("Millennium"), which is accounted for under the equity method of accounting. In addition, the Company owns an equity ownership interest in three regional nuclear generating companies whose facilities have been decommissioned as discussed in Note 13, "Commitments and Contingencies" under "Decommissioning Nuclear Units."

On September 29, 2015, the Company contributed its 20.4% interest in Iroquois Gas Transmission System LP, which was accounted for under the equity method of accounting, to Dominion Midstream Partners, LP ("DM") in exchange for approximately 6.8 million common units (representing approximately a 9% interest) of DM. DM was formed to grow a portfolio of natural gas terminaling, processing, storage, and transportation assets. The transaction resulted in a gain on sale of assets of $74 million in the year ended March 31, 2016. The Company has elected the fair value option with respect to its investment in DM and as such, any changes in the fair value of these common units are recorded as unrealized gains on investment in DM in the accompanying consolidated statements of income. The Company's investment in DM is included within financial investments on the consolidated balance sheet.

Grid NY LLC, a direct wholly-owned subsidiary, was formed on October 10, 2014 to own a 28.261% equity interest in New York Transco LLC ("NY Transco LLC"), a New York limited liability company, which was formed pursuant to the articles of organization filed on November 14, 2014 for the purpose of planning, construction, owning, operating, maintaining, and expanding transmission facilities in the state of New York. The Company has made multiple capital contributions since inception, totaling $31.5 million.

Through a wholly-owned subsidiary, the Company has an investment in Algonquin Gas Transmission LLC ("NGA"), which was formed along with other non-affiliated companies to expand the existing Algonquin Gas Transmission system in a project named Access Northeast. During 2016, a series of adverse regulatory decisions in New England created significant doubt regarding the future prospects of the project and created uncertainty of its economic success. As a result, in December 2016 the Company recorded an impairment charge of $15.3 million representing the full amount of its investment in the project. The Company will continue to consider alternative models and opportunities for utilizing the pipeline project.

Through a wholly-owned subsidiary, the Company has an investment in Vermont Green Line Devco, LLC ("VGL"), originally made in the form of a convertible loan dated March 12, 2015. In January 2016 VGL submitted a joint response, along with Invenergy Wind and Hydro-Quebec US, to a request for proposal from the New England Clean Energy Council. Under the proposal, wind and hydroelectric energy would be transported into the ISO-NE bulk transmission system via a 400 megawatts ("MW") high voltage direct current buried transmission line. During October 2016 VGL learned that its joint proposal had not been selected. On January 1, 2017, the Company exercised its option to convert its loan, becoming the 100% owner of VGL. The Company's carrying value of the development loans and accrued interest ($24.0 million) were written down at December 31, 2016 to $3.0 million. In connection with the January 1, 2017 loan conversion, the remaining $3.0 million carrying value was written-off, based on management's conclusion that the fair value of the Company's convertible loan was zero.

The Company uses the equity method of accounting for its investments in affiliates when it has the ability to exercise significant influence over the operating and financial policies, but does not control the affiliates. The Company's share of the earnings or losses of such affiliates is included as income from equity investments in the accompanying consolidated statements of income.

The accompanying consolidated 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 as applicable. The consolidated financial statements reflect the ratemaking practices of the applicable regulatory authorities.

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. Non-controlling interests of majority-owned subsidiaries are calculated based upon the respective non-controlling interest ownership percentages. All intercompany transactions have been eliminated in consolidation.

Under its holding company structure, the Company has no independent operations or source of income of its own and conducts all of its operations through its subsidiaries. As a result, the Company depends on the earnings and cash flow of, and dividends or distributions from, its subsidiaries to provide the funds necessary to meet its debt and contractual obligations. Furthermore, a substantial portion of the Company's consolidated assets, earnings, and cash flow is derived from the operations of its regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to the Company is subject to regulation by state regulatory authorities.

The Company has evaluated subsequent events and transactions through September 27, 2017, the date of issuance of these consolidated financial statements, and concluded that there were no events or transactions that require adjustment to, or disclosure in, the consolidated financial statements as of and for the year ended March 31, 2017.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

In preparing consolidated 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 consolidated financial statements. Actual results could differ from those estimates.

Regulatory Accounting

The Federal Energy Regulatory Commission ("FERC"), the New York Public Service Commission ("NYPSC"), the Massachusetts Department of Public Utilities ("DPU"), and the Rhode Island Public Utilities Commission ("RIPUC") regulate the rates the Company's regulated subsidiaries charge their customers in the applicable states. In certain cases, the rate actions of the FERC, NYPSC, DPU and RIPUC can result in accounting that differs from non-regulated companies. In these cases, the subsidiaries defer costs (as regulatory assets) or recognize 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 consolidated balance sheet consistent with the treatment of the related costs in the ratemaking process.

Revenue Recognition

Electric and Gas Distribution Revenue

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 state regulators, the Company is allowed to pass through commodity-related costs to customers and also bills for approved rate adjustment mechanisms. In addition, the Company's subsidiaries have revenue decoupling mechanisms ("RDM") which allow for adjustments to the Company's delivery rates as a result of the reconciliation between allowed revenue and billed revenue. Any difference between the allowed revenue and the billed revenue is recorded as a regulatory asset or regulatory liability.

The gas distribution business is influenced by seasonal weather conditions. Brooklyn Union, KeySpan Gas East, Niagara Mohawk, and Narragansett gas utility tariffs contain weather normalization adjustments that provide for recovery from, or refund to, customers of material shortfalls or excesses of delivery revenues (revenues less applicable gas costs and revenue taxes) during a heating season due to variations from normal weather.

Transmission Revenue

Transmission revenues, reflected in electric services in the accompanying statements of income, are generated by NEP, Narragansett, Massachusetts Electric, Nantucket, and Niagara Mohawk. Such revenues are based on a formula rate that recovers actual costs plus a return on investment. Stranded cost recovery revenues are collected through a contract termination charge ("CTC"), which is billed to former wholesale customers of the Company in connection with the Company's divestiture of its electricity generation investments.

Generation Revenue

Electric generation revenue, reflected in electric services in the accompanying statements of income, is derived from billings to LIPA for the electric generation capacity and, to the extent requested, energy from the Company's existing oil and gas-fired generating plants as discussed in Note 13, "Commitments and Contingencies" under "Electric Services and LIPA Agreements."

Other Taxes

The Company's subsidiaries collect 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), while taxes imposed on the Company, such as excise taxes, are recognized on a gross basis. Excise taxes collected and paid for the years ended March 31, 2017 and 2016 were $86 million and $101 million, respectively.

The state of New York imposes on corporations a franchise tax that is computed as the higher of a tax based on income or a tax based on capital. To the extent the Company's New York state ("NYS") tax based on capital is in excess of the state tax based on income, the Company reports such excess in other taxes and taxes accrued in the accompanying consolidated financial statements. The Company was in an excess position this year.

Income Taxes

Federal and state 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 consolidated 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 effects of tax positions are recognized in the consolidated 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 current and deferred taxes based on the separate return method, modified by benefits-for-loss allocation pursuant to a tax sharing agreement between NGNA and its subsidiaries. To the extent that the consolidated return group settles cash differently than the amount reported as realized under the benefit-for-loss allocation, the difference is accounted for as either a capital contribution or as a distribution, and is reflected within the accompanying consolidated statements of changes in stockholders' equity as parent loss tax allocation.

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 and Special Deposits

Restricted cash consists of collateral paid to the Company's counterparties for outstanding derivative instruments. Special deposits primarily consist of a release of property account for mortgaged property under a mortgage trust indenture, a reserve for potential environmental violations, and deposits held by the ISO New England, Inc. ("ISO-NE"). The Company had restricted cash of $25 million and $44 million at March 31, 2017 and 2016, respectively, and special deposits of $49 million at March 31, 2017 and 2016.

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 comprised of materials and supplies, emission credits, renewable energy certificates (“RECs”), and gas in storage.

Materials and supplies are stated at the lower of weighted average cost or market 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, 2017 or 2016.

Emission credits are comprised of sulfur dioxide, nitrogen oxide (“NOx”), and carbon dioxide credits. Emission credits are valued at the lower of weighted average cost or market and are held primarily for consumption or may be sold to third-party purchasers. RECs are stated at cost and used to measure compliance with renewable energy standards. RECs are held primarily for consumption.

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 applicable state regulators.

The Company had materials and supplies of $161 million and $180 million, emission credits of $37 million and $23 million, purchased RECs of $87 million and $117 million, and gas in storage of $114 million and $161 million at March 31, 2017 and 2016, respectively.

Derivative Instruments

The Company uses derivative instruments (including capacity, forward, futures, options, purchase contracts, and swaps) to manage commodity price, interest rate, and foreign currency rate risk. All derivative instruments, except those that qualify for the normal purchase normal sale exception, are recorded on the consolidated balance sheet at their fair value. Qualifying derivative instruments may be designated as either cash flow hedges or fair value hedges.

The effective portion of the change in fair value of a cash flow hedge is recorded in accumulated other comprehensive income (“AOCI”), net of related tax effects, and the ineffective portion is reported in earnings. For the years ended March 31, 2017 and 2016, the Company recorded ineffectiveness related to cash flow hedges of zero and $0.5 million (loss), respectively. Amounts in AOCI are reclassified into earnings in the same period or periods during which the hedged item affects earnings. The effective portion of the change in the fair value of a fair value hedge is offset in the consolidated statements of income by changes in the hedged item. If the hedge relationship is terminated, the fair value adjustment to the hedged item continues to be reported as part of the basis of the item and is amortized to the consolidated statements of income as a yield adjustment over the remainder of the hedging period. For activity subject to regulatory accounting, gains and losses on derivative instruments are reflected as regulatory assets or liabilities, to be collected from, or refunded to, customers consistent with the 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, and 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 consolidated balance sheet.

Power Purchase Agreements

Certain of the Company's subsidiaries enter into power purchase agreements to procure commodity to serve their 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

Certain of the Company's subsidiaries enter into long-term gas contracts to procure commodity to serve its gas customers. Those contracts include Asset Management Agreements, Baseload, and Peaking gas contracts. 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, available-for-sale securities, and financial assets for which it has elected the fair value option 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;
- 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; and
- Not categorized: certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

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") for the regulated subsidiaries and capitalized interest for non-regulated projects.

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 state authorities. The average composite rates for the years ended March 31, 2017 and 2016 are as follows:

	Electric		Gas		Common	
	Years Ended March 31,		Years Ended March 31,		Years Ended March 31,	
	2017	2016	**2017**	2016	**2017**	2016
Composite rates	**2.7%**	2.7%	**2.6%**	2.8%	**4.7%**	5.5%

Depreciation expense, for regulated subsidiaries, 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 $1.7 billion at March 31, 2017 and 2016.

Allowance for Funds Used During Construction

The regulated subsidiaries record AFUDC, which represents the debt and equity costs of financing the construction of new property, plant and equipment. AFUDC equity is reported in the consolidated statements of income as non-cash income in other deductions, 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 $29 million and $19 million and AFUDC related to debt of $16 million and $10 million for the years ended March 31, 2017 and 2016, respectively. The average AFUDC rates for the years ended March 31, 2017 and 2016 were 3.7% and 3.3%, respectively.

In addition, approximately $3 million and $10 million of interest was capitalized for construction of non-regulated projects during the years ended March 31, 2017 and 2016, 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 years ended March 31, 2017, and 2016, there were no impairment losses recognized for long-lived assets, other than in relation to NGA and VGL as previously discussed in Note 1, “Nature of Operations and Basis of Presentation.”

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 each of the Company’s respective reporting units below its carrying amount. The Company tests its goodwill based upon four identified reporting units, aligned with its jurisdictional operational model. Goodwill is tested for impairment using a two-step approach. The first step compares the estimated fair value of each reporting unit 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, then a second step is performed to determine the implied fair value of goodwill. If the carrying value of goodwill exceeds its implied fair value, then an impairment charge equal to the difference is recorded.

The fair value of each reporting unit was calculated in the annual goodwill impairment test for the year ended March 31, 2017 utilizing both income and market approaches. Key assumptions in the income approach include the discount rate of

5.4% (2016: 5.0%) and the terminal growth rate of 2.0% (2016: 2.0%). The key assumption in the market approach is the EBITDA multiplier of 12 (2016: 10). The Company generally uses a 50% weighting for each valuation methodology, as it believes that each methodology provides equally valuable information. In response to recently received rate orders in 2016, the fair values of Massachusetts Electric, Brooklyn Union, and KeySpan Gas East were calculated utilizing solely the income approach for the year ended March 31, 2017. The Company believes that due to the recent rate orders received from these companies' respective regulators, this approach provides the most reliable information. Based on the resulting fair values from the annual analyses, the relative headroom in the four reporting units ranged from 13% to 34%, and as a result the Company determined that no adjustment of the goodwill carrying value was required at March 31, 2017 or 2016.

Financial Investments

Financial investments are comprised of available-for-sale securities, the Company's investment in DM (as discussed in Note 1, "Nature of Operations and Basis of Presentation"), and funds designated for Supplemental Executive Retirement Plans.

The Company holds available-for-sale securities that include equities, municipal bonds, and corporate bonds. These investments are recorded at fair value. Changes in the fair value of these assets are recorded within other comprehensive income.

Both the Company's investment in DM and the available-for-sale are recorded at fair value and included in the tables in Note 7, "Fair Value Measurements."

The Company also has corporate assets representing funds designated for Supplemental Executive Retirement Plans. These funds are invested in corporate owned life insurance policies and available-for-sale securities primarily consisting of equity investments and investments in municipal and corporate bonds. The corporate owned life insurance investments are measured at cash surrender value, not recorded at fair value, with increases and decreases in the value of these assets recorded in the accompanying consolidated statements of income.

The following table presents the financial investments recorded on the consolidated balance sheet:

	March 31,	
	2017	2016
	(in millions of dollars)	
Available-for-sale securities	**$ 279**	$ 261
Dominion Midstream Partners, LP	**217**	202
Supplemental Executive Retirement Plans	**255**	230
Other	**6**	-
Total	**$ 757**	$ 693

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 gas distribution and electric generation 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 consolidated balance sheet. These regulatory assets represent timing differences between the recognition of costs in accordance with U.S. GAAP and costs recovered through the rate-making process.

Employee Benefits

The Company has defined benefit pension and postretirement benefit other than pension ("PBOP") plans for its employees. The Company recognizes all pension and PBOP plans' funded status on the consolidated balance sheet as a net liability or asset with an offsetting adjustment to AOCI in shareholders' equity. In the case of regulated entities, the cost of providing these plans is recovered through rates; therefore, the net funded status is offset by a regulatory asset or liability. The Company measures and records its 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.

New and Recent Accounting Guidance

Accounting Guidance Adopted in Fiscal Year 2017

Presentation of Financial Statements – Balance Sheet Classification of Debt Issuance Costs

In April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-03, "Simplifying the Presentation of Debt Issuance Costs." The new guidance requires that debt issuance costs related to term loans, be presented in the balance sheets as a direct deduction from the carrying value of debt. The guidance was adopted and retrospectively applied as described in Note 10, "Capitalization."

Presentation of Financial Statements – Going Concern, Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern

In August 2014, the FASB issued amendments on reporting about an entity's ability to continue as a going concern in ASU 2014-15, "Presentation of Financial Statements – Going Concern (Subtopic 205 - 40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern." The amendments provide guidance about management's responsibility 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, the amendments require additional disclosures relating to management's evaluation and conclusion. 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 fall due.

Accounting Guidance Not Yet Adopted

Pension and Postretirement Benefits

In March 2017, the FASB issued ASU 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, 2020, 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.

Goodwill

In January 2017, the FASB issued ASU 2017-04, "Intangibles—Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment," 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, 2023, with early adoption permitted. The Company currently anticipates adopting the ASU in the year ended March 31, 2018.

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. For the Company, the requirements of the new standard will be effective for the fiscal year ended March 31, 2020, and interim periods thereafter, with early adoption permitted.

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 standard will be effective for the fiscal year ended March 31, 2020, and interim periods thereafter, with early adoption permitted.

The Company is currently evaluating the impact of the new guidance on the presentation of its consolidated statements of cash flows.

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, 2020, and interim periods thereafter, with early adoption permitted. The Company is currently evaluating the impact of the new guidance on the results of its operations, cash flows, and financial position.

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 thereafter, with early adoption permitted. The Company is currently evaluating the impact of the new guidance on the results of its operations, cash flows, and financial position.

Revenue Recognition

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), which changes the criteria for recognizing revenue from a contract with a customer. In August 2015, the FASB issued ASU 2015-14, "Revenue from Contracts with Customers – Deferral of the Effective Date", which effectively defers by one year the effective date of ASU 2014-09. The underlying principle of "Revenue from Contracts with Customers" 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.

Additionally, there were subsequent amendments to ASU 2014-09. In March 2016, the FASB issued ASU 2016-08, 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 2016-12, providing additional clarity on various aspects of Topic 606. 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.

The new revenue recognition guidance and related amendments must be adopted using either a full retrospective approach or a modified retrospective approach. For the Company, the new guidance is effective for the fiscal year ended March 31, 2019, and interim periods within the reporting period, with early adoption permitted.

The Company continues to assess the impacts this guidance may have on its results of its operations, cash flows and financial position. In performing this assessment the Company is utilizing an implementation team comprising both internal and external resources. The key areas of focus include but not limited to: reviewing the potential new disclosures regarding the nature, amount, timing and uncertainty of revenue and related cash flows; developing an implementation approach and process for complying with these new disclosures; and evaluating existing contracts and revenue streams for potential changes in the amounts and timing of recognizing revenues under the new guidance. While there continues to be ongoing activities in all these areas, the Company has preliminarily concluded that it expects to apply the new guidance using the modified retrospective method.

Leases

In February 2016, the FASB issued a new lease accounting standard, ASU 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, 2021, 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. The Company’s leases are discussed in Note 13, “Commitments and Contingencies” under “Operating Lease Obligations.”

Financial Instruments – Classification and Measurement

In January 2016, the FASB issued ASU 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, 2020, and interim periods thereafter, with early adoption permitted. The Company is currently evaluating the impact of the new guidance on the results of its operations, cash flows, and financial position.

Measurement of Inventory

In July 2015, the FASB issued ASU 2015-11, “Simplifying the Measurement of Inventory.” The new guidance requires that inventory be measured at the lower of cost or net realizable value (other than inventory measured using “last-in, first out” and the “retail inventory method”). For the Company, the new guidance, which must be applied prospectively, is effective for the fiscal year ended March 31, 2018, 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 since the Company’s gas in storage is fully recoverable from customers and material and supplies inventory is stated at the lower of cost or market.

Consolidation

In February 2015, the FASB issued ASU 2015-02, “Consolidation (Topic 810): Amendments to the Consolidation Analysis.” The new guidance eliminates entity specific consolidation guidance for limited partnerships. It also revises other aspects of the consolidation analysis, including how kick-out rights, fee arrangements and related parties are assessed. The new guidance, which requires either modified retrospective or full retrospective basis application, is effective for the fiscal year ended March 31, 2018, 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.

Reclassifications

Certain reclassifications have been made to the financial statements to conform prior year’s data to the current year’s presentation. These reclassifications had no effect on the Company’s results of operations or cash flows. The reclassifications include among others the retrospective adoption of ASU 2015-03 (refer to Note 10, “Capitalization”).

3. REGULATORY ASSETS AND LIABILITIES

The Company records regulatory assets and liabilities that result from the ratemaking process. Regulatory deferrals are recorded by legal entity and separate company results and positions can result in both assets and liabilities. The following table presents the regulatory assets and regulatory liabilities recorded on the consolidated balance sheet:

	March 31,	
	2017	2016
	(in millions of dollars)	
Regulatory assets		
Current:		
Derivative instruments	**$ 69**	$ 120
Energy efficiency	**47**	59
Gas costs adjustment	**129**	121
Rate adjustment mechanisms	**108**	119
Renewable energy certificates	**53**	77
Revenue decoupling mechanism	**102**	131
Transmission service	**9**	57
Other	**13**	28
Total	**530**	712
Non-current:		
Environmental response costs	**2,316**	1,711
Postretirement benefits	**1,167**	1,980
Storm costs	**281**	307
Other	**1,069**	848
Total	**4,833**	4,846
Regulatory liabilities		
Current:		
Derivative instruments	**5**	1
Energy efficiency	**361**	195
Gas costs adjustment	**70**	86
Profit sharing	**52**	54
Rate adjustment mechanisms	**168**	146
Revenue decoupling mechanism	**147**	62
Other	**30**	25
Total	**833**	569
Non-current:		
Carrying charges	**226**	169
Cost of removal	**1,699**	1,702
Environmental response costs	**109**	195
Postretirement benefits	**92**	112
Other	**923**	838
Total	**3,049**	3,016
Net regulatory assets	**$ 1,481**	$ 1,973

Carrying charges: The Company records carrying charges on regulatory balances (with the exception of derivative instruments, cost of removal, environmental response costs, RECs, and regulatory deferred tax 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.

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 state authorities.

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 former manufactured gas plant ("MGP") sites and related facilities. 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 ("SIR") 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 state regulators. These amounts will be refunded to, or recovered from, customers over the next year.

Postretirement benefits: The regulatory asset primarily represents the excess costs of the Company's pension and PBOP plans over amounts received in rates that are to be recovered in future periods and the non-cash accrual of net actuarial gains and losses. 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.

Profit sharing: Represents a portion of deferred margins from off-system sale transactions. Under current rate orders, Boston Gas and Colonial Gas (the "Massachusetts Gas Companies") are required to return 90% of margins earned from such optimization transactions to firm customers. The amounts deferred on the consolidated balance sheet will be refunded to customers over the next year.

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 applicable state regulatory bodies.

Renewable energy certificates: Represents deferred costs associated with the Company's compliance obligation with the Rhode Island and Massachusetts 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: Revenue decoupling mechanisms allow for the periodic adjustment of delivery rates as a result of the reconciliation between allowed revenue and actual revenue. Any difference between the allowed revenue and the actual revenue is recorded as a regulatory asset or regulatory liability.

Storm costs: Represents the incremental operation and maintenance costs to restore power to customers resulting from major storms.

Transmission service: The Company arranges transmission service on behalf of its customers' and bills the costs of those services to customers pursuant to the Company's Transmission Service Cost Adjustment Provision. Any over or under recoveries of these costs are passed on to customers receiving transmission service through the Company over the subsequent twelve months.

Other: The Company has several other regulatory deferrals including temperature control/interruptible sharing, regulatory deferred tax assets, recovery of acquisition premium, delivery rate adjustment, and excess storm reserve.

4. RATE MATTERS

Niagara Mohawk

Electric and Gas Filing

In March 2013, the NYPSC issued a final order regarding Niagara Mohawk's electric and gas base rate filing made on April 27, 2012. The original term of the rate plan was from April 1, 2013 through March 31, 2016. On December 21, 2015, Niagara Mohawk filed a Petition with the NYPSC seeking authorization to recover approximately $150 million in revenue requirements associated with a proposed two-year, $1.4 billion capital spending program for the Company's electric and gas operations in fiscal years 2017 and 2018. The Petition proposed that the revenue requirement be fully funded by existing regulatory deferrals and proposed no increase in customer rates. The Petition also proposed an extension of the existing rate plan which expired in March 2016 through March 2018.

On May 19, 2016, the NYPSC granted approval of the capital investment petition, approving a two-year capital program worth approximately $1.3 billion and funding of the incremental portion of that investment through the use of $140 million in regulatory liabilities due to customers over 24 months.

On April 28, 2017 Niagara Mohawk filed a proposal to reset electric and natural gas delivery prices beginning in April 2018. If approved by the NYPSC, the new prices would take effect April 1, 2018. The proposal requests, based on updates filed on July 10, 2017, a rate increase of $261 million and $70 million for the electric and gas business respectively based upon a 9.79% return on equity and 48% common equity ratio. If a three year settlement is reached Niagara Mohawk proposes that a return on equity of 10.29% be used to calculate the revenue requirement. The current delivery price freeze for upstate electric and natural gas customers will remain in effect through March 31, 2018. NYPSC staff and other intervenors filed their testimonies on August 25, 2017. Rebuttal testimonies were filed on September 15, 2017.

Transmission Formula Rate

Niagara Mohawk's wholesale transmission service charge ("TSC") rates are established based on a FERC-approved formula. Niagara Mohawk is required to make an informational filing annually to update certain components of the TSC formula rate. The revenue requirement component of the annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement in effect in the prior year and the actual revenue requirement for that year.

On January 30, 2017, pursuant to Section 205 of the Federal Power Act and Part 35.13 of the NYPSC's regulations, Niagara Mohawk submitted modifications to its TSC formula rate set forth in Attachment H to the New York Independent System Operator ("NYISO") Open Access Transmission Tariff. In the filing Niagara Mohawk proposed revisions to the calculation of Niagara Mohawk's projected test year revenue requirement. Niagara Mohawk also proposed administrative changes to certain schedules in the formula rate template.

On April 7, 2017 the NYPSC issued an order accepting Niagara Mohawk's tariff revision filing filed on January 30, 2017 and subsequently revised on February 15, 2017. The tariff adjustments are effective April 1, 2017 to ensure that the proposed tariff modifications are in place for purposes of National Grid's next Formula Rate annual update. Any change in revenues received from wholesale transmission customers resulting from the revisions to the Accumulated Deferred Income Tax calculation methodology will be offset by revenues from retail electric distribution customers through the Transmission Revenue Adjustment Clause mechanism.

Operations Audit

In August 2013, the NYPSC initiated an operational audit using a third party to review the accuracy of the customer service, electric reliability, and gas safety data reported by the investor owned utilities operating in New York, including Brooklyn Union and KeySpan Gas East (the "New York Gas Companies") and Niagara Mohawk. On December 19, 2013, the NYPSC selected a third party to conduct the audit, which commenced in February 2014. On April 20, 2016, the NYPSC released the third party audit report publicly and adopted the majority of recommendations in the report. The audit report found that the New York Gas Companies and Niagara Mohawk, in general, are meeting their obligations to supply self-reported data. The report contains recommendations to improve internal controls and allow for greater consistency in reporting among the New York utilities. The recommendations do not affect current rate case performance targets or mechanisms and may be considered for potential implementation in future rate plans. The New York Gas Companies and Niagara Mohawk filed their plan to implement the audit recommendations with the NYPSC on May 19, 2016. On March 10, 2017, the NYPSC issued an Order approving the New York Gas Companies and Niagara Mohawks' implementation plan without modification, with quarterly updates to be made to the NYPSC on the status of implementation. The New York Gas Companies and Niagara Mohawk filed their first implementation plan update on July 10, 2017.

Operations Staffing Audit

In January 2014, the NYPSC initiated an operational audit to review internal staffing levels and use of contractors for the core utility functions of the investor owned utilities operating in New York, including the New York Gas Companies and Niagara Mohawk. On June 26, 2014, the NYPSC selected a third party to conduct the audit. On February 21, 2017, the third party submitted their final report, which contained recommendations for all of National Grid's New York utilities designed to improve the staffing and workforce management processes. The report contained 26 recommendations for National Grid. The New York Gas Companies and Niagara Mohawk filed their implementation plan on March 23, 2017 and anticipate an order regarding the plan later this year.

The New York Gas Companies

Rate Case Filing

On January 29, 2016, the New York Gas Companies filed to adjust their base gas rates, to be effective from January 1, 2017. The filing requested to increase gas delivery base revenues. On September 7, 2016, the New York Gas Companies filed a Joint Proposal establishing a three year rate plan beginning January 1, 2017 and ending December 31, 2019. The NYPSC issued an order approving the Joint Proposal on December 15, 2016 and the new rates went into effect beginning January 1, 2017.

The rate plan provided for a revenue increase of $384.0 million in the first year, an additional $60.6 million in the second year, and an additional $75.9 million in the third year, for a cumulative three year increase of $1,349 million. In an effort to mitigate the potential bill impacts that the revenue increases would have on customers in the first year, the revenue increases will be levelized over the three year rate period. As such, for U.S. GAAP reporting, revenues are recognized equal to the amounts actually billed to customers during each period rather than per the provisions of the rate plan. The settlement is based upon a 9% return on equity and 48% common equity ratio and includes an earning sharing mechanism in which customers will share earnings in excess of 9.5%.

Key provisions of the settlement include funding for removal of a specific mileage of leak prone pipe ("LPP") in each rate year. Additionally, recovery of proactive LPP replacement costs incurred for repairs in excess of this mileage are permitted and recovered through the Gas Safety and Reliability Surcharge. This also includes a positive revenue adjustment mechanism for unit cost savings versus those specific in rates.

The New York Gas Companies have various capital tracker mechanisms that reconcile the New York Gas Companies' capital expenditures to the amounts permitted in rates. The Net Utility Plant and Depreciation Expense tracker is a downward only reconciliation that applies to the New York Gas Companies' aggregate total average net plant and depreciation expense combined. The reconciliation is summed at the end of Rate Year Three (December 31, 2019) to determine whether any underspend is owed to customers. Under the City/State Construction Reconciliation, the New York Gas Companies are authorized to defer 90% of the revenue requirement impact difference (excluding operations and maintenance expense) between actual and forecast city/state construction costs for future recovery from or return to customers.

The New York Gas Companies' RDM was adjusted to include revenue-per-class RDMs for industrial and commercial customers not previously subject to the RDM.
The New York Gas Companies' SIR expense has also been moved from a surcharge to base rates. For Brooklyn Union, beginning in January 2018, to the extent that the difference between actual SIR expense and the Forecast Rate Allowance exceeds $25 million on a cumulative basis, Brooklyn Union will utilize its SIR Recovery Surcharge. The surcharge is designed to provide recovery for the differences between actual SIR expenses and the amounts allowed in rates and will be calculated annually and be limited to an amount no greater than 2% of Brooklyn Union's prior year aggregate revenues.

Massachusetts Electric and Nantucket (the "Massachusetts Electric Companies")

Electric Rate Case Filing

In November 2015, the Massachusetts Electric Companies filed an application for new base distribution rates to become effective October 1, 2016. The DPU approved an overall increase in base distribution revenue of approximately $170 million based upon a 9.9% return on equity and an overall capital structure of 50.69% equity, 49.22% long-term debt, and 0.09% preferred stock. This increase in revenue includes returns on capital and solar assets placed in service after the last rate case test year of December 2008 and previously collected through separate factors. The order also allows recovery over five years of the aggregate test-year balance of protected customer accounts receivable outstanding for more than 365 days of $40.6 million. As a result of the order, the Company recorded an increase to net income of approximately $33 million, which was the amount of the protected accounts previously charged to expense through the bad debt reserve. Storm recovery allowed in base rates increased from $4.3 million to $10.5 million and deferred storm costs as of September 30, 2016 remain subject to carrying charges at the Weighted Average Cost of Capital, however, deferred storm costs incurred after October 1, 2016 will accrue carrying charges at the prime rate. Additionally, the DPU approved the extension of the recovery factor for costs associated with 16 storm events between February 2010 and March 2013 through August 2019, as further explained below.

The order also allows for an increase in the Massachusetts Electric Companies' capital investment recovery mechanism ("CIRM") from $170 million to $249 million and also allows for the inclusion of property taxes related to these incremental capital additions. The CIRM, is a continuation of the Company's capital investment recovery mechanism initially part of its RDM, with an annual cap on capital investment of $249 million, which is a three-year calendar year historical average.

Storm Cost Recovery

The Massachusetts Electric Companies have deferred incremental storm costs to respond to and restore power associated with several major weather events occurring since January 2010, pending ultimate approval by the DPU to charge its deferred costs to the Massachusetts Electric Companies' Storm Contingency Fund. The deferred incremental storm cost and carrying cost amounts have been reduced to reflect the impact of actual and estimated billings to Verizon for vegetation management costs as a result of the DPU's order regarding the December 2008 ice storm. On May 3, 2013, following a request by the Massachusetts Electric Companies for accelerated funding for the Massachusetts Electric Companies' Storm Contingency Fund, the DPU approved a Storm Fund Replenishment Factor ("SFRF") of $40 million annually for up to three years, or $120 million. This is in addition to $4.3 million that the Massachusetts Electric Companies recovered annually in base rates for the Storm Contingency Fund pursuant to the Massachusetts Electric Companies' previous general rate case. In its ruling, the DPU also directed the Massachusetts Electric Companies to submit two filings of all documentation supporting its storm costs for DPU review and approval. The first filing for $128 million of costs relating to qualifying storms that occurred during calendar years 2010 and 2011 was made on May 31, 2013 (later updated to exclude vegetation management costs billed to Verizon – see below), with the second filing for $94 million of storm costs (net of vegetation management costs billable to Verizon) related to storm events that occurred during calendar year 2012 through March 2013 was made on September 30, 2014. In its September 30, 2014 filing, the Massachusetts Electric Companies also requested an extension of the SFRF through June 2018 to eliminate the deficit in the Storm Contingency Fund created by storm events experienced through March 2013. On April 13, 2016, the DPU extended the SFRF for three additional months until August 4, 2016, unless otherwise ordered, while its prudency review is ongoing. Similarly, on August 1, 2016, the DPU further extended the SFRF until the issuance of the final order. On September 30, 2016, the DPU issued its order relative to the Massachusetts Electric Companies' request to recover costs related to the 2010 through March 2013 storm events. In its order, the DPU disallowed approximately $5 million of the $213 million of requested costs primarily on the basis of unclear and/or insufficient documentation. As a result, the Company recorded a reduction to the regulatory asset for the disallowance with a corresponding charge to net income during the year ended March 31, 2017.

The DPU's disallowance of vegetation management costs attributable to Verizon resulted in an over-recovery of costs related to the December 2008 ice storm as of April 30, 2014. Consequently, on May 14, 2014, the Massachusetts Electric Companies proposed to terminate the recovery related to the December 2008 ice storm in its current form effective July 1, 2014 and to combine approximately $7 million it has been recovering annually with the $40 million of SFRF recovery through the remainder of the three-year period. The DPU approved the Massachusetts Electric Companies' request on June 30, 2014. In addition, on August 29, 2014, the Massachusetts Electric Companies submitted a final reconciliation of the December 2008 ice storm recoveries, which resulted in an over-recovery of $1.6 million at June 30, 2014. The Massachusetts Electric Companies proposed to credit the Storm Contingency Fund for the $1.6 million balance, which the DPU approved on March 11, 2015.

As part of the 2015 Base Rate Case Filing, the Massachusetts Electric Companies proposed a further extension of approximately $47 million in total SFRF recoveries to August 2019, or fourteen months beyond the June 2018 date proposed and approved in the storm cost proceeding. This requested was approved in the rate case order on September 30, 2016.

Massachusetts Electric and Verizon jointly own utility poles in Massachusetts under the terms of a Joint Ownership Agreement entered into by the parties. In December 2014, Massachusetts Electric filed a civil action against Verizon in Massachusetts Superior Court, alleging that Verizon breached the terms of Joint Ownership Agreement relating to the jointly owned poles by failing to pay half of the tree-trimming and vegetation management costs Massachusetts Electric incurred to restore service following multiple storms occurring between 2008 and 2013, as indicated previously.

On May 11, 2017, the Massachusetts Electric and Verizon entered into an agreement to resolve the dispute between the parties. The settlement provides for cash payments and future bill credits for telecommunication services to NGUSA Service Company.

Gas Transportation and Storage Contracts

On January 15, 2016, the Massachusetts Electric Companies filed petitions with the DPU for approval of: (1) two long-term gas transportation and storage services agreements with NGA on the proposed Access Northeast pipeline (together, the "ANE Contracts"); (2) two long-term transportation agreements with Tennessee Gas Pipeline, LLC ("Tennessee") on the proposed Northeast Energy Direct pipeline (together, the "NED Contracts"); (3) an Electric Reliability Service Program to set parameters for the release of capacity and sale of LNG supply available by virtue of the ANE and NED Contracts; and (4) Long-Term Gas Transportation and Storage Contracts tariffs, which would allow for recovery of the costs associated with the agreements executed by National Grid for the provision of interstate pipeline transportation and gas storage services to electric generation facilities in the ISO-NE region, as well as an innovation incentive for the Massachusetts Electric Companies equal to 2.75% of the annual fixed contract payments under the proposed contracts. Both pipelines were designed to provide increased natural gas deliverability to the New England markets. However on April 21, 2016, Tennessee notified the Massachusetts Electric Companies that it was suspending work on the NED pipeline, and on April 27, 2016, the DPU granted the Massachusetts Electric Companies' motion to withdraw its petition to approve the NED contracts. Hearings before the DPU on the ANE contracts began in August 2016. However on August 17, 2016, the Massachusetts Supreme Judicial Court issued a decision holding that (1) the DPU does not have the authority under current state law to approve electric distribution company contracts for gas pipeline capacity, and (2) approving such contracts would violate Massachusetts' 1997 Restructuring Act, which moved Massachusetts from a regulated electricity supply market to an open and competitive market for power. In light of this decision, on August 22, 2016, the Massachusetts Electric Companies filed a motion to withdraw its petition to approve the ANE contracts, without prejudice, but reserved its rights to seek DPU approval of the same or similar agreements in the future if there is a change in the DPU's legal authority to approve such agreements. On October 7, 2016, the DPU granted the Massachusetts Electric Companies' motion to withdraw its petition without prejudice, which would allow the Massachusetts Electric Companies to re-file a similar petition if the law changes. The Company recorded an impairment in its interest in Access Northeast as discussed in Note 1, "Nature of Operations and Basis of Presentation" under "Energy Investments."

The Massachusetts Gas Companies

General Rate Case

In November 2010, the DPU issued an order in the Massachusetts Gas Companies' 2010 rate case approving a revenue increase of $58 million based upon a 9.75% return on equity ("ROE") and a 50% equity ratio. The Massachusetts Gas Companies filed two motions in response. These motions resulted in a final revenue increase of $65.3 million.

Gas System Enhancement Plan

The Gas System Enhancement Plan (''GSEP'') is a program designed to accelerate the replacement of the Massachusetts Gas Companies' existing infrastructure pursuant to the Massachusetts' 2014 Gas Leaks Act. The Massachusetts Gas Companies' plan is to replace all leak-prone infrastructure by 2022.

In calendar years 2015, 2016, and 2017, the DPU approved the Massachusetts Gas Companies' GSEP for calendar years 2015, 2016 and 2017, respectively, and the associated gas system enhancement adjustment factors ("GSEAFs"). The approved GSEAFs are designed to provide concurrent recovery of the revenue requirement associated with the Massachusetts Gas Companies' capital costs for the replacement of eligible leak prone pipe and ancillary equipment pursuant to Massachusetts' 2014 Gas Leaks Act. This program replaced the Targeted Infrastructure Replacement ("TIR") Program in 2015; however, recovery of the revenue requirement TIR Program investment will continue until recovery commences through new base distribution rates.

The approved GSEAFs are designed to recover from all firm sales and transportation customers a revenue requirement of approximately $58.3 million, $28.9 million, and $9.7 million for 2017, 2016, and 2015, respectively. For Boston Gas, approximately $5.5 million of the requested revenue requirement for 2017 exceeds the 1.5% revenue cap established in the GSEP legislation, so will be deferred from recovery until such time as Boston Gas has room under the GSEP revenue cap to recover the deferred amount or in the next rate case that covers the period of investment. Additionally, on October 31, 2016, the DPU approved the Massachusetts Gas Companies' GSEP reconciliation filing for 2015, which reconciled the 2015 revenue requirement on 2015 actual GSEP capital investment with revenue billed through the GSEAFs, and proposed to credit customers $3.3 million as a result of this reconciliation effective November 1, 2016. The DPU approved the Massachusetts Gas Companies' filing and the associated Gas System Enhancement Reconciliation Adjustment Factors on October 31, 2016 but deemed approximately $18 million of project costs ineligible for the GSEP program due to the timing of the projects. These projects were subsequently included in the following TIR program filing submitted on May 1, 2017. The DPU order further directed the Massachusetts Gas Companies to reconcile the revenue requirement associated with approximately $18 million of project costs incurred in 2015 in its May 1, 2017 GSEP reconciliation filing. On October 31, 2017, the Massachusetts Gas Companies will submit their 2018 GSEP for calendar year 2018.

New England Power

Stranded Cost Recovery

Under settlement agreements approved by state commissions and the FERC, NEP is permitted to recover stranded costs (those costs associated with its former generating investments (nuclear and non-nuclear) and related contractual commitments that were not recovered through the sale of those investments). NEP earns a ROE of approximately 11% on stranded cost recovery, which consists primarily of nuclear-related investments at March 31, 2017. NEP will recover its remaining non-nuclear stranded costs through 2020. See the “Decommissioning Nuclear Units” section in Note 13, “Commitments and Contingencies”, for a discussion of ongoing costs associated with decommissioned nuclear units.

Transmission Return on Equity

Transmission revenues are based on a formula rate that recovers NEP’s actual costs plus a return on investment. Approximately 70% of NEP’s transmission facilities are included under the Regional Network Service (“RNS”) rates. NEP earns an additional 1% ROE incentive adder on RNS-related transmission facilities approved under the Regional Transmission Organization’s (“RTO”) Regional System Plan and placed in service on or before December 31, 2008. It also earns a 1.25% ROE incentive on its portion of New England East-West Solution (“NEEWS”) as described below.

NEP’s transmission rates applicable to transmission service through October 15, 2014 reflected a base ROE of 11.14% applicable to NEP’s transmission facilities, plus an additional 0.5% RTO participation adder applicable to transmission facilities included under the RNS rate. Starting on October 16, 2014, the FERC issued a series of orders as the result of three ROE complaint cases (see the “FERC ROE Complaints” section in Note 13, “Commitments and Contingencies”), reducing the Company’s base ROE to 10.57%. The FERC also established a maximum ROE such that any incentives, taken together, may not exceed a cap of 11.74%. On April 14, 2017, the U.S. Court of Appeals for the D.C. Circuit (“Court of Appeals”) vacated the FERC’s orders which had reduced the Company’s base ROE to 10.57% and maximum ROE to 11.74% and remanded the issue back to the FERC. On June 5, 2017, the New England Transmission Owners (“NETOs”), including NEP, submitted a filing to the FERC to document the reinstatement of their transmission rates that had been in effect through October 15, 2014. The NETOs do not intend to commence billing under the reinstated rates until 60 days after the FERC has a quorum, which was re-established on August 10, 2017. If the FERC takes no action within this 60-day period, then the NETOs will commence billing under their reinstated rates retroactive to June 6, 2017.

Recovery of Transmission Costs

In conformance with the terms of NEP’s Tariff No. 1, on November 17, 2014, NEP submitted a filing to the FERC under Section 205 of the Federal Power Act (“FPA”) proposing to reduce the ROE under its Tariff No. 1 formula rates so that they were consistent with those applied under the ISO-NE Open Access Transmission Tariff pursuant to the FERC’s Opinion Nos. 531 and 531-A. Under the integrated facilities provisions of Tariff No. 1, NEP supports the cost of transmission facilities owned by its distribution affiliates, Massachusetts Electric and Narragansett, and makes these facilities available for open access transmission service on an integrated basis. The FERC rejected NEP’s filing on April 16, 2015, finding that it was inconsistent with the FERC’s clarifications issued in its Order on Rehearing in Opinion No. 531-B (see the “FERC ROE Complaints” section in Note 13, “Commitments and Contingencies”). On January 21, 2016, NEP re-filed proposed amendments to its Tariff No. 1 formula rates for integrated facilities to be consistent with Opinion No. 531-B among other proposed changes. On March 8, 2016, the FERC accepted the filing approving an effective date of October 16, 2014 for the ROE components. NEP has reduced its compensation to its distribution affiliates in accordance with the Order. As mentioned previously, though, on April 14, 2017, the Court of Appeals vacated the FERC’s Opinion Nos. 531, 531-A, and 531-B, and remanded the issue back to the FERC.

New England East-West Solution

In September 2008, NEP, Narragansett 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. 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% including the RTO participation adder), (2) 100% construction work in progress in rate base, and (3) recovery of plant abandoned for reasons beyond the companies’ control. As discussed in a 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. On April 14, 2017, the Court of Appeals vacated the FERC’s orders which had reduced NEP’s maximum ROE to 11.74%, though, and remanded the issue back to the FERC.

Narragansett

General Rate Case

The RIPUC approved a settlement agreement among the Rhode Island Division of Public Utilities and Carriers, the Department of the Navy, and Narragansett, 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 ROE and a common equity ratio of approximately 49.1%, effective February 1, 2013. The settlement also included reinstatement of base rate recovery of storm fund contributions and implementation of a Pension Adjustment Mechanism for pension and PBOP expenses for the electric business identical to the mechanism in place for the gas business.

5. PROPERTY, PLANT AND EQUIPMENT

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

	March 31,	
	2017	2016
	(in millions of dollars)	
Plant and machinery	**$ 32,907**	$ 30,890
Property held for future use	**15**	15
Land and buildings	**2,269**	2,227
Assets in construction	**1,777**	1,477
Software and other intangibles	**1,066**	991
Total property, plant and equipment	**38,034**	35,600
Accumulated depreciation and amortization	**(8,616)**	(8,136)
Property, plant and equipment, net	**$ 29,418**	$ 27,464

6. DERIVATIVE INSTRUMENTS AND HEDGING

The Company utilizes derivative instruments to manage commodity price, interest rate, and foreign currency rate risk associated with its natural gas and electricity purchases and previously its Euro Medium Term Note borrowings. The Company's commodity risk management strategy is to reduce fluctuations in firm gas and electricity sales prices to its customers. The Company's interest rate risk management strategy is to minimize its cost of capital. The Company's currency rate risk management policy is to hedge the risk associated with its foreign currency borrowings by utilizing instruments to convert principle and interest payments into U.S. dollars.

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") and megawatt hours ("mwhs") are as follows:

	Electric		Gas	
	March 31,		March 31,	
	2017	2016	**2017**	2016
	(in millions)		*(in millions)*	
Gas future contracts (dths)	**-**	-	**3**	14
Gas option contracts (dths)	**-**	-	**8**	16
Gas purchase contracts (dths)	**-**	-	**54**	44
Gas swap contracts (dths)	**-**	-	**83**	76
Electric capacity contracts (mwhs)	**1**	-	**-**	-
Electric swap contracts (mwhs)	**13**	12	**-**	-
Total	**14**	12	**148**	150

Amounts Recognized on the Consolidated Balance Sheet

	March 31,			March 31,	
	2017	2016		**2017**	2016
	(in millions of dollars)			*(in millions of dollars)*	
Current assets:			Current liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas future contracts	**$ -**	$ 1	Gas future contracts	**$ -**	$ 12
Gas purchase contracts	**4**	1	Gas purchase contracts	**7**	2
Gas swap contracts	**14**	5	Gas swap contracts	**1**	16
Electric swap contracts	**13**	2	Electric swap contracts	**45**	63
			Electric swaption contracts	**1**	-
Hedge contracts:			Hedge contracts:		
Foreign exchange forward contracts	**1**	6	Foreign exchange forward contracts	**-**	1
	32	15		**54**	94
Other non-current assets:			Other non-current liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas purchase contracts	**-**	2	Gas future contracts	**-**	2
Electric capacity contracts	**1**	3	Gas purchase contracts	**10**	-
Electric swap contracts	**1**	-	Gas swap contracts	**1**	2
	2	5	Electric option contracts	**-**	1
	$ 34	$ 20	Electric swap contracts	**33**	36
				44	41
Total			Total	**$ 98**	$ 135

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 consolidated statements of income. All of the Company's derivative instruments are subject to rate recovery as of March 31, 2017 and 2016.

Credit and Collateral

The Company is exposed to credit risk related to transactions entered into for commodity price, interest rate, and foreign currency rate 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.

Commodity Transactions

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 $40.4 million and $83.6 million as of March 31, 2017 and 2016, 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, 2017 and 2016 was $65.2 million and $111.8 million, respectively. The Company had $24 million and $29 million collateral posted for these instruments at March 31, 2017 and 2016, respectively. At March 31, 2017, if the Company's credit rating were to be downgraded by one, two, or three levels, it would be required to post additional collateral to its counterparties of $2.9 million, $7.9 million, or $42.4 million, respectively.

Financing Transactions

The credit policy for financing transactions is managed by a central treasury department under policies approved by the Finance Committee. In accordance with these treasury policies, counterparty credit exposure utilizations are monitored daily against the counterparty credit limits. Counterparty credit ratings and market conditions are reviewed continually with limits being revised and utilization adjusted, if appropriate. Management does not expect any significant losses from non-performance by these counterparties.

As the Company no longer holds any cash flow hedge contracts, if the Company's credit rating were to be downgraded by one, two, or three levels, it would not be required to post any collateral.

Offsetting Information for Derivative Instruments Subject to Master Netting Arrangements

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

ASSETS:	Gross amounts of recognized assets *A*	Gross amounts offset in the Consolidated Balance Sheets *B*	Net amounts of assets presented in the Consolidated Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral received *Db*	Net amount *E=C-D*
Derivative instruments						
Gas purchase contracts	$ 4	$ -	$ 4	$ -	$ -	$ 4
Gas swap contracts	14	-	14	-	-	14
Electric capacity contracts	1	-	1	-	-	1
Electric swap contracts	14	-	14	-	-	14
Foreign exchange forward contracts	1	-	1	-	-	1
Total	$ 34	$ -	$ 34	$ -	$ -	$ 34

LIABILITIES:	Gross amounts of recognized liabilities *A*	Gross amounts offset in the Consolidated Balance Sheets *B*	Net amounts of liabilities presented in the Consolidated Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral paid *Db*	Net amount *E=C-D*
Derivative instruments						
Gas purchase contracts	$ 17	$ -	$ 17	$ -	$ -	$ 17
Gas swap contracts	2	-	2	-	-	2
Electric swap contracts	78	-	78	-	24	54
Electric swaption contracts	1	-	1	-	-	1
Total	$ 98	$ -	$ 98	$ -	$ 24	$ 74

March 31, 2016
Gross Amounts Not Offset in the Consolidated Balance Sheets
(in millions of dollars)

ASSETS:	Gross amounts of recognized assets *A*		Gross amounts offset in the Consolidated Balance Sheets *B*		Net amounts of assets presented in the Consolidated Balance Sheets *C=A+B*		Financial instruments *Da*		Cash collateral received *Db*		Net amount *E=C-D*	
Derivative instruments												
Gas future contracts	$	1	$	-	$	1	$	-	$	1	$	-
Gas purchase contracts		3		-		3		-		-		3
Gas swap contracts		5		-		5		-		-		5
Electric capacity contracts		3		-		3		-		-		3
Electric swap contracts		2		-		2		-		-		2
Foreign exchange forward contracts		6		-		6		-		-		6
Total	$	20	$	-	$	20	$	-	$	1	$	19

LIABILITIES:	Gross amounts of recognized liabilities *A*		Gross amounts offset in the Consolidated Balance Sheets *B*		Net amounts of liabilities presented in the Consolidated Balance Sheets *C=A+B*		Financial instruments *Da*		Cash collateral paid *Db*		Net amount *E=C-D*	
Derivative instruments												
Gas future contracts	$	14	$	-	$	14	$	-	$	14	$	-
Gas purchase contracts		2		-		2		-		-		2
Gas swap contracts		18		-		18		-		-		18
Electric option contracts		1		-		1		-		-		1
Electric swap contracts		99		-		99		-		29		70
Foreign exchange forward contracts		1		-		1		-		-		1
Total	$	135	$	-	$	135	$	-	$	43	$	92

7. FAIR VALUE MEASUREMENTS

The following tables present assets and liabilities measured and recorded at fair value on the consolidated balance sheet on a recurring basis and their level within the fair value hierarchy as of March 31, 2017 and 2016:

	March 31, 2017			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Assets:				
Derivative instruments				
Gas purchase contracts	$ -	$ 1	$ 3	$ 4
Gas swap contracts	-	14	-	14
Electric capacity contracts	-	-	1	1
Electric swap contracts	-	14	-	14
Foreign exchange forward contracts	-	1	-	1
Investment in Dominion Midstream Partners, LP	217	-	-	217
Available-for-sale securities	137	142	-	279
Total	354	172	4	530
Liabilities:				
Derivative instruments				
Gas purchase contracts	-	10	7	17
Gas swap contracts	-	2	-	2
Electric swap contracts	-	78	-	78
Electric swaption contracts	-	1	-	1
Total	-	91	7	98
Net assets (liabilities)	$ 354	$ 81	$ (3)	$ 432

	March 31, 2016			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Assets:				
Derivative instruments				
Gas future contracts	$ 1	$ -	$ -	$ 1
Gas purchase contracts	-	-	3	3
Gas swap contracts	-	5	-	5
Electric capacity contracts	-	-	3	3
Electric swap contracts	-	2	-	2
Foreign exchange forward contracts	-	6	-	6
Investment in Dominion Midstream Partners, LP	-	202	-	202
Available-for-sale securities	128	133	-	261
Total	129	348	6	483
Liabilities:				
Derivative instruments				
Gas future contracts	14	-	-	14
Gas purchase contracts	-	-	2	2
Gas swap contracts	-	18	-	18
Electric option contracts	-	-	1	1
Electric swap contracts	-	99	-	99
Foreign exchange forward contracts	-	1	-	1
Total	14	118	3	135
Net assets	$ 115	$ 230	$ 3	$ 348

Derivative instruments: The Company's Level 1 fair value derivative instruments primarily consist of quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access as of the reporting date. Derivative assets and liabilities utilizing Level 1 inputs include active exchange-based derivative instruments (e.g. natural gas futures traded on the NYMEX).

The Company's Level 2 fair value derivative instruments primarily consist of over-the-counter ("OTC") currency swap transactions, and gas swap 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 primarily consist of OTC gas option contracts and 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. The internally developed forward curves have a high level of correlation with published curves and are reviewed by the middle office.

Available-for-sale securities: Available-for-sale securities are included in financial investments on the consolidated 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).

Investment in DM: As of March 31, 2016 the Company's investment in DM was valued based on Level 1 quoted market prices for DM common units, combined with a discount to the quoted market price, which was calculated using Level 2 inputs, to reflect restrictions on the transfer of the units and resulting lack of marketability. As of March 31, 2017 the restrictions on the transfer of the units are no longer in place and as such the Company's investment in DM was valued solely based on Level 1 quoted market prices for DM common units. Transfers are recognized at the end of each period, and as such the investment was transferred from Level 2 to Level 1 in the amount of $162 million.

Changes in Level 3 Derivative Instruments

	Years Ended March 31,	
	2017	2016
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 3**	$ 21
Total gains or losses included in regulatory assets and liabilities	**(18)**	(25)
Settlements	**12**	7
Balance as of the end of the year	**$ (3)**	$ 3
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 into or out of Level 3, during the years ended March 31, 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 forward curves used for financial reporting are developed and verified by the middle office. 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, 2017 Assets	(Liabilities)	Total	Valuation Technique(s)	Significant Unobservable Input	Range
		(in millions of dollars)					
Gas	Purchase contracts	$ 2	$ (7)	$ (5)	Discounted Cash Flow	Forward Curve	$1.67 - $10.89/dth
Gas	Cross commodity contracts	1	-	1	Discounted Cash Flow	Forward Curve	$23.32 - $238/dth
Electric	Capacity contracts	1	-	1	Discounted Cash Flow	Forward Curve	$0.35 - $3.68/MW
	Total	$ 4	$ (7)	$ (3)			

Commodity	Level 3 Position	Fair Value as of March 31, 2016 Assets	(Liabilities)	Total	Valuation Technique(s)	Significant Unobservable Input	Range
		(in millions of dollars)					
Gas	Option contracts	$ -	$ (1)	$ (1)	Discounted Cash Flow	Forward Curve Implied Volatility	$0.09 - $0.36/dth 34% - 38%
Gas	Purchase contracts	-	(1)	(1)	Discounted Cash Flow	Forward Curve LNG Forward Curve	$1.89/dth
Gas	Cross commodity contracts	3	-	3	Discounted Cash Flow	Forward Curve	$10.48 - $271.84/dth
Electric	Option contracts	-	(1)	(1)	Discounted Cash Flow	Implied Volatility	12% - 54%
Electric	Capacity contracts	3	-	3	Discounted Cash Flow	Forward Curve	$0.58 - $5.80/MW
	Total	$ 6	$ (3)	$ 3			

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, gas and electric option, and capacity derivative instruments are forward commodity prices (both gas and electric), implied volatility, and valuation assumptions pertaining to peaking gas deals based on forward gas 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 consolidated balance sheets reflect 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, 2017 and 2016 was $10.3 billion and $10.2 billion, respectively.

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

8. EMPLOYEE BENEFITS

The Company sponsors several non-contributory defined benefit pension plans (the "Pension Plans") and PBOP plans (the "PBOP Plans"). In general, the Company calculates benefits under these plans based on age, years of service, and pay using March 31 as a measurement date. In addition, the Company also sponsors defined contribution plans for eligible employees.

Pension Plans

The Pension Plans are comprised of both qualified and non-qualified plans. The qualified pension plans provide substantially all union employees, as well as all non-union employees hired before January 1, 2011, with a retirement benefit. The qualified pension plans are a cash balance pension plan design in which pay-based credits are applied based on service time and interest credits are applied at rates set forth in the plan. For non-union employees, effective January 1, 2011, pay-based credits are based on a combination of service time and age. The non-qualified pension plans provide additional defined pension benefits to certain eligible executives. The Company funds the qualified plans by contributing at least the minimum amount required under Internal Revenue Service ("IRS") regulations. The Company expects to contribute $287 million to the Pension Plans during the year ending March 31, 2018.

PBOP Plans

The Company's PBOP Plans provide 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. The Company funds these plans based on the requirements of the various regulatory jurisdictions in which it operates. The Company expects to contribute $168 million to the PBOP Plans during the year ending March 31, 2018.

Defined Contribution Plans

The Company has two defined contribution pension plans that cover substantially all employees. For the years ended March 31, 2017 and 2016, the Company recognized an expense in the accompanying statements of income of $53 million and $46 million, respectively.

Components of Net Periodic Benefit Costs

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2017	2016	**2017**	2016
	(in millions of dollars)			
Service cost	**$ 127**	$ 136	**$ 68**	$ 77
Interest cost	**362**	355	**200**	198
Expected return on plan assets	**(472)**	(448)	**(191)**	(185)
Amortization of prior service cost (credit), net	**7**	7	**(8)**	(5)
Amortization of net actuarial loss	**300**	295	**102**	103
Total cost	**$ 324**	$ 345	**$ 171**	$ 188

All of the Company's regulated subsidiaries have regulatory recovery of these costs and therefore have recorded related regulatory assets (liabilities) on the consolidated balance sheet. The Company records amounts for its unregulated subsidiaries within operations and maintenance expense in the accompanying consolidated statements of income.

Amounts Recognized in AOCI and Regulatory Assets

The following tables summarize other pre-tax changes in plan assets and benefit obligations recognized primarily in regulatory assets and accumulated other comprehensive income for the years ended March 31, 2017 and 2016:

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2017	2016	**2017**	2016
	(in millions of dollars)			
Net actuarial (gain) loss	**$ (228)**	$ 261	**$ (658)**	$ (34)
Prior service cost	**9**	-	**-**	-
Amortization of net actuarial loss	**(300)**	(295)	**(102)**	(103)
Amortization of prior service (cost) credit, net	**(7)**	(7)	**8**	5
Total	**$ (526)**	$ (41)	**$ (752)**	$ (132)
Included in regulatory assets	**$ (273)**	$ (20)	**$ (522)**	$ (82)
Included in AOCI	**(253)**	(21)	**(230)**	(50)
Total	**$ (526)**	$ (41)	**$ (752)**	$ (132)

The actuarial gain in the current year was primarily driven by a change in terms for certain PBOP plans for prescriptions, favorable asset returns vs. expected return on assets and changes to the discount rate (FY16: 4.25%, FY17: 4.3%) and other key assumptions (notably terminations).

The Company's regulated subsidiaries have regulatory recovery of these obligations and therefore amounts are included in regulatory assets on the consolidated balance sheet. Costs of non-regulated subsidiaries are recorded as part of AOCI on the consolidated balance sheet.

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, 2017 and 2016:

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2017	2016	**2017**	2016
	(in millions of dollars)			
Net actuarial loss	**$ 1,675**	$ 2,203	**$ 249**	$ 1,009
Prior service cost (credit)	**36**	34	**(16)**	(24)
Total	**$ 1,711**	$ 2,237	**$ 233**	$ 985
Included in regulatory assets	**$ 855**	$ 1,128	**$ 176**	$ 698
Included in AOCI	**856**	1,109	**57**	287
Total	**$ 1,711**	$ 2,237	**$ 233**	$ 985

The amount of expected net actuarial loss and prior service cost to be amortized from regulatory assets and AOCI during the year ending March 31, 2018 for the Pension Plans and PBOP Plans is $280 million and $42 million, respectively.

Reconciliation of Funded Status to Amount Recognized

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2017	2016	**2017**	2016
	(in millions of dollars)			
Change in benefit obligation:				
Benefit obligation as of the beginning of the year	**$ (8,778)**	$ (8,934)	**$ (4,874)**	$ (5,067)
Service cost	**(127)**	(136)	**(68)**	(77)
Interest cost	**(362)**	(355)	**(200)**	(198)
Plan amendments	**(9)**	-	**-**	-
Net actuarial gain	**44**	190	**522**	279
Benefits paid	**445**	457	**208**	211
Employer group waiver plan subsidy received	**-**	-	**(18)**	(22)
Benefit obligation as of the end of the year	**(8,787)**	(8,778)	**(4,430)**	(4,874)
Change in plan assets:				
Fair value of plan assets as of the beginning of the year	**7,383**	7,502	**2,726**	2,827
Actual return (loss) on plan assets	**656**	(3)	**327**	(60)
Company contributions	**329**	341	**369**	170
Benefits paid	**(445)**	(457)	**(208)**	(211)
Fair value of plan assets as of the end of the year	**7,923**	7,383	**3,214**	2,726
Funded status	**$ (864)**	$ (1,395)	**$ (1,216)**	$ (2,148)

The benefit obligation shown above is the projected benefit obligation ("PBO") for the Pension Plans and the accumulated benefit obligation ("ABO") for the PBOP Plans. The Company is required to reflect the funded status of its Pension Plans above in terms of the PBO, which is higher than the ABO, because the PBO includes the impact of expected future compensation increases on the pension obligation. The Pension Plans had ABO balances that exceeded the fair value of plans assets as of March 31, 2017 and 2016. The aggregate ABO balances for the Pension Plans were $8.5 billion and $8.4 billion as of March 31, 2017 and 2016, respectively.

Amounts Recognized on the Consolidated Balance Sheet

	Pension Plans				PBOP Plans			
	March 31,				March 31,			
	2017		2016		**2017**		2016	
	(in millions of dollars)							
Non-current assets	**$**	**280**	$	179	**$**	**13**	$	8
Current liabilities		**(23)**		(23)		**(11)**		(11)
Non-current liabilities		**(1,121)**		(1,551)		**(1,218)**		(2,145)
Total	**$**	**(864)**	$	(1,395)	**$**	**(1,216)**	$	(2,148)

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2017:

(in millions of dollars) Years Ending March 31,	Pension Plans		PBOP Plans	
2018	$	528	$	186
2019		529		195
2020		532		203
2021		535		212
2022		539		222
Thereafter		2,696		1,211
Total	$	5,359	$	2,229

Assumptions Used for Employee Benefits Accounting

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2017	2016	**2017**	2016
Benefit Obligations:				
Discount rate	**4.30%**	4.25%	**4.30%**	4.25%
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	3.50%
Expected return on plan assets	**6.25% - 6.50%**	6.25% - 6.50%	**6.25% - 6.75%**	6.25% - 6.75%
Net Periodic Benefit Costs:				
Discount rate	**4.25%**	4.10%	**4.25%**	4.10%
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	3.50%
Expected return on plan assets	**6.25% - 6.50%**	6.25%	**6.25% - 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,	
	2017	2016
Health care cost trend rate assumed for next year		
Pre 65	**7.00%**	7.50%
Post 65	**6.00%**	6.25%
Prescription	**10.25%**	11.00%
Rate to which the cost trend is assumed to decline (ultimate)	**4.50%**	4.50%
Year that rate reaches ultimate trend		
Pre 65	**2025**	2025
Post 65	**2024**	2024
Prescription	**2025**	2025

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

(in millions of dollars)	**March 31, 2017**
1% point increase	
Total of service cost plus interest cost	$ 52
Postretirement benefit obligation	695
1% point decrease	
Total of service cost plus interest cost	(42)
Postretirement benefit obligation	(581)

Plan Assets

The Company 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 the Company's investment committee on a quarterly basis.

The target asset allocations for the benefit plans as of March 31, 2017 and 2016 are as follows:

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2017	2016	**2017**	2016
U.S. equities	**20%**	20%	**40%**	40%
Global equities (including U.S.)	**7%**	7%	**6%**	6%
Global tactical asset allocation	**10%**	10%	**8%**	8%
Non-U.S. equities	**10%**	10%	**21%**	21%
Fixed income	**40%**	40%	**25%**	25%
Private equity	**5%**	5%	**-**	-
Real estate	**5%**	5%	**-**	-
Infrastructure	**3%**	3%	**-**	-
	100%	100%	**100%**	100%

Fair Value Measurements

The following tables provide the fair value measurements amounts for the pension and PBOP assets and liabilities:

	March 31, 2017				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in millions of dollars)		
Pension Assets:					
Cash and cash equivalents	$ 5	$ 63	$ -	$ 94	$ 162
Accounts receivable	63	-	-	-	63
Accounts payable	(129)	-	-	-	(129)
Equity	1,119	-	-	2,179	3,298
Global tactical asset allocation	-	-	-	383	383
Fixed income securities	-	2,546	-	684	3,230
Preferred securities	-	18	-	-	18
Private equity	-	-	-	479	479
Real estate	-	-	-	419	419
Total	$ 1,058	$ 2,627	$ -	$ 4,238	$ 7,923
PBOP Assets:					
Cash and cash equivalents	$ 54	$ 1	$ -	$ 2	$ 57
Accounts receivable	5	-	-	-	5
Accounts payable	(4)	-	-	-	(4)
Equity	633	2	-	1,451	2,086
Global tactical asset allocation	83	-	-	229	312
Fixed income securities	4	616	-	133	753
Private equity	-	-	-	5	5
Total	$ 775	$ 619	$ -	$ 1,820	$ 3,214

	March 31, 2016				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in millions of dollars)		
Pension Assets:					
Cash and cash equivalents	$ 13	$ 61	$ -	$ 92	$ 166
Accounts receivable	108	-	-	-	108
Accounts payable	(105)	-	-	-	(105)
Equity	1,108	-	-	1,932	3,040
Global tactical asset allocation	-	-	-	373	373
Fixed income securities	-	2,798	-	138	2,936
Preferred securities	1	23	-	-	24
Private equity	-	-	-	445	445
Real estate	-	-	-	397	397
Other	-	(1)	-	-	(1)
Total	$ 1,125	$ 2,881	$ -	$ 3,377	$ 7,383
PBOP Assets:					
Cash and cash equivalents	$ 35	$ 13	$ -	$ 2	$ 50
Accounts receivable	28	-	-	-	28
Accounts payable	(25)	-	-	-	(25)
Equity	507	-	-	1,220	1,727
Global tactical asset allocation	72	-	-	189	261
Fixed income securities	3	675	-	-	678
Private equity	-	-	-	6	6
Other	-	1	-	-	1
Total	$ 620	$ 689	$ -	$ 1,417	$ 2,726

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 the Employee Benefit Temporary Investment Funds and JPMorgan Chase Bank Liquidity Funds are excluded from the fair value hierarchy. Such instruments are generally valued using a curve methodology that includes observable inputs such as money market rates for specific instruments, programs, currencies and maturity points obtained from a variety of market makers, reflective of current trading levels. The methodologies consider an instrument's days to final maturity to generate a yield based on the relevant curve for the instrument.

Accounts receivable and accounts payable: Accounts receivable and accounts payable are classified in the same category as the investments to which they relate. 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. Commingled 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. If the inputs used to measure a financial instrument fall within different levels of the fair value hierarchy within the commingled fund, the categorization is based on the lowest level input that is significant to the measurement of that financial instrument. Those which are open ended mutual funds with observable pricing are classified as Level 1. 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. Commingled 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, derived from the underlying securities' quoted prices in active markets, and are classified as Level 2 investments. 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.

Other Benefits

At March 31, 2017 and 2016, the Company had accrued workers compensation, auto, and general insurance claims which have been incurred but not yet reported ("IBNR") of $74 million and $91 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, 2017 and 2016:

	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total
		(in millions of dollars)		
Balance as of March 31, 2015	$ 8	$ (890)	$ (3)	$ (885)
Other comprehensive income (loss) before reclassifications:				
Unrecognized net acturial loss (net of $42 tax benefit)	-	(61)	-	(61)
Gain on investment (net of $1 tax expense)	2	-	-	2
Amounts reclassified from other comprehensive income (loss):				
Amortization of net actuarial loss (net of $71 tax expense) [2]	-	103	-	103
Amortization of treasury lock (net of $0 tax benefit) [1]	-	-	1	1
Gain on investment (net of $4 tax benefit) [2]	(6)	-	-	(6)
Net current period other comprehensive (loss) income	(4)	42	1	39
Balance as of March 31, 2016	$ 4	$ (848)	$ (2)	$ (846)
Other comprehensive income (loss) before reclassifications:				
Unrecognized net acturial gain (net of $126 tax expense)	-	182	-	182
Gain on investment (net of $8 tax expense)	14	-	-	14
Amounts reclassified from other comprehensive income (loss):				
Amortization of net actuarial loss (net of $71 tax expense) [2]	-	104	-	104
Gain on investment (net of $4 tax benefit) [2]	(6)	-	-	(6)
Net current period other comprehensive income	8	286	-	294
Balance as of March 31, 2017	**$ 12**	**$ (562)**	**$ (2)**	**$ (552)**

(1) Amounts are reported in interest on long-term debt in the accompanying consolidated statements of income.

(2) Amounts are reported as other deductions, net in the accompanying consolidated statements of income.

The Company expects no amount in AOCI related to hedging activity will be reclassified into earnings during the year ending March 31, 2018.

10. CAPITALIZATION

As a result of retrospective adoption of ASU 2015-03, relating to the balance sheet presentation of debt issuance costs, the Company adjusted its long-term debt and other non-current assets by $49 million as of March 31, 2016. Debt issuance costs were $49 million at March 31, 2017.

The aggregate maturities of long-term debt for the years subsequent to March 31, 2017 are as follows:

(in millions of dollars) Years Ending March 31,		
2018	$	106
2019		54
2020		1,026
2021		346
2022		59
Thereafter		7,907
Total	$	9,498

Sinking fund repayment requirements related to certain of the Company's Promissory Notes to NGNA and First Mortgage Bonds ("FMB") for the years subsequent to March 31, 2017 are as follows:

(in millions of dollars) Years Ending March 31,		
2018	$	19
2019		19
2020		19
2021		19
2022		19
Thereafter		125
Total	$	220

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. The Company's subsidiaries also have restrictions on the payment of dividends which relate to their debt to equity ratios. During the years ended March 31, 2017 and 2016, the Company was in compliance with all such covenants.

Significant Debt Facilities

Notes Payable

In March 2016, Brooklyn Union issued $500 million of unsecured senior long-term debt at 3.407% with a maturity date of March 10, 2026 and $500 million of unsecured senior long-term debt at 4.504% with a maturity date of March 10, 2046. In August 2016, Massachusetts Electric issued $500 million of unsecured senior long-term debt at 4.004% with a maturity date of August 15, 2046 and KeySpan Gas East issued $700 million of unsecured senior long-term debt at 2.742% with a maturity date of August 15, 2026.

The following table represents the Company's note payables for the years ended March 31, 2017 and 2016:

	Interest Rate	Maturity Date	March 31, 2017	March 31, 2016
			(in millions of dollars)	
Brooklyn Union Unsecured Notes:				
Senior Note	5.60%	November 29, 2016	$ -	$ 400
Senior Note	3.41%	March 10, 2026	500	500
Senior Note	4.50%	March 10, 2046	500	500
Brooklyn Union Notes			1,000	1,400
KeySpan Gas East Unsecured Notes:				
Senior Note	5.60%	November 29, 2016	-	100
Senior Note	5.82%	April 1, 2041	500	500
Senior Note	2.74%	August 15, 2026	700	-
KeySpan Gas East Notes			1,200	600
Boston Gas Senior Note	4.49%	February 15, 2042	500	500
Boston Gas MTN				
MTN Series 1994 B	6.93%	April 1, 2016	-	10
MTN Series 1992 A	8.33%	July 10, 2017	8	8
MTN Series 1992 A	8.33%	July 10, 2018	10	10
MTN Series 1994 B	6.93%	January 15, 2019	10	10
MTN Series 1989 A	8.97%	December 15, 2019	7	7
MTN Series 1990 A	9.75%	December 1, 2020	5	5
MTN Series 1990 A	9.05%	September 1, 2021	15	15
MTN Series 1992 A	8.33%	July 5, 2022	10	10
MTN Series 1995 C	6.95%	December 1, 2023	10	10
MTN Series 1994 B	6.98%	January 15, 2024	6	6
MTN Series 1995 C	6.95%	December 1, 2024	5	5
MTN Series 1995 C	7.25%	October 1, 2025	20	20
MTN Series 1995 C	7.25%	October 1, 2025	5	5
Boston Gas Notes			611	621
Colonial Gas Unsecured Notes:				
Senior Note-Series A	3.30%	March 15, 2022	25	25
Senior Note-Series A	4.63%	March 15, 2042	25	25
Colonial Gas Notes			50	50
KeySpan Corp MTM	8.00%	November 15, 2030	250	250
KeySpan Corp Unsecured Notes:				
Senior Note	5.80%	April 1, 2035	307	307
Senior Note	5.88%	April 1, 2033	150	150
KeySpan Corp Notes			707	707
Niagara Mohawk Unsecured Notes:				
Senior Note	4.88%	August 15, 2019	750	750
Senior Note	2.72%	November 28, 2022	300	300
Senior Note	3.51%	October 1, 2024	500	500
Senior Note	4.28%	October 1, 2034	400	400
Senior Note	4.12%	November 28, 2042	400	400
Niagara Mohawk Notes			2,350	2,350
Narragansett Electric Unsecured Notes:				
Senior Note	4.53%	March 15, 2020	250	250
Senior Note	5.64%	March 15, 2040	300	300
Senior Note	4.17%	December 10, 2042	250	250
Narragansett Electric Notes			800	800
Massachusetts Electric Unsecured Notes:				
Senior Note	5.90%	Novemeber 15, 2039	800	800
Senior Note	4.00%	August 15, 2046	500	-
Massachusetts Electric Notes:			1,300	800
Total			$ 8,018	$ 7,328

Promissory Notes to National Grid North America Inc.

On November 20, 2015, Genco entered into multiple intercompany loans with NGNA totaling $227 million, composed of a $165 million intercompany loan with an interest rate of 3.25% due to mature on April 30, 2028 and a $62 million intercompany loan with an interest rate of 3.13% due to mature on June 1, 2027. The intercompany loans have an annual sinking fund requirement totaling $18 million. These intercompany loans are included in long-term debt on the consolidated balance sheet.

Gas Facilities Revenue Bonds

Brooklyn Union has outstanding tax-exempt Gas Facilities Revenue Bonds ("GFRB") issued through the New York State Energy Research and Development Authority ("NYSERDA"). At March 31, 2017, $230 million of variable, auction rate GFRB bonds were outstanding. At March 31 2016, $641 million of GFRB were outstanding of which $230 million were variable-rate, auction rate bonds. The interest rate on the various variable rate series is reset weekly and ranged from 0.51% to 2.45% during the year ended March 31, 2017 and 0.08% to 1.10% during the year ended March 31, 2016. The GFRB currently in auction rate mode are backed by bond insurance. These bonds cannot be put back to Brooklyn Union and, in the case of a failed auction, the resulting interest rate on the bonds would revert to the maximum auction rate which depends on the current appropriate, short-term benchmark rates and the senior unsecured rating of the Brooklyn Union's bonds. The effect of the failed auctions on interest on long-term debt was not material for the years ended March 31, 2017 or 2016.

During March 2016, Brooklyn Union issued Notice of Optional Redemption letters to the bond holders of the fixed interest rate gas facilities revenue bonds. Brooklyn Union fully repaid these bonds during April 2016 as follows:

	Interest Rate	Maturity Date	Amount *(in millions of dollars)*
Gas Facilities Revenues Bonds:			
1993A and 1993B	6.37%	April 1, 2020	$ 75
1996	5.50%	January 1, 2021	154
2005A	4.70%	February 1, 2024	82
1991A and 1991B	6.95%	July 1, 2026	100
Total			$ 411

First Mortgage Bonds

The assets of Colonial Gas and Narragansett are subject to liens and other charges and are provided as collateral over borrowings of $75 million and $47 million, respectively, of non-callable FMB at March 31, 2017. These FMB indentures include, among other provisions, limitations on the issuance of long-term debt.

State Authority Financing Bonds

At March 31, 2017, the Company had outstanding $919 million of State Authority Financing Bonds, of which, approximately $496 million were issued through NYSERDA and the remaining $423 million were issued through various other state agencies.

Approximately $430 million of the bonds issued through NYSERDA bear interest at short-term adjustable interest rates (with an option to convert to other rates, including a fixed interest rate). The bonds are currently in auction rate mode and are backed by bond insurance. These bonds cannot be put back to Niagara Mohawk and, in the case of a failed auction, the resulting interest rate on the bonds would revert to the maximum rate which depends on the current appropriate, short-term benchmark rate and the senior secured rating of Niagara Mohawk or the bond insurer, whichever is greater. The effect on interest on long-term debt has not been material in either of the years ended March 31, 2016 or 2015. Additionally, Genco has $41 million of 1999 Series A Pollution Control Revenue Bonds due October 1, 2028. The interest rate on the various variable rate series ranged from 0.19% to 1.57% during the year ended March 31, 2017 and 0.04% to

1.30% during the year ended March 31, 2016. Genco also has outstanding $25 million of variable rate 1997 Series A Electric Facilities Revenue Bonds due December 1, 2027 issued through NYSERDA. The interest rate on the various variable rate series is ranged from 0.53% to 1.10% during the year ended March 31, 2017 and 0.07% to 0.60% during the year ended March 31, 2016.

At March 31, 2017, NEP had outstanding $372 million of Pollution Control Revenue Bonds in tax-exempt commercial paper mode and Nantucket had $51 million of Electric Revenue Bonds in tax exempt commercial paper mode. The Electric Revenue Bonds were issued by the Massachusetts Development Finance Agency in connection with Nantucket's financing of its first and second underground and submarine cable projects.

Standby Bond Purchase Agreement

NEP and Nantucket have a Standby Bond Purchase Agreement, which expires on November 20, 2019. This agreement provides liquidity support for the $423 million long-term bonds in tax-exempt commercial paper mode. The Company has classified the debt as long-term due to its intent and ability to refinance the debt on a long-term basis in the event of a failure to remarket the bonds.

Committed Facility Agreements

At March 31, 2017, the Company, NGNA, and the Parent have committed revolving credit facilities of £2.42 billion, of which £1.77 billion matures in May 2022 and £650 million matures in 2019. These facilities have not been drawn against. The Company, NGNA, and the Parent can all draw on these facilities in a variety of currencies as needed, but the aggregate borrowings across the group cannot exceed the £2.42 billion limit. The terms of the facilities restrict the borrowing of all U.S. subsidiaries of the Company to $25 billion excluding intercompany indebtedness. Additionally, these facilities have a number of non-financial covenants which the Company is obliged to meet. At March 31, 2017 and 2016, the Company, NGNA, and the Parent were in compliance with all covenants.

Commercial Paper and Revolving Credit Agreements

At March 31, 2017, the Company had two commercial paper programs totaling $4 billion; a $2 billion U.S. commercial paper program and a $2 billion Euro commercial paper program. In support of these programs, the Company was a named borrower under National Grid plc credit facilities with $1.4 billion available to the Company. These facilities support both the Parent's and the Company's commercial paper programs for ongoing working capital needs. The facilities expire in 2019 and 2022. At March 31, 2017 and 2016, there were $759 million and $179 million of borrowings outstanding on the U.S. commercial paper program and $223 million and $119 million outstanding on the Euro commercial paper program, respectively.

The credit facilities allow both the Parent and the Company to borrow in multi-currencies. The current annual commitment fees range from 0.20% to 0.21%. If for any reason the Company were not able to issue sufficient commercial paper or source funds from other sources, the facilities could be drawn upon to meet cash requirements. The facilities contain certain affirmative and negative operating covenants, including restrictions on the Company's utility subsidiaries' ability to mortgage, pledge, encumber or otherwise subject their utility property to any lien, as well as financial covenants that require the Company and the Parent to limit the total indebtedness in U.S. and non-U.S. subsidiaries to pre-defined limits. Violation of these covenants could result in the termination of the facilities and the required repayment of amounts borrowed thereunder, as well as possible cross defaults under other debt agreements.

Other Redemptions

The following table indicates the Company's redemptions for the year ended March 31, 2017, in addition to the Brooklyn Union Gas Facility Revenue Bonds redemptions:

	Interest Rate	Maturity Date	Amount
			(in millions of dollars)
Brooklyn Union Unsecured Notes:			
Senior Note	5.60%	November 29, 2016	$ 400
KeySpan Gas East Unsecured Notes:			
Senior Note	5.60%	November 29, 2016	100
Boston Gas MTN:			
MTN Series 1994 B	6.93%	April 1, 2016	10
Genco Promissory Notes:			
Promissory Notes to National Grid North America Inc.	3.13% - 3.25%	June 2027 - April 2028	18
Total			$ 528

11. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,	
	2017	2016
	(in millions of dollars)	
Current tax expense (benefit):		
Federal	**$ 150**	$ 1
State	**(7)**	56
Total current tax expense (benefit)	**143**	57
Deferred tax expense (benefit):		
Federal	**154**	338
State	**62**	12
Total deferred tax expense (benefit)	**216**	350
Amortized investment tax credits [1]	**(4)**	(5)
Total deferred tax expense	**212**	345
Total income tax expense	**$ 355**	$ 402

[1] Investment tax credits ("ITC") are being deferred and amortized over the depreciable life of the property giving rise to the credits.

Statutory Rate Reconciliation

The Company's effective tax rates for the years ended March 31, 2017 and 2016 are 36.2% and 38.1%, respectively. The following table presents a reconciliation of income tax expense at the federal statutory tax rate of 35% to the actual tax expense:

	Years Ended March 31,	
	2017	2016
	(in millions of dollars)	
Computed tax	**$ 343**	$ 370
Change in computed taxes resulting from:		
State income tax, net of federal benefit	**36**	45
Other items, net	**(24)**	(13)
Total	**12**	32
Total income tax expense	**$ 355**	$ 402

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

In December 2015, the Protecting Americans from Tax Hikes Act of 2015 was signed into law. The act extended bonus depreciation for property acquired and placed in service during calendar years 2015 through 2019. The bonus depreciation percentage is 50% for property placed in service during calendar years 2015, 2016 and 2017 and phases down to 40% in 2018, and 30% in 2019. During the year ended March 31, 2017, the Company continued to claim bonus depreciation deduction on its Federal corporate income tax return.

On December 1, 2016 the Commissioner of the New York State Department of Taxation and Finance adopted a rule to increase the Metropolitan Transportation Authority surcharge from 28% to 28.3% effective for tax years beginning on or after January 1, 2017, and before January 1, 2018. The rate will remain the same in succeeding years unless otherwise adjusted. During the year ended March 31, 2017, there was no material change in the Company's deferred tax liability for this increase in rate.

Deferred Tax Components

	March 31,	
	2017	2016
	(in millions of dollars)	
Deferred tax assets:		
Environmental remediation costs	**$ 734**	$ 545
Future federal benefit on state taxes	**216**	171
Net operating losses	**958**	812
Postretirement benefits and other employee benefits	**1,097**	1,673
Regulatory liabilities	**810**	613
Other items	**495**	565
Total deferred tax assets (1)	**4,310**	4,379
Deferred tax liabilities:		
Property related differences	**7,347**	6,803
Regulatory assets - environmental response costs	**826**	682
Regulatory assets - other	**1,191**	1,443
Other items	**465**	410
Total deferred tax liabilities	**9,829**	9,338
Net deferred income tax liabilities	**5,519**	4,959
Deferred investment tax credits	**29**	30
Deferred income tax liabilities, net	**$ 5,548**	$ 4,989

(1) The Company established a valuation allowance for deferred tax assets related to expiring charitable contribution carryforwards in the amount of $7 million and $6 million as of March 31, 2017 and 2016 respectively.

Net Operating Losses

The following table presents the amounts and expiration dates of net operating losses as of March 31, 2017:

Expiration of net operating losses:	Federal	State of New York	New York City	State of Massachusetts
		(in millions of dollars)		
3/31/2029	$ 198	$ -	$ -	$ -
3/31/2030	79	-	-	-
3/31/2032	114	-	-	-
3/31/2033	535	-	-	-
3/31/2034	573	-	-	9
3/31/2035	504	1,473 (1)	286 (1)	221
3/31/2036	746	-	27	139
3/31/2037	577	81	28	44

(1) The amounts represent net operating losses that were incurred before the tax year ended March 31, 2015 that has been converted into a Prior Net Operating Loss Conversion subtraction that can be utilized beginning fiscal year 2017.

Unrecognized Tax Benefits

As of March 31, 2017 and 2016, the Company's unrecognized tax benefits totaled $609 million and $552 million, respectively, of which $64 million and $60 million, respectively, would affect the effective tax rate, if recognized. The unrecognized tax benefits are included in other non-current liabilities on the consolidated balance sheet.

The following table presents changes to the Company's unrecognized tax benefits:

	Years Ended March 31,	
	2017	2016
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 552**	$ 522
Gross increases - tax positions in prior periods	**28**	18
Gross decreases - tax positions in prior periods	**(2)**	(23)
Gross increases - current period tax positions	**33**	35
Gross decreases - current period tax positions	**(1)**	-
Settlements with tax authorities	**(1)**	-
Balance as of the end of the year	**$ 609**	$ 552

As of March 31, 2017 and 2016, the Company has accrued for interest related to unrecognized tax benefits of $97 million and $79 million, respectively. During the years ended March 31, 2017 and 2016, the Company recorded interest expense of $20 million and $36 million, respectively. 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 consolidated statements of income. During the years ended March 31, 2017 and 2016, the Company recognized tax penalties in the amount of $0.3 million and $0.6 million, respectively.

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 the NGNA and subsidiaries' administrative appeal with the IRS related to the environmental deductions, casualty loss deduction, and write-off of certain receivables 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. As of the day of this financial statement the range of the reasonably possible change to uncertain tax positions cannot be estimated. 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 expected to conclude in the next fiscal year. The income tax returns for the years ended March 31, 2013 through March 31, 2017 remain subject to examination by the IRS.

The Company is included in NGNA and subsidiaries' administrative appeal with the Massachusetts Department of Revenue ("MADOR") related to issues disputed in examination cycles for the years ended March 31, 2003 through March 31, 2008. In June 2017, NGNA reached a settlement with MADOR, which had no material impact on the Company's operations, financial position, or cash flows. The state of Massachusetts is in the process of examining the Company's income tax returns for the years ended March 31, 2010 through March 31, 2012. The income tax returns for the years ended March 31, 2013 through March 31, 2017 remain subject to examination by the state of Massachusetts.

During the year, the state of New York concluded its examinations of Brooklyn Union and KeySpan Gas East's income tax returns for the years ended December 31, 2007 through March 31, 2008 and December 31, 2003 through March 31, 2008, respectively. Both companies have reached a settlement with the state of New York related to the transition property depreciation deduction. Pursuant to the settlement, Brooklyn Union received a refund of $3.7 million and KeySpan Gas East paid $1.3 million of tax and $1.5 million of interest.

During the year, the state of New York concluded its examination of National Grid Services Inc.'s income tax returns for the years ended March 31, 2009 through March 31, 2012. The settlement of this examination had no material impact on the Company's operations, financial position, or cash flows. As a result of the state audit settlement, the Company filed amended New York City income tax returns, which had no material impact on the Company's operations, financial position, or cash flows.

On May 15, 2017, the state of New York concluded its examination of Genco's income tax returns for the years ended March 31, 2009 through March 31, 2012. The Company has reached a settlement with the state of New York related to the disallowed pollution control credits. The settlement of this examination had no material impact on the Company's operations, financial position, or cash flows.

The state of New York is expected to conclude its examination of National Grid Development Holdings Inc.'s income tax returns for the years ended March 31, 2009, through March 31, 2012 in the next fiscal year. The settlement of this examination is expected to have no material impact on the Company's operations, financial position, or cash flows.

The state of New York is expected to conclude its examination of KeySpan Corporation and Subsidiaries' income tax returns for the years ended December 31, 2003 through March 31, 2008 in the next fiscal year. The Company is expecting to reach a settlement on most of the issues raised during the examination, including disallowance of interest deductions attributable to subsidiary capital. As of the day of this financial statement, the range of the reasonably possible changes to uncertain tax positions included in this examination and potential settlement amount cannot be estimated.

The state of New York is in the process of examining the Company's NYS income tax returns. The following table presents the subsidiaries and years currently under examination. The income tax returns for the subsequent years through March 31, 2017 remain subject to examination by the state of New York.

Companies	Years Under Examination
KeySpan Corporation and Subsidiaries	December 31, 2003 through March 31, 2008
National Grid Development Holdings, Inc.	March 31, 2009 through March 31, 2012
Niagara Mohawk Holdings, Inc.	March 31, 2009 through March 31, 2012

The city of New York is in the process of examining the Company's New York City income tax returns. The following table presents the subsidiaries and years currently under examination. The income tax returns for the subsequent years through March 31, 2017 remain subject to examination by the city of New York.

Companies	Years Under Examination
KeySpan Corporation and Subsidiaries	December 31, 2003 through December 31, 2005
National Grid Services Inc.	March 31, 2012 through March 31, 2014

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

Jurisdiction	Tax Year
Federal	March 31, 2010
Massachusetts	March 31, 2009
New York	December 31, 2003
New York City	December 31, 2003

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.

Air

Genco's generating facilities are subject to increasingly stringent emissions limitations under current and anticipated future requirements of the United States Environmental Protection Agency ("EPA") and the NYS Department of Environmental Conservation ("DEC"). In addition to efforts to improve both ozone and particulate matter air quality, there has been an increased focus on greenhouse gas emissions in recent years. Genco's previous investments in low NOx boiler combustion modifications, the use of natural gas firing systems at its steam electric generating stations, and the compliance flexibility available under cap and trade programs have enabled Genco to achieve its prior emission reductions in a cost-effective manner. These investments include the installation of enhanced NOx controls and efficiency improvement projects at certain of Genco's Long Island based electric generating facilities. The total cost of these improvements was approximately $103 million, all of which have been placed in service; a mechanism for recovery from LIPA of these investments has been established. Genco has developed a compliance strategy to address anticipated future requirements and is closely monitoring the regulatory developments to identify any necessary changes to its compliance strategy. At this time, Genco is unable to predict what effect, if any, these future requirements will have on its consolidated financial position, results of operations, and cash flows.

Water

Additional capital expenditures associated with the renewal of the surface water discharge permits for Genco's steam electric power plants have been required by the DEC pursuant to Section 316 of the Clean Water Act to mitigate the plants' alleged cooling water system impacts to aquatic organisms. Final permits have been issued for Port Jefferson and Northport. Capital improvements have been completed at Port Jefferson and are in the engineering phase for Northport. The Company continues to engage in discussions with the DEC regarding the nature of capital upgrades or other mitigation measures necessary to reduce any impacts at E.F. Barrett. Total capital costs for these improvements at Northport and E.F. Barrett are estimated to be approximately $89.2 million. Costs associated with these capital improvements are reimbursable from LIPA under the PSA.

Land, Manufactured Gas Plants and Related Facilities

Federal and state environmental regulators, as well as private parties, have alleged that several of the Company's subsidiaries are potentially responsible parties under Superfund laws for the remediation of numerous contaminated sites in New York and New England. The Company's greatest potential Superfund liabilities relate to MGP facilities formerly owned or operated by its subsidiaries or their predecessors. MGP byproducts included fuel oils, hydrocarbons, coal tar, purifier waste and other waste products which may pose a risk to human health and the environment.

Since July 12, 2006, several lawsuits have been filed which allege damages resulting from contamination associated with the historic operations of a former manufactured gas plant located in Bay Shore, New York. KeySpan has been conducting remediation at this location pursuant to Administrative Order on Consent ("ACO") with the DEC. KeySpan intends to contest these proceedings vigorously.

Utility Sites

During the year ended March 31, 2017, Brooklyn Union received new information concerning the remediation work required and additional contamination discovered at three of Brooklyn Union's largest sites (Gowanus Canal, Newtown Creek, and Fulton MGP), which resulted in Brooklyn Union increasing its environmental reserve by approximately $613.9 million. The estimate increases were the result of new information arising from a Preliminary Design and Phase 2 investigation report submitted to the EPA by the potentially responsible parties group as well as a Draft Order issued by the EPA requiring the Company to remediate under an active park. After recording an offsetting increase in regulatory assets relating to environmental remediation, there was no impact to the net assets of the Company.

At March 31, 2017 and 2016, the Company's total reserve for estimated MGP-related environmental matters is $2.0 billion and $1.3 billion. The potential high end of the range at March 31, 2017 is presently estimated at $2.6 billion on an undiscounted basis. Management believes that obligations imposed on the Company because of the environmental laws will not have a material adverse effect on its operations, financial position, or cash flows. Through various rate orders issued by the NYPSC, DPU, and RIPUC, costs related to MGP environmental cleanup activities are recovered in rates charged to gas distribution customers. Accordingly, the Company has reflected a net regulatory asset of $2.2 billion and $1.5 billion on the consolidated balance sheet at March 31, 2017 and 2016, respectively.

Expenditures incurred for the years ended March 31, 2017 and 2016 were approximately $114 million and $115 million, respectively.

In fiscal year 2016 and prior years the Company reflected environmental liabilities on a discounted basis using a 6.5% discount factor. In 2017 the EPA required the Company, to revise their site remediation plans which increased the cost, complexity and potential time horizon to meet the EPA standards. The revised remediation plans and requirements no longer make it feasible for the Company to realistically determine if the payments for these liabilities are fixed and determinable and subject to discounting at March 31, 2017. In 2017 the Company revised its estimate for environmental liabilities and eliminated the discount factor for amounts accrued prior to fiscal year 2017 which resulted in a $149 million increase in the liability and corresponding regulatory asset. This change in estimate had no material impact on the Company's results of operations or cash flows.

The Company is pursuing claims against other potentially responsible parties to recover investigation and remediation costs it believes are the obligations of those parties. The Company cannot predict the likelihood of success of such claims.

Non-Utility Sites

The Company is aware of numerous non-utility sites for which it may have, or share, environmental remediation or ongoing maintenance responsibility. Expenditures incurred for the years ended March 31, 2017 and 2016 were $4 million and $3 million, respectively. In 2017 the Company revised its estimate for environmental liabilities which resulted in a $6 million increase in the liability. The Company estimated the remaining cost of the environmental remediation activities at non-utility sites were $34 million and $30 million at March 31, 2017 and 2016, respectively. The Company believes this to be a reasonable estimate of probable costs for known sites; 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 believes that in the aggregate, the accrued liability for all of the sites and related facilities identified above are reasonable estimates of the probable cost for the investigation and remediation of these sites and facilities. As circumstances warrant, the Company periodically re-evaluates the accrued liabilities associated with MGP sites and related facilities. The Company may be required to investigate and, if necessary, remediate each site previously noted, or other currently unknown former sites and related facility sites, the cost of which is not presently determinable.

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, and 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 since, as noted above, environmental expenditures incurred by the Company are generally recoverable from customers.

13. COMMITMENTS AND CONTINGENCIES

Operating Lease Obligations

The Company has various operating leases for buildings, office equipment, vehicles and power operating equipment utilized by both the Company and its subsidiaries. Total rental expense for operating leases included in operations and maintenance expense in the accompanying consolidated statements of income was $100 million and $99 million for the years ended March 31, 2017 and 2016, respectively.

The future minimum lease payments for the years subsequent to March 31, 2017 are as follows:

(in millions of dollars) Years Ending March 31,		
2018	$	101
2019		87
2020		61
2021		62
2022		59
Thereafter		314
Total	$	684

Purchase Commitments

The Company's electric subsidiaries have several long-term contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the subsidiaries are obligated to make payment. The Company's gas distribution subsidiaries have 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's gas distribution subsidiaries are 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, 2017 are summarized in the table below:

(in millions of dollars) Years Ending March 31,	Energy Purchases	Capital Expenditures
2018	$ 1,625	$ 722
2019	932	60
2020	735	38
2021	635	55
2022	546	24
Thereafter	2,631	-
Total	$ 7,104	$ 899

The Company's subsidiaries can purchase additional energy to meet load requirements from independent power producers, other utilities, energy merchants or on the open market through the NYISO or the ISO-NE at market prices.

Financial Guarantees

The Company has guaranteed the principal and interest payments on certain outstanding debt of its subsidiaries. Additionally, the Company has issued financial guarantees in the normal course of business, on behalf of its subsidiaries, to various third-party creditors. At March 31, 2017, the following amounts would have to be paid by the Company in the event of non-payment by the primary obligor at the time payment is due:

Guarantees for Subsidiaries:		Amount of Exposure	Expiration Dates
		(in millions of dollars)	
KeySpan Ravenswood LLC Lease	(i)	$ 281	May 2040
Reservoir Woods	(ii)	180	October 2029
Surety Bonds	(iii)	214	Revolving
Commodity Guarantees and Other	(iv)	122	August 2025 - August 2042
Letters of Credit	(v)	325	May 2017 - December 2018
NY Transco Parent Guaranty	(vi)	842	None
National Grid Algonqin LLC	(vii)	103	December 2021
Business Development	(viii)	61	None
		$ 2,128	

The following is a description of the Company's outstanding subsidiary guarantees:

(i) The Company had guaranteed all payment and performance obligations of a former subsidiary (KeySpan Ravenswood LLC) associated with a merchant electric generating facility leased by that subsidiary under a sale/leaseback arrangement. The subsidiary and the facility were sold in 2008. However, the original lease remains in place and the Company will continue to make the required payments under the lease through 2040. The cash consideration from the buyer of the facility included the remaining lease payments on a net present value basis. At March 31, 2017, the Company's obligation related to the lease was $86 million and is reflected in other non-current liabilities on the consolidated balance sheet.

(ii) The Company has fully and unconditionally guaranteed $180 million in lease payments through 2029 related to the lease of office facilities by its service company at Reservoir Woods in Waltham, Massachusetts.

(iii) The Company has agreed to indemnify the issuers of various surety bonds associated with various construction requirements or projects of its subsidiaries. In the event that the Company or its subsidiaries fail to perform their obligations under contracts, the injured party may demand that the surety make payments or provide services under the bond. The Company would then be obligated to reimburse the surety for any expenses or cash outlays it incurs.

(iv) The Company has guaranteed commodity-related and operational payments for certain subsidiaries. These guarantees are provided to third-parties to facilitate physical and financial transactions supporting the purchase and transportation of natural gas, oil and other petroleum products for gas and electric production and financing activities. The guarantees cover actual transactions by these subsidiaries that are still outstanding as of March 31, 2017.

(v) The Company has arranged for stand-by letters of credit to be issued to third-parties that have extended credit to certain subsidiaries. Certain vendors require the posting of letters of credit to guarantee subsidiary performance under the Company's contracts and to ensure payment to the Company's subsidiary subcontractors and vendors under those contracts. Certain of the Company's vendors also require letters of credit to ensure reimbursement for amounts they are disbursing on behalf of the Company's subsidiaries, such as to beneficiaries under the Company's self-funded insurance programs. Such letters of credit are generally issued by a bank or similar financial institution. The letters of credit commit the issuer to pay specified amounts to the holder of the letter of credit if the holder demonstrates that the Company has failed to perform specified actions. If this were to occur, the Company would be required to reimburse the issuer of the letter of credit.

(vi) The Company has entered into a Parent Guaranty (the "Guaranty") dated November 14, 2014 for the benefit of NY Transco LLC, which Guaranty irrevocably and unconditionally guarantees all of Grid NY LLC's payment obligations under the New York Transco Limited Liability Company Agreement ("NY Transco LLC Agreement") dated November 14, 2014 entered into by and among Consolidated Edison Transmission, LLC, Grid NY LLC, Iberdrola USA Networks, NY Transco, LLC and Central Hudson Electric Transmission LLC. Grid NY LLC's payment obligations relate to, but are not limited to, funding project development of the initial projects, obtaining initial regulatory approvals and making capital contributions as set forth in the NY Transco LLC Agreement.

(vii) In connection with NGUSA's investment in the Access Northeast natural gas pipeline project, the Company has entered into a guarantee of the required capital contributions of NGA, an indirect wholly-owned subsidiary of the Company. The guarantee agreement, which is dated September 14, 2015, commits the Company to serve as a guarantor for up to $103 million of the capital contributions of NGA from the time of the effective date of the guarantee agreement through the earlier of (i) December 31, 2021, or (ii) the time at which NGA's capital commitments have been fully discharged.

(viii) The Company has entered into a Parent Guaranty dated February 23, 2017 under which the Company unconditionally and irrevocably guarantees to EDF Renewable Development, Inc., the timely payment of the purchase price of a 400 MW hydropower storage plant in accordance with and subject to the conditions and limitations set forth in the Purchase and Sale Agreement. The Company's aggregate liability with respect to such guaranteed obligations shall not exceed the purchase price which totals $13 million and is payable on certain milestones being achieved.

The Company entered into a Guaranty as of December 22, 2016 in favor of Sunrun Neptune Investor 2016, LLC, unconditionally and irrevocably guaranteeing the timely payment when due of all of National Grid's payment obligations to make "Capital Contributions" (as such term is defined in the LLC Agreement). The Company's aggregate liability with respect to such Guaranteed Obligations shall not exceed the Class A Capital Contribution Commitment (remaining commitment as of March 31, 2017 is $48 million).

As of the date of this report, the Company has not had a claim made against it for any of the above guarantees and has no reason to believe that the Company's subsidiaries or former subsidiaries will default on their current obligations. However, the Company cannot predict when, or if, any defaults may take place or the impact any such defaults may have on its consolidated results of operations, financial position, or cash flows.

Long-term Contracts for Renewable Energy

Deepwater Agreement

The 2009 Rhode Island law required Narragansett 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, Narragansett 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. Narragansett 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, RIPUC issued its Consent Decision for Narragansett 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 Narragansett's costs as well as those of NEP. The agreements went into effect on September 30, 2014. On January 30, 2015, Narragansett closed on its purchase of the Transmission Facilities from Deepwater. Narragansett 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, Narragansett 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. Narragansett'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.

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.

In fiscal year 2017, the Massachusetts Gas Companies reported to the DPU and the Massachusetts attorney general's office that they erroneously charged reconnection fees to certain customers. These amounts have been refunded or are in the process of being refunded to customers. Additionally, the Massachusetts attorney general's office indicated a potential penalty related to this matter, which is expected to be resolved in fiscal year 2018. As of March 31, 2017, the Massachusetts Gas Companies have recorded a liability for the balance of fees to be refunded to customers as well as a reserve for the penalty based on the best estimate of the settlement amount.

On September 29, 2014, a jury rendered a verdict in favor of a worker for asbestos-related injuries involving his limited work as a subcontractor at one of Genco's Long Island power plants during its construction in the 1960's and early 1970's. Judgment was entered against National Grid on January 28, 2015 and a motion to appeal was filed by Genco. On February 14, 2017, Genco received a decision denying its motion for leave to appeal on the case. The judgment amount of approximately $7.9 million, inclusive of NYS judgment rate interest, was remitted to the plaintiff on February 17, 2017. Genco's cost and expenses related to asbestos litigation are subject to reimbursement pursuant to the PSA.

FERC ROE Complaints

On October 16, 2014, in response to a complaint initially filed on September 30, 2011 by several state and municipal parties in New England ("Complainants") against the base ROE earned by certain NETOs, including NEP, the FERC issued a final order in Opinion No. 531-A lowering the base ROE from 11.14% to 10.57% for the NETOs effective as of October 16, 2014, and capped the ROE, including incentives, at 11.74%. The FERC also directed that refunds be issued to transmission customers taking service during the 15-month refund period from October 1, 2011 through December 31, 2012 to reflect these reductions. 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 July 18, 2015, the FERC approved an amended tariff compliance filing submitted by the NETOs in response to Opinion No. 531-B. This order constitutes final FERC action on the first ROE complaint. By December 31, 2015, NEP's total refund obligation of approximately $9.2 million for the periods October 1, 2011 through December 31, 2012, and October 16, 2014 through December 31, 2014, was returned to customers, followed by refund compliance reports being submitted to the FERC. The NETOs, including NEP, have appealed certain aspects of the FERC's orders in the first ROE complaint to the Court of Appeals. On April 14, 2017, the Court of Appeals vacated the FERC's orders which had reduced NEP's base ROE to 10.57% and maximum ROE to 11.74% and remanded the issue back to the FERC. On June 5, 2017, the NETOS, including NEP, submitted a filing to the FERC to document the reinstatement of their transmission rates that had been in effect through October 15, 2014. The NETOs do not intend to commence billing under the reinstated rates until 60 days after the FERC has a quorum, which was re-established on August 10, 2017. If the FERC takes no action within this 60-day period, then the NETOs will commence billing under their reinstated rates retroactive to June 6, 2017.

On December 27, 2012, a second ROE complaint was filed against the NETOs by a coalition of consumers seeking to lower the base ROE for New England transmission rates to 8.7% effective as of December 27, 2012. On June 19, 2014, the FERC issued an order setting the complaint for investigation and establishing a 15-month refund period for the second complaint beginning on December 27, 2012.

On July 31, 2014, a third ROE complaint was filed against the NETOs by complainants seeking to lower the base ROE for New England transmission rates to 8.84% effective as of July 31, 2014. On November 24, 2014, the FERC issued an order consolidating this complaint with the second ROE complaint discussed above, setting both matters for investigation and a trial-type, evidentiary hearing on a consolidated basis. The FERC's order established a 15-month refund period for the third ROE complaint beginning on July 31, 2014 and determined that it would be appropriate for the parties to litigate a separate ROE for the two separate refund periods established by each of the complaints.

On March 25, 2016, a FERC Administrative Law Judge ("ALJ") released his decision on the second and third ROE complaints. The ALJ found that the NETOs' base ROE should be reduced to 9.59% for the first period at issue (December 27, 2012 through March 26, 2014); accordingly, NEP recorded a liability of $27.3 million for this refund in other current liabilities. The ALJ also noted that the ROE should be increased to 10.90% for the second period (July 31, 2014 through October 30, 2015, and prospectively after the FERC issues an order on this decision). The new ROEs resulting from the second and third ROE complaints will not go into effect until the FERC issues an order addressing the ALJ's decision. The ALJ's initial decision relied upon the FERC's Opinion Nos. 531, 531-A, and 531-B, though, which have now been vacated. As mentioned previously, the Court of Appeals has remanded the issue back to the FERC.

On April 29, 2016, a group of Massachusetts municipal customers filed a fourth ROE complaint at the FERC arguing that the FERC should reduce the NETOs' base ROE to 8.61% and should cap the NETOs' total ROE, including any ROE incentives, at 11.24%. On June 3, 2016, the NETOs filed an answer to this complaint. The FERC has set the fourth complaint for a trial-type hearing and the first settlement conference was scheduled for November 8, 2016. The judge has also set the fourth ROE complaint on a hearing track, in parallel with the settlement proceedings. Following the decision from the Court of Appeals to remand the ROE issue back to the FERC, NEP has requested that both the settlement proceedings and hearing schedule be pushed back in order for NEP to reevaluate its options. The next hearing is scheduled for December 11, 2017.

FERC 206 Proceeding on Rate Transparency

On December 28, 2015, the FERC initiated a proceeding under Section 206 of the FPA. The FERC found that the ISO-NE Transmission, Markets, and Services Tariff is unjust, unreasonable, and unduly discriminatory or preferential. The FERC found that ISO-NE's Tariff lacks adequate transparency and challenge procedures with regard to the formula rates for ISO-NE Participating Transmission Owners ("PTOs"). In addition, the FERC found that the ISO-NE PTOs', including NEP's, current RNS and Local Network Service ("LNS") formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. The FERC explained that the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates. Accordingly, the FERC established hearing and settlement judge procedures to develop just and reasonable formula rate protocols to be included in the ISO-NE Tariff and to examine the justness and reasonableness of the RNS and LNS rates. The matter is currently in settlement procedures. At this time, NEP is unable to predict and estimate any impact to earnings.

Electric Services and LIPA Agreements

On December 15, 2011, LIPA announced that it was not renewing the Management Service Agreement beyond its expiration on December 31, 2013. Activity in fiscal year 2016 and 2017 primarily relates to charges of certain contingencies, net of income taxes.

Effective May 28, 2013, Genco provides services to LIPA under an amended and restated ("A&R") PSA. Under the A&R PSA, Genco has a return on equity of 9.75% and a capital structure of 50% debt and 50% equity. Genco's annual revenue requirement for the year ended December 31, 2016 was $463.9 million. The A&R PSA has a term of fifteen years, provided LIPA has the option to terminate the agreement as early as April 2025 on two years advance notice. Genco accounts for the A&R PSA as an operating lease.

The A&R PSA provides potential penalties to Genco if it does not maintain the output capability of the generating facilities, as measured by annual industry-standard tests of operating capability, plant availability, and efficiency. These penalties may total $4 million annually. Although the A&R PSA provides LIPA with all of the capacity from the generating facilities, LIPA has no obligation to purchase energy from the generating facilities and can purchase energy on a least-cost basis from all available sources consistent with existing transmission interconnection limitations of the transmission and distribution system. Genco must, therefore, operate its generating facilities in a manner such that Genco can remain competitive with other producers of energy. To date, Genco has dispatched to LIPA and LIPA has accepted the level of energy generated at the agreed to price per megawatt hour. Under the terms of the A&R PSA, LIPA is obligated to pay for capacity at rates that reflect recovery of an agreed level of the overall cost of maintaining and operating the generating facilities, including recovery of depreciation and return on its investment in plant. The capacity charge is approximately 94% of the annual revenue requirement and is adjusted each year using cost escalation and inflation factors applied to the prior year's capacity charge. A monthly variable maintenance charge is billed for each unit of energy actually acquired from the generating facilities. The billings to LIPA under the A&R PSA do not include a provision for fuel costs, as such fuel is procured by LIPA.

Decommissioning Nuclear Units

NEP is a minority equity owner of, and former purchaser of electricity from, the Yankees. The Yankees have been permanently shut down and physically decommissioned. Spent nuclear fuel remains on each site awaiting fulfillment by the U.S. Department of Energy ("DOE") of its statutory and contractual obligation to remove it. Future estimated billings, which are included in accrued Yankee nuclear plant costs and other current liabilities and exactly offset by a component of regulatory assets - deferred on the balance sheet, are as follows:

(in thousands of dollars)	The Company's Investment as of March 31, 2017			Future Estimated Billings to the Company
Unit	%	Amount	Date Retired	Amount
Yankee Atomic	34.5	$ 520	Feb 1992	$ -
Connecticut Yankee	19.5	353	Dec 1996	10,621
Maine Yankee	24.0	658	Aug 1997	-

The Yankees are periodically required to file rate cases for FERC review, which present the Yankees' estimated future decommissioning costs. The Yankees collect the approved costs from their purchasers, including NEP. Future estimated billings from the Yankees are based on cost estimates. These estimates include the projections of groundwater monitoring, security, liability and property insurance, and other costs. They also include costs for interim spent fuel storage facilities which the Yankees have constructed while they await removal of the fuel by the DOE as required by the Nuclear Waste Policy Act of 1982 and contracts between the DOE and each of the Yankees. NEP has recorded a current liability of $0.04 million and $0.1 million (included within other current liabilities) as of March 31, 2017 and 2016, respectively, which represents the current portion of accrued Yankee nuclear plant costs. As of March 31, 2017 and 2016, NEP has recorded a deferred liability of $10.6 million and $29.4 million (included within Other in non-current liabilities), respectively. The sum of the current and deferred liabilities is offset by a regulatory asset of $10.6 million and $29.5 million (included within regulatory assets - deferred) as of March 31, 2017 and 2016, respectively, reflecting the estimated future decommissioning billings from the Yankees.

In 2013, the FERC accepted settlements establishing rate mechanisms by which each of the Yankees maintains funding for operations and decommissioning, and credits to its purchasers, including NEP, any net proceeds in excess of funding costs received as part of the DOE litigation proceedings discussed below.

Each of the Yankees brought litigation against the DOE for failure to remove their respective nuclear fuel stores as required by the Nuclear Waste Policy Act and contracts. Following a trial at the U.S. Court of Claims ("Claims Court") to determine the level of damages, on October 4, 2006, the Claims Court awarded the three companies an aggregate of $143 million for spent fuel storage costs that had been incurred through 2001 and 2002 (the "Phase I Litigation"). The Yankees had requested $176.3 million. The DOE appealed to the U.S. Court of Appeals for the Federal Circuit, which rendered an opinion generally supporting the Claims Court's decision and remanded the matter to it for further proceedings. In September 2010, the Claims Court again awarded the companies an aggregate of approximately $143 million. The DOE again appealed and the Yankees cross-appealed. On May 18, 2012, the U.S. Court of Appeals for the Federal Circuit again ruled in favor of the Yankees, awarding them an aggregate of approximately $160 million. The DOE sought reconsideration, but, on September 5, 2012, the U.S. Court of Appeals for the Federal Circuit denied the petition for rehearing. The DOE elected not to file a petition for writ of certiorari seeking review by the U.S. Supreme Court, and, in January 2013, the awards were paid to the Yankees.

As of March 31, 2017, total net proceeds of $25.6 million have been refunded to NEP by Connecticut Yankee and Maine Yankee. Yankee Atomic did not provide a refund, but reduced monthly billing effective June 1, 2013. NEP refunds its share to its customers through the CTCs.

On December 14, 2007, the Yankees brought further litigation in the Claims Court to recover subsequent damages incurred through 2008 (the "Phase II Litigation"). A Claims Court trial took place in October 2011. On November 1, 2013, the judge awarded the Yankees an aggregate of $235.4 million in damages for the Phase II Litigation. The DOE elected not to seek appellate review, and the awards were paid to the Yankees. In March 2014, Maine Yankee and Yankee Atomic received 100% of the DOE Phase II proceeds expected ($35.8 million and $73.3 million, respectively). Connecticut Yankee received a partial payment of $90 million of the expected $126.3 million. The balance was received in April 2014.

On April 29, 2014, the Yankees submitted informational filings to the FERC in order to flow through the DOE Phase II Litigation proceeds to their Sponsor companies, including NEP, in accordance with financial analyses that were performed earlier that year and supported by stakeholders from Connecticut, Massachusetts, and Maine. The filings allowed for the flow-through of the proceeds to the Sponsors, including NEP, with a rate effective date of June 1, 2014. As of March 31, 2017, total net proceeds of $57.8 million have been refunded to NEP by the Yankees. NEP refunds its share of the net proceeds to its customers through the CTCs.

On August 15, 2013, the Yankees brought further litigation (the "Phase III Litigation") in the Claims Court to recover damages incurred from 2009 through 2012. On March 25, 2016, the judge awarded the Yankees an aggregate of $76.8 million in damages for the Phase III Litigation, which is about 98.6% of the damages sought. The judgment is final and payment to the Yankees has been completed. As of March 31, 2017, total net proceeds of $4.5 million have been refunded to NEP by Connecticut Yankee and Maine Yankee. NEP refunds its share to its customers through the CTCs.

The U.S. Congress and the DOE have effectively terminated budgetary support for the proposed long-term spent fuel storage facility at Yucca Mountain in Nevada, and the DOE took actions designed to prevent its construction. However, on August 12, 2013, the Court of Appeals directed the Nuclear Regulatory Commission ("NRC") to resume the Yucca Mountain licensing process despite insufficient funding to complete it. On October 28, 2013, the Court of Appeals denied the NRC's petition for rehearing. On November 18, 2013, the NRC ordered its staff to resume work on its Yucca Mountain safety report. A Blue Ribbon Commission ("BRC") charged with advising the DOE regarding alternatives to disposal at Yucca Mountain issued its final report on January 26, 2012. In the report, the BRC recommended that priority be given to removal of spent fuel from shutdown reactor sites. A proposal to provide funding for the pursuit of licensing of the Yucca Mountain facility is pending in Congress. Also, private entities are pursuing proposals to site interim storage facilities at two locations in the southwestern United States. It is impossible to predict when the DOE will fulfill its obligation to take possession of the Yankees' spent fuel. The decommissioning costs that are actually incurred by the Yankees may substantially exceed the estimated amounts.

Nuclear Contingencies

As of March 31, 2017 and 2016, Niagara Mohawk had a liability of approximately $168 million, recorded in other non-current liabilities on the balance sheet, for the disposal of nuclear fuel irradiated prior to 1983. The Nuclear Waste Policy Act of 1982 provides three payment options for liquidating such liability and Niagara Mohawk has elected to delay payment, with interest, until the year in which Constellation Energy Group Inc., which purchased Niagara Mohawk's nuclear assets, initially plans to ship irradiated fuel to an approved DOE disposal facility.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository while the Obama Administration devised a new strategy for long-term spent nuclear fuel management. A BRC on America's Nuclear Future, appointed by the U.S. Energy Secretary, released a report on January 26, 2012, detailing comprehensive recommendations for creating a safe, long-term solution for managing and disposing of the nation's spent nuclear fuel and high-level radioactive waste.

In early 2013, the DOE issued an updated "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste" in response to the BRC recommendations. This strategy included a consolidated interim storage facility that was planned to be operational in 2025. However, due to continued delays on the part of the DOE, and the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term spent nuclear fuel storage, Niagara Mohawk cannot predict the date at which the DOE will begin accepting spent nuclear fuel.

14. RELATED PARTY TRANSACTIONS

Accounts Receivable from and Accounts Payable to Affiliates

The Company engages in various transactions with the Parent and its subsidiaries. Certain activities and costs, primarily executive and administrative and some human resources, legal, and strategic planning, are shared between the Company and its affiliates.

The Company records short-term receivables from, and payables to, certain of its affiliates in the ordinary course of business. 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,	
	2017	2016	**2017**	2016
	(in millions of dollars)		*(in millions of dollars)*	
National Grid plc	**$ -**	$ -	**$ 31**	$ 44
NGNA	**1**	28	**-**	-
Other	**1**	-	**1**	-
Total	**$ 2**	$ 28	**$ 32**	$ 44

Advances from Affiliates

In August 2009, the Company and KeySpan entered into an agreement with the Parent, whereby either party can collectively borrow up to $3 billion from time to time for working capital needs. These advances bear interest rates of London Interbank Offered Rate plus 0.6%. At March 31, 2017 and 2016, the Company had $650 million and zero outstanding advances under this agreement.

In August 2008, the Company entered into an agreement with NGNA, whereby the Company can borrow up to $1.5 billion from time to time for working capital needs. The agreement can be amended and restated from time to time with the latest amendment made in February 2016 to increase the borrowing capacity to $8 billion. These advances do not bear interest. At March 31, 2017 and 2016, the Company had $2.4 billion and $3.1 billion outstanding advances from NGNA under this agreement.

Amounts advanced under each of these agreements are repayable on demand and can be structured as interest or non-interest bearing subject to the demands of the lender. The advances support general working capital needs with advances and repayments executed on a daily basis.

Holding Company Charges

The Company received charges from National Grid Commercial Holdings Limited (an affiliated company in the United Kingdom) for certain corporate and administrative services provided by the corporate functions of the Parent to its U.S. subsidiaries. For the years ended March 31, 2017 and 2016, the effect on income before income taxes was $43 million and $32 million.

15. PREFERRED STOCK

Preferred stock of NGUSA subsidiaries

The Company's subsidiaries have certain issues of non-participating preferred stock, some of which provide for redemption at the option of the Company. A summary of the preferred stock of NGUSA subsidiaries at March 31, 2017 and 2016 is as follows:

		Shares Outstanding		Amount		
		March 31,		March 31,		Call
Series	Company	**2017**	2016	**2017**	2016	**Price**
		(in millions of dollars, except per share and number of shares data)				
$100 par value -						
3.40% Series	Niagara Mohawk	**57,524**	57,524	**$ 6**	$ 6	$ 103.500
3.60% Series	Niagara Mohawk	**137,152**	137,152	**14**	14	104.850
3.90% Series	Niagara Mohawk	**95,171**	95,171	**9**	9	106.000
4.44% Series	Massachusetts Electric	**22,585**	22,585	**2**	2	104.068
6.00% Series	NEP	**11,117**	11,117	**1**	1	Non-callable
$50 par value -						
4.50% Series	Narragansett	**49,089**	49,089	**3**	3	55.000
Golden Shares -						
	Niagara Mohawk and KeySpan subsidiaries	**3**	3	**-**	-	Non-callable
Total		**372,641**	372,641	**$ 35**	$ 35	

In connection with the acquisition of KeySpan by NGUSA, each of the Company's New York subsidiaries became subject to a requirement to issue a class of preferred stock, having one share (the "Golden Share") subordinate to any existing preferred stock. The holder of the Golden Share would have voting rights that limit the Company's right to commence any voluntary bankruptcy, liquidation, receivership, or similar proceeding without the consent of the holder of the Golden Share. The NYPSC subsequently authorized the issuance of the Golden Share to a trustee, GSS Holdings, Inc. ("GSS"), who will hold the Golden Share subject to a Services and Indemnity Agreement requiring GSS to vote the Golden Share in the best interests of NYS. On July 8, 2011, the Company issued a total of 3 Golden Shares pertaining to Niagara Mohawk, Brooklyn Union, and KeySpan Gas East each with a par value of $1.

Preferred stock of NGUSA

The Company has cumulative series A through F non-participating non-callable preferred stock (5,000 total shares authorized, 915 outstanding) which have no fixed redemption date. The series A through F shares rank above all common shares, but below the Company's debt holders in an event of liquidation. If the Company does not pay its annual dividend on the A through F series preferred stock, it is subject to limitations on the payment of any dividends to its common shareholder. The par value of the series A through F preferred stock is $0.10. The fixed rate on the series A through E preferred stock is 6.5%. The fixed rate on the series F preferred stock is 8.5%. The Company has zero dividends arrears at March 31, 2017 and 2016.

During the years ended March 31, 2017 and 2016, the Company declared and made dividend payments to NGNA in relation to the series A through E preferred stock of $0.6 billion and $1.2 billion, respectively.

A summary of preferred stock is as follows:

Series	Shares Outstanding March 31, 2017	2016	Amount (par) March 31, 2017	2016	Amount (additional paid-in capital) March 31, 2017	2016	Dividends Paid March 31, 2017	2016
	(in millions of dollars, except per share and number of shares data)							
$0.10 par value -								
Series A	**51**	51	**$ -**	$ -	**$ 400**	$ 400	**$ 26**	$ 52
Series B	**40**	40	**-**	-	**315**	315	**20**	40
Series C	**96**	96	**-**	-	**750**	750	**49**	97
Series D	**79**	79	**-**	-	**616**	616	**40**	79
Series E	**1**	1	**-**	-	**10**	10	**1**	2
Series F	**648**	648	**-**	-	**5,368**	5,368	**456**	909
Total	**915**	915	**$ -**	$ -	**$ 7,459**	$ 7,459	**$ 592**	$ 1,179

16. STOCK-BASED COMPENSATION

The Parent's Remuneration Committee determines remuneration policy and practices with the aim of attracting, motivating and retaining high caliber Executive Directors and other senior employees to deliver value for shareholders, high levels of customer service, and safety and reliability in an efficient and responsible manner. As such, the Remuneration Committee has established a Long-Term Performance Plan ("LTPP") which aims to drive long-term performance, aligning Executive Director incentives to shareholder interests. The LTPP replaces the previous Performance Share Plan ("PSP") which operated for awards between 2003 and 2010 inclusive. Both plans issue performance based restricted stock units ("RSU"s) which are granted in the Parent's common stock traded on the London Stock Exchange for U.K.-based directors and employees or the Parent's American Depository Receipts traded on the New York Stock Exchange for U.S.-based directors and employees. Both plans have a performance period of three years and have been approved by the Parent's Remuneration Committee.

As of March 31, 2017, the Parent had 3.9 billion of ordinary shares issued with 193,515,250 held as treasury shares. The aggregate dilution resulting from executive share-based incentives will not exceed 5% in any ten year period for executive share-based incentives and will not exceed 10% in any ten year period for all employee incentives. This is reviewed by the Remuneration Committee and, currently, the Parent has excess headroom of 4.08% and 7.98%, respectively.

The number of units within each award is subject to change depending upon the Parent's ability to meet the stated performance targets. Under the LTPP, performance conditions are split into two parts as follows: (1) 50% of the award is subject to average annual Value Growth over a period of three years and (2) 50% of the award is subject to average annual Group Return on Equity over a period of three years. Units under the plan generally vest at the end of the performance period.

The following table summarizes the stock based compensation expense recognized by the Company for the years ended March 31, 2017 and 2016:

	Units	Weighted Average Grant Date Fair Value
Non-vested as of March 31, 2015	855,624	$ 49.92
Vested	192,265	58.41
Granted	471,613	66.05
Forfeited/Cancelled	121,787	53.41
Non-vested as of March 31, 2016	1,013,185	66.48
Vested	176,687	56.33
Granted	379,144	69.43
Forfeited/Cancelled	145,201	57.18
Non-vested as of March 31, 2017	1,070,441	$ 65.22

The total expense recognized for non-vested awards was $15.4 million and $15.7 million for the years ended March 31, 2017 and 2016, respectively, and non-vested awards vest over three years. The total tax benefit recorded was approximately $6.2 million and $6.3 million as of March 31, 2017 and 2016, respectively. Total expense expected to be recognized by the Parent in future periods for non-vested awards outstanding as of March 31, 2017 is $19.3 million, $9.7 million, and $1.9 million for the years ended March 31, 2018, 2019, and 2020, respectively.