nationalgrid

National Grid USA and Subsidiaries

Consolidated Financial Statements

For the years ended March 31, 2018 and 2017

NATIONAL GRID USA AND SUBSIDIARIES

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
National Grid USA

We have audited the accompanying consolidated financial statements of National Grid USA and Subsidiaries (the "Company"), which comprise the consolidated balance sheet and statement of capitalization as of March 31, 2018, and the related consolidated statements of income, comprehensive income, changes in shareholders' equity and cash flows for the year then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these 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 these consolidated financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the 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 Subsidiaries as of March 31, 2018, and the results of its operations and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Predecessor Auditors' Opinion on 2017 Consolidated Financial Statements

The consolidated financial statements of the Company as of and for the year ended March 31, 2017 were audited by other auditors whose report, dated September 27, 2017, expressed an unmodified opinion on those statements.

Deloitte + Touche LLP

September 27, 2018

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

	Years Ended March 31, 2018	Years Ended March 31, 2017
Operating revenues:		
Electric services	**$ 6,745**	$ 6,355
Gas distribution	**5,405**	4,645
Other	**23**	21
Total operating revenues	**12,173**	11,021
Operating expenses:		
Purchased electricity	**1,737**	1,556
Purchased gas	**2,035**	1,531
Operations and maintenance	**4,533**	4,340
Depreciation	**1,082**	1,064
Other taxes	**1,203**	1,118
Total operating expenses	**10,590**	9,609
Operating income	**1,583**	1,412
Other income and (deductions):		
Interest on long-term debt	**(434)**	(413)
Other interest, including affiliate interest	**(89)**	(92)
Income from equity investments	**39**	30
Loss on sale of assets	**(45)**	(4)
Unrealized gains on investment in Dominion Midstream Partners, LP	**-**	15
Impairment charge	**-**	(39)
Other income, net	**63**	71
Total other deductions, net	**(466)**	(432)
Income before income taxes	**1,117**	980
Income tax expense	**465**	355
Income from continuing operations	**652**	625
Income (loss) from discontinued operations, net of taxes	**27**	(11)
Net income	**679**	614
Net income attributable to non-controlling interest	**(2)**	(1)
Dividends paid on preferred stock	**(549)**	(592)
Net income attributable to common shares	**$ 128**	$ 21

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,	
	2018	2017
Net income	**$ 679**	$ 614
Other comprehensive income, net of taxes:		
Unrealized gains on securities	**2**	8
Change in pension and other postretirement obligations	**111**	286
Reclassification to regulatory asset	**429**	-
Total other comprehensive income	**542**	294
Comprehensive income	**$ 1,221**	$ 908
Less: comprehensive income attributable to non-controlling interest	**(2)**	(1)
Comprehensive income attributable to common and preferred stock	**$ 1,219**	$ 907
Related tax (expense) benefit:		
Unrealized gains on securities	**$ (2)**	$ (4)
Change in pension and other postretirement obligations	**(58)**	(197)
Reclassification to regulatory asset	**(168)**	-
Total tax expense	**$ (228)**	$ (201)

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,	
	2018	2017
Operating activities:		
Net income	**$ 679**	$ 614
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation	**1,082**	1,064
Regulatory amortizations	**80**	98
Provision for deferred income taxes	**360**	212
Bad debt expense	**136**	152
Loss (income) from equity and financial investments, net of dividends received	**(32)**	(23)
Loss on sale of assets	**45**	4
Unrealized gains on investment in Dominion Midstream Partners, LP	**-**	(15)
Impairment charge	**-**	39
Allowance for equity funds used during construction	**(27)**	(29)
Amortization of debt discount and issuance costs	**11**	12
Net postretirement benefits contributions	**(12)**	(188)
Environmental remediation payments	**(80)**	(118)
Share based compensation	**19**	27
Changes in operating assets and liabilities:		
Accounts receivable, net, and unbilled revenues	**(562)**	(428)
Accounts receivable from/payable to affiliates, net	**(4)**	14
Inventory	**13**	67
Regulatory assets and liabilities, net	**254**	459
Derivative instruments	**(1)**	(51)
Prepaid and accrued taxes	**96**	8
Accounts payable and other liabilities	**307**	361
Renewable energy certificate obligations, net	**46**	(24)
Other, net	**(40)**	(28)
Net cash provided by operating activities	**2,370**	2,227
Investing activities:		
Capital expenditures	**(3,285)**	(2,808)
Proceeds from sale of assets	**172**	-
Proceeds from restricted cash and special deposits	**105**	189
Payments on restricted cash and special deposits	**(92)**	(170)
Cost of removal	**(238)**	(222)
Contributions in equity and financial investments	**(88)**	(102)
Other	**(13)**	(16)
Net cash used in investing activities	**(3,439)**	(3,129)
Financing activities:		
Preferred stock dividends	**(549)**	(592)
Payments on long-term debt	**(336)**	(939)
Proceeds from long-term debt	**1,700**	1,200
Payment of debt issuance costs	**(11)**	(7)
Commercial paper (paid) issued	**(692)**	684
Advance from affiliate and moneypool borrowings	**989**	34
Parent loss tax allocation	**-**	22
Payments on sale/leaseback arrangement	**(41)**	(41)
Net cash provided by financing activities	**1,060**	361
Net decrease in cash and cash equivalents	**(9)**	(541)
Net cashflow from discontinued operations - operating	**29**	11
Cash and cash equivalents, beginning of year	**354**	884
Cash and cash equivalents, end of year	**$ 374**	$ 354
Supplemental disclosures:		
Interest paid	**$ (434)**	$ (428)
Income taxes paid	**(7)**	(3)
Significant non-cash items:		
Capital-related accruals	**157**	154
Parent tax loss allocation - previously reported in financing activities	**39**	-
Reclassification to regulatory asset	**597**	-

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,	
	2018	2017
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 374**	$ 354
Restricted cash and special deposits	**61**	74
Accounts receivable	**2,601**	2,250
Allowance for doubtful accounts	**(411)**	(416)
Unbilled revenues	**578**	508
Inventory	**356**	399
Regulatory assets	**535**	530
Derivative instruments	**20**	32
Prepaid taxes	**242**	159
Other	**141**	85
Total current assets	**4,497**	3,975
Equity investments	**302**	210
Property, plant and equipment, net	**31,874**	29,418
Other non-current assets:		
Regulatory assets	**5,192**	4,935
Goodwill	**7,129**	7,129
Derivative instruments	**2**	2
Postretirement benefits asset	**359**	293
Financial investments	**584**	757
Other	**165**	157
Total other non-current assets	**13,431**	13,273
Total assets	**$ 50,104**	$ 46,876

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,	
	2018	2017
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 1,573**	$ 1,391
Accounts payable to affiliates	**27**	32
Advance from affiliate	**4,082**	3,091
Commercial paper	**290**	982
Current portion of long-term debt	**54**	106
Taxes accrued	**213**	74
Customer deposits	**111**	115
Interest accrued	**122**	145
Regulatory liabilities	**1,039**	833
Derivative instruments	**53**	54
Renewable energy certificate obligations	**189**	140
Payroll and benefits accruals	**334**	296
Other	**317**	242
Total current liabilities	**8,404**	7,501
Other non-current liabilities:		
Regulatory liabilities	**6,189**	3,151
Asset retirement obligations	**95**	96
Deferred income tax liabilities, net	**3,200**	5,548
Postretirement benefits	**1,932**	2,358
Environmental remediation costs	**1,874**	1,922
Derivative instruments	**32**	44
Other	**817**	833
Total other non-current liabilities	**14,139**	13,952
Commitments and contingencies (Note 13)		
Capitalization:		
Common and preferred stock	**14,322**	14,264
Retained earnings	**2,471**	2,343
Accumulated other comprehensive loss	**(10)**	(552)
Common and preferred equity	**16,783**	16,055
Non-controlling interest	**23**	21
Total shareholders' equity	**16,806**	16,076
Long-term debt	**10,755**	9,347
Total capitalization	**27,561**	25,423
Total liabilities and capitalization	**$ 50,104**	$ 46,876

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,	
			2018	2017
Common and preferred equity			**$ 16,783**	$ 16,055
Non-controlling interest			**23**	21
Long-term debt:	Interest Rate	Maturity Date		
Notes Payable[1]	2.72% - 9.75%	July 2017 - March 2048	**9,710**	8,018
Promissory Notes to National Grid North America Inc.	3.13% - 3.25%	June 2027 - April 2028	**192**	209
Gas Facilities Revenue Bonds	Variable	December 2020 - July 2026	**-**	230
First Mortgage Bonds	6.82% - 9.63%	April 2018 - April 2028	**121**	122
State Authority Financing Bonds	Variable	March 2018 - December 2040	**839**	919
Total debt			**10,862**	9,498
Unamortized debt premium			**1**	4
Unamortized debt issuance costs			**(54)**	(49)
Current portion of long-term debt			**(54)**	(106)
Long-term debt			**10,755**	9,347
Total capitalization			**$ 27,561**	$ 25,423

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

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, 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
Net income	-	-	-	-			-	677	2	679
Other comprehensive income:										
Unrealized gains on securities, net of $2 tax expense	-	-	-	2	-	-	2	-	-	2
Change in pension and other postretirement obligations, net of $58 tax expense	-	-	-	-	111	-	111	-	-	111
Reclassification to regulatory asset, net of $168 tax expense	-	-	-	-	429	-	429	-	-	429
Total comprehensive income										1,221
Parent loss tax allocation	-	-	39	-	-	-	-	-	-	39
Share based compensation	-	-	19	-	-	-	-	-	-	19
Preferred stock dividends	-	-	-	-	-	-	-	(549)	-	(549)
Balance as of March 31, 2018	$ -	$ 35	$ 14,287	$ 14	$ (22)	$ (2)	$ (10)	$ 2,471	$ 23	$ 16,806

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, 2018 and 2017.

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").

Effective April 30, 2018 KeySpan Corporation ("KeySpan") merged into NGUSA. Since the merger occurred post fiscal year-end, the intercompany relationships between the Company and KeySpan were still in effect at March 31, 2018. As such, the disclosures in these financial statements and footnotes reflect those relationships that existed at March 31, 2018. NGUSA management is currently reviewing the relationships between KeySpan and all NGUSA subsidiaries and will make the appropriate adjustments to these relationships during the next fiscal year.

Genco provides energy services and supply capacity to and produces 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 also 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, 2018 and 2017.

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 March 31, 2017, the Company owned approximately 6.8 million common units (representing approximately a 9% interest) of Dominion Midstream Partners, LP ("DM"). DM was formed to grow a portfolio of natural gas terminaling, processing, storage, and transportation assets. The Company 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 were recorded as unrealized gains or losses on investment in Dominion Midstream Partners, LP in the accompanying consolidated statements of income.

On February 13, 2018, the Company obtained board approval to sell its investment in DM. The Company completed the sale of its investment in DM to Deutsche Bank for proceeds of $172 million, which settled February 21, 2018. The transaction resulted in a loss on sale of assets of $45 million in the year ended March 31, 2018. The Company's investment in DM was 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. See Note 13, "Commitments and Contingencies" under "Financial Guarantees" for additional information on NGA.

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 Independent System Operator New England ("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 million) were written down at December 31, 2016 to $3 million. In connection with the January 1, 2017 loan conversion, the remaining $3 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, 2018, 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, 2018, except as described in Note 17, "Subsequent Events."

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.

Revenue Recognition

Electric Services Revenue

Electric services revenue consists of the following:

- *Electric 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.

- *Transmission Revenue*

  Transmission revenues 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 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.”

Gas Distribution Revenue

Revenues are recognized for gas 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 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 and KeySpan Gas East (the “New York Gas Companies”), 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.

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, 2018 and 2017 were $112 million and $86 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.

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 Company assesses the available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that the Company will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount.

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

Cash and Cash Equivalents

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

Restricted Cash 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-NE. The Company had restricted cash of $10 million and $25 million and special deposits of $51 million and $49 million at March 31, 2018 and 2017, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

The Company recognizes an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is determined based on a variety of factors including, for each type of receivable, applying an estimated reserve percentage to each aging category, taking into account historical collection and write-off experience, and management's assessment of collectability from individual customers, as appropriate. The collectability of receivables is continuously assessed and, if circumstances change, the allowance is adjusted accordingly. Receivable balances are written off against the allowance for doubtful accounts when the accounts are disconnected and/or terminated and the balances are deemed to be uncollectible. The Company recorded bad debt expense of $136 million and $152 million for the years ended March 31, 2018 and 2017, respectively, within operations and maintenance in the accompanying consolidated statements of income.

Inventory

Inventory is composed of materials and supplies, emission credits, renewable energy certificates ("RECs"), and gas in storage.

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

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 net realizable value 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 $162 million and $161 million, emission credits of $4 million and $37 million, purchased RECs of $90 million and $87 million, and gas in storage of $100 million and $114 million at March 31, 2018 and 2017, respectively.

Derivative Instruments

The Company uses various derivative instruments 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. 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 accompanying 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 accompanying 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. For the years ended March 31, 2018 and 2017, the Company recorded ineffectiveness related to cash flow hedges of zero within other income in the accompanying consolidated statements of income.

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

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

Power Purchase Agreements

Certain of the Company's subsidiaries enter into power purchase agreements ("PPAs") to procure commodity to serve their electric service customers. The Company evaluates whether such agreements are leases, derivative instruments, or executory contracts. The PPAs 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 PPAs, 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. Similar to the PPAs noted above, the Company evaluates whether such agreements are derivative instruments or executory contracts and applies the appropriate accounting treatment.

Fair Value Measurements

The Company measures derivative instruments, 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, 2018 and 2017 are as follows:

	Composite Rates	
	Years Ended March 31,	
	2018	2017
Electric	**2.6%**	2.7%
Gas	**2.9%**	2.6%
Common	**8.5%**	4.7%

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, 2018 and 2017.

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 accompanying consolidated statements of income as non-cash income in other income, net, and AFUDC debt is reported as a non-cash offset to other interest, including affiliate interest. After construction is completed, the Company is permitted to recover these costs through their inclusion in rate base and corresponding depreciation expense. The Company recorded AFUDC related to equity of $27 million and $29 million and AFUDC related to debt of $20 million and $16 million for the years ended March 31, 2018 and 2017, respectively. The average AFUDC rates for the years ended March 31, 2018 and 2017 were 4.1% and 3.7%, respectively.

In addition, approximately $10 million and $3 million of interest were capitalized for construction of non-regulated projects during the years ended March 31, 2018 and 2017, 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, 2018 and 2017, 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. The Company has early adopted Accounting Standards Update ("ASU") 2017-04, "Intangibles—Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment," which eliminates step two from the two-step goodwill impairment test. The one-step approach requires a recoverability test performed based on the comparison of the Company's estimated fair value with its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, then goodwill is considered not impaired. If the carrying value exceeds the estimated fair value, the Company is required to recognize an impairment charge for such excess, limited to the allocated amount of goodwill.

Historically, the fair value of each reporting unit was calculated in the annual goodwill impairment test utilizing both income and market approaches. Key assumptions in the income approach include the discount rate of 5.3% (2017: 5.4%) and the terminal growth rate of 2.3% (2017: 2.0%). The key assumption in the market approach is the earnings before interest, tax, depreciation, and amortization ("EBITDA") multiplier of 12 (2017: 12). The Company generally uses a 50% weighting for each valuation methodology, as it believes that each methodology provides equally valuable information. In response to rate orders received in 2016, the fair values of Massachusetts Electric and the New York Gas Companies were calculated utilizing solely the income approach for the year ended March 31, 2017. Similarly, in response to recently received rate orders or rate filings that had been in progress during 2017, the fair values of Niagara Mohawk, Boston Gas, Colonial Gas, and Narragansett were calculated utilizing solely the income approach for the year ended March 31, 2018. The Company believes that due to the recent rate orders received from these companies' respective regulators, the income 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 20% to 55% for 2018 and 13% to 34% for 2017, and as a result the Company determined that no adjustment to the goodwill carrying value was required at March 31, 2018 or 2017.

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,	
	2018	2017
	(in millions of dollars)	
Available-for-sale securities	**$ 299**	$ 279
Dominion Midstream Partners, LP	**-**	217
Supplemental Executive Retirement Plans	**281**	255
Other	**4**	6
Total	**$ 584**	$ 757

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 ratemaking process.

Employee Benefits

The Company has defined benefit pension plans 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. If the cost of providing these plans is recovered in rates through the Company's regulated subsidiaries, the net funded status is offset by a regulatory asset or liability. If the cost of providing these plans is not recovered in rates through the Company's regulated subsidiaries, the net funded status is offset with an adjustment to AOCI in shareholders' equity. 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.

Going Concern

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

New and Recent Accounting Guidance

Accounting Guidance Recently Adopted

Measurement of Inventory

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

Derivatives and Hedging

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

In March 2016, the FASB issued ASU No. 2016-06, "Derivatives and Hedging (Topic 815): Contingent Put and Call Options in Debt Instruments." The new guidance clarifies the requirements for assessing whether contingent call or put options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. Entities performing this assessment is required to assess the embedded call or put options solely in accordance with the four-step decision sequence in accordance with ASC 815-15-25-1(a). The application of this guidance did not have a material impact on the results of operations, cash flows, or financial position of the Company.

Employee Share-Based Payment Accounting

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

Consolidation

In October 2016, the FASB issued ASU No. 2016-17, "Consolidation (Topic 810): Interests Held through Related Parties That are under Common Control." The new guidance requires that the reporting entity, in determining whether it satisfies the second characteristic of a primary beneficiary during the Variable Interest Entity ("VIE") analysis, to include all of its direct variable interests in a VIE and, on a proportionate basis, its indirect variable interests in a VIE held through related parties, including related parties that are under common control with the reporting entity. The application of this guidance did not have a material impact on the results of operations, cash flows, or financial position of the Company.

In February 2015, the FASB issued ASU No. 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 requires either modified retrospective or full retrospective basis application. The application of this guidance did not have a material impact on the results of operations, cash flows, or financial position of the Company.

Goodwill

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

Stock Compensation

In May 2017, the FASB issued ASU No. 2017-09, "Stock Compensation (Topic 718): Scope of Modification Accounting," which provides clarity on the application of modification accounting upon a change to the terms or conditions of a share-based payment award. The Company early adopted the ASU in the year ended March 31, 2018. The application of this guidance did not have a material impact on the results of operations, cash flows, or financial position of the Company.

Accounting Guidance Not Yet Adopted

Comprehensive Income

In February 2018, the FASB issued amendments to the guidance for reporting comprehensive income through ASU 2018-02, "Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income." The amendments allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act ("Tax Act"). For the Company, the amendments are effective for the fiscal year ended March 31, 2019, and interim periods within the reporting period, 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.

Derivatives and Hedging

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

Pension and Postretirement Benefits

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

Business Combinations

In January 2017, the FASB issued ASU No. 2017-01, "Business Combinations (Topic 805): Clarifying the Definition of a Business," which provides a screen to determine when a set of assets or activities is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired or disposed of is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. The guidance also provides a framework to assist in evaluating whether both an input and a substantive process, two of the three must-have elements of a business, are present. The update will be effective for the fiscal year ended March 31, 2019, with early adoption permitted under conditions specified in the amendments. The Company is currently evaluating the impact of the new guidance on the presentation, results of its operations, cash flows, and financial position.

Statement of Cash Flows

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

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

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

Income Taxes

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

Financial Instruments – Credit Losses

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

Revenue Recognition

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

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

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

Leases

In February 2016, the FASB issued a new lease accounting standard, ASU No. 2016-02, “Leases (Topic 842).” The key objective of the new standard is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Lessees will need to recognize a right-of-use asset and a lease liability for virtually all of their leases (other than leases that meet the definition of a short-term lease). For income statement purposes, a dual model has been retained, with leases to be designated as operating leases or finance leases. Expenses will be recognized on a straight-line basis for operating leases, and a front-loaded basis for finance leases. For the Company, the new standard is effective for the fiscal year ended March 31, 2020, and interim periods thereafter, with early adoption permitted. The new standard must be adopted using a modified retrospective transition, and provides for certain practical expedients. The Company is currently evaluating the impact of the new guidance on the results of its operations, cash flows, and financial position. 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 No. 2016-01, “Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities.” The new guidance principally affects the accounting for equity investments and financial liabilities where the fair value option has been elected, as well as the disclosure requirements for financial instruments. For the Company, the new guidance is effective for the fiscal year ended March 31, 2019, and interim periods therein, with early adoption permitted for fiscal years or interim periods that have not yet been issued. The application of this guidance is not expected to have a material impact on the presentation, results of its operations, cash flows, and financial position.

AOCI - Reclassification to Regulatory Asset

In previous years, annual remeasurement of plan assets and benefit obligations at the Company’s non-regulated subsidiaries, including the Company’s service organization, were recognized in AOCI. In the current year, based on a number of the Company’s recent rate case filings (outlined in Note 4, “Rate Matters”), the Company believes that the recovery of these pension and PBOP costs is probable in accordance with ASC 980, "Regulated Operations." These recent rate case filings indicate that sustained recovery of service company costs through pension reconciliation mechanisms in the regulated subsidiaries is both explicitly permitted at all of the regulated subsidiaries and has occurred. As a result, the Company determined that it is appropriate to recognize a regulatory asset for these incurred costs.

Based on this assertion, the Company has reclassified amounts previously recognized in AOCI (related to the regulated utilities) to a regulatory asset. The impact in the year ended March 31, 2018 was an increase in AOCI and non-current regulatory assets of $597 million with a related tax impact resulting in a decrease in AOCI and an increase in deferred tax liabilities, net of $168 million. The Company was only able to make this assertion in the current fiscal year and accordingly no change has been made to the prior year financial statements. Amounts remaining in AOCI at March 31, 2018 relate to the Company’s non-regulated subsidiaries.

Reclassifications

Certain reclassifications have been made to the prior year financial statements to conform the 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.

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, 2018	March 31, 2017
	(in millions of dollars)	
Regulatory assets		
Current:		
Derivative instruments	**$ 67**	$ 69
Energy efficiency	**3**	47
Gas costs adjustment	**184**	129
Rate adjustment mechanisms	**105**	108
Renewable energy certificates	**57**	53
Revenue decoupling mechanism	**97**	102
Other	**22**	22
Total	**535**	530
Non-current:		
Environmental response costs	**2,283**	2,316
Postretirement benefits	**1,611**	1,269
Regulatory tax asset, net	**-**	160
Storm costs	**293**	281
Other	**1,005**	909
Total	**5,192**	4,935
Regulatory liabilities		
Current:		
Derivative instruments	**4**	5
Energy efficiency	**511**	361
Gas costs adjustment	**47**	70
Profit sharing	**29**	52
Rate adjustment mechanisms	**223**	168
Revenue decoupling mechanism	**201**	147
Other	**24**	30
Total	**1,039**	833
Non-current:		
Carrying charges	**264**	226
Cost of removal	**1,698**	1,699
Postretirement benefits	**250**	194
Regulatory tax liability, net	**2,836**	1
Other	**1,141**	1,031
Total	**6,189**	3,151
Net regulatory (liabilities) assets	**$ (1,501)**	$ 1,481

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

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.

Regulatory tax asset/liability, net: Represents over-recovered federal and state deferred taxes of the Company primarily as a result of regulatory flow through accounting treatment and state income tax rate changes and excess federal deferred taxes as a result of the recently enacted Tax Act.

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.

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

4. RATE MATTERS

Niagara Mohawk

Electric and Gas Filing

On April 28, 2017, Niagara Mohawk filed a proposal to reset electric and natural gas delivery prices beginning in April 2018. On January 19, 2018, Niagara Mohawk reached a settlement agreement with the NYPSC Staff and other parties to the case and filed a Joint Proposal for a three-year rate plan. The proposal reflects the prospective impacts of the new federal tax law changes and provides a cumulative revenue requirement increase of $240.8 million and $60.8 million for the electric and gas business, respectively, based on a 9.0% return on equity (“ROE”) and a 48% common equity ratio. On March 15, 2018, the NYPSC issued a final order approving the Joint Proposal and the new rates took effect on April 1, 2018.

As of March 31, 2018, resulting from the Joint Proposal, a new electric rate plan settlement credit of $44.9 million and a new gas rate plan settlement credit of $28.4 million were established. These credits are included in other non-current regulatory liabilities in the preceding table within Note 3, “Regulatory Assets and Liabilities.” Niagara Mohawk applied $38.4 million of existing regulatory liabilities towards the creation of these credits.

Tax Act

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

In response to the Tax Act signed into law on December 22, 2017, the NYPSC issued an Order Instituting Proceeding under Case 17-M-0815 - Proceeding on Motion of the Commission on Changes in Law that May Affect Rates. This proceeding was instituted to solicit comments on the Tax Act’s implications and places the utilities on notice of the NYPSC’s intent to protect ratepayers’ interest and to ensure that any federal income taxes currently built into rates and accumulated deferred income taxes which, under the Tax Act, would result in excess collection are deferred for future ratepayer benefit. On March 29, 2018, the NYPSC Staff released its proposal to address accounting and ratemaking related to the Tax Act. Comments on NYPSC Staff’s proposal were filed June 27, 2018.

On August 9, 2018, the NYPSC issued an order in its generic proceeding considering the impacts of federal tax reform. NYPSC Staff had advocated that all New York utilities implement a sur-credit by October 1st that would reflect the immediate effects of the Tax Act and also return any deferred benefits to customers. In response, the Company filed a proposal to (i) reduce the New York Gas Companies’ rate prospectively to reflect the impact of the lower federal tax rate (already reflected in Niagara Mohawk’s rates) but delay any sur-credit to January 1st to offset scheduled rate increases and (ii) retain any deferred benefits, including accumulated deferred federal income taxes (“ADFIT”), for future rate moderation.

The NYPSC's order effectively approved all aspects of the Company's proposal. The NYPSC agreed that the Company should be allowed to defer both the pass back of calendar year 2018 tax savings and the amortization of excess ADFIT balances, and use the benefits as a rate moderator when base rates are next revised in 2020/2021. Specifically, the NYPSC directed that:

- for Niagara Mohawk, no sur-credit is required as the current rate plan already reflects the reduction of the tax rate to 21% and the termination of bonus depreciation. The NYPSC approved Niagara Mohawk's proposal to defer the tax benefit realized for the three-month period (January-March) prior to new rates, of $18 million for electric and $4.6 million for gas, to offset future rate increases or investments. Projected balances of $620 million of electric ADFIT and $129 million of gas ADIT and unprotected electric ADFIT of $76 million and unprotected gas ADFIT of $14 million will be deferred for future disposition in rate proceedings.

- the New York Gas Companies implement a sur-credit to reflect the lower tax rate effective January 1, 2019 to offset planned rate increases and retain the calendar year 2018 deferred amounts for future rate mitigation and/or to offset investments. Deferring the tax benefits until January 1, 2019 results in a deferred balance of $40 million for Brooklyn Union and $31 million for KeySpan Gas East. Brooklyn Union estimates a protected excess ADFIT balance of $258 million and an unprotected excess ADFIT balance of $62 million. KeySpan Gas East estimates a protected excess ADFIT balance of $230 million and an unprotected excess ADFIT balance of $45 million.

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 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 Company filed its plan to implement the audit recommendations with the NYPSC on May 19, 2016. On March 10, 2017, the NYPSC issued an Order approving the Company's implementation plan without modification, with quarterly updates to be made to the NYPSC on the status of implementation. On March 13, 2018, NYPSC Staff filed a letter indicating that the Company had implemented all recommendations and therefore the NYPSC was closing the audit.

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 its final report, which contained recommendations for the New York Gas Companies and Niagara Mohawk designed to improve the staffing and workforce management processes. The report contained 26 recommendations for the Company. The New York Gas Companies and Niagara Mohawk filed their implementation plan on March 23, 2017. On December 15, 2017, the NYPSC issued an Order approving the New York Gas Companies and Niagara Mohawk's 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 submitted their first update on April 16, 2018.

New York Management Audit

In 2018, the NYPSC will initiate a comprehensive management and operations audit of the New York Gas Companies and Niagara Mohawk. New York law requires periodic management audits of all utilities at least once every five years. The Company last underwent a New York management audit in 2014/2015, when the NYPSC audited our New York gas business. The audit will be process oriented and forward looking, and presents opportunities to obtain feedback on how to improve service to customers and meet regulatory expectations. Areas of focus will likely include the traditional audit areas of corporate governance, budgeting and finance, customer, work management, and long-term planning, as well as organization design, information systems, and gas safety.

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% ROE and 48% common equity ratio and includes an earning sharing mechanism in which customers will share earnings when the New York Gas Companies' ROE is 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 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 also 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. Differences over this threshold will be deferred for future recovery.

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 that become effective October 1, 2016. The DPU approved an overall increase in base distribution revenue of approximately $169.7 million based upon a 9.9% ROE 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 recovered 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 360 days of $40.6 million. As a result of the order, Massachusetts Electric has recovered revenue of approximately $12.2 million for the year ended March 31, 2018 in relation to the recovery of protected accounts; the remaining $28.4 million of the protected receivables will be collected through 2021.

For Massachusetts Electric, 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, through August 2019, for costs associated with 16 storm events between February 2010 and March 2013.

The order also allows for an increase in the annual capital costs for plant investment placed into service, as part of Massachusetts Electric's 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 Massachusetts Electric's capital investment recovery mechanism initially included as part of its RDM with an annual cap on capital investment of $249 million, which is a three-year calendar year historical average.

Tax Act

The DPU issued an order opening an investigation docketed as DPU 18-15 to examine the effect of the Tax Act on the rates of the investor-owned utilities in Massachusetts (including the Massachusetts Electric Companies and the Massachusetts Gas Companies). The DPU order explains that the statutory reduction in the federal corporate income tax rates pursuant to the Tax Act constitutes evidence that the rates being charged by each utility may no longer be just and reasonable as of January 1, 2018. To address this issue, the DPU has ordered each utility, as of January 1, 2018, to account for any revenues associated with the difference between the previous and current corporate income tax rates, and also establish a regulatory liability for excess recovery in rates of accumulated deferred income taxes resulting from the lower federal corporate income tax rate. The order requires utilities to file a plan for how it will refund these amounts by May 1, 2018, with an expectation that a rate reduction shall go into effect by July 1, 2018. To the extent that a utility seeks to implement any part of its rate adjustment, including the refund of excess deferred taxes, on a date later than July 1, 2018, that party must demonstrate that customers will not be harmed by the proposal and that the proposal is otherwise in the public interest. The filing was submitted to the DPU on May 1, 2018. On June 29, 2018, the DPU ordered the Massachusetts Electric Companies to prospectively reduce rates effective July 1, 2018 and reduce its annual target revenue in its RDM by $28 million. The DPU has begun the second phase of its investigation for determining the proper treatment of the impact of the change in the federal corporate income tax rate between January 1, 2018 and June 30, 2018, and excess deferred federal income taxes.

Grid Modernization Plan

On August 19, 2015, Massachusetts Electric filed its proposed grid modernization plan with the DPU, with four different proposed investment scenarios. On May 10, 2018, the DPU issued an order in this proceeding in which it approved $82 million in grid-facing investments over three years in: (1) Conservation Voltage Reduction and Volt Ampere Reactive Optimization; (2) advanced distribution automation; (3) feeder monitors; (4) communications and information/operational technologies; and (5) advanced distribution management. The DPU allowed recovery of both operation and maintenance expense and capital costs through a reconciling mechanism, and in the future will consider grid modernization plans outside of general rate cases. The DPU did not approve any customer-facing (i.e., advanced metering infrastructure) investments and will address these types of investments in a separate investigation to see if there are ways to achieve cost-effective deployment of advanced metering functionality (“AMF”). The DPU found that there needs to be widespread adoption of dynamic pricing in order for AMF to be successful, and it needs to address how to facilitate this first. The DPU also refined its grid modernization objectives to place additional focus on improved access to the distribution system planning process.

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 combined revenue increase of $58 million based upon a 9.75% ROE and a 50% equity ratio. The Massachusetts Gas Companies filed various motions in response. The combined effect of the DPU’s orders was a total revenue increase of $65.3 million with rates effective November 1, 2011 and February 1, 2013 for Boston Gas and Colonial Gas, respectively. Rates have remained in effect since this time.

On November 15, 2017, the Massachusetts Gas Companies filed a request for a combined net increase in revenue of $87 million to be in effect October 1, 2018 with a 10.5% ROE and a 53.04% equity ratio. The Massachusetts Gas Companies’ filing is based on capital additions since the last rate case, and includes cost changes associated with operation and maintenance expenses related to capital projects. As part of the request, the Massachusetts Gas Companies proposed recovery for two new programs. The first is the gas, safety, and reliability program, which is a set of critical projects specifically aimed at meeting safety and reliability requirements and modernizing the gas system. The second is the gas business enablement program, which will consolidate and modernize the Massachusetts Gas Companies’ systems and operating platforms to facilitate internal efficiencies and improve customer experience. The DPU held evidentiary hearings on the Massachusetts Gas Companies’ filing in May 2018 and an order is expected by September 30, 2018. The Massachusetts Gas Companies cannot predict the outcome of this proceeding.

Gas System Enhancement Plan

The Gas System Enhancement Plan (‘’GSEP’’) is a program designed to accelerate the replacement of the Massachusetts Gas Companies’ existing leak prone infrastructure pursuant to the Massachusetts’ 2014 Gas Leaks Act.

The DPU approved the Massachusetts Gas Companies’ GSEP for calendar years 2015 through 2018, including 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 LPP and ancillary equipment. The approved GSEAFs were designed to recover from all firm sales and transportation customers a revenue requirement of approximately $69.1 million for 2018, $50.6 million for 2017, $28.9 million for 2016, and $5.8 million for 2015.

On May 1, 2018, and updated on July 11, 2018, the Massachusetts Gas Companies filed their GSEP reconciliation filings for 2017, which reconciled the 2017 revenue requirement on 2017 actual GSEP capital investment with revenue billed through the GSEAFs, resulting in an under-collection of approximately $15.5 million.

On October 31, 2017, the Massachusetts Gas Companies filed its GSEP for calendar year 2018, which entailed a revenue requirement of approximately $87.2 million, recovery of funds to repair Grade 3 leaks, a proposal to extend the plan timeline from 20 to 25 years for Boston Gas and from 8 to 11 years for Colonial Gas, and a request for a waiver of the 1.5% cap**.** On January 31, 2018, the Massachusetts Gas Companies filed an update to its GSEP due to the ongoing rate case, federal tax law changes, and other updates. As a result of the updated GSEP filing, the requested revenue requirement was reduced to approximately $72.2 million, which still exceeded the 1.5% cap. The DPU approved the 2018 GSEP on April 30, 2018, including the extended timeframe to complete the plan, but denied recovery of Grade 3 leak repair funds and the waiver of the 1.5% cap. The Massachusetts Gas Companies will seek recovery of these amounts in a future filing.

Carrying Charge Adjustment

In August 2017, the DPU ordered Boston Gas to provide compound interest on its PBOP carrying charges related to calendar years 2003 through 2006. Boston Gas calculated the compound interest to be approximately $1.2 million and was ordered to revise its pending 2017 Pension Adjustment Factor ("PAF") petition and include this amount in the revised filing. The Order is in conjunction with the DPU's annual investigation of Boston Gas' pension and PBOP rate reconciliation mechanism and the Massachusetts Attorney General's ("AG") contention that Boston Gas is obligated to provide compound interest on its PBOP carrying charges which Boston Gas disputes. Boston Gas complied with the DPU's order when it included the interest in its revised PAF filing submitted on October 24, 2017. The new PAF factor went into effect on November 1, 2017. Boston Gas has also filed a motion for reconsideration of this matter to the DPU. Boston Gas cannot predict the outcome of the matter at this time.

New England Power

Stranded Cost Recovery

Under the 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 related to stranded cost recovery consisting of nuclear-related investments, through March 31, 2018. In Massachusetts, prior to 2014, NEP earned a ROE of approximately 10.65%. Due to state and federal tax rate changes in 2014 and 2018, respectively, the current ROE is 9.2%. In Rhode Island, prior to 2014, NEP earned a ROE of 12.16%. Due to state and federal tax rate changes in 2014 and 2018, respectively, the current ROE is 10.46%. 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 74% 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. NEP 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 NEP'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 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 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 FERC denied this filing and stated that, until further notice, the base ROE in New England must remain at the filed rate of 10.57%.

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.

Narragansett

General Rate Case

On February 1, 2013, the RIPUC approved a settlement agreement among the Rhode Island Division of Public Utilities and Carriers ("Division"), 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. This rate agreement remained in effect until August 31, 2018.

Narragansett reached a settlement with the Division and several other intervening parties to increase distribution revenue for its electric and gas operations over the three year period commencing September 1, 2018, that was approved by the RIPUC on August 24, 2018. This settlement agreement was reached in response to the base distribution revenue increase requests that Narragansett filed with the RIPUC on November 27, 2017. Pursuant to the settlement, electric distribution revenue will increase by approximately $14 million, $11 million, and $4 million and gas distribution revenue will increase by approximately $6 million, $8 million, and $4 million annually, commencing September 1, 2018. The settlement reflects an allowed ROE rate of 9.275% based on a common equity ratio of approximately 51%.

These revenue increases are intended to fund significant systems-related investments including the replacement of several aging operational systems used in Narragansett's gas business with newer integrated systems that will be shared by Narragansett and its gas affiliates. The settlement introduces new incentive-only Performance Incentive Mechanisms of 8 to 20 basis points to address important state policy goals around modernizing Narragansett's energy delivery systems and achieving clean energy targets. The increases set in place for the second and third years of this rate plan may be reopened for recovery of the implementation of advanced metering and grid modernization costs.

Tax Act

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

Storm Contingency Fund

On December 29, 2016, Narragansett filed with the RIPUC a petition to implement a Storm Fund Replenishment Factor effective July 1, 2017 to collect approximately $84.3 million over a four-year period to be credited to Narragansett's Storm Contingency Fund ("Storm Fund"), to restore the Storm Fund to a positive balance. In addition, Narragansett also requested to extend the annual $3 million of supplemental base distribution rate contributions beyond the current expiration date of January 31, 2019, to coincide with the four-year replenishment period. The Division, which is the primary intervener in Rhode Island on rate matters, filed testimony challenging the recovery of $10.6 million of the $84.3 million being sought through the Storm Fund Replenishment Factor ("SFRF"). On June 21, 2017, the RIPUC unanimously approved Narragansett's request to collect the $84.3 million. On April 27, 2018, the RIPUC approved the Joint Proposal Settlement Agreement which proposed a Storm Fund Deficit balance reduction of $2 million instead of $10.6 million as previously challenged. The SFRF is applicable to all retail delivery service customers for effect July 1, 2017, for a four-year period. In addition, the RIPUC unanimously approved Narragansett's request to extend the annual $3 million of supplemental base distribution rate contributions to the Storm Fund, which the RIPUC authorized in Narragansett's last rate case, for an additional 26-month period beyond its current expiration to March 31, 2021.

Power Purchase Agreements for Renewable Energy Projects

On April 9, 2018, the RIPUC approved eight PPAs had filed for approval with the RIPUC on November 1, 2017. The PPAs were the outcome of the 2015 Clean Energy RFP that Rhode Island, Massachusetts, and Connecticut participated in. The Massachusetts Electric Companies also entered into PPAs for the same eight projects, plus two others. The RIPUC approved the PPAs under the Long-Term Contracting Standard.

5. PROPERTY, PLANT AND EQUIPMENT

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

	March 31,	
	2018	2017
	(in millions of dollars)	
Plant and machinery	**$ 35,762**	$ 32,907
Land and buildings	**2,351**	2,284
Assets in construction	**2,215**	1,777
Software and other intangibles	**1,141**	1,066
Total property, plant and equipment	**41,469**	38,034
Accumulated depreciation and amortization	**(9,595)**	(8,616)
Property, plant and equipment, net	**$ 31,874**	$ 29,418

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,	
	2018	2017	**2018**	2017
	(in millions)		*(in millions)*	
Gas future contracts (dths)	**-**	-	**-**	3
Gas option contracts (dths)	**-**	-	**7**	8
Gas purchase contracts (dths)	**-**	-	**53**	54
Gas swap contracts (dths)	**-**	-	**100**	83
Electric capacity contracts (mwhs)	**1**	1	**-**	-
Electric swap contracts (mwhs)	**13**	13	**-**	-
Total	**14**	14	**160**	148

Amounts Recognized on the Consolidated Balance Sheet

	Asset Derivatives			Liability Derivatives	
	March 31,			March 31,	
	2018	2017		**2018**	2017
	(in millions of dollars)			*(in millions of dollars)*	
Current assets:			Current liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas option contracts	**$ -**	$ -	Gas option contracts	**$ 1**	$ -
Gas purchase contracts	**10**	4	Gas purchase contracts	**7**	7
Gas swap contracts	**1**	14	Gas swap contracts	**4**	1
Electric option contracts	**-**	-	Electric option contracts	**1**	-
Electric swap contracts	**9**	13	Electric swap contracts	**40**	45
Electric swaption contracts	**-**	-	Electric swaption contracts	**-**	1
Hedge contracts:			Hedge contracts:		
Foreign exchange forward contracts	**-**	1	Foreign exchange forward contracts	**-**	-
	20	32		**53**	54
Other non-current assets:			Other non-current liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas purchase contracts	**-**	-	Gas purchase contracts	**5**	10
Gas swap contracts	**-**	-	Gas swap contracts	**2**	1
Electric capacity contracts	**1**	1	Electric capacity contracts	**-**	-
Electric swap contracts	**1**	1	Electric swap contracts	**25**	33
	2	2		**32**	44
Total	**$ 22**	$ 34	Total	**$ 85**	$ 98

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. The majority of the Company's derivative instruments are subject to rate recovery as of March 31, 2018 and 2017.

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 $55 million and $40.4 million as of March 31, 2018 and 2017, respectively.

The aggregate fair value of the Company's commodity derivative instruments with credit-risk-related contingent features that were in a liability position at March 31, 2018 and 2017 was $62 million and $65.2 million, respectively. The Company had $10 million and $24 million collateral posted for these instruments at March 31, 2018 and 2017, respectively. At March 31, 2018, 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 $5 million, $14 million, or $55 million, 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, 2018

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	$ 10	$ -	$ 10	$ -	$ -	$ 10
Gas swap contracts	1	-	1	-	-	1
Electric capacity contracts	1	-	1	-	-	1
Electric swap contracts	10	-	10	-	-	10
Total	$ 22	$ -	$ 22	$ -	$ -	$ 22

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 option contracts	$ 1	$ -	$ 1	$ -	$ -	$ 1
Gas purchase contracts	12	-	12	-	-	12
Gas swap contracts	6	-	6	-	-	6
Electric option contracts	1	-	1	-	-	1
Electric swap contracts	65	-	65	-	10	55
Total	$ 85	$ -	$ 85	$ -	$ 10	$ 75

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

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, 2018 and 2017:

	March 31, 2018			
	Level 1	**Level 2**	**Level 3**	**Total**
		(in millions of dollars)		
Assets:				
Derivative instruments				
Gas purchase contracts	$ -	$ -	$ 10	$ 10
Gas swap contracts	-	1	-	1
Electric capacity contracts	-	-	1	1
Electric swap contracts	-	10	-	10
Available-for-sale securities	144	155	-	299
Total	144	166	11	321
Liabilities:				
Derivative instruments				
Gas option contracts	-	-	1	1
Gas purchase contracts	-	5	7	12
Gas swap contracts	-	6	-	6
Electric option contracts	-	-	1	1
Electric swap contracts	-	65	-	65
Total	-	76	9	85
Net assets	$ 144	$ 90	$ 2	$ 236

	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

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. The Company also has equity options, which are designated as Level 3 derivatives as they are traded on illiquid markets. Industry-standard valuation techniques, such as the Black-Scholes pricing model, Monte Carlo simulation, and Financial Engineering Associates libraries are used for valuing such instruments. A derivative is designated Level 3 when it is valued based on a forward curve that is internally developed, extrapolated, or derived from market observable curves with correlation coefficients less than 95%, where optionality is present, or if non-economic assumptions are made.

Available-for-sale securities: Available-for-sale securities are included in 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: Prior to September 30, 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 were 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.

Changes in Level 3 Derivative Instruments

	Years Ended March 31,	
	2018	2017
	(in millions of dollars)	
Balance as of the beginning of the year	**$ (3)**	$ 3
Total gains (losses) included in regulatory assets and liabilities	**65**	(18)
Settlements	**(60)**	12
Balance as of the end of the year	**$ 2**	$ (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, 2018 or 2017.

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

Quantitative Information About Level 3 Fair Value Measurements

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

Commodity	Level 3 Position	Fair Value as of March 31, 2018			Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)	Total			
		(in millions of dollars)					
Gas	Option contracts	$ -	$ (1)	$ (1)	Discounted Cash Flow	Forward Curve Implied Volatility	$0.19 - $0.35/dth 22% - 28%
Gas	Purchase contracts	10	(7)	$ 3	Discounted Cash Flow	Forward Curve	$3.96 - $10.68/dth
Electric	Option contracts	-	(1)	(1)	Discounted Cash Flow	Implied Volatility	28% - 96%
Electric	Capacity contracts	1	-	1	Discounted Cash Flow	Forward Curve	$0.25 - $2.59/MW
	Total	$ 11	$ (9)	$ 2			

Commodity	Level 3 Position	Fair Value as of March 31, 2017			Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)	Total			
		(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)			

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 sheet reflects long-term debt at amortized cost. The fair value of the Company's long-term debt was based on quoted market prices when available, or estimated using quoted market prices for similar debt. The fair value of this debt at March 31, 2018 and 2017 was $11.6 billion and $10.3 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 qualified and non-qualified non-contributory defined benefit plans (the "Pension Plans") and PBOP plans (together with the Pension Plan (the "Plans")), covering substantially all employees.

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.

Pension Plans

The Pension Plans are defined benefit plans which provide union employees, as well as non-union employees hired before January 1, 2011, with a retirement benefit. Supplemental non-qualified, non-contributory executive retirement programs provide additional defined pension benefits for certain executives. During the years ended March 31, 2018 and 2017, the Company made contributions of approximately $258 million and $305 million, respectively, to the qualified pension plans. The Company expects to contribute $310 million to the Pension Plans during the year ending March 31, 2019.

Benefit payments to Pension Plan participants for the years ended March 31, 2018 and 2017 were approximately $492 million and $445 million, respectively.

PBOP Plans

The 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. During the years ended March 31, 2018 and 2017, the Company made contributions of approximately $138 million and $350 million, respectively, to the PBOP plans. The Company does not expect to contribute to the PBOP Plans during the year ending March 31, 2019.

Benefit payments to PBOP plan participants for the years ended March 31, 2018 and 2017 were approximately $207 million and $208 million, respectively.

Net Periodic Benefit Costs

The Company's net periodic benefit pension cost for the years ended March 31, 2018 and 2017 was $277 million and $324 million, respectively.

The Company's net periodic benefit PBOP cost for the years ended March 31, 2018 and 2017 was $65 million and $171 million, respectively.

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 AOCI for the years ended March 31, 2018 and 2017:

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2018	2017	**2018**	2017
	(in millions of dollars)			
Net actuarial loss (gain)	**$ 28**	$ (228)	**$ (137)**	$ (658)
Prior service cost	**-**	9	**-**	-
Amortization of net actuarial loss	**(276)**	(300)	**(40)**	(102)
Amortization of prior service (cost) credit, net	**(6)**	(7)	**6**	8
Total	**$ (254)**	$ (526)	**$ (171)**	$ (752)
Included in regulatory assets	**$ 415**	$ (273)	**$ (74)**	$ (522)
Included in AOCI	**(669)**	(253)	**(97)**	(230)
Total	**$ (254)**	$ (526)	**$ (171)**	$ (752)

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. See the "AOCI – Reclassification to Regulatory Asset" section in Note 2, "Summary of Significant Accounting Policies" for additional discussion.

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 consolidated balance sheet that have not yet been recognized as components of net actuarial loss at March 31, 2018 and 2017:

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2018	2017	**2018**	2017
	(in millions of dollars)			
Net actuarial loss	**$ 1,427**	$ 1,675	**$ 72**	$ 249
Prior service cost (credit)	**30**	36	**(10)**	(16)
Total	**$ 1,457**	$ 1,711	**$ 62**	$ 233
Included in regulatory assets	**$ 1,270**	$ 855	**$ 102**	$ 176
Included in AOCI	**187**	856	**(40)**	57
Total	**$ 1,457**	$ 1,711	**$ 62**	$ 233

The amount of net actuarial loss and prior service cost to be amortized from regulatory assets and AOCI during the year ending March 31, 2019 for the Pension Plans is $261 million and $7 million, respectively, and net actuarial loss and prior service benefit to be amortized from regulatory assets and AOCI during the year ending March 31, 2019 for the PBOP Plans is $33 million and ($6) million, respectively.

Amounts Recognized on the Consolidated Balance Sheet

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

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2018	2017	**2018**	2017
	(in millions of dollars)			
Projected benefit obligation	**$ (9,068)**	$ (8,787)	**$ (4,489)**	$ (4,430)
Fair value of plan assets	**8,460**	7,923	**3,506**	3,214
Total	**$ (608)**	$ (864)	**$ (983)**	$ (1,216)
Non-current assets	**$ 341**	$ 280	**$ 18**	$ 13
Current liabilities	**(23)**	(23)	**(11)**	(11)
Non-current liabilities	**(926)**	(1,121)	**(990)**	(1,218)
Total	**$ (608)**	$ (864)	**$ (983)**	$ (1,216)

The benefit obligation shown above is the projected benefit obligation for the Pension Plans and the accumulated benefit obligation ("ABO") for the PBOP Plans. The Pension Plans had ABO balances that exceeded the fair value of plan assets as of March 31, 2018 and 2017. The aggregate ABO balances for the Pension Plans were $8.7 billion and $8.5 billion as of March 31, 2018 and 2017, respectively.

In addition, the Company provides supplemental welfare benefits to certain former non-employee directors and designated former executives. The Company has recognized a liability of $17 million on the consolidated balance sheets as of both March 31, 2018 and 2017 related to these supplemental welfare benefits.

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2018:

(in millions of dollars) Years Ending March 31,	Pension Plans	PBOP Plans
2019	$ 550	$ 183
2020	554	193
2021	551	203
2022	549	213
2023	553	222
2024-2028	2,690	1,201
Total	$ 5,447	$ 2,215

Assumptions Used for Employee Benefits Accounting

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2018	2017	**2018**	2017
Benefit Obligations:				
Discount rate	**4.10%**	4.30%	**4.10%**	4.30%
Rate of compensation increase	**3.50%**	3.50%	**N/A**	N/A
Expected return on plan assets	**6.00% - 6.25%**	6.25% - 6.50%	**6.25% - 6.75%**	6.50% - 6.75%
Net Periodic Benefit Costs:				
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%	**6.50% - 6.75%**	6.25% - 6.75%

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

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

Assumed Health Cost Trend Rate

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

Plan Assets

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 fixed income securities and other investments. 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. Approximately ten percent of the total investment portfolio is approved for investments in private equity, 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 Pension Plan is a trusted non-contributory defined benefit plan covering all eligible represented employees of the Company and eligible non-represented employees of the participating National Grid companies. The PBOP Plans are both a contributory and non-contributory, trusteed, employee life insurance and medical benefit plan sponsored by the Company. Life insurance and medical benefits are provided for eligible retirees, dependents, and surviving spouses of the Company.

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

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

Fair Value Measurements

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

	March 31, 2018				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in millions of dollars)		
Pension Assets:					
Cash and cash equivalents	$ 2	$ 73	$ -	$ 102	$ 177
Accounts receivable	352	-	-	-	352
Accounts payable	(567)	-	-	-	(567)
Equity	1,068	-	-	2,344	3,412
Global tactical asset allocation	-	-	-	627	627
Fixed income securities	-	2,289	-	1,249	3,538
Preferred securities	-	26	-	-	26
Private equity	-	-	-	503	503
Real estate	-	-	-	392	392
Total	$ 855	$ 2,388	$ -	$ 5,217	$ 8,460
PBOP Assets:					
Cash and cash equivalents	$ 40	$ -	$ -	$ 1	$ 41
Accounts receivable	6	-	-	-	6
Equity	714	-	-	1,556	2,270
Global tactical asset allocation	89	-	-	394	483
Fixed income securities	6	696	-	-	702
Private equity	-	-	-	4	4
Total	$ 855	$ 696	$ -	$ 1,955	$ 3,506

	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

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

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

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

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

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

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

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

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

Defined Contribution Plans

The Company has two defined contribution pension plans that cover substantially all employees. For the years ended March 31, 2018 and 2017, the Company recognized an expense in the accompanying consolidated statements of income of $67 million and $53 million, respectively.

Other Benefits

At March 31, 2018 and 2017, the Company had accrued workers compensation, auto, and general insurance claims which have been incurred but not yet reported ("IBNR") of $78 million and $74 million, respectively. IBNR reserves have been established for claims and/or events that have transpired, but have not yet been reported to the Company for payment.

9. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total
		(in millions of dollars)		
Balance as of March 31, 2016	$ 4	$ (848)	$ (2)	$ (846)
Other comprehensive income 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)
Other comprehensive income before reclassifications:				
Unrecognized net acturial gain (net of $6 tax expense)	-	18	-	18
Gain on investment (net of $5 tax expense)	7	-	-	7
Reclassification to regulatory asset (net of $168 tax expense)	-	429	-	429
Amounts reclassified from other comprehensive income (loss):				
Amortization of prior service cost (net of $1 tax benefit)	-	(2)	-	(2)
Amortization of net actuarial loss (net of $53 tax expense) (2)	-	95	-	95
Gain on investment (net of $3 tax benefit) (2)	(5)	-	-	(5)
Net current period other comprehensive income	2	540	-	542
Balance as of March 31, 2018	**$ 14**	**$ (22)**	**$ (2)**	**$ (10)**

(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, 2019.

10. CAPITALIZATION

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

(in millions of dollars) Years Ending March 31,	
2019	$ 54
2020	1,026
2021	221
2022	59
2023	473
Thereafter	9,029
Total	$ 10,862

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, 2018 are as follows:

(in millions of dollars) Years Ending March 31,		
2019	$	19
2020		19
2021		19
2022		19
2023		19
Thereafter		106
Total	$	201

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, 2018 and 2017, the Company was in compliance with all such covenants.

Significant Debt Facilities

Notes Payable

In August 2016, Massachusetts Electric issued $500 million of unsecured senior long-term debt at 4.00% with a maturity date of August 15, 2046 and KeySpan Gas East issued $700 million of unsecured senior long-term debt at 2.74% with a maturity date of August 15, 2026. On July 31, 2017, Boston Gas issued $500 million of unsecured senior long-term debt at 3.15% for $499.5 million ($0.5 million discount) with a maturity date of August 1, 2027. On October 6, 2017, Colonial Gas issued $150 million of unsecured senior long-term debt at 3.13% with a maturity date of October 5, 2027. On December 5, 2017, NEP issued $400 million of unsecured senior long-term debt at 3.80% for $397.3 million ($2.7 million discount) with a maturity date of December 5, 2047. In March 2018, Brooklyn Union issued $650 million of unsecured senior long-term debt at 4.27% with a maturity date of March 15, 2048.

The following table represents the Company's note payables for the years ended March 31, 2018 and 2017:

	Interest Rate	Maturity Date	March 31, 2018	2017
			(in millions of dollars)	
Brooklyn Union Unsecured Notes:				
Senior Note	4.27%	March 15, 2048	**$ 650**	$ -
Senior Note	3.41%	March 10, 2026	**500**	500
Senior Note	4.50%	March 10, 2046	**500**	500
Brooklyn Union Notes			**1,650**	1,000
KeySpan Gas East Unsecured Notes:				
Senior Note	5.82%	April 1, 2041	**500**	500
Senior Note	2.74%	August 15, 2026	**700**	700
KeySpan Gas East Notes			**1,200**	1,200
Boston Gas Unsecured Notes:				
Senior Note	4.49%	February 15, 2042	**500**	500
Senior Note	3.15%	August 1, 2027	**500**	-
Boston Gas MTN:				
MTN Series 1992 A	8.33%	July 10, 2017	**-**	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			**1,103**	611
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
Senior Note-Series A	3.13%	October 5, 2027	**150**	-
Colonial Gas Notes			**200**	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**	500
Massachusetts Electric Notes:			**1,300**	1,300
New England Power Unsecured Notes:				
Senior Notes	3.80%	December 5, 2047	**400**	-
Total			**$ 9,710**	$ 8,018

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. Genco had outstanding debt of $192 million and $209 million as of March 31, 2018 and 2017, respectively, of which $18 million is included in current portion of long-term debt on the consolidated balance sheet as of March 31, 2018 and 2017.

Gas Facilities Revenue Bonds

Brooklyn Union had outstanding tax-exempt Gas Facilities Revenue Bonds ("GFRB") issued through the New York State Energy Research and Development Authority ("NYSERDA"). Prior to March 31, 2018, $230 million of variable rate, auction rate GFRB were outstanding. The interest rate on the various variable rate series was reset weekly and ranged from 0.64% to 4.52% during the year ended March 31, 2018 and 0.51% to 2.45% during the year ended March 31, 2017. The GFRB was in auction rate mode and was backed by bond insurance. These bonds were not permitted to be put back to Brooklyn Union and, in the case of a failed auction, the resulting interest rate on the bonds would reverted to the maximum auction rate which depends on the current appropriate, short-term benchmark rates and the senior unsecured rating of 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, 2018 or 2017.

In April 2016 and March 2018, the Brooklyn Union repaid its fixed and variable rate GFRB as follows:

			Years Ended March 31,	
	Interest Rate	Maturity Date	**2018**	2017
			(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
1997	Variable	December 1, 2020	**125**	-
2005B	Variable	June 1, 2025	**55**	-
1991D	Variable	July 1, 2026	**50**	-
Total			**$ 230**	$ 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 $46 million, respectively, of non-callable FMB at March 31, 2018. These FMB indentures include, among other provisions, limitations on the issuance of long-term debt.

State Authority Financing Bonds

At March 31, 2018, the Company had outstanding $839 million of State Authority Financing Bonds, of which, approximately $495 million were issued through NYSERDA and the remaining $344 million were issued through various other state agencies.

Approximately $429 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) ranging from 0.66% to 4.69% for the year ended March 31, 2018 and 1.08% to 2.46% for the year ended March 31, 2017. 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 auction rate which depends on the current appropriate, short-term benchmark rate and the senior unsecured 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, 2018 or 2017. 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 0.50% to 18.00% during the year ended March 31, 2018 and 0.19% to 1.57% during the year ended March 31, 2017. 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 0.90% to 1.77% during the year ended March 31, 2018 and 0.53% to 1.10% during the year ended March 31, 2017.

At March 31, 2018, NEP had outstanding $293 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 $344 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, 2018, the Company, NGNA, and the Parent have committed revolving credit facilities of $3.4 billion, of which $0.9 billion matures in August and September 2019 and $2.5 billion matures in May 2022. 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 $3.4 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, 2018 and 2017, the Company, NGNA, and the Parent were in compliance with all covenants.

Commercial Paper and Revolving Credit Agreements

At March 31, 2018, 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 $3.4 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, 2018 and 2017, there were $290 million and $759 million of borrowings outstanding on the U.S. commercial paper program and zero million and $223 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 0.10% to 0.26%. 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, 2018 and 2017, in addition to the Brooklyn Union GFRB redemptions:

	Interest Rate	Maturity Date	Years Ended March 31, 2018	2017
			(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
MTN Series 1992 A	8.33%	July 10, 2017	**8**	-
Narragansett Electric First Mortgage Bonds				
FMB Series P & R	7.5% - 8.09%	September 30, 2022 - December 15, 2025	**1**	-
New England Power Pollution Control Revenue Bonds:				
Massachusetts Development Finance Agency 1	Variable	March 1, 2018	**79**	-
Genco Promissory Notes:				
Promissory Notes to National Grid North America Inc.	3.13% - 3.25%	June 2027 - April 2028	**18**	18
Total			**$ 106**	$ 528

11. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31, 2018	2017
	(in millions of dollars)	
Current tax expense (benefit):		
Federal	**$ 80**	$ 150
State	**25**	(7)
Total current tax expense (benefit)	**105**	143
Deferred tax expense (benefit):		
Federal	**329**	154
State	**35**	62
Total deferred tax expense (benefit)	**364**	216
Amortized investment tax credits [1]	**(4)**	(4)
Total deferred tax expense	**360**	212
Total income tax expense	**$ 465**	$ 355

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

Statutory Rate Reconciliation

The Company's effective tax rates for the years ended March 31, 2018 and 2017 are 41.6% and 36.2%, respectively. The following table presents a reconciliation of income tax expense at the federal statutory tax rate of 31.55% and 35%, respectively, to the actual tax expense:

	Years Ended March 31,			
	2018		2017	
	(in millions of dollars)			
Computed tax	**$**	**353**	$	343
Change in computed taxes resulting from:				
State income tax, net of federal benefit		**42**		36
Tax rate change		**112**		-
Other items, net		**(42)**		(24)
Total		**112**		12
Total income tax expense	**$**	**465**	$	355

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

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

On August 3, 2018, the IRS and the U.S. Department of Treasury released proposed regulations associated with the expanded depreciation rules under Section 168(k) enacted as part of the Tax Act. The Company is evaluating the potential impact of the proposed regulations and will include a potential adjustment to its financial statements in the next fiscal year when final regulations are issued.

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

The Company recognized a decrease in its net deferred income tax liability in the amount of $2.1 billion with $0.1 billion of the remeasurement recorded to deferred income tax expense and $2.2 billion recorded as a deferred regulatory liability for the refund of excess deferred income taxes to the ratepayers.

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

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

Deferred Tax Components

	March 31,	
	2018	2017
	(in millions of dollars)	
Deferred tax assets:		
Environmental remediation costs	**$ 564**	$ 734
Net operating losses	**546**	958
Postretirement benefits and other employee benefits	**615**	1,097
Regulatory liabilities - other	**559**	810
Regulatory tax liability	**797**	-
Other items	**487**	711
Total deferred tax assets	**3,568**	4,310
Deferred tax liabilities:		
Property related differences	**5,030**	7,347
Regulatory assets - environmental response costs	**605**	826
Regulatory assets - postretirement benefits	**372**	408
Regulatory assets - other	**442**	783
Other items	**287**	465
Total deferred tax liabilities	**6,736**	9,829
Net deferred income tax liabilities	**3,168**	5,519
Deferred investment tax credits	**32**	29
Deferred income tax liabilities, net	**$ 3,200**	$ 5,548

Net Operating Losses

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

	Carryforward Amount		Expiration Period
	(in millions of dollars)		
Federal	$ 3,070		2029-2038
New York	1,561	1	2035-2038
New York City	365	1	2035-2038
Massachusetts	547		2034-2038

(1) The amount contains 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.

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

The Company recognizes interest related to unrecognized tax benefits in other interest, including affiliate interest and related penalties, if applicable, in other income, net, in the accompanying consolidated statements of income. As of March 31, 2018 and 2017, the Company has accrued for interest related to unrecognized tax benefits of $120 million and $97 million, respectively. During the years ended March 31, 2018 and 2017, the Company recorded interest expense of $24 million and $20 million, respectively. During the years ended March 31, 2018 and 2017, the Company recognized tax penalties in the amount of zero and $0.3 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 Internal Revenue Service ("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. The Company does not believe that the outcome of the settlement will have a material impact to its results of operations, financial position, or cash flows. The IRS continues its examination of the next cycle which includes income tax returns for the years ended March 31, 2010 through March 31, 2012. The examination is not expected to conclude in the next fiscal year. The income tax returns for the years ended March 31, 2013 through March 31, 2018 remain subject to examination by the IRS.

The state of New York concluded its examination of Niagara Mohawk Holdings, Inc. & Combined Affiliates' income tax returns for the years ended March 31, 2009 through March 31, 2012. The examination resulted in a capital tax refund of $3.3 million.

The state of New York concluded its examination of National Grid Development Holdings 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.

The state of New York is expected to conclude its examination of KeySpan income tax returns for the years ended December 31, 2003 through March 31, 2009 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 and transition property depreciation deduction. 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 New York State 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, 2018 remain subject to examination by the state of New York.

Companies	Years Under Examination
KeySpan	December 31, 2003 through March 31, 2009
National Grid Development Holdings, Inc.	March 31, 2013 through March 31, 2015
Genco	March 31, 2013 through March 31, 2015
Wayfinder Inc.	March 31, 2009 through March 31, 2012
National Grid Engineering and Survey, 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, 2018 remain subject to examination by the city of New York.

Companies	Years Under Examination
KeySpan	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, 2010
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 as of the date of this report; a mechanism for recovery from LIPA of these investments has been established. Genco will continue to make investments for additional emissions reductions, as needed. 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 National Grid Port Jefferson Energy Center LLC ("Port Jefferson") and Northport. Capital improvements have been completed at Port Jefferson and are in the design, procurement, and construction 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 $84 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

At March 31, 2018 and 2017, the Company's total reserve for estimated MGP-related environmental matters is $2.0 billion. The Company had a current portion of environmental remediation costs of $108 million and $80 million included in other current liabilities on the balance sheet at March 31, 2018 and 2017, respectively. The potential high end of the range at March 31, 2018 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 $2.1 billion and $2.2 billion on the consolidated balance sheet at March 31, 2018 and 2017, respectively.

Expenditures incurred for the years ended March 31, 2018 and 2017 were approximately $78 million and $114 million, respectively.

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, 2018 and 2017 were $2 million and $4 million, respectively. The Company estimated the remaining cost of the environmental remediation activities at non-utility sites were $29 million and $34 million at March 31, 2018 and 2017, 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 $96 million and $100 million for the years ended March 31, 2018 and 2017, respectively.

The future minimum lease payments for the years subsequent to March 31, 2018 are as follows:

(in millions of dollars) Years Ending March 31,		
2019	$	67
2020		41
2021		42
2022		41
2023		41
Thereafter		275
Total	$	507

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, 2018 are summarized in the table below:

(in millions of dollars) Years Ending March 31,	Energy Purchases	Capital Expenditures
2019	$ 1,700	$ 87
2020	967	-
2021	789	-
2022	628	-
2023	571	-
Thereafter	2,772	-
Total	$ 7,427	$ 87

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 New York Independent System Operator 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, 2018, 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 *(in millions of dollars)*	Expiration Dates
KeySpan Ravenswood LLC Lease	(i)	$ 250	May 2040
Reservoir Woods	(ii)	159	October 2029
Surety Bonds	(iii)	220	Revolving
Commodity Guarantees and Other	(iv)	122	August 2025 - August 2042
Letters of Credit	(v)	307	May 2018 - February 2019
NY Transco Parent Guaranty	(vi)	842	None
National Grid Algonqin LLC	(vii)	100	December 2021
Business Development	(viii)	18	None
		$ 2,018	

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, 2018, the Company's obligation related to the lease was $50 million and is reflected in other non-current liabilities on the consolidated balance sheet.

(ii) The Company has fully and unconditionally guaranteed $159 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, 2018.

(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 $100 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. As of March 31, 2018, the Company has made $15 million of capital contributions to NGA.

(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 related to the acquisition of the development rights for 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, 2018 is $5 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 requires 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 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, the Division 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 Narragansett 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 Narragansett will need to backfill the MW capacity from that project to meet the 90 MW minimum long-term capacity requirements under the state statute.
- Fourth Solicitation: On October 29, 2015, the RIPUC approved a 15-year PPA with Copenhagen Wind Farm, LLC for an 80 MW land-based wind project located in Denmark, New York.

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

Legal Matters

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

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 1960s and early 1970s. Judgment was entered against National Grid on January 28, 2015, and a motion to appeal was filed by Genco. On February 14, 2017, the Company received a decision denying its motion for leave to appeal on the case. The judgment amount of approximately $7.9 million, inclusive of New York State judgment rate interest, was remitted to the plaintiff on February 17, 2017. Genco has received full reimbursement from LIPA for all defense costs and for the entire amount of the judgment paid, pursuant to the amended and restated ("A&R") PSA more fully described in Note 13, "Commitments and Contingencies" under "Electric Services and LIPA Agreements."

In fiscal year 2017, the Massachusetts Gas Companies reported to the DPU and the AG's office that it erroneously charged reconnection fees to certain customers. These amounts have been refunded or are in the process of being refunded to customers. Additionally, the AG's office imposed a potential penalty related to this matter, which was settled in fiscal year 2018. As of March 31, 2018, the Company 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 March 6, 2018, the Massachusetts Gas Companies signed a Settlement Agreement with the AG on the gas reconnection issue.

In addition to $1.6 million that the Massachusetts Gas Companies previously credited to affected customers, the Massachusetts Gas Companies have established a Restitution Fund in the amount of $2.3 million for those customers that had previously not been located. This amount includes interest for each reconnection fee. Other components of the settlement include a $3.2 million payment by the Company to the AG.

FERC ROE Complaints

There have been four complaints against NEP, attempting to lower NEP's ROE. There has only been one FERC order on any of the four complaints so far, an order on the first ROE complaint, setting the base ROE at 10.57%. That decision was appealed to the Court of Appeals and has been vacated and remanded to the FERC. NEP is waiting for the FERC to issue an order on remand addressing the first ROE complaint. NEP also is waiting for FERC action on the initial decision in the second and third ROE complaints, which set the ROE at 10.90%, and FERC action on the initial decision on the fourth ROE complaint where an administrative law judge found that the complaint had not been supported by the complaining parties.

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. On August 17, 2018, NEP and the other New England transmission owners filed for FERC approval a settlement with all the New England states and many other parties which lends more transparency to the formula rates in New England. A small group of municipal customers and FERC Trial Staff oppose aspects of the settlement. NEP hopes to get a FERC order approving the settlement by the first quarter of calendar year 2019, though the FERC is under no time constraint to act. NEP does not expect any impact to earnings as a result of the settlement.

Work Continuation Plan

On June 25, 2018, the Massachusetts Gas Companies activated a work continuation plan after contractual agreements with two of their steelworkers unions expired and new agreements could not be reached. This work continuation plan, which is utilizing skilled personnel from other NGUSA service areas and contracted resources, is in place to enable safe and reliable gas operations while negotiations with the unions continue. The work continuation plan will remain in effect until there is final agreement on new labor contracts with the unions. We cannot predict when the work continuation plan will be lifted or what the final terms of the new labor agreements will be.

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. As of March 23, 2018 the parties have entered an agreement for the resolution of any outstanding matters under the MSA. Activity in fiscal year 2017 and 2018 primarily relates to charges of certain contingencies, net of income taxes.

Effective May 28, 2013, Genco provides services to LIPA under the A&R PSA. Under the A&R PSA, Genco has a ROE of 9.75% and a capital structure of 50% debt and 50% equity. Genco's annual revenue requirement for the year ended December 31, 2017 was $449 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 95% 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 owned 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 consolidated balance sheet, are as follows:

(in thousands of dollars)	The Company's Investment as of March 31, 2018			Future Estimated Billings to the Company
Unit	%	Amount	Date Retired	Amount
Yankee Atomic	34.5	$ 515	February 1992	$ -
Connecticut Yankee	19.5	370	December 1996	4,358
Maine Yankee	24.0	562	August 1997	3,009

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 $119 thousand and $40 thousand (included within other current liabilities on the consolidated balance sheet) as of March 31, 2018 and 2017, respectively, which represents the current portion of accrued Yankee nuclear plant costs. As of March 31, 2018 and 2017, NEP has recorded a deferred liability of $7.2 million and $10.6 million (included within other non-current liabilities on the consolidated balance sheet), respectively. The sum of the current and deferred liabilities is offset by a regulatory asset of $7.4 million and $10.6 million (included within other non-current liabilities) as of March 31, 2018 and 2017, 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. Under the law, the Yankees can only recover past costs, so new lawsuits must be initiated every few years. To date, the Yankees have recovered the following:

- Phase I: $160 million for 2001 - 2002;
- Phase II: $235.4 million for 2003 - 2008; and
- Phase III: $76.8 million for 2009 - 2012.

Most recently on May 22, 2017, the Yankees brought further litigation (the "Phase IV Litigation") in the U.S. Court of Claims ("Claims Court") to recover damages totaling approximately $100 million incurred from 2013 through 2016. Discovery is continuing. Trial is scheduled for January 29 and 30, 2019.

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 in 2010 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. However, scarce funding has precluded progress in the licensing process. A proposal to provide funding for the resumption of pursuit of NRC licensing of the Yucca Mountain facility is pending Congress. 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. Private entities have initiated proposals, and submitted license applications to the NRC, to site consolidated 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, 2018 and 2017, Niagara Mohawk had a liability of $170 million and $168 million, respectively, recorded in other non-current liabilities on the consolidated 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. 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 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 outstanding accounts payable to affiliates is as follows:

	March 31,	
	2018	2017
	(in millions of dollars)	
National Grid plc	**$ 23**	$ 31
Other	**4**	1
Total	**$ 27**	$ 32

In addition, there are balances with National Grid plc of $85 million and $66 million in accounts receivable and $73 million and $56 million in accounts payable as of March 31, 2018 and 2017, respectively.

Advance from Affiliate

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, 2018 and 2017, the Company had zero and $650 million 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, 2018 and 2017, the Company had $4.1 billion and $2.4 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, 2018 and 2017, the effect on income before income taxes was $48 million and $43 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, 2018 and 2017 is as follows:

		Shares Outstanding		Amount		
		March 31,		March 31,		Call
Series	Company	**2018**	2017	**2018**	2017	**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%.

During the current fiscal year, the Company changed the dividend payment date from August 24 to July 28, which resulted in less than a full year elapsing from the dividend payment date of August 24, 2016 to the dividend payment date of July 28, 2017. Accordingly, the amendment to NGUSA's Certificate of Incorporation provided, for the 2017 dividend only, that the outstanding shares of Series A-E Preferred Stock pay dividends at the rate of 6.03% and that the outstanding shares of Series F Preferred Stock pay dividends at the rate of 7.89%, with the rates reverting back to 6.5% and 8.5%, respectively, thereafter.

The Company has paid all declared dividends in full.

A summary of preferred stock is as follows:

	Shares Outstanding		**Amount (par)**		**Amount (additional paid-in capital)**		**Dividends Paid**	
	March 31,		**March 31,**		**March 31,**		**March 31,**	
Series	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
	(in millions of dollars, except per share and number of shares data)							
$0.10 par value -								
Series A	**51**	51	**$ -**	$ -	**$ 400**	$ 400	**$ 24**	$ 26
Series B	**40**	40	-	**-**	**315**	315	**19**	20
Series C	**96**	96	-	**-**	**750**	750	**45**	49
Series D	**79**	79	-	**-**	**616**	616	**37**	40
Series E	**1**	1	-	**-**	**10**	10	**1**	1
Series F	**648**	648	-	**-**	**5,368**	5,368	**423**	456
Total	**915**	915	**$ -**	$ -	**$ 7,459**	$ 7,459	**$ 549**	$ 592

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, 2018, the Parent had 3.6 billion of ordinary shares issued with 282,960,111 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 3.95% and 7.73%, 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 ROE 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, 2018 and 2017:

	Units	Weighted Average Grant Date Fair Value
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
Vested	193,642	57.48
Granted	551,542	58.37
Forfeited/Cancelled	328,381	56.75
Non-vested as of March 31, 2018	1,099,960	$ 57.72

The total expense recognized for non-vested awards was $17.2 million and $15.4 million for the years ended March 31, 2018 and 2017, respectively, and non-vested awards vest over three years. The total tax benefit recorded was approximately $6.2 million as of March 31, 2018 and 2017. Total expense expected to be recognized by the Parent in future periods for non-vested awards outstanding as of March 31, 2018 is $17.7 million, $12.2 million, and $3.2 million for the years ended March 31, 2019, 2020, and 2021, respectively.

17. SUBSEQUENT EVENTS

In August 2018, Narragansett issued $350 million of unsecured long-term debt at 3.92% with a maturity date of August 1, 2028.