nationalgrid

National Grid USA and Subsidiaries

Consolidated Financial Statements

For the years ended March 31, 2013 and March 31, 2012

NATIONAL GRID USA AND SUBSIDIARIES

TABLE OF CONTENTS

Independent Auditor's Report

To the Shareholder and Board of Directors of National Grid USA and Subsidiaries:

We have audited the accompanying consolidated financial statements of National Grid USA and Subsidiaries (the "Company"), which comprise the consolidated balance sheets as of March 31, 2013 and March 31, 2012, and the related consolidated statements of income, comprehensive income, cash flows, capitalization and shareholders' equity for the years then ended.

Management's Responsibility for the Consolidated Financial Statements

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

Auditor's Responsibility

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

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

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of National Grid USA and Subsidiaries at March 31, 2013 and March 31, 2012, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

October 23, 2013

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

	March 31,	
	2013	2012
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 684**	$ 794
Restricted cash	**149**	108
Accounts receivable	**2,303**	1,731
Allowance for doubtful accounts	**(310)**	(367)
Other receivable	**67**	-
Accounts receivable from affiliates	**13**	135
Unbilled revenues	**942**	554
Materials, supplies, and gas in storage	**348**	459
Derivative contracts	**61**	52
Regulatory assets	**537**	703
Current portion of deferred income tax assets	**125**	208
Prepaid taxes	**205**	4
Prepaid and other current assets	**241**	330
Current assets held for sale	**-**	72
Total current assets	**5,365**	4,783
Equity investments	**184**	171
Property, plant, and equipment, net	**22,522**	21,321
Property, plant, and equipment, net, held for sale	**-**	350
Total	**22,522**	21,671
Deferred charges and other assets:		
Regulatory assets	**4,507**	4,454
Goodwill	**7,151**	7,133
Derivative contracts	**14**	42
Financial investments	**427**	405
Other deferred charges	**143**	159
Postretirement benefits asset	**297**	248
Deferred assets held for sale	**-**	105
Total deferred charges and other assets	**12,539**	12,546
Total assets	**$ 40,610**	$ 39,171

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,	
	2013	2012
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 1,519**	$ 1,187
Accounts payable to affiliates	**123**	-
Commercial paper	**625**	-
Other tax liabilities	**34**	34
Current portion of long-term debt	**263**	195
Taxes accrued	**112**	114
Customer deposits	**108**	123
Interest accrued	**160**	183
Regulatory liabilities	**459**	398
Derivative contracts	**11**	135
Payroll and benefits accruals	**272**	274
Other current liabilities	**188**	190
Current liabilities held for sale	**-**	34
Total current liabilities	**3,874**	2,867
Deferred credits and other liabilities:		
Regulatory liabilities	**2,592**	2,526
Asset retirement obligations	**105**	119
Deferred income tax liabilities	**4,257**	3,779
Postretirement benefits	**3,643**	3,675
Environmental remediation costs	**1,370**	1,386
Derivative contracts	**64**	57
Other deferred liabilities	**948**	1,165
Deferred liabilities held for sale	**-**	200
Total deferred credits and other liabilities	**12,979**	12,907
Capitalization:		
Shareholders' equity	**14,787**	14,814
Long-term debt	**8,970**	8,583
Total capitalization	**23,757**	23,397
Total liabilities and capitalization	**$ 40,610**	$ 39,171

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

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

	Years Ended March 31,	
	2013	2012
Operating revenues:		
Electric services	**$ 7,776**	$ 7,334
Gas distribution	**4,797**	4,925
Other	**28**	30
Total operating revenues	**12,601**	12,289
Operating expenses:		
Purchased electricity	**2,049**	2,139
Purchased gas	**2,013**	2,213
Contract termination charges and nuclear shutdown charges	**10**	16
Operations and maintenance	**5,249**	4,319
Depreciation and amortization	**859**	801
Impairment of intangible assets and property, plant and equipment	**-**	102
Decommissioning charges	**2**	45
Amortization of regulatory assets	**269**	503
Other taxes	**1,052**	1,001
Total operating expenses	**11,503**	11,139
Operating income	**1,098**	1,150
Other income and (deductions):		
Interest on long-term debt	**(389)**	(332)
Other interest expense	**(27)**	(122)
Equity income in unconsolidated subsidiaries	**36**	27
Gain on sale of investments	**-**	9
Other (deductions) income, net	**(14)**	45
Total deductions	**(394)**	(373)
Income before income taxes	**704**	777
Income taxes:		
Current	**(187)**	(64)
Deferred	**474**	397
Income tax expense	**287**	333
Income from continuing operations	**417**	444
Net (loss) income from discontinued operations, net of taxes	**(7)**	105
Net income	**410**	549
Net loss (income) attributable to non-controlling interest	**1**	(2)
Dividends paid on preferred stock	**(578)**	(283)
Net (loss) income attributable to common shares	**$ (167)**	$ 264

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,	
	2013	2012
Net income	**$ 410**	$ 549
Other comprehensive income (loss):		
Unrealized gains on securities, net of $0 and $1 tax expense	**1**	6
Unrealized (losses) gains on hedges, net of $1 tax benefit and $3 tax expense	**(2)**	7
Changes in pension and other postretirement obligations, net of $73 and $124 tax benefit	**(118)**	(186)
Adjustment for establishment of Narragansett pension tracker, net of $54 tax expense	**91**	-
Reclassification of gains (losses) into net income, net of $61 tax expense and $23 tax benefit	**87**	(34)
Other comprehensive income (loss)	**59**	(207)
Comprehensive income	**469**	342
Less: comprehensive loss (income) attributable to non-controlling interest	**1**	(2)
Comprehensive income attributable to National Grid USA	**$ 470**	$ 340

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,	
	2013	2012
Operating activities:		
Net income	**$ 410**	**$ 549**
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**859**	**801**
Amortization of regulatory assets	**269**	**503**
Provision for deferred income taxes	**474**	**397**
Bad debt expense	**74**	**123**
Equity (income) loss in unconsolidated subsidiaries, net of dividends received	**(4)**	**15**
Gain on sale of investments	**-**	**(108)**
Decommissioning charges	**-**	**45**
Impairment of intangible assets and property, plant and equipment	**-**	**102**
Regulatory deferrals	**32**	**36**
Net prepayments and other amortizations	**12**	**5**
Pension and other postretirement contributions	**(761)**	**(662)**
Pension and other postretirement expense	**713**	**1,147**
Net environmental payments	**(125)**	**(89)**
Changes in operating assets and liabilities:		
Accounts receivable and other receivable, net, and unbilled revenue	**(1,146)**	**434**
Materials, supplies, and gas in storage	**111**	**(99)**
Accounts payable and accrued expenses	**311**	**(195)**
Prepaid and accrued taxes	**(197)**	**91**
Accounts receivable from/accounts payable to affiliates, net	**245**	**(112)**
Other liabilities	**(219)**	**(374)**
Regulatory assets and liabilities, net	**71**	**(683)**
Derivatives, net	**(98)**	**149**
Other, net	**69**	**(76)**
Net cash provided by continuing operating activities	**1,100**	**1,999**
Investing activities:		
Capital expenditures	**(1,800)**	**(1,783)**
Net proceeds from disposal of discontinued operations and subsidiary assets	**294**	**183**
Equity investments in unconsolidated subsidiaries	**(9)**	**(6)**
Restricted cash	**(41)**	**(19)**
Cost of removal and other	**(214)**	**(131)**
Net cash used in continuing investing activities	**(1,770)**	**(1,756)**
Financing activities:		
Preferred stock dividends paid to parent	**(578)**	**(283)**
Payments of long-term debt	**(95)**	**(517)**
Proceeds from long-term debt	**1,047**	**1,213**
Commercial paper issued (paid)	**625**	**(735)**
Changes in loans from affiliates	**(500)**	**(577)**
Other	**62**	**(1)**
Net cash provided by (used in) continuing financing activities	**561**	**(900)**
Net decrease in cash and cash equivalents from continuing operations	**(109)**	**(657)**
Net cashflow from discontinued operations - operating	**4**	**(47)**
Net cashflow from discontinued operations - investing	**(5)**	**7**
Cash and cash equivalents, beginning of year	**794**	**1,491**
Cash and cash equivalents, end of year	**$ 684**	**$ 794**
Supplemental disclosures:		
Interest paid	$ (365)	$ (280)
Income taxes paid	(94)	(175)
Supplemental non-cash item:		
Capital-related accruals included in accounts payable	84	100

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,	
			2013	2012
Shareholders' equity attributable to common and preferred shares			**$ 14,761**	$ 14,805
Non-controlling interest in subsidiaries			**26**	9
Long-term debt:	**Interest Rate**	**Maturity Date**		
European Medium Term Note	Variable	December 2013 - January 2016	**876**	845
Notes Payable	3.30% - 9.75%	April 2013 - December 2042	**6,113**	5,179
Gas Facilities Revenue Bonds	Variable	December 2020 - July 2026	**230**	230
Gas Facilities Revenue Bonds	4.7% - 6.95%	April 2020 - July 2026	**411**	411
Pollution Control Revenue Bonds	5.15%	March 2016	**108**	108
Electric Facility Revenue Bonds	5.30%	November 2023 - August 2025	**47**	47
First Mortgage Bonds	6.34% - 9.63%	April 2018 - April 2028	**128**	129
State Authority Financing Bonds	Variable	October 2013 - August 2042	**1,199**	1,200
Industrial Development Revenue Bonds	5.25%	June 2027	**128**	128
Intercompany Notes	Variable	November 2012 - November 2015	**-**	500
Total debt			**9,240**	8,777
Other			**(7)**	1
Current maturities			**(263)**	(195)
Total long-term debt			**8,970**	8,583
Total capitalization			**$ 23,757**	$ 23,397

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in millions of dollars, except per share and number of shares data)

	Common Stock, Par Value $0.10 per share		Preferred Stock, Par Value $0.10 per share		Cumulative Preferred Stock, Par Value $100 and $50 per share				Accumulated Other Comprehensive Income					
	Shares Issued and Outstanding	Amount	Shares Issued and Outstanding	Amount	Shares Issued and Outstanding	Amount	Additional Paid-in Capital	Retained Earnings	Unrealized Gain (Loss) on Available for Sale Securities	Pension and Postretirement Benefit Plans	Hedging Activity	Total Accumulated Other Comprehensive Income	Non-controlling interest	Total
Balance as of March 31, 2011	1,289	$ -	267	$ -	372,638	$ 35	$ 13,043	$ 2,383	$ (9)	$ (702)	$ (5)	$ (716)	$ 10	$ 14,755
Net income	-	-	-	-	-	-	-	549	-	-	-	-	-	549
Comprehensive income (loss):														
Unrealized gains on securities, net of $1 tax expense	-	-	-	-	-	-	-	-	6	-	-	6	-	6
Unrealized gains on hedges, net of $3 tax expense	-	-	-	-	-	-	-	-	-	-	7	7	-	7
Changes in pension and other postretirement obligations, net of $124 tax benefit	-	-	-	-	-	-	-	-	-	(186)	-	(186)	-	(186)
Reclassification adjustment for gains included in net income, net of $23 tax benefit	-	-	-	-	-	-	-	-	-	(34)	-	(34)	-	(34)
Total comprehensive income														342
Net earnings attributable to non-controlling interest	-	-	-	-	-	-	-	(2)	-	-	-	-	(1)	(3)
Parent loss tax allocation	-	-	-	-	-	-	3	-	-	-	-	-	-	3
Issuance of Golden Shares (par value $1 per share)	-	-	-	-	3	-	-	-	-	-	-	-	-	-
Conversion of common stock to preferred stock	(648)	-	648	-	-	-	-	-	-	-	-	-	-	-
Dividend on preferred stock	-	-	-	-	-	-	-	(283)	-	-	-	-	-	(283)
Balance as of March 31, 2012	641	$ -	915	$ -	372,641	$ 35	$ 13,046	$ 2,647	$ (3)	$ (922)	$ 2	$ (923)	$ 9	$ 14,814
Net income	-	-	-	-	-	-	-	411	-	-	-	-	(1)	410
Comprehensive income (loss):														
Unrealized gains on securities, net of $0 tax expense	-	-	-	-	-	-	-	-	1	-	-	1	-	1
Unrealized losses on hedges, net of $1 tax benefit	-	-	-	-	-	-	-	-	-	-	(2)	(2)	-	(2)
Changes in pension and other postretirement obligations, net of $73 tax benefit	-	-	-	-	-	-	-	-	-	(118)	-	(118)	-	(118)
Adjustment for establishment of Narragansett pension tracker, net of $54 tax expense	-	-	-	-	-	-	-	-	-	91	-	91	-	91
Reclassification adjustment for gains included in net income, net of $61 tax expense	-	-	-	-	-	-	-	-	-	87	-	87	-	87
Total comprehensive income														469
Consolidation of variable interest entity	-	-	-	-	-	-	-	-	-	-	-	-	22	22
Other equity transactions with non-controlling interest	-	-	-	-	-	-	-	-	-	-	-	-	(4)	(4)
Share based compensation	-	-	-	-	-	-	64	-	-	-	-	-	-	64
Dividend on preferred stock	-	-	-	-	-	-	-	(578)	-	-	-	-	-	(578)
Balance at March 31, 2013	641	$ -	915	$ -	372,641	$ 35	$ 13,110	$ 2,480	$ (2)	$ (862)	$ -	$ (864)	$ 26	$ 14,787

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

NATIONAL GRID USA AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

A. Nature of Operations

National Grid USA (referred to as "NGUSA," the "Company," "we," and "our") 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. The Company delivers electricity to customers in New York, Massachusetts, and Rhode Island. We also own and operate electric generating plants in Nassau and Suffolk Counties on Long Island, New York, with approximately 4,100 megawatts ("MW") of electric generation capacity and manage the electricity network on Long Island under an agreement with Long Island Power Authority ("LIPA"). The Company's generation resources are dedicated to serving LIPA under a Power Supply Agreement ("PSA"), which entitles LIPA to 3,640 MW of the Company's generation, and to satisfy which, the Company has commitments for an additional 159.9 MW under separate power purchase agreements ("PPA"s). The Company also distributes natural gas to customers in New York, Massachusetts, and Rhode Island.

The Company is a wholly-owned subsidiary of National Grid North America Inc. ("NGNA") (formerly National Grid Holdings Inc.) and an indirectly-owned subsidiary of National Grid plc (the "Parent"), a public limited company incorporated under the laws of England and Wales.

The Company has two major lines of business, "Electric Services" and "Gas Distribution," and invests in various energy companies. 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 ("National Grid Generation"), The Brooklyn Union Gas Company ("Brooklyn Union"), and KeySpan Gas East Corporation ("KeySpan Gas East").

On July 3, 2012, our previous subsidiaries, Granite State Electric Company ("Granite State") and EnergyNorth Natural Gas, Inc., ("EnergyNorth") were sold to Liberty Energy Utilities Co. ("Liberty Energy"), a subsidiary of Algonquin Power & Utilities Corp. Additionally, Seneca-Upshur Petroleum, Inc. ("Seneca") was sold in October 2011, as discussed in Note 15, "Discontinued Operations." The results of Granite State, EnergyNorth, and Seneca are reflected as discontinued operations in the accompanying consolidated statements of income and the assets and liabilities of Granite State and EnergyNorth are classified as assets held for sale in the accompanying consolidated balance sheet at March 31, 2012.

Certain of the Company's subsidiaries provide operational and energy management services, supply capacity to, and produce energy for the use of LIPA's customers. These services are provided through the following contractual arrangements. The Management Service Agreement (the "MSA"), expiring on December 31, 2013, provides operation, maintenance and construction services and significant administrative services relating to the Long Island electric transmission and distribution system. Pursuant to the MSA, the Company will be required to perform transition assistance. The PSA provides LIPA with electric generating capacity, energy conversion and ancillary services from our Long Island generating units. The Energy Management Agreement (the "EMA"), which expired on May 28, 2013, provides management of all aspects of the fuel supply for our Long Island generating facilities. In total, these contracts represent approximately 14% of the Company's annual revenue.

Other Services and Investments

Certain of the Company's subsidiaries provide energy-related services to customers located primarily within the northeastern United States. These services comprise the operation, maintenance and design of energy systems for commercial and industrial customers.

We also invest in gas production and development investments such as natural gas pipelines, as well as certain other domestic energy-related investments. Through the Company's wholly-owned subsidiary, National Grid LNG, it owns a 600,000 barrel liquefied natural gas storage and receiving facility 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. In

addition, the Company's gas production and development activities included its wholly-owned subsidiary Seneca. Seneca was engaged in gas production and development activities primarily in West Virginia.

The Company's consolidated financial statements include a 26.25% interest in Millennium Pipeline Company LLC ("Millennium") and a 20.4% interest in Iroquois Gas Transmission System, which are 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 11, "Commitments and Contingencies" under "Decommissioning Nuclear Units."

Under our holding company structure, we have no independent operations or source of income of our own and conduct all of our operations through our subsidiaries. As a result, we depend on the earnings and cash flow of, and dividends or distributions from, our subsidiaries to provide the funds necessary to meet our debt and contractual obligations. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operations of our 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 October 23, 2013, 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, 2013, except as described in Note 2, "Rates and Regulation."

B. Basis of Presentation

The consolidated financial statements for the years ended March 31, 2013 and March 31, 2012 are prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"), including the accounting principles for rate-regulated entities with respect to the Company's subsidiaries engaged in the transmission and distribution of gas and electricity. The consolidated financial statements reflect the rate-making practices of the applicable regulatory authorities.

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

The consolidated financial statements include the accounts of the Company and its subsidiaries. Non-controlling interests' share of the Company's net income is included as net loss (income) attributable to non-controlling interest in the accompanying consolidated statements of income. All intercompany transactions have been eliminated in consolidation.

The Company uses the equity method of accounting for its investments in affiliates which are not consolidated and for which the Company has the ability to exercise significant influence over the respective operating and financial policies. The Company's share of the earnings or losses of such affiliates is included as equity income in unconsolidated subsidiaries in the accompanying consolidated statements of income.

C. Regulatory Accounting

The Federal Energy Regulatory Commission ("FERC"), the New York State Public Service Commission ("NYPSC"), the Massachusetts Department of Public Utilities ("DPU"), and the Rhode Island Public Utilities Commission ("RIPUC") provide the final determination of the rates that the Company's regulated subsidiaries charge their customers. In certain cases, the rate actions of the FERC and the applicable state regulatory bodies can result in accounting that differs from non-regulated companies. In these cases, the Company defers costs (as regulatory assets) or recognizes obligations (as regulatory liabilities) if it is probable that such amounts will be recovered or refunded through the rate-making process, which would result in a corresponding increase or decrease in future rates.

D. Revenue Recognition

Electric Services and Gas Distribution

Electric and gas distribution customers are generally billed on a monthly basis. Revenues are determined based on these bills plus an estimate for unbilled energy delivered between the cycle meter read date and the end of the accounting period. The Company's distribution subsidiaries follow the policy of accruing the estimated amount of base rate revenues for electricity and gas delivered but not yet billed (unbilled revenues), to match costs and revenues. Electric distribution revenues are based on billing rates and the allowed distribution revenue, as approved by the applicable state regulatory agency. The Company's regulated entities are permitted to pass through commodity-related costs to customers for recovery.

The cost of gas used is recovered when billed to customers through the operation of a cost of gas adjustment factor ("CGAF") included in utility tariffs. The CGAF provision requires an annual reconciliation of recoverable gas costs and revenues. Any difference is deferred pending recovery from or refund to customers.

Narragansett, Massachusetts Electric, Nantucket, Boston Gas, Colonial Gas, Niagara Mohawk, Brooklyn Union, and KeySpan Gas East have a Revenue Decoupling Adjustment Factor ("RDAF") which requires them to adjust semi-annually their base rates to reflect the over or under recovery of targeted base distribution revenues from the prior season. Revenue decoupling is a rate-making mechanism that breaks the link between the Company's base revenue requirement and sales. This mechanism allows the Company to offer various energy efficiency measures to its customers without financial detriment to the Company resulting from reductions in electricity and gas usage.

The gas distribution business is influenced by seasonal weather conditions. Brooklyn Union, KeySpan Gas East, Niagara Mohawk and Narragansett gas utility tariffs contain weather normalization adjustments that provide for recovery from, or refund to customers of material shortfalls or excesses of delivery revenues (revenues less applicable gas costs and revenue taxes) during a heating season due to variations from normal weather. Revenues are adjusted each month the clause is in effect. Gas utility rate structures for the other gas distribution subsidiaries contain no weather normalization feature; therefore net revenues are subject to weather related demand fluctuations. As a result, fluctuations from normal weather may have a significant positive or negative effect on the results of these operations.

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.

Additional electricity revenues are derived from billings to LIPA for electric generation capacity and, to the extent requested, energy from our existing oil and gas-fired generating plants as discussed in Note 11, "Commitments and Contingencies" under "Electric Services and LIPA Agreements."

Other Revenues

Revenues earned for service and maintenance contracts associated with commercial energy systems are recognized as earned or over the life of the service contract, as appropriate.

E. Property, Plant and Equipment

Property, plant and equipment is stated at original cost. The cost of additions to property, plant and equipment and replacements of retired units of property are capitalized. Costs include direct material, labor, overhead and allowance for funds used during construction ("AFUDC") for regulated operations and the interest cost of debt used to finance capital expenditures for non-regulated operations. The cost of renewals and betterments that extend the useful life of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects, which do not extend the useful life or increase the expected output of the asset, are expensed as incurred. Depreciation is generally computed over the estimated useful life of the assets using the composite straight-line method. Depreciation studies are conducted periodically to update the composite rates and are approved for regulated entities by the state regulatory authorities. Whenever property, plant and equipment in the regulated subsidiaries 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 average composite rates and average service lives for the years ended March 31, 2013 and March 31, 2012 are as follows:

	Electric		Gas		Common	
	March 31,		March 31,		March 31,	
	2013	2012	**2013**	2012	**2013**	2012
Composite rates - depreciation	**2.1%**	2.1%	**2.2%**	2.2%	**2.1%**	2.1%
Composite rates - cost of removal	**0.5%**	0.3%	**0.9%**	0.9%	**0.1%**	0.1%
Total composite rates	**2.6%**	2.4%	**3.1%**	3.1%	**2.2%**	2.2%
Average service lives	**48 years**	48 years	**45 years**	45 years	**47 years**	47 years

Depreciation expense for the Company's regulated subsidiaries includes estimated costs to remove property, plant and equipment, which is recovered through rates charged to customers. At March 31, 2013 and March 31, 2012, the Company had cumulative costs recovered in excess of costs incurred totaling $1.6 billion and $1.5 billion, respectively. These amounts are reflected as regulatory liabilities in the accompanying consolidated balance sheets.

In accordance with applicable regulatory accounting guidance, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated facilities. The equity component of AFUDC is a non-cash amount within the consolidated statements of income. AFUDC is capitalized as a component of the cost of property, plant and equipment, with an offsetting credit to other income and deductions for the equity component and other interest expense for the debt component in the accompanying consolidated statements of income. After construction is completed, the Company's regulated entities are permitted to recover these costs through inclusion in rate base and corresponding depreciation expense.

The components of AFUDC capitalized and composite AFUDC rates for the years ended March 31, 2013 and March 31, 2012 are as follows:

	March 31,	
	2013	2012
	(in millions of dollars)	
Debt	**$ 7**	$ 7
Equity	**21**	22
	$ 28	$ 29
Composite AFUDC rate	**4.1%**	6.1%

In addition, approximately $8 million of interest was capitalized for construction of non-regulated projects during fiscal year 2013.

F. Goodwill and Other Intangible Assets

Goodwill

Goodwill represents the excess of the purchase price of a business over the fair value of the tangible and intangible assets acquired, net of the fair value of liabilities assumed and the fair value of any non-controlling interest in the acquisition. The Company tests goodwill for impairment annually on January 31, and whenever events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount.

The goodwill impairment analysis is comprised of two steps. In the first step, the estimated fair value of the reporting unit is compared with its carrying value. If the fair value exceeds the carrying value, goodwill is not impaired and no further analysis is required. If the carrying value exceeds the fair value, then a second step is performed to determine the implied fair value of goodwill. If the carrying value of goodwill exceeds its implied fair value, then an impairment charge equal to the difference is recorded.

Goodwill is required to be analyzed and tested for impairment at a level of reporting referred to as a reporting unit. A reporting unit is an operating segment or one level below an operating segment (referred to as a component). NGUSA has defined its reporting units as its gas distribution, electric distribution, and transmission operations.

The Company calculated the fair value of its reporting units in the performance of its annual goodwill impairment test for the fiscal year ended March 31, 2013 utilizing both income and market approaches.

- To estimate fair value utilizing the income approach, the Company used a discounted cash flow methodology incorporating its most recent business plan forecasts together with a projected terminal year calculation. Key assumptions used in the income approach were: (a) expected cash flows for the period from April 1, 2013 to March 31, 2018; (b) a discount rate of 5.5%, which was based on the Company's best estimate of its after-tax weighted-average cost of capital; and (c) a terminal growth rate of 2.25%, based on the Company's expected long-term average growth rate in line with estimated long-term US economic inflation.

- To estimate fair value utilizing the market approach, the Company followed a market comparable methodology. Specifically, the Company applied a valuation multiple of earnings before interest, taxes, depreciation and amortization ("EBITDA"), derived from data of publicly-traded benchmark companies, to business operating data. Benchmark companies were selected based on comparability of the underlying business and economics. Key assumptions used in the market approach included the selection of appropriate benchmark companies and the selection of an EBITDA multiple of 10.0, which we believe is appropriate based on comparison of our business with the benchmark companies.

The Company ultimately determined the fair value of the business using 50% weighting for each valuation methodology. The resulting fair value of the annual analyses determined that no adjustment of the goodwill carrying value was required at March 31, 2013 or March 31, 2012.

Intangible Assets

Intangible assets represent finite-lived assets that are amortized over their respective estimated useful lives and, along with other long-lived assets, are evaluated for impairment periodically whenever events or changes in circumstances indicate that their related carrying amounts may not be recoverable. During the year ended March 31, 2012, the Company recorded a non-cash impairment charge of $102 million to reduce the net carrying value of its MSA LIPA contract intangible asset to a fair value of zero, as discussed in Note 10, "Goodwill and Other Intangible Assets."

G. Impairment of Long-Lived Assets

The Company evaluates long-lived assets, including property, plant and equipment and finite-lived intangibles, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. In evaluating long-lived assets for recoverability, the Company uses its best estimate of future cash flows expected to result from the use of the asset and its eventual disposition. If the estimated future undiscounted net cash flows attributable to the asset are less than the carrying amount, an impairment loss is recognized equal to the difference between the carrying value of such asset and its fair value. Assets to be disposed of and for which there is a committed plan of disposal are reported at the lower of carrying value or fair value less costs to sell.

H. Available-For-Sale Securities

The Company holds available-for-sale securities which primarily include equity securities for which the equity method is not applied, municipal bonds and corporate bonds. These investments are recorded at fair value and are included in financial investments in the accompanying consolidated balance sheets. Changes in the fair value of these assets are recorded within other comprehensive income.

I. Cash and Cash Equivalents

The Company classifies short-term investments that are highly liquid and have original maturities of three months or less as cash equivalents. Cash and cash equivalents are carried at cost which approximates fair value.

J. Restricted Cash and Special Deposits

Restricted cash primarily consists of deposits held by the New York Independent System Operator ("NYISO") and the ISO New England ("ISO-NE"). Special deposits primarily consist of health care claims deposits and are included within prepaid and other current assets in the accompanying consolidated balance sheets.

K. Allowance for Doubtful Accounts

The Company recognizes an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is calculated by applying a reserve factor to outstanding receivables. The reserve factor is based upon historical write-off experience and assessment of customer collectability.

L. Materials, Supplies and Gas in Storage

Materials and supplies are stated at the lower of weighted average cost or market, and are expensed or capitalized into specific capital additions as used. At March 31, 2013 and March 31, 2012, materials and supplies were $175 million and $167 million, respectively. 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, 2013 or March 31, 2012.

Gas in storage is stated at weighted average cost, and is expensed when delivered to customers. Existing rate orders allow the Company to pass through the cost of gas purchased directly to customers along with any applicable authorized delivery surcharge adjustments. Accordingly, the value of gas in storage does not fall below the cost to the Company. Gas costs passed through to customers are subject to regulatory approvals and are reported periodically to the state regulatory authorities. At March 31, 2013 and March 31, 2012, gas in storage was $164 million and $292 million, respectively.

M. Income and Other 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. NGNA files consolidated federal tax returns including all of the activities of its subsidiaries. Each subsidiary company is included in the consolidated group and determines its current and deferred taxes based on the separate return method. The Company settles its current tax liability or benefit each year with NGNA pursuant to a tax sharing arrangement between NGNA and its included subsidiaries. Benefits allocated by NGNA are treated as capital contributions.

Deferred income taxes reflect the tax effect of net operating losses, capital losses and general business credit carryforwards and the net tax effects of temporary differences between the carrying amounts of assets and liabilities for consolidated financial statement and income tax purposes, as determined under enacted tax laws and rates. 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. Additionally, the Company follows the current accounting guidance relating to uncertainty in income taxes which applies to all income tax positions reflected in the accompanying consolidated balance sheets that have been included in previous tax returns or are expected to be included in future tax returns. The accounting guidance for uncertainty in income taxes provides that the financial effects of a tax position shall initially be recognized in the consolidated financial statements when it is more likely than not, based on the technical merits, that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

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 tax based on capital is in excess of the state tax based on income, the Company reports such excess in other taxes and taxes accrued in the accompanying consolidated financial statements.

The Company collects from customers various taxes that are levied by state and local governments on the sale or distribution of gas. The Company presents taxes that are imposed on customers (such as sales taxes) on a net basis (i.e., excluded from revenues) and presents excise taxes on a gross basis.

Gas distribution revenues include the collection of excise taxes and the related expense is included in other taxes in the accompanying consolidated statements of income.

N. Employee Benefits

The Company follows the accounting guidance related to the accounting for defined benefit pension and postretirement benefit ("PBOP") plans for recording pension expenses and resulting plan asset and liability balances. The guidance requires employers to fully recognize all pension and postretirement plans' funded status on the balance sheet as a net liability or asset and requires an offsetting adjustment to accumulated other comprehensive income in shareholders' equity. In the case of regulated entities, this offsetting entry is recorded as a regulatory asset or liability when the balance will be recovered from or refunded to customers in future rates. The Company has determined that such amounts for its regulated subsidiaries will be included in future rates and follows the regulatory format for recording the balances. The Company measures and records its pension and PBOP assets at the year-end date. Pension and PBOP assets are measured at fair value, using the year-end market value of those assets.

O. Supplemental Executive Retirement Plans

The Company has corporate assets included in financial investments in the accompanying consolidated balance sheets 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 with increases and decreases in the value of these assets recorded through earnings in the accompanying consolidated statements of income.

P. Derivatives

Derivatives are financial instruments that derive their value from the price of an underlying item such as interest rates, foreign exchange, credit spreads, commodities, equity or other indices. Derivatives enable their users to manage their exposure to these markets or credit risks. The Company uses derivative instruments to manage operational market risks from commodities and economically hedge a portion of the Company's exposure to commodity price risk. When economic hedge positions are in effect, the Company is exposed to credit risks in the event of non-performance by counterparties to derivative contracts (hedging transactions), as well as non-performance by the counterparties of the underlying transactions. The Company also enters into financial derivatives to hedge exposure to interest rate risk. These derivatives are designated in hedging relationships when they qualify.

Commodity Derivative Instruments – Regulated Accounting

All of the Company's commodity derivative instruments are held by its regulated subsidiaries. The Company utilizes derivatives to reduce the cash flow variability associated with the purchase price for a portion of future natural gas and electricity purchases. The Company's strategy is to minimize fluctuations in firm gas and electricity sales costs to the Company's customers. The accounting for these derivative instruments is subject to the current accounting guidance for rate-regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or deferred assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the accompanying consolidated balance sheets. Gains or losses on the settlement of these contracts are initially deferred and then refunded to or collected from the Company's customers consistent with regulatory requirements.

Certain non-trading contracts for the physical purchase of electricity qualify for the normal purchase normal sales exception and are accounted for upon settlement. If the Company were to determine that a contract for which it elected the normal purchase normal sales exception no longer qualifies, the Company would recognize the fair value of the contract in accordance with the regulatory accounting described above.

Balance Sheet Offsetting

Accounting guidance related to derivatives permits the offsetting of fair value amounts recognized for derivative instruments and fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) arising from derivative instrument(s) recognized at fair value executed with the same counterparty under a master netting arrangement. The Company's accounting policy is to not offset fair value amounts recognized for derivative instruments and related cash collateral receivable or payable with the same counterparty under a master netting agreement, and to record and present the fair value of derivative instrument(s) on a gross basis.

Q. Fair Value Measurements

The Company measures derivatives and available for sale securities at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The following is the fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value:

Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access as of the reporting date;

Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data; and

Level 3 — unobservable inputs, such as internally-developed forward curves and pricing models for the asset or liability due to little or no market activity for the asset or liability with low correlation to observable market inputs.

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

R. New and Recent Accounting Guidance

Accounting Guidance Adopted in Fiscal Year 2013

Fair Value Measurements

In May 2011, the Financial Accounting Standards Board ("FASB") issued accounting guidance that amended existing fair value measurement guidance. The amendment was issued with a goal of achieving common fair value measurement and disclosure requirements in GAAP and International Financial Reporting Standards. Consequently, the guidance changes the wording used to describe many of the requirements in GAAP for measuring fair value, requires new disclosures about fair value measurements, and changes specific applications of the fair value measurement guidance. Some of the amendments clarify the FASB's intent about the application of existing fair value measurement requirements. Other amendments change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements including, but not limited to: fair value measurement of a portfolio of financial instruments; fair value measurement of premiums and discounts; and additional disclosures about fair value measurements. This guidance became effective for financial statements issued for annual periods (for non-public entities such as the Company) beginning after December 15, 2011. The Company adopted this guidance for the fiscal year ended March 31, 2013, which only impacted its fair value disclosures. There were no changes to the Company's approach to measuring fair value as a result of adopting this new guidance.

Goodwill Impairment

In September 2011, the FASB issued accounting guidance related to goodwill impairment testing, whereby an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is not required. Otherwise, the entity is required to perform the two-step impairment test. This guidance became effective for annual and interim

goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The Company adopted this guidance in its fiscal year ended March 31, 2013 and did not elect the option to perform a qualitative analysis.

Other Comprehensive Income

In June 2011, the FASB issued accounting guidance that eliminated the option to present the components of other comprehensive income as part of the statement of changes in stockholders' equity. This new guidance seeks to improve financial statement users' ability to understand the causes of an entity's change in financial position and results of operations. As a result of this guidance entities are required to either present the statement of income and statement of comprehensive income in a single continuous statement or in two separate, but consecutive statements of net income and other comprehensive income. This guidance does not change the items that are reported in other comprehensive income or any reclassification of items to net income. In addition, the new guidance does not change an entity's option to present components of other comprehensive income net of or before related tax effects. This guidance became effective for non-public companies for fiscal years ending after December 15, 2012, and for interim and annual periods thereafter, and it is to be applied retrospectively. The Company adopted this guidance for the fiscal year ended March 31, 2013, with no impact on its consolidated financial position, results of operations, or cash flows.

Accounting Guidance Not Yet Adopted

Offsetting Assets and Liabilities

In December 2011, the FASB issued accounting guidance requiring enhanced disclosure related to offsetting assets and liabilities. Under the new guidance, reporting entities will be required to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting agreement, such as for derivatives. In January 2013, the FASB issued additional guidance to clarify that the specific instruments and activities that should be considered in these disclosures will be limited to recognized derivatives, repurchase and reverse repurchase agreements, and securities lending transactions. This guidance is effective for fiscal years, and interim periods within those years, beginning after January 1, 2013, and is to be applied retrospectively. The Company will begin including the new required disclosures in its fiscal year 2014 interim financial statements as applicable and does not expect any impact on its consolidated financial position, results of operations, or cash flows.

Reclassifications From Accumulated Other Comprehensive Income

In February 2013, the FASB issued accounting guidance that requires an entity to report information about significant reclassifications out of accumulated other comprehensive income. The new guidance requires presentation either in a single footnote or parenthetically on the financial statements, of the effect of significant amounts reclassified out of accumulated other comprehensive income based on the corresponding line items in the statement of net income. For amounts that are not required to be reclassified in their entirety to net income in the same reporting period, an entity would cross-reference other disclosures that provide additional detail about those amounts. The amendments do not change the current requirements for reporting net income or other comprehensive income in the financial statements. For non-public entities, the amendments are effective prospectively for reporting periods beginning after December 15, 2013. Early adoption is permitted. The Company is evaluating the impact, if any, on its consolidated financial position, results of operations, and cash flows.

S. Financial Statement Revisions and Reclassifications

During 2013, management determined that the Company's previously issued financial statements for the year ended March 31, 2012 included an error relating to the classification of the gain on sale of its previous subsidiary, Seneca. The error consisted of an incorrect classification of the $99 million gain on sale within income from continuing operations. In addition, related income taxes of $42 million were recorded within income taxes in continuing operations. The net gain on sale of $57 million should have been classified within discontinued operations.

The Company corrected these errors by revising the prior period financial statements, the impacts of which are described below. Management has concluded that the errors did not have a material impact on any previously issued financial statements and has therefore revised the previously reported amounts within the financial statements for the year ended March 31, 2012.

The following table shows the amounts previously reported as revised:

	As Previously Reported	Revision	As Adjusted
	(in millions of dollars)		
Statement of Income			
Gain on sale of investments	$ 108	$ (99)	$ 9
Income taxes			
Current taxes	$ (22)	$ (42)	$ (64)
Income from continuing operations	$ 501	$ (57)	$ 444
Net income from discontinued operations, net of taxes	48	57	105
Net income	$ 549	$ -	$ 549

In addition to the above, certain reclassifications have been made to the financial statements to conform prior year's data to the current year's presentation. These reclassifications had no effect on the Company's results of operations or cash flows.

Note 2. Rates and Regulation

The following table presents the Company's regulatory assets and regulatory liabilities included in the accompanying consolidated balance sheets at March 31, 2013 and March 31, 2012:

	March 31,	
	2013	2012
Regulatory assets		
Current:		
Renewable energy credits	**$ 78**	$ 63
Rate adjustment mechanisms	**77**	221
Derivative contracts	**11**	134
Postretirement benefits	**50**	63
Gas costs	**90**	61
Revenue decoupling	**22**	89
Storm costs	**48**	-
Transmission service	**21**	-
Contract termination charges	**-**	-
Environmental costs	**77**	13
Yankee nuclear decommissioning costs	**13**	12
Other	**50**	47
Total	**537**	703
Non-current:		
Postretirement benefits	**1,710**	1,642
Environmental costs	**1,714**	1,968
Derivative contracts	**6**	34
Regulatory tax asset	**123**	82
Storm costs	**306**	189
Recovery of acquisition premium	**208**	216
Yankee nuclear decommissioning costs	**11**	16
Losses on reacquired debt	**26**	31
Property and other taxes	**25**	61
Capital tracker	**59**	46
Asset retirement obligation	**54**	50
Other	**265**	119
Total	**4,507**	4,454
Regulatory liabilities		
Current:		
Gas costs	**91**	88
Rate adjustment mechanisms	**163**	179
Alliance profit	**43**	23
Environmental costs	**4**	-
Postretirement benefits	**26**	-
Energy efficiency	**35**	36
Statement of policy buyback	**-**	20
Long-term debt true-up	**9**	-
Derivative contracts	**50**	39
Other	**38**	13
Total	**459**	398
Non-current:		
Cost of removal	**1,563**	1,478
Contract termination charges	**35**	45
Excess earnings	**95**	94
Postretirement benefits	**285**	260
Economic development fund	**36**	12
Unbilled gas revenue	**23**	22
Derivative contracts	**12**	40
Environmental costs	**105**	184
Net delivery rate adjustment	**130**	111
Excess storm reserve	**30**	-
Energy efficiency	**41**	-
Federal income tax repair cost deferral	**30**	-
Transition balancing accounts	**-**	36
Revenue subject to refund	**25**	50
Regulatory deferred tax liabilities	**24**	23
Capital tracker	**29**	35
Other	**129**	136
Total	**2,592**	2,526
Net regulatory assets	**$ 1,993**	$ 2,233

Alliance profit: This regulatory liability represents a portion of deferred margins from off-system sale transaction Under current rate orders, the Company is required to return 90% of margins earned from such optimization transactior to firm customers. The amounts deferred at the balance sheet date will be refunded to customers over the next year.

Capital tracker: Brooklyn Union and KeySpan Gas East have capital tracker mechanisms that reconcile their capit expenditures to the amounts permitted in rates. The mechanism provides for a two way (upward and downward) track for City and State Construction ("CSC") related expenditures and a one way (downward only) tracker for all other capit expenditures. Brooklyn Union and KeySpan Gas East defer the full revenue requirement equivalent of CSC expenditure above or below the CSC rate allowance and defer the revenue requirement equivalent of any other unspent capit expenses below the rate allowance for all other capital expenditures. Brooklyn Union's recent rate settlement, discusse below, eliminated the CSC tracker effective January 1, 2013. The effect of the tracker is to adjust the Company's retur on common equity capital ("ROE") for the difference between actual capital expenditures and the amount provided i rates.

Cost of removal: The Company's depreciation expense includes estimated costs to remove property, plant ar equipment, which is recovered through the rates charged to customers. This regulatory liability represents cumulativ costs recovered in excess of costs incurred. For a vast majority of its regulated utility plant assets, the Company use these funds to remove the asset so a new one can be installed in its place.

Environmental costs: This regulatory asset represents deferred costs associated with the Company's share of th estimated costs to investigate and perform certain remediation activities at sites with which it may be associated. Th Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates.

Excess earnings: The base rates in Brooklyn Union's and KeySpan Gas East's rate plans (2008-12) provide for a 9.8% ROE. At the end of each rate year (calendar year), these entities are required to provide the NYPSC with a computatio of its ROE. If the level of earned common equity in the applicable rate year exceeds 10.5%, the company is required t defer a portion of the revenue equivalent associated with any over earnings for the benefit of customers. Brookly Union's recent rate settlement modified its ROE and revenue sharing mechanism for the rate year beginning January 2013, as described below.

Gas costs: The Company's regulated subsidiaries are subject to rate adjustment mechanisms for commodity cost whereby an asset or liability is recognized resulting from differences between actual revenues and the underlying co being recovered or differences between actual revenues and targeted amounts as approved by state authorities. Thes amounts will be refunded to or recovered from customers over the next year.

Net delivery rate adjustment: A $15 million combined annual surcharge for the recovery of regulatory asse ("Delivery Rate Surcharge" or "DRS") was implemented in January 2008 and January 2009 for Brooklyn Union ar KeySpan Gas East, respectively. The Delivery Rate Surcharge increased by $5 million for the first five years of th Brooklyn Union's rate plan and increased by $10 million per year in rate years 2010 through 2012 of KeySpan Ga East's rate plan, resulting in the combined aggregate recovery of approximately $175 million. The first $25.2 millio collected from the DRS was used to offset deferred special franchise taxes with the remainder deferred and used to offs future increases in rates for the costs such as Site Investigation and Remediation ("SIR") or other costs deferrals. Th DRS expired on December 31, 2012. In January 2010, the New York Gas Companies submitted a filing on the status o its regulatory deferrals so that the NYPSC could determine if the New York Gas Companies should adjust their revenu levels under the rate plan so as to minimize outstanding deferral balances. On November 28, 2012, the NYPSC issued a order authorizing the Companies to recover a combined $215.6 million of SIR deferral balances through th implementation of an SIR surcharge that supersedes the expired DRS. The SIR surcharge is designed to collect combined $65.0 million per year beginning January 1, 2013, to amortize the SIR balance approved for recovery by th NYPSC.

Postretirement benefits: The amount in regulatory assets primarily represents the excess costs of the Company pension and postretirement benefits plans over amounts received in rates that are deferred to a regulatory asset to b recovered in future periods and the non-cash accrual of net actuarial gains and losses. The amount in regulatory liabilitie primarily represents accrued carrying charges as calculated in accordance with the Company's Pension and PBO internal reserve mechanism.

Rate adjustment mechanisms: The Company's regulated subsidiaries are subject to a number of rate adjustme mechanisms such as for commodity costs, whereby an asset or liability is recognized resulting from differences betwee

actual revenues and the underlying cost being recovered, or differences between actual revenues and targeted amounts as approved by the applicable state regulatory bodies.

Recovery of acquisition premium: This represents the unrecovered amount (plus related taxes) by which the purchase price paid exceeded the net book value of Colonial Gas' assets in the 1998 acquisition of Colonial Gas by Eastern Enterprises, Inc. In exchange for certain rate concessions and the achievement of certain merger savings targets, the DPU has allowed Colonial Gas to recover the acquisition premium through rates for the next 26 years (through August 2039).

Storm costs: This regulatory asset represents the incremental operation and maintenance costs to restore power to customers resulting from major storms.

Carrying Charges

The Company records carrying charges on the regulatory balances related to rate adjustment mechanisms, storm costs, gas costs, postretirement benefits, environmental costs and revenue decoupling for which cash expenditures have been made and are subject to recovery or for which cash has been collected and is subject to refund. The regulatory items above are not included in the utility rate base at the time the expenses are incurred or the revenue is billed. Carrying charges are not recorded on items for which expenditures have not yet been made. The Company anticipates recovering these costs in the rates concurrently with future cash expenditures. If recovery is not concurrent with the cash expenditures, the Company will record the appropriate level of carrying charges. Carrying charges are not earned on regulatory deferred tax assets, losses on reacquired debt, renewable energy credits, transmission service, acquisition premium, derivative contracts and certain postretirement benefits and environmental costs.

The following table presents the carrying charges that were recognized in the accompanying consolidated statements of income during the years ended March 31, 2013 and March 31, 2012:

	March 31,	
	2013	2012
	(in millions of dollars)	
Other interest income (expense), including affiliate interest	**$ 18**	$ (42)
Other (deductions) income, net	**(9)**	45
	$ 9	$ 3

Rate Matters

The Company's regulated subsidiaries are involved in numerous regulatory rate cases and proceedings as follows:

New England Power

The FERC enables transmission companies to recover their specific costs of providing transmission service. Additionally, NEP has received authorization from the FERC to recover through CTCs, substantially all of the costs associated with its former generating business not recovered through their divestiture. Therefore, substantially all of NEP's business, including the recovery of its stranded costs, remains under cost-based rate regulation.

Under settlement agreements approved by state commissions and the FERC, NEP is permitted to recover costs associated with its former generating investments (nuclear and nonnuclear) and related contractual commitments that were not recovered through the sale of those investments (stranded costs). Stranded costs are recovered from NEP's affiliated former wholesale customers with whom it has settlement agreements through a CTC. NEP's affiliated former wholesale customers in turn recover the stranded cost charges through delivery charges to their distribution customers. NEP earns a ROE of approximately 11% on stranded cost recovery. NEP will recover remaining stranded costs through 2020.

NEP is a Participating Transmission Owner ("PTO") in the New England region operated by the Regional Transmission Organization ("RTO"), ISO-NE, which commenced operations effective February 1, 2005. The ISO-NE has been authorized by the FERC to exercise the operations and system planning functions required of RTOs and is the

independent regional transmission provider under the ISO-NE Open Access Transmission Tariff ("ISO-NE OATT"). The ISO-NE OATT is designed to provide non-discriminatory open access transmission services over the transmission facilities of the PTOs and recover their revenue requirements. The FERC issued a series of orders in 2004 and 2005 that approved the establishment of the RTO.

On September 30, 2011, several state and municipal parties in New England, including the Massachusetts Attorney General's Office ("Attorney General"), the Connecticut Public Utilities Regulatory Authority and the DPU ("Complainants"), filed with the FERC a complaint under Section 206 of the Federal Power Act against certain New England Transmission Owners, including NEP ("NETOs"), to lower the base ROE for transmission rates in New England from the FERC approved rate of 11.14%, to 9.2%. On May 3, 2012, the FERC set the matter for hearing and settlement procedures. A hearing on the initial complaint commenced on May 6, 2013 and concluded on May 10, 2013.

On August 6, 2013, a FERC Administrative Law Judge ("ALJ") issued an Initial Decision in the complaint proceeding, finding that the just and reasonable base ROE for the refund period is 10.6% and the just and reasonable base ROE for the prospective period is 9.7%, prior to any adjustments that would be applied by the FERC in a final order based on the change in 10-year US Treasury Bond rates from the date hearings closed to the date of the FERC's order. The refund period is the 15-month period from October 1, 2011 through December 31, 2012. The prospective period begins when the FERC issues its order on the Initial Decision. An ALJ's Initial Decision does not itself affect the ROE rate or create an obligation to issue refunds to customers. Instead, the FERC will act on the Initial Decision and adopt or modify the ALJ's recommendations in an order that is expected no sooner than early 2014. Although the ALJ's Initial Decision is non-binding upon the FERC, based on an evaluation of facts and circumstances, and consideration of the accounting guidance for contingencies, the Company has recorded an estimated reduction to revenues of $7.1 million and $0.2 million of interest expense for the fiscal year ended March 31, 2013. In addition, the following has been recorded: (1) a regulatory liability of $5.9 million for the portion which would be refunded to the customers of affiliated local electric distribution companies through existing rate agreements, and (2) an accrued liability of $1.4 million for the portion which would be refunded to non-affiliated transmission customers.

On December 27, 2012, a new ROE complaint was filed against the NETOs by a coalition of consumers seeking to lower the base ROE for New England transmission rates to 8.7% effective as of December 27, 2012. The FERC has not yet acted on this complaint.

In September 2008, NEP, Narragansett, and Northeast Utilities jointly filed an application with the FERC to recover financial incentives for the New England East-West Solution ("NEEWS"), pursuant to the FERC's Transmission Pricing Policy Order, 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 the tri-state area of Connecticut, Massachusetts, and Rhode Island. Effective November 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 ("CWIP") in rate base and (3) recovery of plant abandoned for reasons beyond the companies' control.

Niagara Mohawk

March 2013 Electric and Gas Filing

On April 27, 2012, Niagara Mohawk filed with the NYPSC to adjust its base electric and gas rates. Niagara Mohawk's filing sought to increase electric delivery base revenues by approximately $130.7 million and gas delivery base revenues by approximately $39.8 million. In October 2012, the Department of Public Service ("DPS") Staff of the NYPSC ("Staff"), Niagara Mohawk and other parties reached a comprehensive agreement to settle both cases. A joint proposal formalizing the settlement agreement was filed December 7, 2012 and Niagara Mohawk received a final order from the NYPSC in these proceedings in March 2013. The term of the new rate plan is from April 1, 2013 through March 31, 2016. The joint proposal provides for an increase in the electric revenue requirement of $43.4 million in the first year, an increase of $51.4 million in the second year, and an increase of $28.3 million in the third year. It also provides for a decrease in the gas revenue requirement of $3.3 million in the first year, and increases of $5.9 million and $6.3 million in the second and third years, respectively.

Transmission ROE Complaint

On September 11, 2012, the New York Association of Public Power filed with the FERC a complaint under Section 206 of the Federal Power Act against Niagara Mohawk, seeking to have the base ROE for transmission service from the FERC approved rate of 11.5% which includes a NYISO participation incentive adder, lowered to 9.49%. Similarly, on November 2, 2012 the Municipal Electric Utilities Association ("MEUA") filed a Section 206 complaint with the FERC seeking to lower Niagara Mohawk's ROE to 9.25% including the NYISO participation adder. MEUA also challenges certain aspects of Niagara Mohawk's transmission formula rate. At this time, Niagara Mohawk cannot predict the outcome of the complaint. Any change in the ROE would not have an impact on net income because the retail rate plan fully reconciles any increase or decrease in wholesale transmission revenue under the FERC Transmission Service Charge rate through a Transmission Revenue Adjustment Clause mechanism.

Wholesale Transmission Service Charge

On March 29, 2013, Niagara Mohawk filed with the FERC to amend Niagara Mohawk's Scheduling, System Control and Dispatch Costs formula under the Wholesale Transmission Service Charge to incorporate costs incurred by Niagara Mohawk for Reliability Support Services ("RSS"), which are for the purpose of securing the ongoing reliability of NGUSA's transmission system. On August 30, 2013, the FERC rejected the Company's request without prejudice to make a new filing to provide additional support for recovery of RSS costs. The Company plans to submit the additional filing in fiscal year 2014.

Other Regulatory Matters

The NYPSC's January 2011 Order in Niagara Mohawk's 2010 electric rate case (the "January 2011 Electric Rate Case Order") required an audit relating to Niagara Mohawk's service company cost allocations, policies and procedures. In February 2011, the NYPSC selected Overland Consulting Inc. ("Overland"), a management consulting firm, to perform the audit of Niagara Mohawk, KeySpan Gas East Corporation and Brooklyn Union Gas Company. Management has evaluated the need for and amount of a reserve based on consideration of the matters set out in the audit and taking into account all known information about the audit related to transaction testing, normalization adjustments, efficiency adjustments and the impact of our new cost allocation methodologies. As of December 31, 2011, Niagara Mohawk had reserved $50 million based on the identified issues above. Overland issued a final report identifying approximately $5 million of service company overcharges to Niagara Mohawk based on extrapolated test results, which Niagara Mohawk is contesting. On January 18, 2013 the NYPSC issued an order commencing a new proceeding to determine what, if any, ratemaking adjustments are appropriate. The Company determined that the revenue subject to refund that was previously contingent in the amount of $44.7 million is no longer probable of refund and has been recognized in income. A reserve of $5.3 million has been recorded in Niagara Mohawk's financial statements as of March 31, 2013 and $5.0 million and $15.0 million have been recorded in KeySpan Gas East Corporation's and Brooklyn Union Gas Company's financial statements, respectively. Niagara Mohawk does not believe that the outcome of this matter will have a material impact on its financial position, results of operations, or cash flows.

In February 2013, the NYPSC initiated a comprehensive management and operational audit of NGUSA's New York gas businesses, including Niagara Mohawk, pursuant to the Public Service Law requirement that major electric and gas utilities undergo an audit every five years. On June 13, 2013, the NYPSC selected NorthStar Consulting Group to conduct the audit, which commenced in July 2013. At the time of the issuance of these financial statements, the Company cannot predict the outcome of this management and operational audit.

On August 15, 2013, the NYPSC initiated a focused operations audit of the investor owned New York utilities, including Niagara Mohawk, KeySpan Gas East Corporation and The Brooklyn Union Gas Company. The purpose of the audit is to review the accuracy of electric interruption, gas safety, and customer service data reported to the NYPSC. An auditor is scheduled to be selected by the NYPSC in November 2013 with the audit commencing in December. At the time of the issuance of these financial statements, the Company cannot predict the outcome of this operations audit.

Temporary State Assessment Pursuant to PSL Section 18-a

In June 2009, Niagara Mohawk made a gas and electric compliance filing with the NYPSC regarding the implementation of the Temporary State Energy & Utility Conservation Assessment ("Temporary State Assessment"). The NYPSC authorized recovery of the costs required for payment of the Temporary State Assessment, including carrying charges, subject to reconciliation over the five years of July 1, 2009 through June 30, 2014. On June 14, 2013, Niagara Mohawk

submitted a compliance filing proposing to maintain the currently effective surcharge. The estimated Temporary State Assessment filed amounted to $55.1 million and $15.0 million for electric and gas, respectively.

Compliance Filing to Eliminate Competitive Transition Charges from Electric Rates and Petition to Recover Certain Deferral Balances

On July 29, 2011, Niagara Mohawk made a compliance filing with the NYPSC to remove Competitive Transition Charges from electric rates and recover certain deferral account balances. In the January 2011 Electric Rate Case Order, the NYPSC directed Niagara Mohawk to file tariff revisions, to become effective January 1, 2012, to remove the Competitive Transition Charges from rates and establish a mechanism to recover certain deferral account balances. Niagara Mohawk has proposed eliminating $544.9 million of Competitive Transition Charges from rates partially offset by the proposed recovery of $236.2 million of outstanding deferral account balances over a 15-month period. On December 16, 2011, the NYPSC approved Niagara Mohawk's compliance filing with modifications. The NYPSC authorized Niagara Mohawk to recover $247.6 million in outstanding deferral account balances over a 15-month period, but conditioned recovery on Staff's ability to audit. Included in the $247.6 million was $25.2 million of Hurricane Irene storm costs that the NYPSC allowed Niagara Mohawk to recover, subject to Staff audit and disposition, which is pending. In addition, the NYPSC extended the amortization period beyond 15-months for Niagara Mohawk's PSC 214 customer classes. The balance of the deferrals not recovered from these classes during the 15-month period will be recovered from these classes over a subsequent period to be determined in Niagara Mohawk's next rate case.

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

Rates for services rendered by the Massachusetts Electric Companies are subject to approval by the DPU. The DPU approved a revenue decoupling mechanism ("RDM") arising from the Massachusetts Electric Companies' 2009 distribution rate case. In connection with the Massachusetts Electric Companies' first RDM filing made in November 2010 and supplemented in February 2011, the DPU opened a proceeding in March 2011, as requested by the Attorney General, for an independent audit of the Massachusetts Electric Companies' 2009 capital investments which, in part, formed the basis for the Massachusetts Electric Companies' RDM rate adjustment. The selection of an auditor, following a competitive solicitation process that has been completed, is at the discretion of the DPU. The Company cannot currently predict the outcome of this proceeding.

In November 2012, the Massachusetts Electric Companies made their annual RDM filing in which the Massachusetts Electric Companies estimated an under recovery of the 2012 annual target revenue. The Massachusetts Electric Companies made a supplemental filing in February 2013 to present the final under recovery of the 2012 annual target revenue of approximately $14.6 million and proposed an RDM factor which went into effect on March 1, 2013. The Massachusetts Electric Companies also filed proposed Net CapEx factors to recover the 2013 revenue requirement of approximately $18.4 million associated with 2009, 2010, and 2011 incremental capital investment recorded since December 31, 2008.

The Massachusetts Electric Companies are allowed to recover non-capitalized pension and PBOP costs outside of base rates through a separate factor. As a result, the Massachusetts Electric Companies are authorized to recover all pension and PBOP expenses from their customers. The difference in the costs of the Massachusetts Electric Companies' pension and PBOP plans from the amounts billed through this separate factor is deferred as a regulatory asset or liability to be recovered or refunded over the following three years.

As part of their last general rate case, the Massachusetts Electric Companies received approval from the DPU to recover approximately $65.7 million of incremental costs associated with a December 2008 winter storm ("December 2008 Storm") subject to further DPU review, reconciliation and demonstration by the Massachusetts Electric Companies that they reasonably and prudently incurred the costs. On April 1, 2011, the Massachusetts Electric Companies filed an audit report of costs incurred to restore electric service following the December 2008 Storm. On December 7, 2011 the DPU issued an interlocutory order requiring the companies to file testimony in support of the reasonableness and prudency of the costs. On March 1, 2012 the Massachusetts Electric Companies filed testimony consistent with the requirements of the interlocutory order and reduced their request for recovery to $64.9 million. On July 3, 2012, the Attorney General issued rebuttal testimony challenging certain of the Massachusetts Electric Companies' costs. Hearings were held at the DPU in August 2012. Following the hearings, the Massachusetts Electric Companies reduced their request for recovery to $64.8 million.

The Massachusetts Electric Companies have deferred net costs of approximately $214 million as of March 31, 2013, net of customer contributions to the Massachusetts Electric Companies' Storm Contingency Fund, to restore power associated with several major weather events occurring since January 2010, pending ultimate approval by the DPU to charge its deferred costs to the Massachusetts Electric Companies' Storm Contingency Fund. This amount represents approximately $228 million of deferred storm costs, excluding net carrying costs of $16 million. On March 5, 2013, the Massachusetts Electric Companies filed with the DPU a request for accelerated funding for the Massachusetts Electric Companies' Storm Contingency Fund of $40 million per year over a period of up to five years, or $200 million. On May 3, 2013, the DPU approved $40 million annually for up to three years, or $120 million. In its ruling, the DPU also directed the Massachusetts Electric Companies to submit two filings of all documentation supporting their storm costs for DPU approval. The Massachusetts Electric Companies submitted the first filing for $128 million of costs on May 31, 2013 for qualifying storms occurring during calendar years 2010 and 2011. The Massachusetts Electric Companies must submit documentation of storm costs incurred during calendar year 2012 and January and February 2013 by December 31, 2013. The Company cannot currently predict the outcome of any proceedings related to storm cost recovery.

In addition to the rates and tariffs put into effect following its most recent rate case, Massachusetts Electric continues to be authorized to recover costs associated with the procurement of electricity for its customers, all transmission costs, and costs charged by Massachusetts Electric's affiliate, NEP, for stranded costs associated with NEP's former electric generation investments.

Other Regulatory Matters

In January 2011, the DPU opened an investigation into the Massachusetts Electric Companies' preparation and response to a December 2010 winter storm. The DPU has the authority to issue fines not to exceed approximately $0.3 million for each violation for each day that the violation persists. On September 22, 2011, the DPU approved a settlement between the Massachusetts Electric Companies and the Attorney General that included a $1.2 million refund to customers. The DPU also investigated the Massachusetts Electric Companies' response to Tropical Storm Irene and the October 2011 winter storm in a consolidated proceeding. On December 11, 2012, the DPU issued an order in which it assessed the Massachusetts Electric Companies a penalty of $18.7 million associated with the Massachusetts Electric Companies' performance in responding to these two weather events, consisting of $8.1 million for Tropical Storm Irene and $10.6 million for the October 2011 winter storm. The Massachusetts Electric Companies have appealed this ruling, however credited customers during March 2013 subject to recoupment of the amount of penalty, if any, vacated by the court pursuant to the Massachusetts Electric Companies' appeal. In addition, in its order, the DPU ordered a management audit of the Massachusetts Electric Companies' emergency planning, outage management, and restoration. The Massachusetts Electric Companies cannot predict the outcome of the appeal or of the management audit.

Energy Efficiency and Renewables

Pursuant to the 2008 Green Communities Act, the Massachusetts Legislature mandated large scale and innovative ideas for implementing renewable and alternative energy sources, as well as increased energy efficiency spending. On January 28, 2013, the DPU approved the Massachusetts Electric Companies' second three-year energy efficiency plan which covers calendar years 2013 through 2015 and which significantly expands energy efficiency spending. The Massachusetts Electric Companies' approved electric energy efficiency budget for calendar years 2013 through 2015 is approximately $680 million. In addition to cost recovery, the Massachusetts Electric Companies have the opportunity to earn performance incentives over the 3-year period of the plan.

In October 2009 the DPU approved the Massachusetts Electric Companies' proposal to construct, own, and operate approximately 5 MW of solar generation on five separate properties owned by the Massachusetts Electric Companies and/or their affiliates in Dorchester, Everett, Haverhill, Revere, and a location on the Sutton/Northbridge border. The actual capital cost of the projects amounted to $29 million. As each unit went into service, the Massachusetts Electric Companies requested and received approval to recover the costs of each site with a return equal to the weighted average cost of capital approved by the DPU in the Massachusetts Electric Companies' most recent rate proceeding. The Massachusetts Electric Companies requested rate adjustments under this mechanism for the Sutton/Northbridge facility in August 2010 for recovery of approximately $1.0 million, and for the Revere, Everett and Haverhill facilities in February 2011 for recovery of approximately $2.5 million. In February 2012, the Massachusetts Electric Companies filed for recovery of approximately $1.4 million associated with the Dorchester facility. In each instance, the DPU issued an order approving recovery subject to its ongoing review and further investigation and reconciliation of the Massachusetts Electric Companies' costs for the sites. The DPU has issued final orders approving recovery for each of the sites.

In May 2010, the Massachusetts Electric Companies announced that they entered into a 15-year power purchase agreement with Cape Wind Associates, LLC to purchase half of the energy, capacity and renewable energy credits generated by a proposed offshore wind project with capacity of up to 468 MW. The base price is specified at 18.7 cents per kilowatt hour beginning in 2014 and is subject to escalation by 3.5% in each annual period thereafter. The base price can be adjusted based on several factors, including eligibility for tax credits, the size of the facility, financing and construction costs, and performance. In November 2010, the DPU approved the contract including the Massachusetts Electric Companies' proposed cost recovery mechanism with 4% remuneration on the contract cost, as provided for by the Green Communities Act. The Supreme Judicial Court of Massachusetts affirmed the DPU Order approving the contract on December 28, 2011. Cape Wind expects the project to achieve initial commercial operation in May 2016. Construction of the project has not yet begun.

Narragansett

On December 20, 2012, the RIPUC approved a settlement agreement amongst the Rhode Island Division of Public Utilities and Carriers ("Division"), the Department of the Navy, and Narragansett which provide for an increase in electric base distribution revenue of $21.5 million and an increase in gas base distribution revenue of $11.3 million based on a 9.5% allowed ROE and a common equity ratio of approximately 49.1%, effective February 1, 2013. The settlement also included reinstatement of base rate recovery of storm fund contributions at a level of $4.8 million per year, implementation of a pension adjustment mechanism for pension and PBOP expenses for the electric business identical to the mechanism in place for the gas business; and implementation of a property tax adjustment mechanism. New rates resulting from the approved settlement went into effect for both the electric and gas business on February 1, 2013.

In May 2010, Rhode Island enacted a decoupling law that provides for the annual reconciliation of the revenue requirement allowed in Narragansett's base distribution rate case to actual revenue billed by the electric and gas business. The new law also provides for submission and approval of an annual infrastructure spending plan spanning the fiscal year April 1 through March 31 without having to file a full general rate case. In the fiscal year 2013 plans, Narragansett requested a revenue requirement increase of approximately $4.1 million for the electric business and $5.4 million for the gas business, which the RIPUC approved for rates effective April 1, 2012. Because Narragansett's 2012 rate base included forecasted capital investment through January 31, 2014, Narragansett's fiscal year 2014 infrastructure spending plans represented only two months of fiscal year 2014 to reflect investment not included in Narragansett's gas and electric distribution rates. In the plans, Narragansett requested a revenue requirement of $0.7 million for gas and $12.1 million for electric, which the RIPUC approved on March 21, 2013 and March 22, 2013, respectively.

Narragansett's affiliate, NEP operates the transmission facilities of its New England affiliates as a single integrated system and reimburses Narragansett for the cost of its transmission facilities in Rhode Island, including a return on those facilities, under NEP's Tariff No. 1. In turn, these costs are allocated among transmission customers in New England in accordance with the ISO New England transmission tariff. Effective June 1, 2007, the FERC approved amendments to Tariff No. 1 whereby Narragansett is compensated for its actual monthly transmission costs with its authorized ROE ranging from 11.14% to 12.64%.

In August 2012, Narragansett made its annual distribution adjustment charge ("DAC") filing for its gas business. The DAC was established to provide for the recovery and reconciliation of the costs of identifiable special programs, as well as to facilitate the timely revenue recognition of incentive provisions. On October 31, 2012, the RIPUC approved a DAC rate that resulted in recovery of approximately $13.3 million from customers for the period November 2012 through October 2013. In August 2013, Narragansett made its annual DAC filing for its gas business. The latest DAC seeks to recover $11.7 million from customers for the period November 2013 through October 2014.

Narragansett is allowed recovery of all of its electric and gas commodity costs through a fully reconciling rate recovery mechanism. In addition, Narragansett is allowed to recover from its electric customers all of its electric transmission costs and costs charged by Narragansett's affiliate NEP for stranded costs associated with NEP's former electric generation investments.

Long-Term Contracts for Renewable Energy

In 2009, Rhode Island passed a law promoting the development of renewable energy resources through long-term contracts for the purchase of capacity, energy, and attributes. The law also required Narragansett to negotiate a contract for an electric generating project fueled by landfill gas from the Rhode Island Central Landfill. The project, referred to as

the Town of Johnston Project, is a combined cycle power plant with an average output of 32 MW for which Narragansett entered into a contract with Rhode Island LFG Genco, LLC in June 2010. The facility reached commercial operation on May 28, 2013.

The 2009 law also required Narragansett to solicit proposals for a small scale renewable energy generation project of up to eight wind turbines with an aggregate nameplate capacity of up to 30 MW to benefit the Town of New Shoreham that also included a transmission cable to be constructed between Block Island and the mainland of Rhode Island. On June 30, 2010, Narragansett entered into a 20-year amended power purchase agreement with Deepwater Wind Block Island LLC ("Deepwater"), which was approved by the RIPUC in August 2010. Narragansett is currently negotiating with Deepwater to purchase the permits, engineering, real estate and other site development work for construction of the undersea transmission cable. Narragansett intends to file an unexecuted copy of the purchase agreement with the Division for review and consent in late 2013, following which Narragansett will make a filing with the FERC to recover the costs associated with the cable in transmission rates.

On July 28, 2011, the RIPUC unanimously approved a 15-year power purchase agreement with Orbit Energy Rhode Island, LLC for a 3.2 MW anaerobic digester biogas project. This is the first power purchase agreement that Narragansett submitted to the RIPUC for review as a result of Narragansett's annual solicitation process that was approved by the RIPUC on March 1, 2010. Following Narragansett's second annual solicitation, Narragansett executed a 15-year power purchase agreement with Black Bear Development Holdings, LLC on February 17, 2012, for a 3.9 MW run-of-river hydroelectric plant located in Orono, Maine. Narragansett submitted the contract to the RIPUC on March 19, 2012. The RIPUC approved the contract on May 11, 2012. On August 2, 2013, the Company executed a 15-year power purchase agreement with Champlain Wind, LLC for a 48 MW land-based wind project in Carroll Plantation and Kossuth Township, Maine for a fixed bundled price of $78.00 per megawatt hour ("Mwh"). The Company filed the contract with the RIPUC on September 3, 2013 and responded to four record requests the RIPUC issued to the Company during a hearing held on October 9, 2013. The RIPUC will hold an open meeting on October 25, 2013.

In June 2011, Rhode Island established a 10% carve out to the 90 MW of long-term contracting requirement for renewable energy to be used for long-term contracts for smaller distributed generation projects over a four year period from 2011 through 2014. From 2011 through April 2013, Narragansett conducted four distributed generation enrollments and awarded contracts for a total of approximately 18.4 MW of project nameplate capacity. In early July 2013, the Rhode Island legislature passed an amendment to state law that extended the deadline for meeting 100% of the long-term contract capacity from December 30, 2013 to December 30, 2014.

Energy Efficiency

On December 21, 2011, the RIPUC approved the annual Energy Efficiency ("EE") plan for the calendar year 2012, which included a portfolio of electric and gas energy efficiency programs along with the associated budgets and electric and gas EE program charges effective January 1, 2012. The calendar year 2012 electric and gas EE programs contained spending budgets of approximately $61.4 million and $13.7 million, respectively, which are to be collected through the approved EE program charges. On November 2, 2012, Narragansett filed its EE plan for the calendar year 2013 with proposed electric and gas spending budgets of $77.5 million and $19.5 million, respectively. The 2013 annual plan also contains a newly proposed combined heat and power ("CHP") program pursuant to a newly enacted amendment to the Rhode Island least cost procurement statute to support the development of CHP projects through energy efficiency. The plan consists of enhanced incentives and a proposed tariff amendment to assure that customers who receive incentives under the CHP program will continue to pay a fair share of the costs of the distribution system when the CHP unit is offline. The plan was approved by the RIPUC and reflected in rates effective January 1, 2013. On March 5, 2013, Narragansett filed a Petition with the RIPUC for approval of a $15.9 million incentive package to Toray Plastics (America), Inc. to install a 12.5 MW CHP system at their manufacturing facilities in North Kingstown, Rhode Island. This is the first incentive package offered pursuant to the 2013 EE Plan and the new law. The RIPUC approved the incentive package on June 20, 2013. The Company will file its 2014 annual program plan on November 1, 2013.

Brooklyn Union and KeySpan Gas East (the "New York Gas Companies")

Rate Matters

The New York Gas Companies are subject to a rate plan with a primary term of five years (through December 31, 2012) that remains in effect until modified by the NYPSC. Base delivery rates are based on an allowed ROE of 9.8%. An earnings sharing mechanism in the rate plan is triggered if annual earnings result in a ROE that exceeds 10.5%. Earnings

above this threshold are shared with customers. Brooklyn Union recorded excess earnings sharing of $35 million related to the rate year ended December 31, 2011.

On February 22, 2013, a joint proposal was filed with the NYPSC that memorialized an agreement between Staff and Brooklyn Union for a two year rate settlement covering Brooklyn Union's rate years ending December 31, 2013 and December 31, 2014. On June 13, 2013, the NYPSC issued an order adopting the settlement. As a result, Brooklyn Union's revenue requirements for calendar years 2013 and 2014 have changed as follows: (i) there is no change in base delivery rates, other than those previously approved by the NYPSC in the rate plan, (ii) the allowed ROE has decreased from 9.8% to 9.4%, and (iii) the common equity ratio in the capital structure has increased from 45% to 48%. Additionally, the joint proposal provides that 80% of any earnings above the 9.4% allowed return will be applied as a credit to Brooklyn Union's SIR balance for the benefit of customers.

Carrying Charges

During fiscal year 2013, the New York Gas Companies received an order from the NYPSC relating to SIR, requiring that carrying charges on SIR related balances be calculated net of deferred taxes. As a result, management concluded that all of its carrying charges should be calculated in the same manner and recognized impairment on existing carrying charges deferred within regulatory assets of $62.7 million and derecognized existing carrying charges accrued within regulatory liabilities of $32.2 million.

Other Regulatory Matters

In June 2009, the New York Gas Companies made a compliance filing with the NYPSC regarding the implementation of the Temporary State Assessment. The NYPSC authorized recovery of the revenues required for payment of the Temporary State Assessment subject to reconciliation over five years, July 1, 2009 through June 30, 2014. On June 14, 2013, the New York Gas Companies submitted a compliance filing proposing to maintain the currently effective combined surcharge of $38.9 million for the July 1, 2013 through June 30, 2014 collection period. The New York Gas Companies had a combined deferred payable balance related to the Temporary State Assessment in the amount of $12.7 million at March 31, 2013. The New York Gas Companies had a combined deferred receivable balance related to the Temporary State Assessment in the amount of $4.6 million at March 31, 2012.

In February 2011, the NYPSC selected Overland Consulting Inc., a management consulting firm, to perform a management audit of NGUSA's affiliate cost allocation, policies and procedures. The audit of these service company charges sought to determine if any service company transactions have resulted in unreasonable costs to New York customers for the provision of delivery service. A final report was provided to the New York Gas Companies by the NYPSC in October 2012. In its January 16, 2013 Order Directing Submission of Implementation Plan and Establishing Further Findings, the NYPSC disclosed the findings of the Overland Audit of the affiliate cost allocations, policies and procedures of NGUSA's service companies as applicable to its New York utilities. The final audit report concluded that the New York Gas Companies were overcharged $35.5 million in service company related costs. The New York Gas Companies dispute the audit conclusions as they believe that sampling amounts found by Overland to be in error should not have been extrapolated to the larger population. The NYPSC has ordered that further proceedings be conducted to address the New York Gas Companies' disagreement with the testing results and statistical extrapolation. Reserves of $5.0 million and $15.0 million have been recorded in KeySpan Gas East Corporation's and Brooklyn Union Gas Company's financial statements, respectively.

On December 2009, the NYPSC adopted the terms of a Joint Proposal between Staff and the New York Gas Companies that provided for a RDM to take effect as of January 1, 2010. The RDM applies only to the New York Gas Companies' firm residential heating sales and transportation customers, and permits the New York Gas Companies to reconcile actual revenue per customer to target revenue per customer for the affected customer classes on an annual basis. The RDM is designed to eliminate the disincentive for the New York Gas Companies to implement energy efficiency programs by breaking the link between sales volumes and revenues. The New York Gas Companies had deferred receivable balances related to the RDM in the amount of $3.7 million at March 31, 2013. Payable balances are fully refundable and receivable balances fully recoverable from the affected customer class.

Boston Gas and Colonial Gas (the "Massachusetts Gas Companies")

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. In November 2010, the Massachusetts

Gas Companies filed two motions in response to the DPU's November 2010 rate order, whereby in its motion for recalculation, the Massachusetts Gas Companies had requested that the DPU recalculate certain adjustments that it made in determining the $58 million increase approved in its order, which would have resulted in an additional $10.4 million in revenue. On October 26, 2011, the DPU ruled on the Massachusetts Gas Companies' Motion for recalculation awarding them a combined increase of $2.8 million effective November 1, 2011. On January 31, 2013, the DPU ruled on the Massachusetts Gas Companies' motion for reconsideration and upheld its decision on all of the financial matters raised by the Massachusetts Gas Companies, including the disallowance of fixed asset additions of $11.3 million from calendar years 1996 to 1998 and associated depreciation expense of approximately $0.8 million, with the exception of the issue of Colonial Gas merger related costs. The combined effects of the DPU's orders are a total revenue increase of $65.3 million, with $4.5 million reflected in rates effective February 1, 2013.

In May 2011, May 2012 and May 2013, the Massachusetts Gas Companies made filings with the DPU for recovery of cumulative capital costs related to infrastructure replacement of approximately $10.4 million, $24.4 million and $37.0 million, respectively (the incremental investments were $14.0 million and $12.6 million for the May 2012 and May 2013 filings, respectively). The May 2011 and May 2012 requests have been reflected in rates effective on the following November 1, with a final resolution pending before the DPU. The May 2013 request is currently being reviewed by the DPU and, if approved, will be reflected in rates effective November 1, 2013. Boston Gas filed a revision to its May 2013 request in July 2013 based on revised cumulative capital costs of $32.5 million. A subsequent revision was filed in October 2013 to provide supporting documentation for capital costs incurred during November and December 2012. This revision did not change the cumulative capital costs of $32.5 million.

On August 3, 2012, the Massachusetts Gas Companies submitted their peak RDM filing with the DPU proposing to surcharge customers $28.6 million, and deferring $27.7 million which exceeded the allowable cap under the Massachusetts Gas Companies' RDM. The Massachusetts Gas Companies have the opportunity to recover the $27.7 million in the future. On October 12, 2012, the DPU approved the Massachusetts Gas Companies' RDAF, effective November 1, 2012, subject to further investigation and reconciliation. On September 25, 2013, the DPU issued a final order approving the peak RDAF. On January 31, 2013, the Massachusetts Gas Companies submitted their off peak RDM filing with the DPU proposing a surcharge to customers of $3.1 million, which is below the allowable cap. As with the peak RDM filing, on March 29, 2013, the DPU approved the off peak RDAF effective May 1, 2013. On August 2, 2013, the Massachusetts Gas Companies submitted their peak RDM filing with the DPU proposing to surcharge customers $8.2 million for the period November 2012 through April 2013 as well as an additional $26.5 million associated with the prior year's RDM that had exceeded the allowable cap under the Massachusetts Gas Companies' RDM. This matter is currently pending before the DPU.

Other Regulatory Matters

In August 2011, the Massachusetts Gas Companies sought approval for six natural gas asset management services agreements. On October 17, 2011, the DPU approved the agreements, which commenced on November 1, 2011 and expired on March 31, 2012. Under these agreements, the Massachusetts Gas Companies were eligible to share in 25% of the asset management fees that are clearly attributable to capacity release activities above the prior year's margin threshold as directed in the DPU's Order, and pursuant to the incentive sharing mechanism set forth in DPU 91-141-A. The Massachusetts Gas Companies earned $1 million from May 2011 to April 2012 per the mechanism. Effective February 20, 2013, by order of the DPU, the mechanism for the sharing of margins under such optimization transactions has been revised whereby the Massachusetts Gas Companies retain 10% of all margins earned from contracts entered into after the effective date, without regard to a threshold. There were no such agreements in effect as of March 31, 2013.

On June 1, 2011, in conjunction with the DPU's annual investigation of the Boston Gas calendar year 2009 pension and PBOP rate reconciliation mechanism, the Attorney General argued that Boston Gas be obligated to provide carrying charges to the benefit of customers on its PBOP liability balances related to its 2003 to 2006 rate reconciliation filings. In August 2010, the DPU ordered Boston Gas to provide carrying charges on its PBOP liability balances on its 2007 and 2008 rate reconciliation filings, but the order was silent about providing carrying charges prior to those years. The matter is pending before the DPU.

Associated with its general rate case, the DPU opened an investigation to address the allocation and assignment of costs to the Massachusetts Gas Companies by the NGUSA service companies. In June 2011, the Attorney General requested that the DPU expand the scope of the audit to address the allocation and assignment of costs to the Massachusetts Gas Companies' electric distribution affiliates by the NGUSA service companies and to review NGUSA's cost allocation practices. The Massachusetts Gas Companies and Massachusetts Electric Companies agreed to expand the scope of the

audit to include the Massachusetts Electric Companies. On March 12, 2012 the DPU issued an order confirming that the scope of the audit would include the Massachusetts Electric Companies and directing the Massachusetts Gas Companies to revise their draft request for proposal consistent with the DPU's order and re-file it within seven days. The Massachusetts Gas Companies cannot predict the outcome of this proceeding.

Energy Efficiency

The Massachusetts Gas Companies operate a single combined Three-Year Energy Efficiency Plan. The recent plan covering the period 2013 through 2015 was approved by the DPU on January 31, 2013 with a three-year budget of $290.8 million ($94.2 million for 2013, $97.0 million for 2014, and $99.6 million for 2015). In addition, the Massachusetts Gas Companies have the opportunity to recover a total performance incentive over the three-year plan of approximately $8.3 million dollars with a fixed amount to be collected in the budget for each year of the plan. After the conclusion of the plan, the Massachusetts Gas Companies will reconcile the energy efficiency surcharge amounts as well as amount collected for the performance incentives.

National Grid Generation

In January 2009, our indirectly-owned subsidiary, National Grid Generation filed an application with the FERC for a rate increase of $92 million for the final five year rate term of the fifteen year contract under the PSA. In December 2009, the FERC approved the proposed tariff rates, effective from February 1, 2009, subject to refund and the outcome of any proceedings instituted by the FERC. In October 2009, LIPA and National Grid Generation filed a settlement with the FERC for a revenue requirement of $436 million, an annual increase of approximately $66 million, a ROE of 10.75% and a capital structure of 50% debt and 50% equity, which was approved by the FERC in January 2010. All outstanding balances associated with the revenue increases were settled in March 2010.

On October 2, 2012, National Grid Generation announced it had reached an agreement with LIPA to amend and restate the current PSA (the "A&R PSA") upon expiration of the current agreement. Pursuant to the A&R PSA, LIPA will continue to purchase all of the energy and capacity from the generating units designated in the PSA. The A&R PSA has a term of fifteen years, expiring April 2028, provided LIPA has the option to terminate the agreement as early as April 2025 on two years advance notice. On May 23, 2013, the FERC accepted the PSA, and approved a revenue requirement of $418.6 million, an annual decrease of $27.4 million, a ROE of 9.75% and a capital structure of 50% debt and 50% equity. The PSA became effective as of May 28, 2013.

Note 3. Employee Benefits

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

Pension Plans

The Pension Plans are comprised of both qualifying and non-qualifying plans. The qualified pension plans 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. We fund the qualified plans by contributing at least the minimum amount required under IRS regulations. The Company expects to contribute approximately $278 million to the Pension Plans during fiscal year 2014.

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. We fund these plans based on the requirements of the various regulatory jurisdictions in which the Company operates. The Company expects to contribute approximately $298 million to the PBOP Plans during fiscal year 2014.

Defined Contribution Plan

The Company also has several defined contribution pension plans (primarily 401(k) employee savings fund plans) that cover substantially all employees. In addition, employees may receive certain employer contributions, including matching contributions and a 15% discount on the purchase of National Grid plc common stock. Employer matching contributions of approximately $30 million and $35 million, respectively, were expensed in the years ended March 31, 2013 and March 31, 2012.

Net Periodic Costs and Amount Recognized in Regulatory Assets (Liabilities) and Other Comprehensive Income

The following table summarizes the Company's Pension Plans and PBOP Plans costs during the years ended March 31, 2013 and March 31, 2012:

	Pension Plans		PBOP Plans	
	March 31,		**March 31,**	
	2013	2012	**2013**	2012
	(in millions of dollars)			
Service cost, benefits earned during the year	**$ 133**	$ 118	**$ 68**	$ 60
Interest cost	**361**	371	**207**	223
Expected return on plan assets	**(414)**	(425)	**(145)**	(131)
Net amortization and deferral	**275**	212	**111**	96
Settlements/curtailments	**7**	-	**(2)**	-
Special termination benefits	**-**	1	**-**	-
Total cost	**$ 362**	$ 277	**$ 239**	$ 248

All of the Company's regulated subsidiaries have regulatory recovery of these costs and therefore have recorded related regulatory assets (liabilities) in the accompanying consolidated balance sheets. Other subsidiaries that do not receive regulatory recovery of these costs are recorded as part of operations and maintenance expense in the accompanying consolidated statements of income.

The following table summarizes changes in amounts recorded to regulatory assets (liabilities) and accumulated other comprehensive income during the years ended March 31, 2013 and March 31, 2012:

	Pension Plans		PBOP Plans	
	March 31,		**March 31,**	
	2013	2012	**2013**	2012
	(in millions of dollars)			
Net actuarial loss	**$ 150**	$ 706	**$ 227**	$ 173
Prior service cost	**11**	2	**-**	2
Amortization of gain	**(272)**	(204)	**(98)**	(86)
Amortization of prior service cost	**(9)**	(8)	**(11)**	(10)
Total	**$ (120)**	$ 496	**$ 118**	$ 79
Included in regulatory assets (liabilities)	**$ 22**	$ 209	**$ 66**	$ (1)
Included in accumulated other comprehensive income	**(142)**	287	**52**	80
Total	**$ (120)**	$ 496	**$ 118**	$ 79

The following table summarizes the Company's amounts in regulatory assets and accumulated other comprehensive income in the accompanying consolidated balance sheets that have not yet been recognized as components of net actuarial loss at March 31, 2013 and March 31, 2012, and the amount expected to be amortized during the year ended March 31, 2014:

	Pension Plans		PBOP Plans		Expected Amortization
	March 31,		**March 31,**		**March 31,**
	2013	2012	**2013**	2012	2014
			(in millions of dollars)		
Cumulative loss	**$ 1,966**	$ 2,088	**$ 905**	$ 776	**$ 348**
Prior service cost	**56**	54	**17**	27	**38**
Total	**$ 2,022**	$ 2,142	**$ 922**	$ 803	**$ 386**
Included in regulatory assets	**$ 1,067**	$ 1,045	**$ 459**	$ 393	
Included in accumulated other comprehensive income	**955**	1,097	**463**	410	
Total	**$ 2,022**	$ 2,142	**$ 922**	$ 803	

Changes in Benefit Obligations and Assets

The following table summarizes the change in the benefit obligation plans' funded status:

	Pension Plans		PBOP Plans	
	March 31,		**March 31,**	
	2013	2012	**2013**	2012
		(in millions of dollars)		
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ (7,340)**	$ (6,459)	**$ (4,213)**	$ (4,000)
Service cost	**(133)**	(118)	**(68)**	(60)
Interest cost on projected benefit obligation	**(361)**	(371)	**(207)**	(223)
Plan amendments	**(11)**	(2)	**-**	(2)
Net actuarial loss	**(379)**	(819)	**(283)**	(502)
Benefits paid	**418**	429	**194**	204
Actual Medicare Part D subsidy received	**-**	-	**(33)**	(9)
Curtailments and settlements	**3**	1	**-**	5
Divestitures	**79**	-	**21**	-
Other	**-**	(1)	**-**	374
Benefit obligation at end of year	**$ (7,724)**	$ (7,340)	**$ (4,589)**	$ (4,213)
Change in plan assets:				
Fair value of plan assets at beginning of year	**$ 6,159**	$ 5,705	**$ 1,907**	$ 1,714
Actual return on plan assets	**623**	536	**189**	82
Company contributions	**352**	347	**409**	315
Benefits paid	**(418)**	(429)	**(194)**	(204)
Settlements	**(3)**	-	**-**	-
Divestitures	**(59)**	-	**(9)**	-
Fair value of plan assets at end of year	**$ 6,654**	$ 6,159	**$ 2,302**	$ 1,907
Funded status	**$ (1,070)**	$ (1,181)	**$ (2,287)**	$ (2,306)

The benefit obligation shown above is the projected benefit obligation ("PBO") for the Pension Plans and the accumulated benefit obligation ("ABO") for the PBOP Plans. The Company is required to reflect the funded status of its Pension Plans above in terms of the PBO, which is higher than the ABO, because the PBO includes the impact of expected future compensation increases on the pension obligation. The Pension Plans had ABO balances that exceeded

the fair value of plans assets as of March 31, 2013 and March 31, 2012. The aggregate ABO balances for the Pension Plans were $7.2 billion and $6.8 billion as of March 31, 2013 and March 31, 2012, respectively.

The amounts recognized in the accompanying consolidated balance sheets are as follows:

	Pension Plans		PBOP Plans	
	March 31,		**March 31,**	
	2013	2012	**2013**	2012
	(in millions of dollars)			
Non-current assets	**$ 297**	$ 248	**$ -**	$ -
Current liabilities	**(23)**	(25)	**(11)**	(11)
Non-current liabilities	**(1,344)**	(1,404)	**(2,276)**	(2,295)
Total	**$ (1,070)**	$ (1,181)	**$ (2,287)**	$ (2,306)

The above table includes Granite State's and EnergyNorth's net pension liabilities of $8 million and PBOP liabilities of $17 million at March 31, 2012, which are reflected as assets held for sale in the Company's consolidated balance sheets.

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2013:

For the Years Ended March 31,	Pension Benefits	Postretirement Benefits
	(in millions of dollars)	
2014	$ 443	$ 187
2015	455	193
2016	462	199
2017	468	203
2018	472	207
2019-2023	2,364	1,072
Total	$ 4,664	$ 2,061

Assumptions

The weighted-average assumptions used to determine the benefit obligations for the years ended March 31, 2013 and March 31, 2012 are as follows:

	Pension Plans		PBOP Plans	
	March 31,		**March 31,**	
	2013	2012	**2013**	2012
Discount rate	4.70%	5.10%	4.70%	5.10%
Rate of compensation increase	3.50%	3.50%	n/a	n/a
Expected return on plan assets	6.75%-7.25%	6.75%-7.25%	7.25%-7.50%	7.25%-7.50%

The weighted-average assumptions used to determine the net periodic cost for the years ended March 31, 2013 and March 31, 2012 are as follows:

	Pension Plans		PBOP Plans	
	March 31,		**March 31,**	
	2013	2012	**2013**	2012
Discount rate	5.10%	5.90%	5.10%	5.90%
Rate of compensation increase	3.50%	3.50%	n/a	n/a
Expected return on plan assets	6.75%-7.25%	7.75%	7.25%-7.50%	7.25%-8.50%

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.

The assumed health care cost trend rates are as follows:

	PBOP Plans	
	March 31,	
	2013	2012
Ultimate rate to which cost trend rate gradually declines	5.00%	5.00%
Year ultimate rate is reached		
Pre 65	2019	2018
Post 65	2018	2017
Prescription	2020	2019

A one-percentage-point change in the assumed health care cost trend rate would have the following effects:

One-Percentage-Point	Increase	/ (Decrease)
	(in millions of dollars)	
Effect on postretirement obligations as of March 31, 2013	$ 688	$ (575)
Effect on annual combined service and interest cost for 2013	51	(41)

Pension Adjustment Mechanism ("PAM")

In February 2013, the RIPUC approved implementation of a PAM for Narragansett's electric operations. The PAM reconciles annual pension and PBOP expense with a base amount established in distribution rates through a base-rate proceeding and allows for recovery of the difference between the rate base amount and an annual expense. As a result of the implementation of a rate tracker, Narragansett reclassified $145.1 million, pre-tax, of accumulated other comprehensive income to regulatory assets. This reclassification is presented as an adjustment to accumulated other comprehensive income in the accompanying consolidated statements of comprehensive income.

In implementing the PAM, Narragansett will pay a carrying charge to customers at the weighted average cost of capital, which will be applied to any cumulative shortfall between the minimum funding obligation and amounts contributed to the pension and PBOP plans by Narragansett and/or its affiliated service company. The minimum funding obligation is equal to the amount of pension and PBOP costs recovered from customers, plus amounts capitalized on Narragansett's balance sheet. This carrying charge is asymmetrical, meaning that it is not applied to any excess company contributions based on the same criteria.

Plan Assets

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

The target asset allocations for the Pension Plans and PBOP Plans as of March 31, 2013 and March 31, 2012 are as follows:

	Pension Plans		PBOP Plans	
	March 31,		**March 31,**	
	2013	2012	**2013**	2012
US equities	**20%**	20%	**39%**	39%
Global equities (including US)	**7%**	7%	**6%**	6%
Global tactical asset allocation	**10%**	10%	**9%**	9%
Non-US equities	**10%**	10%	**21%**	21%
Fixed income	**40%**	40%	**25%**	25%
Private equity	**5%**	5%	**0%**	0%
Real estate	**5%**	5%	**0%**	0%
Infrastructure	**3%**	3%	**0%**	0%
	100%	100%	**100%**	100%

Fair Value Measurements

The Company determines the fair value of plan assets using unadjusted quoted prices in active markets (Level 1) or pricing inputs that are observable (Level 2) whenever that information is available. The Company uses unobservable inputs (Level 3) to estimate fair value only when relevant observable inputs are not available. Assets are classified within this fair value hierarchy based on the lowest level of inputs which significantly affect the fair value measurement.

The following tables depict by level, within the fair value hierarchy, the plan assets as of March 31, 2013 and March 31, 2012:

	March 31, 2013			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Pension Plans:				
Cash and cash equivalents	$ 4	$ 102	$ -	$ 106
Accounts receivable	141	-	-	141
Accounts payable	(124)	-	-	(124)
Equity	988	1,778	56	2,822
Global tactical asset allocation	-	261	52	313
Fixed income securities	-	2,697	56	2,753
Preferred securities	6	-	-	6
Private equity	-	-	376	376
Real estate	-	-	261	261
Total	**$ 1,015**	**$ 4,838**	**$ 801**	**$ 6,654**
PBOP Plans:				
Cash and cash equivalents	$ 94	$ 42	$ -	$ 136
Accounts receivable	8	-	-	8
Accounts payable	(7)	-	-	(7)
Equity	419	1,030	22	1,471
Global tactical asset allocation	64	79	18	161
Fixed income securities	-	517	1	518
Private equity	-	-	15	15
Total	**$ 578**	**$ 1,668**	**$ 56**	**$ 2,302**

	March 31, 2012			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Pension Plans:				
Cash and cash equivalents	$ 4	$ 157	$ -	$ 161
Accounts receivable	179	19	-	198
Accounts payable	(220)	-	-	(220)
Equity	1,211	1,299	109	2,619
Global tactical asset allocation	-	239	50	289
Fixed income securities	-	2,462	49	2,511
Preferred securities	5	-	-	5
Private equity	-	-	357	357
Real estate	-	-	239	239
Total	**$ 1,179**	**$ 4,176**	**$ 804**	**$ 6,159**
PBOP Plans:				
Cash and cash equivalents	$ 7	$ 48	$ -	$ 55
Accounts receivable	6	2	-	8
Accounts payable	(7)	-	-	(7)
Equity	471	722	41	1,234
Global tactical asset allocation	51	68	16	135
Fixed income securities	-	466	-	466
Private equity	-	-	16	16
Total	**$ 528**	**$ 1,306**	**$ 73**	**$ 1,907**

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

Accounts Receivable and Accounts Payable

Accounts receivable and accounts payable are classified in the same category as the investments to which they relate. Such amounts are short term and settle within a few days of the measurement date.

Equity and Preferred Securities

Common stocks, preferred stocks, and real estate investment trusts are valued using the official close of the primary market on which the individual securities are traded.

Equity securities are primarily comprised of securities issued by public companies in domestic and foreign markets plus investments in commingled funds, which are valued on a daily basis. The Company can exchange shares of the publicly traded securities and the fair values are primarily sourced from the closing prices on stock exchanges where there is active trading, in which case they are classified as Level 1 investments. If there is less active trading, then the publicly traded securities would typically be priced using observable data, such as bid and ask prices, and these measurements are classified as Level 2 investments. Investments that are not publicly traded and valued using unobservable inputs are classified as Level 3 investments. Commingled funds with publicly quoted prices and active trading are classified as

Level 1 investments. For investments in commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the net asset value ("NAV") per fund share, derived from the underlying securities' quoted prices in active markets, and they are classified as Level 2 investments. Investments in commingled funds with redemption restrictions and that use NAV are classified as Level 3 investments.

Global Tactical Asset Allocation

Assets held in global tactical asset allocation funds are managed by investment managers who use both top-down and bottom-up valuation methodologies to value asset classes, countries, industrial sectors, and individual securities in order to allocate and invest assets opportunistically. If the inputs used to measure a financial instrument fall within different levels of the fair value hierarchy within the commingled fund, the categorization is based on the lowest level input that is significant to the measurement of that financial instrument. The assets invested through commingled funds are classified as Level 2. Those which are open ended mutual funds are classified as Level 1 and have observable pricing. However, the underlying Level 3 assets that makeup these funds are classified in the same category as the investments to which they relate.

Fixed Income Securities

Fixed income securities (which include corporate debt securities, municipal fixed income securities, US 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. If prices are based on uncorroborated and unobservable inputs, then the investments are classified as Level 3 investments. Commingled funds with publicly quoted prices and active trading are classified as Level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, derived from the underlying securities' quoted prices in active markets, and are classified as Level 2 investments. Investments in commingled funds with redemption restrictions and that use NAV are classified as Level 3 investments.

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 net asset value.

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. As a result, the Company classifies these investments as Level 3 investments.

While management believes its valuation methodologies are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of Level 3 financial instruments could result in a different fair value measurement at the reporting date.

The following is a summary of changes in the fair value of the Pension Plans' and PBOP Plans' Level 3 investments:

	Pension Plans		PBOP Plans	
	March 31,		**March 31,**	
	2013	2012	**2013**	2012
	(in millions of dollars)			
Balance at beginning of year	**$ 804**	$ 874	**$ 73**	$ 103
Transfers out of Level 3	**(4)**	(338)	**(24)**	(55)
Transfers in to Level 3	**6**	65	**27**	11
Actual gain or loss on plan assets				
Realized gain	**17**	29	**-**	-
Unrealized gain	**37**	20	**1**	1
Purchases	**296**	457	**188**	60
Sales	**(355)**	(303)	**(209)**	(47)
Balance at end of year	**$ 801**	$ 804	**$ 56**	$ 73

Other Benefits

The Company accrued $74.6 million and $58.4 million at March 31, 2013 and March 31, 2012, respectively, regarding workers compensation, auto and general insurance claims which have been incurred but not yet reported.

Note 4. Property, Plant and Equipment

At March 31, 2013 and March 31, 2012, property, plant and equipment, at cost, along with accumulated depreciation and amortization are as follows:

	March 31,	
	2013	2012
	(in millions of dollars)	
Plant and machinery	**$ 25,195**	$ 24,061
Property held for future use	**24**	24
Land and buildings	**2,030**	1,980
Assets in construction	**1,388**	1,341
Software	**736**	552
Total	**29,373**	27,958
Accumulated depreciation and amortization	**(6,851)**	(6,637)
Property, plant and equipment, net	**$ 22,522**	$ 21,321

Note 5. Renewable Energy Credits

Legislation in Rhode Island and Massachusetts has established requirements to foster the development of new renewable energy sources through implementation of a Renewable Portfolio Standard ("RPS"). As a Retail Electricity Supplier ("RES"), the Company is required to source a minimum portion of its resources each calendar year from certain renewable or alternative energy resources, such as wind, solar, municipal waste combustion, coal gasification, cogeneration, and flywheel energy storage. To demonstrate compliance with the program, a RES can (1) obtain and deliver renewable energy credits ("RECs"); (2) contract for the output from a renewable or alternative energy resource; or (3) make an alternative compliance payment for each Mwh of obligation not met under alternatives (1) or (2).

The Company does not self-generate any RECs but rather purchases them from various providers primarily via standalone contracts. Purchased RECs are recorded within prepaid and other current assets on the accompanying balance sheets. In addition, the Company records a compliance liability based on retail electricity sales, which are classified within other current liabilities or other deferred liabilities on the accompanying balance sheets based on the period of the compliance requirement. Our costs associated with the RPS are recoverable from customers through our rate adjustment mechanism. As a result, expenses associated with the compliance obligation are deferred as a regulatory asset and

relieved through the rate adjustment mechanism. We recorded a regulatory asset of $78 million and $63 million as of March 31, 2013 and March 31, 2012, respectively.

Note 6. Derivatives

In the normal course of business, the Company enters into derivative instruments, such as swaps and physical contracts that are principally used to manage commodity prices associated with natural gas distribution operations. These financial exposures are monitored and managed as an integral part of the Company's overall financial risk management policy. The Company generally engages in activities at risk only to the extent that those activities fall within commodities and financial markets to which it has a physical market exposure in terms and volumes consistent with its core business.

Treasury Derivative Instruments- Fair Value Hedge Accounting

Financial derivatives are used for hedging purposes in the management of exposure to interest rate risk enabling the Company to optimize the overall cost of accessing debt capital markets, and mitigating the market risk which would otherwise arise from the maturity of its treasury related assets and liabilities.

Treasury related derivative instruments may qualify as either fair value hedges or cash flow hedges. The Company has entered into interest rate and cross-currency swaps that are used to protect against changes in the fair value of fixed-rate, long-term financial instruments due to movements in market interest rates. The Company has designated these instruments in fair value hedging relationships. For qualifying fair value hedges, all changes in the fair value of the derivative financial instrument and changes in the fair value of the item in relation to the risk being hedged are recognized in the consolidated statements of income. If the hedge relationship is terminated, the fair value adjustment to the hedged item continues to be reported as part of the basis of the item and is amortized to the consolidated statements of income as a yield adjustment over the remainder of the hedging period. At March 31, 2013, the Company had a net hedging (swap) asset position of $0.8 million on $60 million of debt. At March 31, 2012, the Company had a net hedging (swap) asset position of $1.5 million on $49 million of debt.

Treasury Derivative Instruments– Cash Flow Hedge Accounting

We continually assess the cost relationship between fixed and variable rate debt. Consistent with our objective to minimize our cost of capital, we periodically enter into cross-currency swaps and hedging transactions that effectively convert the terms of underlying debt obligations from fixed rate to variable rate or variable rate to fixed rate. Payments made or received on these derivative contracts are recognized as an adjustment to interest expense as incurred. We have designated hedging transactions that effectively convert the terms of underlying debt obligations from variable to fixed, and that qualify, as cash flow hedges. For qualifying cash flow hedges, the effective portion of a derivative's gain or loss is reported in other comprehensive income, net of related tax effects, and the ineffective portion is reported in earnings. Amounts in accumulated other comprehensive income are reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. For the year ended March 31, 2013, the Company recorded ineffectiveness related to cash flow hedges of $0.9 million (gain) with a $5 million liability for the effective portion in other comprehensive income.

Commodity Derivative Instruments - Regulated Accounting

The Company utilizes derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas and electricity purchases associated with the Company's New York and New England gas and electric service territories. The Company's strategy is to minimize fluctuations in gas and electricity sales prices to our regulated customers.

The following are commodity volumes in dekatherms ("dths") and Mwhs associated with our derivative contracts as of March 31, 2013 and March 31, 2012:

		Electric		Gas	
		March 31,		March 31,	
		2013	2012	**2013**	2012
		(in millions)		*(in millions)*	
Physicals:	Gas purchase (dths)	**-**	-	**59**	106
Financials:	Gas swaps (dths)	**-**	-	**66**	84
	Gas options (dths)	**-**	-	**4**	8
	Gas futures (dths)	**-**	-	**17**	21
	Electric swaps (Mwhs)	**6**	5	**-**	-
Total:		**6**	5	**146**	219

The following table presents the Company's derivative assets and liabilities at March 31, 2013 and March 31, 2012 that are included in the accompanying consolidated balance sheets for the above contracts:

	Asset Derivatives			Liability Derivatives		
	March 31,			March 31,		
	2013	2012		**2013**	2012	
	(in millions of dollars)			*(in millions of dollars)*		
Current assets:			Current liabilities:			
Rate recoverable contracts:			Rate recoverable contracts:			
Gas swaps contracts	**$ 15**	$ 19	Gas swaps contracts	**$ 6**	$ 59	
Gas futures contracts	**1**	1	Gas futures contracts	**2**	22	
Gas options contracts	**1**	1	Gas options contracts	**-**	3	
Gas purchase contracts	**15**	18	Gas purchase contracts	**3**	12	
Electric swaps contracts	**18**	1	Electric swaps contracts	**-**	37	
Contracts not subject to rate recovery:			Contracts not subject to rate recovery:			
Gas swaps contracts	**-**	-	Gas swaps contracts	**-**	1	
Hedge contracts:			Hedge contracts:			
Fair value hedge contracts	**-**	1	Fair value hedge contracts	**-**	1	
Cash flow hedge contracts	**11**	11	Cash flow hedge contracts	**-**	-	
	61	52		**11**	135	
Deferred assets:			Deferred liabilities:			
Rate recoverable contracts:			Rate recoverable contracts:			
Gas swaps contracts	**1**	-	Gas swaps contracts	**-**	7	
Gas futures contracts	**2**	-	Gas futures contracts	**-**	6	
Gas purchase contracts	**4**	40	Gas purchase contracts	**7**	19	
Electric swaps contracts	**6**	-	Electric swaps contracts	**1**	3	
Hedge contracts:			Hedge contracts:			
Fair value hedge contracts	**1**	2	Fair value hedge contracts	**-**	-	
Cash flow hedge contracts	**-**	-	Cash flow hedge contracts	**56**	22	
	14	42		**64**	57	
Total	**$ 75**	$ 94	Total	**$ 75**	$ 192	

The changes in fair value of our 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 on the accompanying consolidated statements of income. The changes in fair value of our contracts not subject to rate recovery are recorded within purchased gas in the accompanying consolidated statements of income.

The following table presents the impact the change in the fair value of the Company's derivative contracts had on the accompanying consolidated balance sheets and consolidated statements of income for the years ended March 31, 2013 and March 31, 2012:

	Years Ended March 31,	
	2013	2012
	(in millions of dollars)	
Regulatory assets:		
Gas swaps contracts	**$ (60)**	$ 31
Gas futures contracts	**(26)**	17
Gas options contracts	**(3)**	2
Gas purchase contracts	**(21)**	(10)
Electric swaps contracts	**(39)**	11
	(149)	51
Regulatory liabilities:		
Gas swaps contracts	**(3)**	16
Gas futures contracts	**2**	-
Gas options contracts	**-**	1
Gas purchase contracts	**(39)**	4
Electric swaps contracts	**23**	(5)
Electric options contracts	**-**	(101)
	(17)	(85)
Total (decrease) increase in net regulatory assets	**$ (132)**	$ 136
Other income (deductions):		
Gas swaps contracts	**$ 1**	$ -
Hedge contracts	**(35)**	(13)
	$ (34)	$ (13)

Credit and Collateral

Derivative contracts are primarily used to manage exposure to market risk arising from changes in commodity prices and interest rates. In the event of non-performance by the counterparty to a derivative contract, the desired impact may not be achieved. The risk of counterparty non-performance is generally considered a credit risk and is actively minimized by assessing each counterparty credit profile and negotiating appropriate levels of collateral and credit support.

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

The credit policy for commodity transactions is owned and monitored by the NGUSA Energy Procurement Risk Management Committee ("EPRMC"), which establishes controls and procedures to determine, monitor and minimize the credit risk of counterparties. Counterparty credit exposure is monitored, 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 reduces its exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. The Company's credit exposure for all derivative instruments, normal

purchase normal sales contracts, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements was $43 million as of March 31, 2013.

In instances where a counterparty's credit quality has declined, or credit exposure exceeds certain levels, we may limit our 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 aggregate fair value of the Company's derivative instruments with credit-risk-related contingent features that are in a liability position on March 31, 2013 and March 31, 2012 was $5.0 million and $108.3 million, respectively. The Company had no collateral posted for these instruments at March 31, 2013 and had $19.8 million posted as collateral at March 31, 2012. If the Company's credit rating were to be downgraded by one or two levels, it would not be required to post any additional collateral. If the Company's credit rating were to be downgraded by three levels, it would be required to post $5.3 million additional collateral to its counterparties.

Additionally, in relation to its cash flow hedge contracts, the Company had $5.8 million posted as collateral at March 31, 2013. If the Company's credit rating were to be downgraded by one or more levels, it would be required to post $38.6 million additional collateral to its counterparties.

Note 7. Fair Value Measurements

The Company measures derivatives and available for sale securities at fair value. The following table presents assets and liabilities measured and recorded at fair value in the accompanying consolidated balance sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2013 and March 31, 2012:

	March 31, 2013			
	Level 1	Level 2	Level 3	Total
	(in millions of dollars)			
Assets:				
Derivative contracts	$ 3	$ 53	$ 19	$ 75
Available for sale securities	148	108	-	256
Total assets	151	161	19	331
Liabilities:				
Derivative contracts	2	65	8	75
Net assets	$ 149	$ 96	$ 11	$ 256

	March 31, 2012			
	Level 1	Level 2	Level 3	Total
	(in millions of dollars)			
Assets:				
Derivative contracts	$ 1	$ 34	$ 59	$ 94
Available for sale securities	132	100	-	232
Total assets	133	134	59	326
Liabilities:				
Derivative contracts	28	130	34	192
Net assets	$ 105	$ 4	$ 25	$ 134

The following is a description of the inputs to and valuation techniques used to measure the fair values above:

Derivatives

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 derivatives (e.g. natural gas futures traded on NYMEX).

The Company's Level 2 fair value derivative instruments primarily consist of over-the-counter ("OTC") swaps and forward physical gas deals where market data for pricing inputs is observable. Level 2 pricing inputs are obtained from the NYMEX and Intercontinental Exchange ("ICE"), except cases in which ICE publishes seasonal averages or there were no transactions within the last seven days. Level 2 derivative instruments may utilize discounting based on quoted interest rate curves that may include a liquidity reserve calculated based on bid/ask spread. 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 0.95 or higher.

Level 3 fair value derivative instruments primarily consist of our gas OTC forwards, options, and physical gas transactions where pricing inputs are unobservable, as well as other complex and structured transactions. Complex or structured transactions can introduce the need for internally-developed models based on reasonable assumptions. 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 contract is also deemed to be Level 3 when the forward curve is internally developed, extrapolated or derived from market observable curves with correlation coefficients less than 0.95, optionality is present, or non-economical assumptions are made.

Available for Sale Securities

Available for sale securities are included in financial investments in the accompanying balance sheets 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).

Level 3 Fair Value Measurements

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended March 31, 2013 and March 31, 2012:

	Years Ended March 31,	
	2013	2012
	(in millions of dollars)	
Balance at beginning of year	$ 25	$ 116
Transfers into Level 3	-	1
Transfers out of Level 3	(4)	-
Total gains or losses:		
included in regulatory assets and liabilities	(21)	(36)
Purchases	4	(7)
Settlements	7	(49)
Balance at end of year	$ 11	$ 25
The amount of total gains or losses for the period 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. A transfer out of Level 3 represents assets and liabilities that were previously classified as Level 3 for which the inputs became observable based on the criteria discussed previously for classification in Level 2. These transfers, which are recognized at the end of each period, result from changes in the observability of forward curves from the beginning to the end of each reporting period. There were no transfers between Level 1 and Level 2 during the years ended March 31, 2013 and March 31, 2012, respectively.

Additional Information Regarding Level 3 Measurements

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 derivatives 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 EPRMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The EPRMC is responsible for approving risk policies, transaction strategies, and annual supply plans, as well as all valuation and control procedures. The EPRMC is chaired by the Global Tax and Treasury Director and includes the Global Tax and Treasury Director, Senior Vice President ("SVP") Regulatory Affairs, SVP US General Counsel and Regulatory, and Vice President US Treasury. The EPRMC reports to the Finance Committee. The forward curves used for financial reporting are developed and verified by the middle office. NGUSA considers nonperformance risk and liquidity risk in the valuation of derivative contracts categorized in Level 2 and Level 3.

The following table provides detail surrounding significant Level 3 valuations, of which the most significant positions are financial gas option contracts. These option contracts are measured at fair value using the implied volatility as a key input to the option pricing function of the risk management system. The implied volatilities used are an approximation of the actual volatility curves for various strikes and option types and not observable in the market.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of March 31, 2013			Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)	Total			
Physical		(millions of dollars)					
Gas	Gas Purchase Contract (A)	$ 19	$ (8)	$ 11	Discounted Cash Flow	Forward Curve	(A)
	Total	$ 19	$ (8)	$ 11			

(A) Includes long-term gas supply contracts (greater than one year) with unobservable gas forward curve inputs and valuation assumptions which are made when estimating the fair value of physical gas options. Natural gas prices range between $3.53/Dth to $6.41/Dth for the term of open positions.

Other Fair Value Measurements

The Company's consolidated balance sheets reflect long-term debt at amortized cost. The fair value of the Company's long-term debt was estimated based on quoted market prices for similar issues or on current rates offered to the Company and its subsidiaries for similar debt. The fair value of this debt at March 31, 2013 and March 31, 2012 was $10.4 billion and $9.1 billion, respectively.

All other financial instruments in the accompanying consolidated balance sheets such as intercompany balances, accounts receivable and accounts payable are stated at cost, which approximates fair value.

Note 8. Income Taxes

The components of federal and state income tax expense (benefit) for the years ended March 31, 2013 and March 31, 2012 are as follows:

	Years Ended March 31,	
	2013	2012
	(in millions of dollars)	
Current tax expense (benefit):		
Federal	**$ (206)**	$ (132)
State	**19**	68
Total current tax benefit	**(187)**	(64)
Deferred tax expense (benefit):		
Federal	**418**	371
State	**62**	32
	480	403
Amortized investment tax credits [1]	**(6)**	(6)
Total deferred tax expense	**474**	397
Total income tax expense	**$ 287**	$ 333

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

A reconciliation between the expected federal income tax expense, using the federal statutory rate of 35%, to the Company's actual income tax expense for the years ended March 31, 2013 and March 31, 2012 is as follows:

	Years Ended March 31,	
	2013	2012
	(in millions of dollars)	
Computed tax	**$ 246**	$ 271
Change in computed taxes resulting from:		
State income tax, net of federal benefit	**53**	65
Investment tax credit	**(6)**	(6)
Other items, net	**(6)**	3
Total	**41**	62
Federal and state income taxes	**$ 287**	$ 333

Significant components of the Company's net deferred tax assets and liabilities at March 31, 2013 and March 31, 2012 are as follows:

	March 31,	
	2013	2012
	(in millions of dollars)	
Deferred tax assets:		
Pensions, PBOP and other employee benefits	**$ 1,435**	$ 1,597
Reserve - environmental	**580**	586
Regulatory liabilities - other	**294**	163
Future federal benefit on state taxes	**172**	190
Net operating losses	**167**	26
Allowance for uncollectible accounts	**130**	154
Other items	**131**	140
Total deferred tax assets[1]	**2,909**	2,856
Deferred tax liabilities:		
Property related differences	**5,196**	4,639
Regulatory assets - pension and PBOP	**474**	621
Regulatory assets - environmental	**728**	778
Regulatory assets - other	**327**	248
Other items	**271**	96
Total deferred tax liabilities	**6,996**	6,382
Net deferred income tax liabilities	**4,087**	3,526
Deferred investment tax credits	**45**	45
Net deferred income tax liability and investment tax credits	**4,132**	3,571
Current portion of net deferred income tax asset	**125**	208
Non-current deferred income tax liability	**$ 4,257**	$ 3,779

(1) As of March 31, 2013 and March 31, 2012, the Company has approximately $30 million and $111 million of net operating losses in the state of Massachusetts that are being carried forward. A valuation allowance has been established for the full amount of these loss carryforwards as the Company believes that the losses will not be utilized in the foreseeable future. These state net operating losses will expire between 2013 and 2014. Due to issuance of Revenue Procedure 2011-43, the Company has written off prior year valuation allowance related to New York State net operating losses that are no longer believed to be realizable.

The following table presents the amounts and expiration dates of operating losses as of March 31, 2013:

Expiration of net operating losses:	Federal
	(in millions of dollars)
03/31/2024	$ 482

Expiration of New York state and city net operating losses	NYS	NYC
	(in millions of dollars)	
03/31/2024	$ 1	$ -
03/31/2025	81	81
03/31/2028	8	7
03/31/2029	183	37
03/31/2030	58	28
03/31/2031	-	-
03/31/2032	33	10
03/31/2033	57	1

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

Unrecognized Tax Benefits

As of March 31, 2013 and March 31, 2012, the Company's unrecognized tax benefits totaled $673 million and $707 million, respectively, of which $85 million and $90 million would affect the effective tax rate, if recognized.

The following table reconciles the changes to the Company's unrecognized tax benefits for the years ended March 31, 2013 and March 31, 2012:

	Years Ended March 31,	
	2013	2012
	(in millions of dollars)	
Balance at the beginning of the year	**$ 707**	$ 798
Gross increases related to prior period	**16**	51
Gross decreases related to prior period	**(75)**	(145)
Gross increases related to current period	**41**	5
Gross decreases related to current period	**(12)**	(2)
Settlements with tax authorities	**(4)**	-
Balance at the end of the year	**$ 673**	$ 707

As of March 31, 2013 and March 31, 2012, the Company has accrued for interest related to unrecognized tax benefits of $71 million and $75 million, respectively. During the years ended March 31, 2013 and March 31, 2012, the Company recorded interest expense of $0.4 million and $10 million, respectively. The Company recognizes accrued interest related to unrecognized tax benefits in other interest expense and related penalties, if applicable, in other deductions in the accompanying consolidated statements of income. No penalties were recognized during the years ended March 31, 2013 and March 31, 2012.

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 liquidity.

During the year ended March 31, 2013, the Company entered into an oral agreement with the Internal Revenue Service ("IRS") to settle issues related to the tax deductibility of disputed items under appeal for fiscal years 2005 through 2007. This oral agreement was made with the IRS Appeals Officer in charge subject to the finalization and execution of IRS Form 870-AD, Offer to Waive Restrictions on Assessment and Collection of Tax Deficiency and to Accept Over-assessment. The Company believes that this agreement will be completed on substantially consistent terms. On the basis of this agreement the Company has concluded that in its assessment the potential exposure has declined and has reclassified a portion of its reserve for uncertain tax positions, in the amount of $37 million, to deferred income tax liabilities.

In fiscal year 2012, the Company adopted Revenue Procedure 2011-43, which provides a safe harbor method of accounting that taxpayers may use to determine whether expenditures to maintain, replace, or improve electric transmission and distribution property must be capitalized under Section 263(a) of the Internal Revenue Code and therefore has reversed $92 million of tax reserves related to unrecognized tax benefits recorded in prior years, with a corresponding offset in deferred income tax liabilities.

In September 2011, the IRS commenced an audit of NGNA and subsidiaries for the fiscal years ending March 31, 2008 and March 31, 2009, as well as KeySpan Corporation and subsidiaries for the short year ended August 24, 2007. Fiscal years ended March 31, 2010 through March 31, 2013 remain subject to examination by the IRS.

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

Jurisdiction	Tax Year
Federal	March 31, 2005 *
Massachusetts	March 31, 2010
New York	December 31, 2000
New York City	December 31, 2000
New Hampshire	March 31, 2009

*The Company is in the process of appealing certain disputed issues with the IRS Office of Appeals relating to its tax returns for March 31, 2005 through March 31, 2007. The Company does not anticipate a change in its unrecognized tax positions in the next twelve months as a result of filing the appeals. However, pursuant to the Company's tax sharing agreement the audit or appeals may result in a change to allocated tax.

The Company is in the process of appealing adjustments made by the Massachusetts Department of Revenue ("MADOR") for the years ended March 31, 2003 through March 31, 2005. The Company is currently under audit by the MADOR for years ended March 31, 2006 through March 31, 2008.

The State of New York is in the process of examining the Company's NYS income tax returns for the short years ended August 24, 2007 and March 31, 2008. The tax returns for the fiscal years ended March 31, 2009 through March 31, 2013 remain subject to examination by the State of New York. The Company has filed New York Investment Tax Credit claims for the tax years ended December 31, 2002 through March 31, 2010. New York State has disallowed the claims for December 31, 2002 through December 31, 2006 upon audit, and also denied them on appeal to the New York Tax Tribunal, which decision was further appealed to the Supreme Court, Appellate Division. On June 6, 2013, the Company received an adverse decision from the Supreme Court, Appellate Division, and therefore expects to make a payment with regard to tax and interest within the next twelve months.

The State of New York is in the process of examining the Niagara Mohawk Holdings Inc. and subsidiaries combined returns for fiscal years ended March 31, 2006 through March 31, 2008.

Note 9. Debt

European Medium Term Note Program

At March 31, 2013, the Company had a Euro Medium Term Note program (the "Program") under which it is able to issue debt instruments ("Instruments") up to a total of the equivalent of 4 billion Euros. Instruments issued under the Program are admitted to trading on the London Stock Exchange. The Program commenced in December 2007 and is renewed annually, with the latest renewal of the Program expiring in December 2013. If the Program is not renewed in December 2013, it would preclude the issuance of new notes under this Program, but it would not impact the outstanding debt balances and their maturity dates. Instruments carry certain affirmative and negative covenants, including a restriction on the Company's ability to mortgage, pledge, charge or otherwise encumber its assets in order to secure, guarantee or indemnify other listed or quoted debt obligations, as well as cross-acceleration in the event of breach by the Company or its principal subsidiaries of other listed or quoted debt obligations. At March 31, 2013 and March 31, 2012, the Company was in compliance with all covenants.

The Company is able to draw down on this facility in currencies other than the US dollar. The Company hedges the risk associated with foreign currency debt instruments by using cross currency swaps which convert the interest and principle payments into US dollars. These swaps are accounted for as fair value hedges or cash flow hedges, with fair value movements recognized in other comprehensive income. As at March 31, 2013 the Company had $796.3 million of foreign currency debt and $11 million of current derivative assets and $56 million of non-current derivative liabilities designated in cash flow hedging relationships, with $5 million recognized in other comprehensive income for the period ended March 31, 2013. The Company expects $2.6 million in other comprehensive income will be reclassified into earnings within the next twelve months. The ineffective portion of the hedge for the year ended March 31, 2013 was $0.9 million.

On June 3, 2011, the Company raised $667 million through the Program. These notes are due June 3, 2015 with a weighted average interest rate of 2.604%. On June 25, 2012 and September 24, 2012, the Company raised an additional

$38.3 million and $96.1 million, respectively. These notes are due on June 25, 2014 and September 24, 2014 with a weighted average interest rate of 1.176%. At March 31, 2013 and March 31, 2012, $876 million and $845 million, respectively, of these notes were issued and outstanding, excluding the impact of interest rate and currency swaps.

Notes Payable

At March 31, 2013 and March 31, 2012 the Company had outstanding $6.1 billion and $5.2 billion, respectively, of unsecured medium and long-term notes. In December 2012, Narragansett issued $250 million of unsecured long-term debt at 4.17% with a maturity date of December 10, 2042. In November 2012, Niagara Mohawk issued $400 million of unsecured long-term debt at 4.119% with a maturity date of November 28, 2042 and $300 million of unsecured long-term debt at 2.721% with a maturity date of November 28, 2022. In February 2012, Boston Gas issued $500 million of Senior Unsecured Notes at 4.487% due February 15, 2042. In March 2012, Colonial Gas issued two tranches of $25 million each of Senior Unsecured Notes at 3.296% due March 15, 2022 and 4.628% due March 15, 2042. The interest rates on the unsecured notes range from 3.296% to 9.750% and maturity dates range from November 2012 through December 2042.

Gas Facilities Revenue Bonds

Brooklyn Union has outstanding tax-exempt Gas Facilities Revenue Bonds ("GFRB") issued through the New York State Energy Research and Development Authority ("NYSERDA"). There are no sinking fund requirements for any of the Company's GFRB. At March 31, 2013 and March 31, 2012, $641 million of GFRBs were outstanding; $230 million of which are variable-rate, auction rate bonds. The interest rate on the various variable rate series due starting December 1, 2020 through July 1, 2026 is reset weekly and ranged from 0.14% to 2.17% during the year ended March 31, 2013 and 0.21% to 2.17% during the year ended March 31, 2012. The bonds are currently in auction rate mode and are backed by bond insurance. These bonds cannot be put back to Brooklyn Union and in the case of a failed auction, the resulting interest rate on the bonds revert to the maximum rate which depends on the current appropriate, short term benchmark rates and the senior unsecured rating of the Brooklyn Union's bonds. The effect of the failed auctions on interest expense was not material for the years ended March 31, 2013 and March 31, 2012.

Promissory Notes to LIPA

KeySpan Corporation issued promissory notes to LIPA to support certain debt obligations assumed by LIPA. At March 31, 2013 and March 31, 2012, $155 million of these promissory notes remained outstanding with maturity dates between March 2016 and August 2025. Interest rates range from 5.15% to 5.30%. Under these promissory notes, the Company is required to obtain letters of credit to secure its payment obligations if its long-term debt is not rated at least in the "A" range by at least two nationally recognized credit rating agencies. At March 31, 2013 and March 31, 2012, the Company was in compliance with this requirement as the Company's debt rating met the required threshold.

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 $53 million, respectively, of non-callable First Mortgage Bonds ("FMB"). These FMB indentures include, among other provisions, limitations on the issuance of long-term debt. Interest rates range from 6.82% to 9.63% and maturity dates range from 2018 to 2028.

State Authority Financing Bonds

At March 31, 2013, the Company had outstanding $1.2 billion of State Authority Financing Bonds. Of the $1.2 billion outstanding at March 31, 2013, approximately $716 million of these bonds were issued through NYSERDA and the remaining $484 million were issued through various other state agencies.

Approximately $650 million of State Authority Financing Bonds were issued to secure a like amount of tax-exempt revenue bonds issued by NYSERDA. Approximately $575 million of such securities bear interest at short-term adjustable interest rates (with an option to convert to other rates, including a fixed interest rate) ranging from 0.42% to 0.73% for the year ended March 31, 2013. The bonds are currently in auction rate mode and are backed by bond insurance. These bonds cannot be put back to the Company and in the case of a failed auction, the resulting interest rate on the bonds revert to the maximum rate which depends on the current appropriate, short-term benchmark rate and the

senior secured rating of the Company or the bond insurer, whichever is greater. The effect on interest expense has not been material to date.

The Company also has $75 million of 5.15% fixed rate pollution control revenue bonds issued through NYSERDA which are callable at par. Pursuant to agreements between NYSERDA and the Company, proceeds from such issues were used for the purpose of financing the construction of certain pollution control facilities at the Company's generation facilities (which the Company subsequently sold) or to refund outstanding tax-exempt bonds and notes.

Additionally, the Company has $41 million of 1999 Series A Pollution Control Revenue Bonds due October 1, 2028. The interest rate ranged from 0.25% to 1.60% for the year ended March 31, 2013, at which time the rate was 0.61%. The interest rate ranged from 0.35% to 3.00% for the year ended March 31, 2012, at which time the rate was 0.97%. Interest expense related to these notes for each of the years ended March 31, 2013 and March 31, 2012 was approximately $0.5 million and $0.7 million, respectively.

We also have outstanding $25 million variable rate 1997 Series A Electric Facilities Revenue Bonds due December 1, 2027. The interest rate on these bonds is reset weekly and ranged from 0.10% to 0.27% and from 0.07% to 0.28% during the years ended March 31, 2013 and March 31, 2012, respectively. The interest rate was 0.12% and 0.20% at March 31, 2013 and March 31, 2012, respectively. Interest expense related to these notes for each of the years ended March 31, 2013 and March 31, 2012 was approximately $0.1 million.

At March 31, 2013, the Company had outstanding $430 million of the Pollution Control Revenue Bonds in tax exempt commercial paper mode with maturity dates ranging from October 2015 to October 2022 and variable interest ranging from 0.35% to 0.90% for the year ended March 31, 2013. In addition, at March 31, 2013, the Company had $52 million of tax exempt Electric Revenue Bonds in commercial paper mode with varying maturity dates from 2016 through 2042 and variable interest rates ranging from 0.38% to 0.55% during the year ended March 31, 2013. The bonds were issued by the Massachusetts Development Finance Agency in connection with the Company's financing of its first and second underground and submarine cable projects. Sinking fund payments of $275 thousand were made during the year ended March 31, 2013.

At March 31, 2012, three of the Company's subsidiaries had a Standby Bond Purchase Agreement ("SBPA") totaling $500 million, which was due to expire in November 2012. On November 15, 2012, the Company amended the SBPA to a maturity date of November 20, 2015 with a limit of $483 million. This agreement was available to provide liquidity support for $483 million of the Company's long-term bonds in tax-exempt commercial paper mode. The Company has classified this 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. NGUSA, together with other affiliates of National Grid plc, has rights to issue debt under an $850 million syndicated revolving credit facility which can be drawn upon at any time until its maturity in November 2015 and may be used, if needed, to refinance the tax-exempt commercial paper on a long-term basis. This facility has a number of financial and non-financial covenants which the Company is obliged to meet. At March 31, 2013 and March 31, 2012, the Company was in compliance with all covenants.

Industrial Development Revenue Bonds

At March 31, 2013 and March 31, 2012, KeySpan had outstanding $128 million of tax-exempt bonds with a 5.25% coupon maturing in June 2027, $53 million of these Industrial Development Revenue Bonds were issued on its behalf through the Nassau County Industrial Development Authority for the construction of the Glenwood Energy Center, an electric-generation peaking plant, and the balance of $75 million was issued on its behalf by the Suffolk County Industrial Development Authority for the Port Jefferson Energy Center, an electric-generation peaking plant. KeySpan has guaranteed all payment obligations of these subsidiaries with regard to these bonds.

Committed Facility Agreements

At March 31, 2013, NGUSA, NGNA, and National Grid plc have a committed revolving credit facility of $850 million which matures in November 2015. This facility, bearing a commitment fee of 0.21%, has not been drawn against and therefore there is no balance outstanding. NGUSA, NGNA, and National Grid plc can all draw on this facility in a variety of currencies as needed, but the aggregate borrowings across the group cannot exceed the $850 million limit. The terms of the facility restrict the borrowing of all US subsidiaries of the Company to $18 billion excluding intercompany indebtedness. Additionally, this facility has a number of non-financial covenants which the Company is obliged to meet. At March 31, 2013 and March 31, 2012, the Company was in compliance with all covenants.

NGUSA and National Grid plc have two additional committed revolving credit facilities of $280 million and £155 million which mature in July 2017. These facilities, bear a commitment fee of 0.20% each, have not been drawn against and therefore there is no balance outstanding. NGUSA and National Grid plc can draw on these facilities in a variety of currencies as needed, but the aggregate borrowings across the group cannot exceed the $280 million and £155 million limit, respectively. The terms of the facilities restrict the borrowing of all US subsidiaries of the Company to $18 billion excluding intercompany indebtedness. Additionally, these facilities have a number of non-financial covenants which the Company is obliged to meet. At March 31, 2013 and March 31, 2012, the Company was in compliance with all covenants.

Intercompany Notes Payable

At March 31, 2012, the Company had intercompany notes due to Parent of $500 million at an interest rate ranging from 0.7% to 0.9% over LIBOR, due November 2012 through November 2015. These notes were paid in full in November 2012.

Debt Maturities

The following table reflects the maturity schedule for our debt repayment requirements at March 31, 2013:

(in millions of dollars)		
Years Ended March 31,		
2014	$	263
2015		664
2016		952
2017		511
2018		89
Thereafter		6,761
Total	$	9,240

The Company is obligated to meet certain financial and non-financial covenants. 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, 2013 and March 31, 2012, respectively, the Company was in compliance with all such covenants and restrictions.

Some of the Company's State Authority Financing Bonds, First Mortgage Bonds, and Notes Payable have sinking fund requirements which totaled $7 million during the years ended March 31, 2013 and March 31, 2012. The following table reflects the sinking fund repayment requirements at March 31, 2013:

(in millions of dollars)		
Years Ended March 31,		
2014	$	7
2015		7
2016		4
2017		1
2018		1
Thereafter		9
Total	$	29

Commercial Paper and Revolving Credit Agreements

Commercial Paper

At March 31, 2013, the Company had two commercial paper programs totaling $4 billion; a $2 billion US commercial paper program and a $2 billion Euro commercial paper program. In support of these programs, the Company was a

named borrower under National Grid plc credit facilities with $1.4 billion available to the Company. These facilities support both the Parent's and the Company's commercial paper programs for ongoing working capital needs. The facilities expire in 2015 to 2017. At March 31, 2013 and March 31, 2012, there was $625 million and $0 million of borrowings outstanding on the US commercial paper program and no borrowings outstanding on the Euro commercial paper program.

The credit facilities allow both the Parent and the Company to borrow in multi-currencies. The current annual commitment fees range from 0.20% to 0.21%. If for any reason we 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 US and non-US 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. At March 31, 2013 and March 31, 2012, the Company was in compliance with all covenants.

Note 10. Goodwill and Other Intangible Assets

At March 31, 2013 and March 31, 2012, the carrying amount of goodwill, net of accumulated impairment losses is as follows:

	March 31,	
	2013	2012
	(in millions of dollars)	
Goodwill, beginning of year	**$ 7,133**	$ 7,133
Consolidation of variable interest entity	**20**	-
Revaluation in relation to Granite State	**(1)**	-
Regulatory recovery	**(1)**	-
Goodwill, end of year	**$ 7,151**	$ 7,133

In January 2013, the Company made an investment in Clean Line Energy Partners LLC ("Clean Line"). Clean Line is a development-stage entity engaged in the development of long distance, high voltage direct current transmission lines that connect wind farms and other renewable resources in remote parts of the United States with electric demand. The Company committed to a $40 million investment in Clean Line. As of March 31, 2013, the Company has contributed $12.5 million. Based on an analysis of the contractual terms and rights contained in the related agreements, the Company determined that under the applicable accounting standards, Clean Line is a variable interest entity and that NGUSA has effective control over the entity. Therefore, as the primary beneficiary, the Company has consolidated Clean Line. Upon consolidation, the Company recognized approximately $20 million of goodwill.

Colonial Gas has authority from the DPU to recover $234.8 million of goodwill ($141.5 million of acquisition premium, plus tax of $93.3 million). The regulatory asset for the recovery of the acquisition premium was $216.6 million at March 31, 2013, and will be amortized on a straight-line basis as it is recovered through rates at $8.2 million per year through August 2039.

The net regulatory recovery adjustments of $1 million shown in the table above include, with respect to Colonial Gas: (1) a reclassification adjustment of $5 million from regulatory assets to goodwill in order to correct these balances and properly reflect the authorized recovery period of acquisition premium under DPU 10-55, and (2) a reclassification adjustment of ($6.0) million from goodwill to regulatory assets related to a ruling by the DPU in January 2013.

Impairment of Intangible Assets

During the year ended March 31, 2012, the Company recorded a non-cash impairment charge of $102 million to reduce the net carrying value of its finite-lived net intangible assets, related to the MSA LIPA contract, to a fair value of zero, which was determined using an income-based approach. The impairment was triggered by LIPA announcing on December 15, 2011 that it will terminate the service agreement contract on December 31, 2013.

Note 11. 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 $105 million and $89 million for the years ended March 31, 2013 and March 31, 2012, respectively.

A summary of future minimum lease payments due each year subsequent to March 31, 2013 is as follows:

(in millions of dollars) Years Ended March 31,	
2014	$ 122
2015	95
2016	95
2017	94
2018	94
Thereafter	446
Total	$ 946

Energy Purchase and Capital Expenditure 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. The Company's gas distribution subsidiaries are liable for these payments regardless of the level of services required from third parties. Such charges are currently recovered from utility customers as gas costs. In addition, Company has various capital commitments related to the construction of property, plant, and equipment.

The Company's commitments under these long-term contracts for years subsequent to March 31, 2013 are summarized in the table below:

(in millions of dollars) Years Ended March 31,	Energy Purchases	Capital Expenditures
2014	$ 1,837	$ 550
2015	860	130
2016	656	88
2017	504	2
2018	419	-
Thereafter	2,133	-
Total	$ 6,409	$ 770

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

Pursuant to the A&R PSA, the Company is required to invest in capital improvements in accordance with prudent utility practice. Such investments may approach the range of $500 million to $590 million subject to certain provisions in the contract.

Asset Retirement Obligations

The Company has various asset retirement obligations associated with its gas and electric activities. Generally, the Company's largest asset retirement obligations relate to: (i) legal requirements to cut (disconnect from the gas distribution system), purge (clean of natural gas and PCB contaminants) and cap gas mains within its gas distribution and transmission system when mains are retired in place; or dispose of sections of gas main when removed from the pipeline system; (ii) cleaning and removal requirements associated with storage tanks containing waste oil and other waste contaminants; and (iii) legal requirements to remove asbestos upon major renovation or demolition of structures and facilities.

On December 17, 2010, LIPA requested information associated with its contractual rights under its PSA with the Company to reduce ("Ramp Down") the amount of capacity purchased from the Company. The PSA gives LIPA the right to Ramp Down specified generating units at certain points during the term of the agreement. Per the terms of the PSA, in the event of a Ramp Down: (a) LIPA would pay the Company a percentage of the present value of the remaining capacity charges related to agreed-upon ramped down generating unit(s) due through the end of the previous PSA termination date, May 27, 2013 and (b) the Company would then reduce the future monthly capacity charges for the unit(s) billed to LIPA.

On June 23, 2011, National Grid Generation and LIPA entered into an amendment to the existing purchase and sale agreement with LIPA (the "Ramp Down Amendment"), pursuant to which the parties agreed to ramp down electric generating units located at the Glenwood and Far Rockaway New York generating facilities ("the Facilities"). The Ramp Down Amendment was approved by the New York State Comptroller and the New York State Attorney General ("AG"); and has been accepted by the FERC. Under the Ramp Down Amendment, the Ramp Down of Glenwood and Far Rockaway was deemed to have occurred for purpose of calculating the economic impact (the net of items (a) and (b) above) on May 27, 2011. Notwithstanding, the Company continued to provide capacity, energy, and ancillary services from Glenwood and Far Rockaway to LIPA until such time as the units became eligible for retirement, pending completion of certain transmission projects in the area currently served by these facilities. The electric generation subsidiary of the Company has a legal obligation to remediate/demolish after these Facilities became eligible for retirement in June 2012. Pursuant to the existence of this legal obligation, the Company recorded an asset retirement obligation of $45 million during the year ended March 31, 2012.

The following table represents the changes in the asset retirement obligations for the years ended March 31, 2013 and March 31, 2012:

	March 31,	
	2013	2012
	(in millions of dollars)	
Balance as of beginning of year	**$ 119**	$ 69
Electric generation retirement obligation	**-**	45
Accretion expense	**5**	5
Liabilities settled	**(19)**	(2)
Liabilities incurred in the current year	**-**	2
Balance as of end of year	**$ 105**	$ 119

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, 2013, 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:

		Amount of Exposure	Expiration Dates
		(in millions of dollars)	
Guarantees for Subsidiaries:			
Industrial Development Revenue Bonds	(i)	$ 128	June 2027
KeySpan Ravenswood LLC Lease	(ii)	445	May 2040
Reservoir Woods	(iii)	245	October 2029
Surety Bonds	(iv)	159	Revolving
Commodity Guarantees and Other	(v)	108	May 2013 - August 2042
Letters of Credit	(vi)	102	May 2013 - December 2014
		$ 1,187	

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

(i) KeySpan has fully and unconditionally guaranteed the payment obligations of its subsidiaries with regard to $128 million of Industrial Development Revenue Bonds issued through the Nassau County and Suffolk County Industrial Development Authorities for the construction of two electric-generation peaking plants on Long Island, New York. The face value of these notes is included in long-term debt in the accompanying consolidated balance sheets.

(ii) 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 we 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, 2013, the Company's obligation related to the lease was $233 million and is reflected in other deferred liabilities in the accompanying consolidated balance sheets.

(iii) The Company has fully and unconditionally guaranteed $245 million in lease payments through 2029 related to the lease of office facilities by its service company at Reservoir Woods in Waltham, Massachusetts.

(iv) The Company has agreed to indemnify the issuers of various surety and performance bonds associated with certain construction projects being performed by certain current and former subsidiaries. In the event that the 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. Although the Company is not guaranteeing any new bonds for any of the former subsidiaries, the Company's indemnity obligation supports the contractual obligation of these former subsidiaries. The Company has also received from a former subsidiary an indemnity bond issued by a third party insurance company, the purpose of which is to reimburse the Company in an amount up to $80 million in the event it is required to perform under all other indemnity obligations previously incurred by the Company to support such company's bonded projects existing prior to divestiture.

(v) The Company has guaranteed commodity-related payments for certain subsidiaries. These guarantees are provided to third parties to facilitate physical and financial transactions involved in the purchase and

transportation of natural gas, oil and other petroleum products for gas and electric production and marketing activities. The guarantees cover actual purchases by these subsidiaries that are still outstanding as of March 31, 2013.

(vi) 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 Company to post letters of credit to guarantee subsidiary performance under their contracts and to ensure payment to our subsidiary subcontractors and vendors under those contracts. Certain of our vendors also require letters of credit to ensure reimbursement for amounts they are disbursing on behalf of our subsidiaries, such as to beneficiaries under our 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 we have failed to perform specified actions. If this were to occur, the Company would be required to reimburse the issuer of the letter of credit.

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

The Company has guaranteed $210 million of an $800 million Millennium Pipeline construction loan. The $210 million represents the Company's proportionate share of the $800 million loan based on the Company's 26.25% ownership interest in the Millennium Pipeline project.

Transfer Tax

As a condition of the acquisition by NGUSA of KeySpan in 2007, NGUSA was required to divest the acquired Ravenswood merchant generating unit, and completed the disposal in August 2008. Ravenswood was accounted for as a business held for sale, which required NGUSA to record Ravenswood at fair value, including valuing at approximately $36 million certain contingencies relating to potential disposal costs where there was uncertainty as to whether they would be payable. These contingencies have been resolved through the expiration of the relevant statute of limitations, resulting in no payments being necessary. As a result, a gain of $36 million was recorded in fiscal 2012 within net income from discontinued operations in the accompanying consolidated statements of income.

Legal Matters

A collective and class action lawsuit has been filed by Local 1049 and its members alleging violations of the Fair Labor Standards Act and the New York Labor Law as a result of the payroll irregularities that occurred after the Company's implementation in November 2012 of its back office financial system. The lawsuit has been discontinued and settled in the amount of approximately $1.9 million pursuant to agreement between Local 1049 and the Company.

In addition to the above matter, the Company is subject to various legal proceedings, primarily injury claims, arising out of the ordinary course of its business. Except as described below, 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.

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.

During the year ended March 31, 2012, Brooklyn Union received new information concerning the proposed remediation plans for a site in downstate New York which resulted in Brooklyn Union increasing its environmental reserve by approximately $107 million. During the year ended March 31, 2013, Brooklyn Union increased its environmental reserve by approximately $17 million. After recording an offsetting increase in regulatory assets relating to environmental remediation, there was no impact to the net assets of the Company.

On April 26, 2013, General Electric ("GE") filed a lawsuit against the Niagara Mohawk seeking contribution under the Comprehensive Environmental Response, Compensation, and Liability Act for an unspecified portion of GE's alleged response costs incurred in remediating polychlorinated biphenyl ("PCB") contamination in the Hudson River. GE alleges that Niagara Mohawk's removal of the Fort Edward Dam in 1973 resulted in the migration of sediments, contaminated with PCBs released into the environment by GE, downstream of the former dam's location. Niagara Mohawk denies liability and is defending this action.

Air

Our generating facilities are subject to increasingly stringent emissions limitations under current and anticipated future requirements of the United States Environmental Protection Agency ("USEPA") and the 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. Our previous investments in low NOx boiler combustion modifications, the use of natural gas firing systems at our steam electric generating stations, and the compliance flexibility available under cap and trade programs have enabled the Company to achieve its prior emission reductions in a cost-effective manner. Ongoing investments include the installation of enhanced NOx controls and efficiency improvement projects at certain of our Long Island based electric generating facilities. The total cost of these improvements is estimated to be approximately $92 million ($72 million had been placed in service and the Company expects to spend another $20 million); a mechanism for recovery from LIPA of these investments has been established. We are currently developing a compliance strategy to address anticipated future requirements. At this time, we are unable to predict what effect, if any, these future requirements will have on our financial condition, results of operations, and cash flows.

Water

Additional capital expenditures associated with the renewal of the surface water discharge permits for our power plants will likely be required by the DEC at each of the Long Island power plants pursuant to Section 316 of the Clean Water Act to mitigate the plants' alleged cooling water system impacts to aquatic organisms. We are currently engaged in discussions with the DEC and environmental groups regarding the nature of capital upgrades or other mitigation measures necessary to reduce any impacts. Although these discussions have been productive and have led to mutually agreeable final permits at some of the plants, it is possible that the determination of required capital improvements and the issuance of final renewal permits for the remaining plants could involve adjudicatory hearings among the Company, the agency, and the environmental groups. Capital costs for expected mitigation requirements at the plants had been estimated on the order of approximately $100 million and did not anticipate a need for cooling towers at any of the plants. Depending on the outcome of the adjudicatory process, which could extend beyond the next fiscal year, ultimate costs could be substantially higher. Costs associated with any finally ordered capital improvements would be 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 a remediation at this location pursuant to Administrative Order on Consent ("ACO") with the New York State Department of Environmental Conservation ("DEC"). KeySpan intends to contest these proceedings vigorously.

On February 8, 2007, we received a Notice of Intent to File Suit from the AG against KeySpan and four other companies in connection with the cleanup of historical contamination found in certain lands located in Greenpoint, Brooklyn and in an adjoining waterway. KeySpan has previously agreed to remediate portions of the properties referenced in this notice and will work cooperatively with the DEC and AG to address environmental conditions associated with the remainder of the properties. KeySpan has entered into an ACO with the DEC for the land-based sites. The United States Environmental Protection Agency ("EPA") assumed control of the waterway and, on September 29, 2010, listed this site on its National Priorities List of Superfund sites. We signed a consent decree with the EPA on July 7, 2011 and are currently performing a Remedial Investigation and Feasibility Study. At this time, we are unable to predict what effect, if any, the outcome of these proceedings will have on our financial condition, results of operations, and cash flows.

Utility Sites

At March 31, 2013, the Company's total reserve for estimated MGP-related environmental matters is $1.4 billion. The potential high end of the range at March 31, 2013 is presently estimated at $2.1 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 condition 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 regulatory asset of $1.7 billion and $2 billion on the consolidated balance sheets at March 31, 2013 and March 31, 2012, respectively.

Upon the acquisition of KeySpan by NGUSA, the Company recognized those environmental liabilities at fair value. The fair values included discounting of the reserve at a rate of 6.5%, which is being accreted over the period for which remediation is expected to occur. Following the acquisition of KeySpan, its new environmental liabilities are recognized in accordance with the current accounting guidance for environmental obligations.

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 two non-utility sites for which it may have or share environmental remediation or ongoing maintenance responsibility. Expenditures incurred were approximately $1 million for each of the years ended March 31, 2013 and March 31, 2012. The Company presently estimates the remaining cost of the environmental cleanup activities for these two non-utility sites will be approximately $22 million, which has been accrued at March 31, 2013 and March 31, 2012. The Company's environmental obligation is net of a discount rate of 6.5%, and the undiscounted amount totaled $27 million in liabilities at both March 31, 2013 and March 31, 2012. 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 noted, depending upon 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, we periodically re-evaluate the accrued liabilities associated with MGP sites and related facilities. We 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. The Company believes that the obligations imposed on it because of the environmental laws will not have a material impact on its results of operations or financial position since, as noted above, environmental expenditures incurred by the Company are generally recoverable from customers.

Electric Services and LIPA Agreements

KeySpan and LIPA have three major long-term service agreements to; (i) provide to LIPA all operation, maintenance and construction services and significant administrative services relating to the Long Island electric transmission and distribution system pursuant to the MSA, expiring on December 31, 2013; (ii) supply LIPA with electric generating capacity, energy conversion and ancillary services from our Long Island generating units pursuant to the amended and

restated PSA, the rates of which are approved by the FERC; and (iii) manage all aspects of the fuel supply for our Long Island generating facilities, pursuant to the EMA, which was renewed on May 28, 2013.

KeySpan's compensation for managing the electric transmission and distribution system owned by LIPA under the MSA consists of two components: a minimum fixed compensation component of $224 million per year and a variable component based on electric sales. The fixed component remained unchanged for three years commencing January 2006 and thereafter increased annually by 1.7%, plus inflation. The variable component is based on electric sales adjusted for inflation.

In June 2011, LIPA and the Company executed an amendment to the PSA pursuant to which the parties agreed that LIPA would reduce purchases of capacity from specified generating facilities, specifically the Glenwood and Far Rockaway, New York steam facilities. The Company has retired these generating facilities and removed them from the PSA and is in the process of demolishing these facilities over the next two years. As part of this amendment, the Company is required to make an Economic Equivalent Payment ("EEP") of $18 million which represents the economic benefit to LIPA which would have been realized under the original agreement. One-half of the EEP was paid in June 2012 upon confirmation from LIPA that requisite transmission improvements were completed and units became retirement eligible. The remaining balance was paid to LIPA on May 27, 2013. The EEP was accrued on a straight-line basis over the 24-month term, from June 2011 through May 2013, as a reduction in operating revenues.

Pursuant to the EMA, KeySpan procures and manages fuel supplies for LIPA to fuel KeySpan's Long Island based generating facilities. In exchange for these services, KeySpan earns an annual fee of $750,000. The EMA expired on May 28, 2013.

Decommissioning Nuclear Units

NEP has minority interests in three nuclear generating companies: Yankee Atomic Electric Company ("Yankee Atomic"), Connecticut Yankee Atomic Power Company ("Connecticut Yankee"), and Maine Yankee Atomic Power Company ("Maine Yankee") (together, the "Yankees"). These ownership interests are accounted for on the equity method. The Yankees operated nuclear generating units which have been permanently decommissioned. Spent nuclear fuel remains on each site, awaiting fulfillment by the US Department of Energy ("DOE") of its statutory obligation to remove it. In addition, groundwater monitoring is ongoing at each site. Future estimated billings, which are included in other deferred liabilities and other current liabilities in the accompanying consolidated balance sheets, are as follows:

(in thousands of dollars)	The Company's Investment as of March 31, 2013				Future Estimated Billings to the Company	
Unit	%		Amount	Date Retired		Amount
Yankee Atomic	34.5	$	538	Feb 1992	$	7,543
Connecticut Yankee	19.5		289	Dec 1996		16,085
Maine Yankee	24.0		540	Aug 1997		-

The Yankees are periodically required to file rate cases for FERC review, which present the Yankees' estimated future decommissioning costs. The Yankees are currently collecting decommissioning and other costs under FERC orders issued in their respective rate cases. Rate cases were filed by each Yankee on May 1, 2013 reflecting, in part, receipt of payments from the DOE referred to below. The Yankees collect the approved costs from their purchasers, including the Company.

The Company's share of the Yankees' decommissioning costs is accounted for in contracts termination charges and nuclear shutdown charges on the consolidated statements of income. The Company has recorded a liability and a regulatory asset reflecting the estimated future decommissioning billings from the Yankees. Under settlement agreements, NEP is permitted to recover prudently incurred decommissioning costs through CTCs.

Future estimated billings from the Yankees are based on cost estimates. These estimates include the projected costs 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 during litigation they brought to enforce the DOE's obligation to remove the fuel as required by the Nuclear Waste Policy Act of 1982.

Following a trial at the US Court of Claims ("Claims Court") to determine the level of damages, on October 4, 2006, the Claims Court awarded the three companies an aggregate of $143 million for spent fuel storage costs that had been incurred through 2002. The Yankees had requested $176.3 million. The DOE appealed to the US Court of Appeals for the Federal Circuit, which rendered an opinion generally supporting the Claims Court's decision and remanded the matter to it for further proceedings. In September, 2010, the Claims Court again awarded the companies an aggregate of approximately $143 million. The DOE again appealed and the Yankees cross-appealed. On May 18, 2012, the Court of Appeals again ruled in favor of the Yankees, awarding them an aggregate of approximately $160 million. The DOE sought reconsideration but, on September 5, 2012, the Court of Appeals for the Federal Circuit denied the U S petition for rehearing. The US DOE elected not to file a petition for writ of certiorari seeking review by the US Supreme Court. Thus, the awards are final and have been paid. The Company's reserves and related regulatory assets for current and long-term decommissioning costs at March 31, 2013 reflect the Company's share of damages awarded to the Yankees as a result of the judgment in the Yankees Phase I Litigation. The expected $40.5 million of proceeds have been accounted for as a reduction in the reserves and regulatory assets for estimated future billings.

On December 14, 2007, the Yankees brought further litigation in the Claims Court to recover damages incurred subsequent to 2002. A Claims Court trial took place in October 2011. The record is now closed, briefs have been submitted, and the judge still has the case under advisement. If the Yankees are successful, the damages they receive, net of litigation expense and taxes, will be applied to benefit their purchasers, including the Company.

The US Congress and the DOE have effectively terminated budgetary support for the proposed long-term spent fuel storage facility at Yucca Mountain in Nevada and the DOE has taken actions designed to prevent its construction. 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. 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, 2013 and March 31, 2012, Niagara Mohawk had a liability of $168 million, recorded in other deferred liabilities in the accompanying consolidated balance sheets, 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.

In March 2010, the DOE filed a motion with the Nuclear Regulatory Commission to withdraw the license application for a high-level nuclear waste repository at Yucca Mountain. The DOE's withdrawal motion has been challenged and is being litigated before the NRC and the District of Columbia Circuit. In January 2010 the US government announced that it has established a BRC to perform a comprehensive review and provide recommendations regarding the disposal of the nation's spent nuclear fuel and waste. In January 2012, the BRC issued its report and recommendations which provides for numerous policy recommendations currently under review and consideration by the US Secretary of Energy. Therefore, Niagara Mohawk cannot predict the impact that the recent actions of the DOE and the US government will have on the ability to dispose of the spent nuclear fuel and waste.

Storm Costs Recovery

In October 2012, SuperStorm Sandy hit the northeastern United States affecting gas and power supply to customers in the Company's service territory. Total costs from SuperStorm Sandy associated with gas customers' service restoration through March 31, 2013 for the New York Gas Companies were approximately $150.5 million. The Company has recorded an other receivable on the consolidated balance sheets at March 31, 2013 in the amount of $67 million relating to claims filed against property damage and business interruption insurance policies, net of insurance deductibles. Total costs from SuperStorm Sandy associated with electricity customers' service restoration charged to LIPA through March 31, 2013, were approximately $681.9 million. The Company had outstanding accounts receivable from LIPA of $333.8 million at March 31, 2013 of which $172.2 million has been received as of the date of these financial statements.

Note 12. Related Party Transactions

Accounts Receivable from Affiliates and Accounts Payable to Affiliates

The Company engages in various transactions with National Grid plc 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 payables to and receivables from certain of its affiliates in the ordinary course of business. At March 31, 2013 and March 31, 2012, the Company had net outstanding accounts receivable from affiliates/accounts payable to affiliates balances as follows:

	Accounts Receivable from Affiliates		**Accounts Payable to Affiliates**	
	March 31, 2013	March 31, 2012	**March 31, 2013**	March 31, 2012
	(in millions of dollars)		*(in millions of dollars)*	
NGNA	**$ -**	$ 102	**$ 87**	**$ -**
Grid UK Billing	-	33	-	-
NG plc	-	-	**36**	-
Other	**13**	-	-	-
	$ 13	$ 135	**$ 123**	$ -

Advances to Affiliates

In August 2009, the Company and KeySpan Corporation 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 LIBOR plus 1.4%. At March 31, 2013 and March 31, 2012, the Company had no outstanding advance from or to its affiliates 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. These advances do not bear interest. At March 31, 2013 and March 31, 2012, the Company had no outstanding advance from affiliate.

Holding Company Charges

NGUSA receives charges from National Grid Commercial Holdings Limited, an affiliated company in the UK, for certain corporate and administrative services provided by the corporate functions of National Grid plc to its US subsidiaries. For the years ended March 31, 2013 and March 31, 2012, the effect on net income was $40 million before tax and $26 million after tax.

Note 13. 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, 2013 and March 31, 2012 is as follows:

		Shares Outstanding		Amount		
		March 31,		**March 31,**		Call
Series	Company	**2013**	2012	**2013**	2012	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	Noncallable
$50 par value -						
4.50% Series	Narragansett	**49,089**	49,089	**3**	3	55.000
Golden Shares -						
	Niagara Mohawk and KeySpan subsidiaries	**3**	3	**-**	-	Noncallable
Total		**372,641**	372,641	**$ 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 New York State. 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 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%. On April 28, 2011, the Company converted 648 shares of common stock into non-voting cumulative, fixed-rate, preferred stock (Series F), having a par value of $0.10. The fixed rate on this series is 8.5%.

In August 2012, by written consent of the Company's shareholders, the annual dividend payment date on the series A through E preferred stock was changed from September 30 to August 24. As a result, the amount of the preferred stock dividend for the series A through E preferred stock was adjusted during the year ended March 31, 2013.

A summary of preferred stock of NGUSA at March 31, 2013 and March 31, 2012 is as follows:

	Shares Outstanding		Amount (par)		Amount (additional paid-in capital)	
	March 31,		**March 31,**		**March 31,**	
Series	**2013**	2012	**2013**	2012	**2013**	2012
	(in millions of dollars, except per share and number of shares data)					
$0.10 par value -						
Series A	**51**	51	**$ -**	$ -	**$ 400**	$ 400
Series B	**40**	40	**-**	-	**315**	315
Series C	**96**	96	**-**	-	**750**	750
Series D	**79**	79	**-**	-	**616**	616
Series E	**1**	1	**-**	-	**10**	10
Series F	**648**	648	**-**	-	**5,368**	5,368
Total	**915**	915	**$ -**	$ -	**$ 7,459**	$ 7,459

Note 14. Stock-Based Compensation

The 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 is designed to drive medium to long-term performance, aligning key strategic objectives to shareholder interests. The LTPP replaces the previous Performance Share Plan ("PSP"). 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 UK-based directors and employees or the Parent's American Depository Receipts traded on the New York Stock Exchange for US-based directors and employees. Both plans have a performance period of three years and have been approved by the Company's Remuneration Committee.

As of May 15, 2013, the number of ordinary shares issued was 3.8 billion and 127,142,880 were held as treasury shares. The aggregate dilution resulting from executive share-based incentives will not exceed 5% in any 10-year period for executive share-based incentives and will not exceed 10% in any 10-year period for all employee incentives. This is reviewed by the Remuneration Committee and currently, the Company has excess headroom of 4.07% and 7.75% respectively.

The number of units within each award is subject to change depending upon the Company's ability to meet the stated performance targets. Under the LTPP, performance conditions are split into three parts as follows: (i) 50% of the units awarded are subject to annualized growth in the Company's earnings per share ("EPS") over a general index of retail prices over a period of three years; (2) 25% of the units awarded will vest based upon the Company's Total Shareholder Return ("TSR") compared to that of the Financial Times Stock Exchange ("FTSE") 100 over a period of three years; and (3) 25% of the units awarded are subject to the average achieved regulatory ROE. Under the PSP, performance conditions are split into two parts as follows: (1) 50% of the units awarded are subject to annualized growth in the Company's EPS over a general index of retail prices over a period of three years; and (2) 50% of the units awarded will vest based upon the Company's TSR compared to that of the FTSE 100 over a period of three years. Units under both plans generally vest at the end of the performance period.

Fair value of the performance restricted stock of the PSP units is calculated at the end of each fiscal year. Fair value for the LTPP awards is calculated as of the grant date and at the end of each period. A Monte Carlo simulation model has been used to estimate the fair value for the TSR portion of the awards. For the EPS and ROE portions of the awards, the fair value of the award is determined using the stock price as quoted per the London Stock Exchange or the price for the American Depository Shares as quoted on the New York Stock Exchange as of the earlier of the reporting date or vesting date.

The following table represents the assumptions used to calculate the fair value of the TSR portion of the awards:

Expected volatility	12.72% - 14.48%
Expected term	3 years
Risk free rates	0.07% - 0.26%

The EPS portions of the PSP and LTTP awards and the ROE portion of the LTTP awards are classified as liability awards as they are each indexed to a factor that is not a market, performance, or service condition. Therefore, the changes in the fair value of the EPS portions of the PSP and EPS and ROE portions of the LTTP awards are reflected within net income. The TSR portions of the PSP and LTTP awards are classified as equity awards as they are indexed to market conditions, and are expensed over the performance period.

The following table summarizes the stock based compensation expense recognized by the Company for the years ended March 31, 2013 and March 31, 2012:

	Units	Weighted Average Grant Date Fair Value
Nonvested as of March 31, 2011	1,081,801	$ 45.42
Vested	179,612	53.92
Granted	310,468	42.19
Forfeited/Cancelled	197,117	51.26
Nonvested as of March 31, 2012	1,015,540	42.19
Vested	119,468	45.53
Granted	272,274	48.29
Forfeited/Cancelled	222,401	42.97
Nonvested as of March 31, 2013	945,945	$ 40.36

The total expense recognized for unvested awards was $24.7 million and $12.3 million for the years ended March 31, 2013 and March 31, 2012 respectively, and will vest over three years. The total tax benefit recorded was approximately $9.9 million and $4.9 million as of March 31, 2013 and March 31, 2012 respectively. Total expense expected to be recognized by the Company in future periods for unvested awards outstanding as of March 31, 2013 is $9.0 million, $5.2 million, and $1.0 million for the years ended March 31, 2014, 2015, and 2016 respectively.

Note 15. Discontinued Operations

On December 8, 2010, NGUSA and Liberty Energy entered into a stock purchase agreement which was subsequently amended and restated on January 21, 2011, pursuant to which NGUSA sold and Liberty Energy purchased all of the common stock of Granite State and EnergyNorth. The sale of Granite State and EnergyNorth was consummated on July 3, 2012 for proceeds of $294 million.

On September 23, 2011, National Grid Development Holdings Corp., a wholly-owned subsidiary of KeySpan, entered into a purchase agreement to sell all of its outstanding membership interest in Seneca to PDC Mountaineer, LLC. The sale was completed on October 3, 2011 for proceeds of $163 million with a related gain on sale of investment of $99 million recorded in the quarter ended December 31, 2011. The Company recorded a $30 million reserve at March 31, 2012 for post-closing due diligence against which $30 million was subsequently applied.

The information below highlights the major classes of revenues and expenses of Granite State, EnergyNorth, and Seneca for the years ended March 31, 2013 and March 31, 2012:

	March 31,	
	2013	2012
	(in millions of dollars)	
Revenues	**$ 37**	$ 219
Operating expenses:		
Fuel and purchase power	**16**	117 [1]
Operations and maintenance	**7**	9
Operating taxes	**2**	10
Operating income	**12**	83
Other deductions	**-**	(1)
(Loss) gain on sale of discontinued operations	**(34)**	99
Income tax (benefit) expense	**(15)**	76
Net (loss) income from discontinued operations	**$ (7)**	**$ 105**

[1] Includes $36 million Ravenswood transfer tax contingency now resolved, as discussed in Note 11, "Commitments and Contingencies."

nationalgrid

National Grid USA and Subsidiaries

Consolidated Financial Statements

For the years ended March 31, 2014 and 2013

NATIONAL GRID USA AND SUBSIDIARIES

TABLE OF CONTENTS

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Independent Auditor's Report

To the Shareholders and Board of Directors
of National Grid USA

We have audited the accompanying consolidated financial statements of National Grid USA (the "Company"), which comprise the consolidated balance sheets as of March 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, cash flows, capitalization, and changes in shareholders' equity for the years then ended.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

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

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

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of National Grid USA at March 31, 2014 and 2013, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

October 24, 2014

PricewaterhouseCoopers LLP, 300 Madison Avenue, New York, NY 10017
T: (646) 471 3000, F: (646) 471 8320, www.pwc.com/us

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

	Years Ended March 31,	
	2014	2013
Operating revenues:		
Electric services	**$ 7,177**	$ 6,525
Gas distribution	**5,355**	4,784
Other	**24**	28
Total operating revenues	**12,556**	11,337
Operating expenses:		
Purchased electricity	**2,503**	2,059
Purchased gas	**2,360**	2,013
Operations and maintenance	**4,541**	4,280
Depreciation and amortization	**896**	854
Other taxes	**1,063**	1,055
Total operating expenses	**11,363**	10,261
Operating income	**1,193**	1,076
Other income and (deductions):		
Interest on long-term debt	**(400)**	(389)
Other interest, including affiliate interest	**(47)**	(25)
Equity income in unconsolidated subsidiaries	**35**	36
Other deductions, net	**(18)**	(10)
Total other deductions, net	**(430)**	(388)
Income before income taxes	**763**	688
Income tax expense	**277**	272
Income from continuing operations	**486**	416
Net income (loss) from discontinued operations, net of taxes	**133**	(14)
Net income	**619**	402
Net loss attributable to non-controlling interest	**20**	1
Dividends paid on preferred stock	**(597)**	(578)
Net income (loss) attributable to common shares	**$ 42**	$ (175)

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,	
	2014	**2013**
Net income	**$ 619**	$ 402
Other comprehensive income (loss):		
Unrealized gains on securities, net of $3 and $0 tax expense	**4**	1
Unrealized losses on hedges, net of $1 and $1 tax benefit	**(2)**	(2)
Change in pension and other postretirement obligations, net of $103 tax expense and $73 tax benefit	**145**	(117)
Adjustment for establishment of Narragansett pension tracker, net of $0 $54 tax expense	**-**	91
Reclassification of gains into net income, net of $45 and $61 tax expense	**67**	87
Other comprehensive income	**214**	60
Comprehensive income	**833**	462
Less: comprehensive loss attributable to non-controlling interest	**20**	1
Comprehensive income attributable to National Grid USA	**$ 853**	$ 463

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, 2014	Years Ended March 31, 2013
Operating activities:		
Net income	**$ 619**	$ 402
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**896**	854
Regulatory amortizations	**50**	265
Provision for deferred income taxes	**255**	427
Bad debt expense	**136**	59
Equity income in unconsolidated subsidiaries, net of dividends received	**(10)**	(13)
Allowance for equity funds used during construction	**(27)**	(21)
Amortization of debt discount and issuance costs	**10**	12
Net pension and other postretirement expense (contributions)	**113**	(48)
Net environmental remediation payments	**(136)**	(125)
Changes in operating assets and liabilities:		
Accounts receivable and other receivable, net, and unbilled revenues	**(718)**	(821)
Accounts receivable from/payable to affiliates, net	**(49)**	245
Inventory	**45**	101
Regulatory assets and liabilities, net	**45**	118
Derivative contracts	**22**	(98)
Prepaid and accrued taxes	**(33)**	(166)
Accounts payable and other liabilities	**-**	(16)
Other, net	**7**	93
Net cash provided by operating activities	**1,225**	1,268
Investing activities:		
Capital expenditures	**(1,960)**	(1,806)
Net proceeds from disposal of subsidiary assets	**-**	294
Changes in restricted cash and special deposits	**53**	(41)
Cost of removal and other	**(206)**	(201)
Net cash used in investing activities	**(2,113)**	(1,754)
Financing activities:		
Dividends paid on common and preferred stock	**(597)**	(578)
Payments on long-term debt	**(304)**	(95)
Proceeds from long-term debt	**-**	1,047
Commercial paper (paid) issued	**(204)**	625
Advances from affiliates	**2,171**	(500)
Equity infusion from Parent	**1,000**	-
Other	**34**	62
Net cash provided by financing activities	**2,100**	561
Net increase in cash and cash equivalents	**1,212**	75
Net cashflow from discontinued operations - operating	**(352)**	(168)
Net cashflow from discontinued operations - investing	**28**	(18)
Cash and cash equivalents, beginning of year	**683**	794
Cash and cash equivalents, end of year	**$ 1,571**	$ 683
Supplemental disclosures:		
Interest paid	$ (457)	$ (365)
Income taxes paid	(108)	(94)
Significant non-cash items:		
Capital-related accruals included in accounts payable	161	84
Long Island Power Authority settlement	371	-

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,	
	2014	2013
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 1,571**	$ 683
Restricted cash and special deposits	**168**	221
Accounts receivable	**2,761**	2,206
Allowance for doubtful accounts	**(300)**	(296)
Other receivable	**58**	67
Accounts receivable from affiliates	**2**	13
Unbilled revenues	**620**	592
Inventory	**344**	355
Regulatory assets	**571**	313
Derivative contracts	**70**	61
Current portion of deferred income tax assets	**171**	193
Prepaid taxes	**145**	177
Prepaid and other current assets	**125**	142
Current assets related to discontinued operations	**153**	423
Total current assets	**6,459**	5,150
Equity investments	**194**	184
Property, plant, and equipment, net		
Property, plant, and equipment, net	**23,875**	22,499
Property, plant, and equipment, net related to discontinued operations	**-**	28
Total property, plant, and equipment, net	**23,875**	22,527
Other non-current assets:		
Regulatory assets	**4,322**	4,590
Goodwill	**7,151**	7,151
Derivative contracts	**26**	14
Postretirement benefits asset	**305**	297
Financial investments	**476**	427
Other	**141**	124
Other non-current assets related to discontinued operations	**29**	28
Total other non-current assets	**12,450**	12,631
Total assets	**$ 42,978**	$ 40,492

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,	
	2014	2013
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 1,339**	$ 1,372
Accounts payable to affiliates	**63**	123
Advances from affiliates	**2,171**	-
Other tax liabilities	**35**	34
Commercial paper	**421**	625
Current portion of long-term debt	**633**	263
Taxes accrued	**21**	102
Customer deposits	**98**	104
Interest accrued	**134**	160
Regulatory liabilities	**524**	412
Derivative contracts	**43**	11
Payroll and benefits accruals	**228**	272
Other	**279**	171
Current liabilities related to discontinued operations	**37**	173
Total current liabilities	**6,026**	3,822
Other non-current liabilities:		
Regulatory liabilities	**2,688**	2,605
Asset retirement obligations	**87**	105
Deferred income tax liabilities	**4,850**	4,238
Postretirement benefits	**2,872**	3,639
Environmental remediation costs	**1,341**	1,370
Derivative contracts	**14**	64
Other	**892**	948
Other non-current liabilities related to discontinued operations	**-**	155
Total other non-current liabilities	**12,744**	13,124
Commitments and contingencies (Note 13)		
Capitalization:		
Shareholders' equity	**16,000**	14,731
Long-term debt	**8,208**	8,815
Total capitalization	**24,208**	23,546
Total liabilities and capitalization	**$ 42,978**	$ 40,492

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,	
			2014	2013
Shareholders' equity attributable to common and preferred shares			**$ 15,988**	$ 14,705
Non-controlling interest in subsidiaries			**12**	26
Long-term debt:	Interest Rate	Maturity Date		
European Medium Term Note	Variable	June 2014 - January 2016	**842**	876
Notes Payable	3.30% - 9.75%	October 2014 - December 2042	**5,948**	6,113
Gas Facilities Revenue Bonds	Variable	December 2020 - July 2026	**230**	230
Gas Facilities Revenue Bonds	4.7% - 6.95%	April 2020 - July 2026	**411**	411
First Mortgage Bonds	6.34% - 9.63%	April 2018 - April 2028	**127**	128
State Authority Financing Bonds	Variable	October 2015 - August 2042	**1,153**	1,199
Industrial Development Revenue Bonds	5.25%	June 2027	**128**	128
Total debt			**8,839**	9,085
Unamortized debt premium (discount)			**2**	(7)
Current portion of long-term debt			**(633)**	(263)
Long-term debt			**8,208**	8,815
Total capitalization			**$ 24,208**	$ 23,546

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

NATIONAL GRID USA AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in millions of dollars, except per share and number of shares data)

					Accumulated Other Comprehensive Income (Loss)						
	Common Stock	Preferred Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Unrealized Gain (Loss) on Available for Sale Securities	Pension and Postretirement Benefits	Hedging Activity	Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest	Total
Balance as of March 31, 2012	**$ -**	**$ -**	**$ 35**	**$ 13,046**	**$ (3)**	**$ (925)**	**$ 2**	**$ (926)**	**$ 2,601**	**$ 9**	**$ 14,765**
Net income	-	-	-	-	-	-	-	-	403	(1)	402
Other comprehensive income (loss):											
Unrealized gains on securities, net of $0 tax expense	-	-	-	-	1	-	-	1	-	-	1
Unrealized losses on hedges, net of $1 tax benefit	-	-	-	-	-	-	(2)	(2)	-	-	(2)
Change in pension and other postretirement obligations, net of $73 tax benefit	-	-	-	-	-	(117)	-	(117)	-	-	(117)
Adjustment for establishment of Narragansett pension tracker, net of $54 tax expense	-	-	-	-	-	91	-	91	-	-	91
Reclassification of gains into net income, net of $61 tax expense	-	-	-	-	-	87	-	87	-	-	87
Total comprehensive income											462
Consolidation of variable interest entity	-	-	-	-	-	-	-	-	-	22	22
Other equity transactions with non-controlling interest	-	-	-	-	-	-	-	-	-	(4)	(4)
Share based compensation	-	-	-	64	-	-	-	-	-	-	64
Dividends on preferred stock	-	-	-	-	-	-	-	-	(578)	-	(578)
Balance as of March 31, 2013	**$ -**	**$ -**	**$ 35**	**$ 13,110**	**$ (2)**	**$ (864)**	**$ -**	**$ (866)**	**$ 2,426**	**$ 26**	**$ 14,731**
Net income	-	-	-	-	-	-	-	-	639	(20)	619
Other comprehensive income (loss):											
Unrealized gains on securities, net of $3 tax expense	-	-	-	-	4	-	-	4	-		4
Unrealized losses on hedges, net of $1 tax benefit	-	-	-	-	-	-	(2)	(2)	-	-	(2)
Change in pension and other postretirement obligations, net of $103 tax expense	-	-	-	-	-	145	-	145	-	-	145
Reclassification of gains into net income, net of $45 tax expense	-	-	-	-	-	67	-	67	-	-	67
Total comprehensive income											833
Other equity transactions with non-controlling interest	-	-	-	(7)	-	-	-	-	-	6	(1)
Equity infusion from Parent	-	-	-	1,000	-	-	-	-	-	-	1,000
Parent tax allocation	-	-	-	1	-	-	-	-	-	-	1
Share based compensation	-	-	-	33	-	-	-	-	-	-	33
Dividends on preferred stock	-	-	-	-	-	-	-	-	(597)	-	(597)
Balance as of March 31, 2014	**$ -**	**$ -**	**$ 35**	**$ 14,137**	**$ 2**	**$ (652)**	**$ (2)**	**$ (652)**	**$ 2,468**	**$ 12**	**$ 16,000**

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, 2014 and 2013.

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 ("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 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 ("National Grid Generation"), The Brooklyn Union Gas Company ("Brooklyn Union"), and KeySpan Gas East Corporation ("KeySpan Gas East").

In addition, the Company has certain subsidiaries which have provided operational and energy management services and continue to supply capacity to and produce energy for the use of customers of the Long Island Power Authority ("LIPA"), on Long Island, New York. The services provided to LIPA were or continue to be provided through the following contractual arrangements. The Power Supply Agreement ("PSA") which was amended and restated for a maximum term of 15 years in October 2012 provides LIPA with electric generating capacity, energy conversion and ancillary services from the Company's Long Island generating units. The Energy Management Agreement ("EMA"), which expired on May 28, 2013, provided management of all aspects of fuel supply for the Company's Long Island generating facilities. The Management Service Agreement ("MSA"), which expired on December 31, 2013, provided operation, maintenance and construction services, and significant administrative services relating to the Long Island electric transmission and distribution system. The results of the MSA are reflected as discontinued operations in the accompanying consolidated financial statements for the years ended March 31, 2014 and 2013.

On July 3, 2012, the Company's previous subsidiaries, Granite State Electric Company ("Granite State") and EnergyNorth Natural Gas, Inc., ("EnergyNorth") were sold to Liberty Energy Utilities Co. ("Liberty Energy"), a subsidiary of Algonquin Power & Utilities Corp. The results of Granite State and EnergyNorth are reflected as discontinued operations in the accompanying consolidated statements of income for the year ended March 31, 2013.

Other Services and Investments

The Company's Energy Services business includes companies that provide energy-related services to customers located primarily within the northeastern United States. These services comprise the operation, maintenance, and design of energy systems for commercial and industrial customers.

The Company's Energy Investments business consists of gas production and development investments such as natural gas pipelines, as well as certain other domestic energy-related investments. Through the Company's wholly-owned subsidiary, National Grid LNG, it owns a 600,000 barrel liquefied natural gas storage and receiving facility 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") and a 20.4% interest in Iroquois Gas Transmission System, which are 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."

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 equity income in unconsolidated subsidiaries 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 rate-making 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 October 24, 2014, 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, 2014, except as described in Note 4, "Rate Matters" and Note 18, "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 State 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 subsidiaries charge their customers in the applicable states. In these cases, the subsidiaries defer costs (as regulatory assets) or recognize obligations (as regulatory liabilities) if it is probable that such amounts will be recovered from or refunded to customers through future rates. Regulatory assets and liabilities are amortized to the consolidated statements of income consistent with the treatment of the related costs in the rate-making process.

Revenue Recognition

Electric and Gas Distribution Revenue

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

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

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

Transmission Revenue

Transmission revenues 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."

Other Revenues

Revenues earned for service and maintenance contracts associated with commercial energy systems are recognized as earned or over the life of the service contract, as appropriate.

Other Taxes

The Company's subsidiaries collect from customers various taxes that are levied by state or local governments on the sale or distribution of gas. The Company presents taxes that are imposed on customers (such as sales taxes) on a net basis (i.e., excluded from revenues) and presents excise taxes on a gross basis.

Gas distribution revenues include the collection of excise taxes and the related expense is included in other taxes in the accompanying consolidated statements of income.

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 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.

Narragansett and Niagara Mohawk accrue for property taxes on a calendar year basis, taking into account the assessment period. Narragansett and Niagara Mohawk had prepaid property taxes of $3.4 million and $9.4 million at March 31, 2014 and 2013, respectively.

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 financial statement carrying amounts and the tax basis of

existing assets and liabilities. Deferred income taxes also reflect the tax effect of net operating losses, capital losses and general business credit carryforwards.

The effects of tax positions are recognized in the 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 company determines its current and deferred taxes based on the separate return method. The Company settles its current tax liability or benefit each year with NGNA pursuant to a tax sharing arrangement between NGNA and its subsidiaries. Tax benefits attributable to the tax attributes of other group companies and allocated by NGNA are treated as capital contributions.

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 primarily consists of deposits held by the New York Independent System Operator ("NYISO") and by the ISO New England ("ISO-NE"). Special deposits primarily consist of health care claims deposits. The Company had restricted cash of $144 million and $149 million and special deposits of $24 million and $72 million at March 31, 2014 and 2013 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. During the fiscal year ended March 31, 2014, the Company enhanced its estimation methodology. 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. In prior years, the estimate placed a higher emphasis on write-off history. Management believes the more fulsome analysis of all information disclosed above results in an improved estimate and the updated approach resulted in a decrease of approximately $50.1 million in the reserve. The collectability of receivables is continuously assessed, and if circumstances change, the allowance is adjusted accordingly. Receivable balances are written off against the allowance for doubtful accounts when the accounts are disconnected and/or terminated and the balances are deemed to be uncollectible.

Inventory

Inventory is comprised of materials and supplies, gas in storage and renewable energy certificates ("RECs"). Materials and supplies are stated at the lower of weighted average cost or market and are expensed or capitalized as used. The Company's policy is to write-off obsolete inventory; there were no material write-offs of obsolete inventory for the years ended March 31, 2014 or 2013.

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.

RECs are used to measure compliance with renewable energy standards and are held primarily for consumption. The Company recorded a compliance liability based on retail electricity sales of $142 million and $99 million within other current liabilities in the accompanying balance sheets at March 31, 2014 and 2013, respectively.

At March 31, 2014 and 2013, the Company had materials and supplies of $178 million and $170 million, respectively, gas in storage of $111 million and $164 million, respectively, and purchased RECs of $55 million and $21 million, respectively.

Derivatives

The Company uses derivative instruments to manage commodity price risk, interest and foreign currency rate risk. All derivative instruments are recorded in the accompanying consolidated balance sheets at their fair value. Qualifying derivative instruments may be designated as either cash flow hedges or fair value hedges.

Commodity Derivative Instruments

All commodity costs, including the impact of derivative instruments, are passed on to customers through the Company's commodity rate adjustment mechanisms. Therefore, gains or losses on the settlement of these contracts are initially deferred and then refunded to, or collected from, customers consistent with regulatory requirements.

Certain non-trading contracts for the physical purchase of natural gas and electricity qualify for the normal purchase normal sale exception and are accounted for upon settlement. If the Company were to determine that a contract for which it elected the normal purchase normal sale exception no longer qualifies, the Company would recognize the fair value of the contract in accordance with the regulatory accounting described above.

Financing Derivative Instruments

Treasury related derivative instruments may qualify as either fair value hedges or cash flow hedges. The Company has entered into cross-currency and interest rate swaps ("CCIRS") to protect against changes in the fair value of fixed-rate borrowings due to movements in market interest rates. The Company has designated these instruments as fair value hedging relationships. For qualifying fair value hedges, all changes in the fair value of the derivative financial instrument and changes in the fair value of the item in relation to the risk being hedged are recognized in the consolidated statements of income. If the hedge relationship is terminated, the fair value adjustment to the hedged item continues to be reported as part of the basis of the item and is amortized to the consolidated statements of income as a yield adjustment over the remainder of the hedging period. At March 31, 2014, the Company held no CCIRS designated in fair value hedging relationships. At March 31, 2013, the Company had a net hedging (swap) asset position of $1 million on $60 million of debt.

The Company continually assesses the cost relationship between fixed and variable rate debt and periodically enters into CCIRS to convert the terms of the underlying debt obligations from fixed rate to variable rate or variable rate to fixed rate. Payments made, or received, on these derivative contracts are recognized as an adjustment to interest expense as incurred. The Company has designated these instruments as cash flow hedges. For qualifying cash flow hedges, the effective portion of a derivative's gain or loss is reported in other comprehensive income, net of related tax effects, and the ineffective portion is reported in earnings. Amounts in accumulated other comprehensive income are reclassified into earnings in the same period or periods during which the hedged transaction affects earnings.

As at March 31, 2014, the Company had $792 million of foreign currency debt and $5.0 million of current derivative assets designated in cash flow hedging relationships, with $4.5 million recognized in other comprehensive income for the year ended March 31, 2014. As at March 31, 2013 the Company had $796.3 million of foreign currency debt and $11 million of current derivative assets and $56 million of non-current derivative liabilities designated in cash flow hedging relationships, with $5 million recognized in other comprehensive income for the year ended March 31, 2013. The Company expects $2.8 million in other comprehensive income will be reclassified into earnings within the next twelve months. For the years ended March 31, 2014 and 2013, the Company recorded ineffectiveness related to cash flow hedges of $2.0 million (loss) and $0.9 million (loss), respectively.

The Company's accounting policy is to not offset fair value amounts recognized for derivative instruments and related cash collateral receivable or payable with the same counterparty under a master netting agreement, and to record and present the fair value of the derivative instrument on a gross basis, with related cash collateral recorded within restricted cash and special deposits in the accompanying consolidated balance sheets. There was no related cash collateral as of March 31, 2014 or 2013 for commodity derivatives. There was zero and $6 million of cash collateral posted for financing derivatives at March 31, 2014 and 2013, respectively.

Power Purchase Agreements

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

Fair Value Measurements

The Company measures derivatives and available-for-sale securities at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The following is the fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value:

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

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

Property, Plant and Equipment

Property, plant and equipment is stated at original cost. The cost of repairs and maintenance is charged to expense and the cost of renewals and betterments that extend the useful life of property, plant and equipment is capitalized. The capitalized cost of additions to property, plant and equipment includes costs such as direct material, labor and benefits, and an allowance for funds used during construction ("AFUDC") 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 and average service lives for the years ended March 31, 2014 and 2013 are as follows:

	Electric		Gas		Common	
	Years Ended March 31,		Years Ended March 31,		Years Ended March 31,	
	2014	2013	**2014**	2013	**2014**	2013
Composite rates	**2.8%**	2.9%	**2.9%**	2.9%	**5.3%**	5.2%
Average service lives	48 years	48 years	**46 years**	45 years	**36 years**	38 years

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 $1.6 billion at March 31, 2014 and 2013.

Allowance for Funds Used During Construction

In accordance with applicable accounting guidance, the regulated subsidiaries record AFUDC, which represents the debt and equity costs of financing the construction of new property, plant and equipment. AFUDC equity is reported in the consolidated statements of income as non-cash income in other income (deductions), net, and AFUDC debt is reported as a non-cash offset to other interest, including affiliate interest. After construction is completed, the Company is permitted to recover these costs through their inclusion in rate base and corresponding depreciation expense. The Company recorded AFUDC related to equity of $27 million and $21 million for the years ended March 31, 2014 and 2013, respectively. The Company recorded AFUDC related to debt of $13 million and $7 million for the years ended March 31, 2014 and 2013. The average AFUDC rates for the years ended March 31, 2014 and 2013 were 4.5% and 4.1%, respectively.

In addition, approximately $1 million and $8 million of interest was capitalized for construction of non-regulated projects during the years ended March 31, 2014 and 2013, respectively.

Goodwill and Other Intangible Assets

Goodwill

The Company tests goodwill for impairment annually on January 31, 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. Goodwill is tested for impairment using a two-step approach. The first step compares the estimated fair value of each reporting unit with its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, then goodwill is considered not impaired. If the carrying value exceeds the estimated fair value, then a second step is performed to determine the implied fair value of goodwill. If the carrying value of goodwill exceeds its implied fair value, then an impairment charge equal to the difference is recorded.

The fair value of each reporting unit was calculated in the annual goodwill impairment test for the year ended March 31, 2014 utilizing both income and market approaches.

- To estimate fair value utilizing the income approach, the Company used a discounted cash flow methodology incorporating its most recent business plan forecasts together with a projected terminal year calculation. Key assumptions used in the income approach were: (a) expected cash flows for the period from April 1, 2014 to March 31, 2019; (b) a discount rate of 5.5%, which was based on the Company's best estimate of its after-tax weighted-average cost of capital; and (c) a terminal growth rate of 2.25%, based on the Company's expected long-term average growth rate in line with estimated long-term U.S. economic inflation.

- To estimate fair value utilizing the market approach, the Company followed a market comparable methodology. Specifically, the Company applied a valuation multiple of earnings before interest, taxes, depreciation and amortization ("EBITDA"), derived from data of publicly-traded benchmark companies, to business operating data. Benchmark companies were selected based on comparability of the underlying business and economics. Key assumptions used in the market approach included the selection of appropriate benchmark companies and the selection of an EBITDA multiple of 10.0, which the Company believes is appropriate based on comparison of its business with the benchmark companies.

The Company determined the fair value of the business using 50% weighting for each valuation methodology, as it believes that each methodology provides equally valuable information. Based on the resulting fair value from the annual analyses, the Company determined that no adjustment of the goodwill carrying value was required at March 31, 2014 or 2013.

Intangible Assets

Intangible assets represent finite-lived assets that are amortized over their respective estimated useful lives and, along with other long-lived assets, are evaluated for impairment periodically whenever events or changes in circumstances indicate that their related carrying amounts may not be recoverable.

Impairment of Long-Lived Assets

The Company evaluates long-lived assets, including property, plant and equipment and finite-lived intangibles, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. In evaluating long-lived assets for recoverability, the Company uses its best estimate of future cash flows expected to result from the use of the asset and its eventual disposition. If the estimated future undiscounted net cash flows attributable to the asset are less than the carrying amount, an impairment loss is recognized equal to the difference between the carrying value of such asset and its fair value. Assets to be disposed of and for which there is a committed plan of disposal are reported at the lower of carrying value or fair value less costs to sell.

Available-For-Sale Securities

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

Asset Retirement Obligations

Asset retirement obligations are recognized for legal obligations associated with the retirement of property, plant, and equipment, primarily associated with the Company's 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 has a legal obligation to dismantle the Glenwood and Far Rockaway facilities and remediate the associated sites. These facilities were shut down and decommissioning began in July 2012; demolition and remediation activities are expected to be completed between October 2014 and April 2015.

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

	Years Ended March 31,	
	2014	2013
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 105**	$ 119
Accretion expense	**6**	5
Liabilities settled	**(24)**	(19)
Balance as of the end of the year	**$ 87**	$ 105

Accretion expense for the Company's regulated subsidiaries is deferred as part of the Company's asset retirement obligation regulatory asset as management believes it is probable that such amounts will be collected in future rates.

Employee Benefits

The Company has defined benefit pension and postretirement benefit ("PBOP") plans for its employees. The Company recognizes all pension and PBOP plans' funded status in the accompanying consolidated balance sheets as a net liability or asset with an offsetting adjustment to accumulated other comprehensive income ("AOCI") in shareholders' equity. In the case of regulated entities, the cost of providing these plans is recovered through rates; therefore, the net funded status is offset by a regulatory asset or liability. The Company measures and records its pension and PBOP assets at the year-end date. Pension and PBOP plan assets are measured at fair value, using the year-end market value of those assets.

Supplemental Executive Retirement Plans

The Company has corporate assets included in financial investments in the accompanying consolidated balance sheets 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 with increases and decreases in the value of these assets recorded in the accompanying consolidated statements of income.

New and Recent Accounting Guidance

Accounting Guidance Adopted in Fiscal Year 2014

Offsetting Assets and Liabilities

In December 2011 and January 2013, the Financial Accounting Standards Board ("FASB") issued amendments to address and clarify the scope of the disclosures related to offsetting assets and liabilities. Under the amendments, reporting entities are required to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting agreement, such as for derivatives. The instruments and activities subject to these disclosures are recognized derivatives, repurchase and reverse repurchase agreements, and securities lending transactions. The Company adopted this guidance effective April 1, 2013, which only impacted its disclosures.

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists

In July 2013, the FASB issued amendments to address diversity in practice related to the presentation of unrecognized tax benefits in certain situations. The amendments require a liability related to an unrecognized tax benefit to be presented on a net basis with its associated deferred tax asset when utilization of such deferred tax assets is required or expected in the event the uncertain tax position is disallowed. Otherwise, the unrecognized tax benefit will be presented as a liability and

will not be netted against deferred tax assets. The Company early adopted this guidance effective April 1, 2013 with no material impact on its financial position, results of operations or cash flows.

Accounting Guidance Not Yet Adopted

Reclassifications From Accumulated Other Comprehensive Income

In February 2013, the FASB issued amendments to improve the reporting of reclassifications out of AOCI. The amendments require an entity to provide information either on the face of the financial statements or in a single footnote on significant amounts reclassified out of AOCI and the related income statement line items to the extent an amount is reclassified in its entirety to net income. For significant items not reclassified to net income in their entirety, an entity is required to cross-reference to other disclosures that provide additional information. For non-public entities, the amendments are effective prospectively for reporting periods beginning after December 15, 2013. Early adoption is permitted. The Company will adopt this guidance effective April 1, 2014, which will only impact its disclosures.

Revenue Recognition

In May 2014, the FASB and the International Accounting Standards Board jointly issued a new revenue recognition standard ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." The objective of the new guidance is to provide a single comprehensive revenue recognition model for all contracts with customers to improve comparability. The standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services in an amount that reflects the consideration the entity expects to receive. The new guidance must be adopted using either a full retrospective approach or a modified retrospective approach. For non-public entities, the new guidance is effective for periods beginning after December 15, 2017. The Company is currently evaluating the impact of the new guidance on its financial position, results of operations and cash flows.

Financial Statement Revisions

During 2014, management determined that certain accounting transactions were not properly recorded in the Company's previously issued consolidated financial statements. The Company corrected the accounting by revising the prior period consolidated financial statements, the key impacts of which are described below. The Company concluded that the revisions were not material to any prior periods.

- Historically, the Company has calculated its capital tracker regulatory asset using its weighted average cost of capital ("WACC") and carrying charges on regulatory assets using its AFUDC rate. The WACC and AFUDC have both a debt and equity component. Accounting standards allow for the capitalization of all or part of an incurred cost that would otherwise be charged to expense if the regulator's actions create probable recovery of those costs through future rates. Because the equity component of a WACC or an AFUDC rate is not an incurred cost that would otherwise be charged to expense, accounting guidance for rate regulated activities does not allow for the capitalization of such equity amounts, and thus, the equity component should not have been included in the Company's capital tracker and carrying charges calculations.

  A cumulative adjustment of $57 million (net of income taxes) was recorded in the consolidated financial statements for the year ended March 31, 2013, of which $58 million was recorded as an adjustment to opening retained earnings (as of March 31, 2012), and $1 million was recorded as an increase to net income within gas distribution revenues, operations and maintenance expense, and other deductions, net for the year ended March 31, 2013 to reflect the fiscal year 2013 activity related to these corrections. This adjustment also resulted in a decrease of $111 million in non-current regulatory assets, a decrease of $17 million in non-current regulatory liabilities and a decrease of $38 million in deferred income tax liabilities as of March 31, 2013.

- During management's review of the Company's allowance for doubtful accounts methodology, management determined it had insufficiently provided for its allowance for doubtful accounts reserve in prior years. A

cumulative adjustment of $12 million (net of income taxes) was recorded in the financial statements for the year ended March 31, 2013, of which $9 million was recorded as an adjustment to opening retained earnings (as of March 31, 2012), and $3 million was recorded as a decrease to net income for the year ended March 31, 2013 to reflect the fiscal year 2013 activity related to this correction.

In addition, the Company has corrected various account balances in continuing and discontinued operations that were improperly recorded. A cumulative adjustment of $15 million (net of income taxes) was recorded in the consolidated financial statements for the year ended March 31, 2013, of which $21 million was recorded as an adjustment to opening retained earnings (as of March 31, 2012), and $6 million was recorded as a decrease to net income for the year ended March 31, 2013 to reflect the fiscal year 2013 activity related to these items.

The following tables show the amounts previously reported as revised:

	As Previously Reported [1]	Discontinued Operations	Adjustments	As Revised
	(in millions of dollars)			
	March 2013			March 2013
Consolidated Statement of Income				
Operating revenues	$ 12,601	$ (1,251)	$ (13)	$ 11,337
Operating income	1,098	(2)	(20)	1,076
Other deductions, net	(394)	7	(1)	(388)
Income before income taxes	704	5	(21)	688
Income tax expense	287	9	(24)	272
Net loss from discontinued operations, net of taxes	(7)	4	(11)	(14)
Net income	410	(1)	(7)	402
Net loss attributable to common shares	(167)	-	(8)	(175)
Consolidated Statement of Cash Flows				
Net cash provided by operating activities	$ 1,100	$ 182	$ (14)	$ 1,268
Net cash used in investing activities	(1,770)	12	4	(1,754)
Net cashflow from discontinued operations - operating	4	(183)	11	(168)
Net cashflow from discontinued operations - investing	(5)	(12)	(1)	(18)

	As Previously Reported [1]	Discontinued Operations	Adjustments	As Revised
	(in millions of dollars)			
	March 2013			March 2013
Consolidated Balance Sheet				
Total current assets	$ 5,219	$ (9)	$ (60)	$ 5,150
Property, plant, and equipment, net	22,522	-	5	22,527
Total other non-current assets	12,746	9	(124)	12,631
Total current liabilities	3,826	-	(4)	3,822
Total other non-current liabilities	13,088	155	(119)	13,124
Long-term debt	8,970	(155)	-	8,815
Accumulated other comprehensive income (loss)				
March 31, 2013	(864)	-	(2)	(866)
March 31, 2012	(923)	-	(3)	(926)
Retained Earnings				
March 31, 2013	2,480	-	(54)	2,426
March 31, 2012	2,647	-	(46)	2,601

(1) Certain reclassifications have been made to the financial statements to conform prior year data to the current year presentation.

3. REGULATORY ASSETS AND LIABILITIES

The Company records regulatory assets and liabilities that result from the rate-making process. The following table presents the regulatory assets and regulatory liabilities recorded in the accompanying consolidated balance sheets.

	March 31,	
	2014	2013
	(in millions of dollars)	
Regulatory assets		
Current:		
Derivative contracts	**$ 16**	$ 6
Energy efficiency	**23**	6
Gas costs adjustment	**287**	83
Rate adjustment mechanisms	**110**	68
Renewable energy certificates	**91**	78
Revenue decoupling mechanism	**20**	36
Other	**24**	36
	571	313
Non-current:		
Capital tracker	**34**	30
Environmental response costs	**1,739**	1,766
Postretirement benefits	**1,476**	1,756
Recovery of acquisition premium	**208**	217
Regulatory deferred tax asset	**134**	122
Storm costs	**319**	342
Other	**412**	357
Total	**4,322**	4,590
Regulatory liabilities		
Current:		
Derivative contracts	**50**	48
Energy efficiency	**146**	122
Gas costs adjustment	**50**	91
Profit sharing	**38**	43
Rate adjustment mechanisms	**68**	74
Revenue decoupling mechanism	**66**	25
Other	**106**	9
	524	412
Non-current:		
Capital tracker	**39**	29
Carrying charges	**60**	26
Cost of removal	**1,617**	1,563
Delivery rate adjustment	**128**	130
Environmental response costs	**104**	114
Excess earnings	**95**	95
Postretirement benefits	**220**	315
Regulatory deferred tax liability	**7**	24
Temporary state assessment	**111**	34
Other	**307**	275
Total	**2,688**	2,605
Net regulatory assets	**$ 1,681**	$ 1,886

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

Cost of removal: The Company's depreciation expense includes estimated costs to remove property, plant and equipment, which are recovered through the rates charged to customers. This regulatory liability represents cumulative costs recovered

in excess of costs incurred. For a vast majority of its regulated utility plant assets, the Company uses these funds to remove the asset so a new one can be installed in its place.

Delivery rate adjustment: The NYPSC authorized a combined annual surcharge for recovery of regulatory assets ("Delivery Rate Surcharge") of $15.0 million in January 2008 and 2009, respectively, for Brooklyn Union and KeySpan Gas East ("The New York Gas Companies"). The annual surcharge increased incrementally by $5.0 million for the first five years of the Brooklyn Union's rate plan and increased by $10.0 million in rate year 2010 through 2012 of KeySpan Gas East's rate plan, aggregating to a total of $175.0 million over the term of the rate agreement. In its order issued and effective November 28, 2012, the NYPSC authorized a Site Investigation and Remediation ("SIR") Surcharge in the amount of $65.0 million which superseded the Delivery Rate Surcharge effective January 1, 2013.

Derivative contracts (assets and liabilities): Gains or losses resulting from commodity derivatives are required to be refunded to, or recovered from, customers through the Company's commodity rate adjustment mechanisms. Accordingly, the Company's regulated subsidiaries evaluate open derivative contracts to determine if they are probable of recovery, or refund, through future rates charged to customers and qualify for regulatory deferral. Derivative contracts that qualify for regulatory deferral 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: This amount represents the difference between revenue billed to customers through the Company's energy efficiency charge and the costs of its energy efficiency programs as approved by the state authorities.

Environmental response costs: This regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at sites with which it may be associated. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates. The regulatory liability primarily represents the amount of customer contributions and insurance proceeds recovered to pay for costs to investigate and perform certain remediation activities at sites with which it may be associated as well as the excess of amounts received in rates over the Company's actual site investigation and remediation ("SIR") costs.

Excess earnings: At the end of each rate year (calendar year), the New York Gas Companies are required to provide the NYPSC with a computation of its return on common equity capital ("ROE"). If the ROE in the applicable rate year exceeds 10.5%, the New York Gas Companies are required to defer a portion of the revenue equivalent associated with any over earnings for the benefit of customers. Beginning January 1, 2013, Brooklyn Union's threshold for earnings sharing has been reduced from 10.5% to 9.4% and the sharing mechanism will be calculated based upon a cumulative average ROE over rate years 2013 and 2014 with 80% of any excess earnings applied as a credit against the SIR deferral balance.

Gas costs adjustment: The Company's gas regulated subsidiaries are 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 amount in regulatory assets primarily represents the excess costs of the Company's pension and PBOP plans over amounts received in rates that are deferred to a regulatory asset to be recovered in future periods and the non-cash accrual of net actuarial gains and losses. The amount in regulatory liabilities primarily represents accrued carrying charges as calculated in accordance with the Company's pension and PBOP internal reserve mechanism.

Profit sharing: This regulatory liability 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 in the accompanying balance sheet will be refunded to customers over the next year.

Rate adjustment mechanisms: The Company's regulated subsidiaries are subject to a number of rate adjustment mechanisms such as for commodity costs, whereby an asset or liability is recognized resulting from differences between

actual revenues and the underlying cost being recovered or differences between actual revenues and targeted amounts as approved by the applicable state regulatory bodies.

Recovery of acquisition premium: This represents the unrecovered amount (plus related taxes) by which the purchase price paid exceeded the net book value of Colonial Gas' assets in the 1998 acquisition of Colonial Gas by Eastern Enterprises, Inc. In exchange for certain rate concessions and the achievement of certain merger savings targets, the DPU has allowed Colonial Gas to recover the acquisition premium through rates for the next 25 years (through August 2039).

Regulatory deferred tax asset (liability): This amount represents unrecovered federal and state deferred taxes of the Company primarily as a result of regulatory flow through accounting treatment and tax rate changes. The income tax benefits or charges for certain plant related timing differences, such as equity AFUDC, are immediately flowed through to, or collected from, customers. The amortization of the related regulatory deferred tax asset or liability, for these items, follows the book life of the underlying plant asset.

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 per customer and actual revenue per customer. Any difference between the allowed revenue per customer and the actual revenue per customer is recorded as a regulatory asset or regulatory liability.

Temporary state assessment: In June 2009, the NYPSC authorized utilities, including the New York Gas Companies, to recover the costs required for payment of the Temporary State Energy & Utility Service Conservation Assessment ("Temporary State Assessment"), including carrying charges. The Temporary State Assessment is subject to reconciliation over a five year period beginning July 1, 2009 and ending June 30, 2014. On June 18, 2014, the NYPSC issued an order authorizing certain utilities, including the New York Gas Companies, to recover the Temporary State Assessment subject to reconciliation, including carrying charges, from July 1, 2014 through June 30, 2017. As of May 31, 2014, the New York Gas Companies over-collected on these costs. The New York Gas Companies are required to net any deferred over-collected amounts against the amount to be collected during fiscal years 2014 and 2015 as well as the first payment relating to fiscal years 2015 and 2016.

Storm costs: This regulatory asset represents the incremental operation and maintenance costs to restore power to customers resulting from major storms.

The Company records carrying charges on all regulatory balances, with the exception of derivative contracts, cost of removal, environmental response costs, renewable energy certificates, and regulatory deferred tax balances, where cash expenditures have been made and are subject to recovery, or for which cash has been collected and is subject to refund. Carrying charges are not recorded on items for which expenditures have not yet been made.

4. RATE MATTERS

Niagara Mohawk

March 2013 Electric and Gas Filing

In March 2013 the NYPSC issued a final order regarding Niagara Mohawk's electric and gas base rate filing made on April 27, 2012. The term of the new rate plan is from April 1, 2013 through March 31, 2016 and provides for an electric revenue requirement of $1,338 million in the first year, $1,396 million in the second year, and $1,443 million in the third year. It also provides for a gas revenue requirement of $307 million in the first year, $315 million in the second year, and $322 million in the third year.

Transmission Return on Equity Complaint

On September 11, 2012, the New York Association of Public Power ("NYAPP") filed a complaint against Niagara Mohawk, seeking to have the base ROE for transmission service of 11.5%, which includes a NYISO participation incentive adder, lowered to 9.49%. Similarly, on November 2, 2012 the Municipal Electric Utilities Association ("MEUA") filed a complaint to lower Niagara Mohawk's ROE to 9.25% including the NYISO participation adder. The MEUA also challenges certain aspects of Niagara Mohawk's transmission formula rate. On February 6, 2014, the NYAPP filed a further complaint against Niagara Mohawk seeking an order effective February 6, 2014 to reduce the ROE used in calculating rates for transmission service under the NYISO Open Access Transmission Tariff ("OATT") to 9.36%, inclusive of the 50 basis point adder for participation in the NYISO, with a corresponding overall weighted cost of capital of 6.60%. At this time, Niagara Mohawk cannot predict the outcome of the complaint. Any change in the ROE would not have an impact on net income because the retail rate plan fully reconciles any increase or decrease in wholesale transmission revenue under the FERC Transmission Service Charge rate through a Transmission Revenue Adjustment Clause mechanism.

Wholesale Transmission Service Charge

On December 6, 2013, Niagara Mohawk submitted a filing for FERC approval of revisions to its Wholesale Transmission Service Charge ("TSC Rate") under the NYSIO OATT to recover its RSS costs under two agreements with NRG to support the reliability of Niagara Mohawk's transmission system while transmission reinforcements are constructed. On February 4, 2014 the FERC allowed the RSS charges to become effective in TSC Rates as of July 1, 2013, subject to refund and further consideration of the matter by the FERC.

Management Audit

In February 2011, the NYPSC selected Overland Consulting Inc., ("Overland") to perform a management audit of NGUSA's affiliate cost allocations, policies and procedures. Niagara Mohawk and the New York Gas Companies disputed certain of Overland's final audit conclusions and the NYPSC ordered that further proceedings be conducted to address what, if any, rate-making adjustments were necessary. On September 5, 2014, the NYPSC approved a settlement that resolves all outstanding issues relating to the audit. The order provides for no rate adjustments for Niagara Mohawk and $24.7 million to be returned for the benefit of customers for the New York Gas Companies. This amount is recorded as a regulatory liability in the accompanying consolidated balance sheets.

Gas Management Audit

In February 2013, the NYPSC initiated a comprehensive management and operational audit of the NGUSA's New York gas businesses, including Niagara Mohawk, pursuant to the Public Service Law requirement that major electric and gas utilities undergo an audit every five years. On June 13, 2013, the NYPSC selected NorthStar Consulting Group to conduct the audit, which commenced in July 2013. The final audit report was issued on October 2, 2014 and contained recommendations primarily relating to gas operations, organizational structure and governance. The next phase of the audit presents an opportunity for NGUSA to develop implementation plans that address the recommendations.

Operations Audit

In August 2013, the NYPSC initiated an operational audit 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 Niagara Mohawk and the New York Gas Companies. On December 19, 2013, the NYPSC selected Overland to conduct the audit, which commenced in February 2014. At the time of the issuance of these consolidated financial statements, the Company has not received the final audit findings and cannot predict the outcome of this 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 Niagara Mohawk. On June 26, 2014,

the NYPSC selected The Liberty Consulting Group to conduct the audit. At the time of the issuance of these consolidated financial statements, Niagara Mohawk cannot predict the outcome of this operational audit.

Recovery of Deferral Costs Relating to Emergency Order

On January 28, 2014, Niagara Mohawk filed a petition requesting a waiver of Rule 46.3.2 of its tariff. Rule 46.3.2 describes the manner in which Niagara Mohawk calculates its supply-related Mass Market Adjustment ("MMA"). Niagara Mohawk proposed the waiver of the rule to mitigate adverse financial impacts anticipated from a significant and unusual increase in electric commodity prices for its mass market customers.

On that same date, the NYPSC issued, on an emergency basis pursuant to the State Administrative Procedure Act §202(6), an Emergency Order granting Niagara Mohawk's waiver request (the "Emergency Order"). In the Emergency Order, the NYPSC waived the requirements of Rule 46.3.2 and approved deferral treatment of the costs and associated carrying charges related to the one-time credit provided via the waiver. However, the NYPSC denied, pending further review and consideration of public comments, Niagara Mohawk's request to recover such deferral over a six-month period beginning May 2014.

The NYPSC issued another order on April 25, 2014 permanently approving the Emergency Order and authorizing Niagara Mohawk to collect $33.3 million, plus carrying charges at the customer deposit rate, over a six-month period commencing with the June 2014 billing period. The deferral recovery will be performed in a manner consistent with the method that was used to provide the benefit to the mass market customers, through an adjustment to the MMA as calculated by NYISO load zone.

Petition for Authorization to Defer an Actuarial Experience Pension Settlement Loss for Fiscal Year 2014

On February 28, 2014, Niagara Mohawk filed a petition seeking authorization to defer a pension settlement loss incurred during fiscal year 2014. The petition reflected actual loss amounts through December 31, 2013. On August 13, 2014, Niagara Mohawk filed a supplemental petition with actual results through March 31, 2014. In total, Niagara Mohawk seeks authorization to defer $14.1 million related to a pension settlement loss that occurred in fiscal year 2014.

The New York Gas Companies

General Rate Case

KeySpan Gas East has been subject to a rate plan with a primary term of five years (2008-2012), which remains in effect until modified by the NYPSC. Under this rate plan, base delivery rates include an allowed ROE of 9.8%.

On June 13, 2013, the NYPSC approved a settlement covering the Brooklyn Union's 2013 and 2014 rate years. Brooklyn Union's revenue requirements for both years have been modified as follows: (i) there is no change in base delivery rates, other than those previously approved by the NYPSC in the rate plan, (ii) the allowed ROE has decreased from 9.8% to 9.4%, and (iii) the common equity ratio in the capital structure has increased from 45% to 48%.

Capital Investment

On June 13, 2014, KeySpan Gas East filed a petition with the NYPSC to implement a three-year capital investment program that would allow KeySpan Gas East to invest more than $700.0 million in gas infrastructure projects designed to enhance the safety and reliability of its gas systems and promote gas growth, while maintaining base delivery rates. The petition seeks (i) a new deferral mechanism that would permit KeySpan Gas East to defer for future recovery in rates the pre-tax revenue requirement associated with its capital spending program to the extent the amount of such investments exceeds the level of book depreciation expense reflected in KeySpan Gas East's rates; and (ii) the elimination of its existing city/state construction and non-growth related capital deferral mechanisms. KeySpan Gas East has requested that the NYPSC grant this relief by the end of September 2014, however, the NYPSC has not yet acted on the petition.

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

2009 Capital Investments Audit

Rates for services rendered by the Massachusetts Electric Companies are subject to approval by the DPU. The DPU approved an RDM arising from the 2009 distribution rate case filed by the Massachusetts Electric Companies. As part of their RDM provision, the Massachusetts Electric Companies file a report by July 1st of each year on their capital investment for the prior calendar year. In connection with the Massachusetts Electric Companies' first capital expenditure ("CapEx") filing made in July 2010, the DPU opened a proceeding in March 2011, as requested by the Massachusetts Attorney General's Office ("Attorney General"), for an independent audit of the Massachusetts Electric Companies' 2009 capital investments which, in part, formed the basis for the Massachusetts Electric Companies' RDM rate adjustment. On July 31, 2014, the DPU issued an order approving the sole bidder's bid to perform the CapEx audit. As required by the Order, the Massachusetts Electric Companies have conferred with the Attorney General and the auditor, and on August 21, 2014 the Massachusetts Electric Companies submitted a revised work plan and final contract for the audit to the DPU. After a comment period the DPU will issue a final order on the revised work plan and contract, which will determine the next steps for the audit. The Massachusetts Electric Companies cannot currently predict the outcome of this proceeding.

Cost Recovery

In addition to the rates and tariffs put into effect following its most recent rate case, Massachusetts Electric continues to be authorized to recover costs associated with the procurement of electricity for its customers, all transmission costs, and costs charged by Massachusetts Electric's affiliate NEP, for stranded costs associated with NEP's former electric generation investments.

DPU Audit Settlement Agreement

In the general rate case involving the Company's Massachusetts gas distribution subsidiaries, the DPU opened an investigation to address the allocation and assignment of costs to the gas affiliates by the NGUSA service companies. The audit was later expanded to include the Massachusetts Electric Companies. The Massachusetts Electric Companies, the Massachusetts Gas Companies and the Attorney General's Office executed a Settlement Agreement that the DPU approved on July 25, 2014. As a result of the approval of the Settlement, there is no need for an audit, and both the Massachusetts Gas and Massachusetts Electric Companies will implement reporting and review practices similar to those in place for their New York affiliates, and NGUSA contributed $1 million to the Massachusetts Association for Community Action that will be used for the benefit of the Massachusetts Electric Companies' electric customers and customers of its Massachusetts gas distribution affiliates who are eligible for fuel assistance.

Storm Management Audit

In January 2011, the DPU opened an investigation into the Massachusetts Electric Companies' preparation and response to a December 2010 winter storm. The DPU has the authority to issue fines not to exceed approximately $0.3 million for each violation for each day that the violation persists. On September 22, 2011, the DPU approved a settlement between the Massachusetts Electric Companies and the Attorney General that included a $1.2 million refund to customers. The DPU also investigated the Massachusetts Electric Companies' response to Tropical Storm Irene and the October 2011 winter storm in a consolidated proceeding. On December 11, 2012, the DPU issued an order in which it assessed the Massachusetts Electric Companies a penalty of $18.7 million associated with the Massachusetts Electric Companies' performance in responding to these two weather events, consisting of $8.1 million for Tropical Storm Irene and $10.6 million for the October 2011 winter storm. The Massachusetts Electric Companies appealed this ruling and on September 4, 2014 the Court affirmed all but two violations, reducing the penalty by $0.9 million. The Massachusetts Electric Companies had recorded the original penalty and credited customers during March 2013. In addition, in the December 11, 2012 order, the DPU ordered a management audit of the Massachusetts Electric Companies' emergency planning, outage management, and restoration. The auditors have completed their audit, and submitted their Final Report to the DPU on July 9, 2014. No parties submitted comments on the Final Report. The Massachusetts Electric Companies cannot predict the outcome of the management audit.

2010 Service Quality Report

On December 30, 2013, the DPU issued an order on Massachusetts Electric's calendar year 2010 Service Quality report, ordering that Massachusetts Electric refund to customers a net penalty of $6.7 million. On January 21, 2014, Massachusetts Electric filed a Motion for Clarification/Reconsideration regarding a portion of the penalty amount related to Circuit Average Interruption Frequency Index which totaled $2.7 million. In addition, Massachusetts Electric filed a proposal to credit customers the $6.7 million penalty along with a proposed tariff that would allow for recovery of the $2.7 million if the DPU rules in favor of Massachusetts Electric regarding the Motion for Clarification/Reconsideration. On May 21, 2014, the DPU denied Massachusetts Electric's motion.

Boston Gas and Colonial Gas (the "Massachusetts Gas Companies")

General Rate Case

In November 2010, the DPU issued an order in the Massachusetts Gas Companies' 2010 rate case approving a revenue increase of $58.0 million based upon a 9.75% rate of return on equity and a 50% equity ratio. The Massachusetts Gas Companies filed two motions in response. These motions resulted in a final revenue increase of $65.3 million reflected in rates effective February 1, 2013.

PBOP Carrying Charges

On June 1, 2011, in conjunction with the DPU's annual investigation of Boston Gas' calendar year 2009 pension and PBOP rate reconciliation mechanism, the Massachusetts Attorney General ("AG") argued that Boston Gas be obligated to provide carrying charges to the benefit of customers on its PBOP liability balances related to its 2003 to 2006 rate reconciliation filings. In August 2010, the DPU ordered Boston Gas to provide carrying charges on its PBOP liability balances on its 2007 and 2008 rate reconciliation filings, but the order was silent about providing carrying charges prior to those years. On August 29, 2014, the DPU agreed with the AG and ordered Boston Gas to provide carrying charges on its 2003 to 2006 PBOP liability balances in its next annual pension and PBOP reconciliation filing. Boston Gas is evaluating the impact of this decision.

New England Power

Stranded Cost Recovery

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

Transmission Return on Equity

NEP's transmission rates during the reporting period reflect a base ROE of 11.14% applicable to all transmission facilities, plus an additional 0.5% Regional Transmission Organizations (''RTO") participation adder applicable to transmission facilities included under the Regional Network Service ("RNS") rate. Approximately 70% of the NEP's transmission facilities are included under RNS rates. NEP earns an additional 1.0% ROE incentive adder on RNS-related transmission facilities approved under the RTO's Regional System Plan and placed in service on or before December 31, 2008. It also earns 1.25% ROE on its portion of New England East-West Solution ("NEEWS") as described below. On October 16, 2014, the FERC issued an order as the result of a ROE complaint case (as described in "FERC ROE Complaints" in Note 13 "Commitments and Contingencies,") that set NEP's base ROE, effective from the date of the order, at 10.57% with total or maximum ROE including the aforementioned incentives not to exceed 11.74%.

New England East-West Solution

In September 2008, NEP, its affiliate Narragansett, and Northeast Utilities jointly filed an application with the FERC to recover financial incentives for the NEEWS, 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 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. In its June 19, 2014 order on the first NETO ROE complaint, the FERC ordered that all ROE incentives, such as the NEEWS incentive ROE, be capped at 11.74% subject to further limited proceedings to determine growth rates that would be used in calculating the final cap. It is currently unclear how the FERC's order will affect the ROE for NEEWS.

Narragansett

General Rate Case

On December 20, 2012, the RIPUC approved a settlement agreement among the Rhode Island Division of Public Utilities and Carriers, the Department of the Navy, and Narragansett, which provided for an increase in electric base distribution revenue of $21.5 million and an increase in gas base distribution revenue of $11.3 million based on a 9.5% allowed ROE and a common equity ratio of approximately 49.1%, effective February 1, 2013. The settlement also included reinstatement of base rate recovery of storm fund contributions and implementation of a Pension Adjustment Mechanism ("PAM") for pension and PBOP expenses for the electric business identical to the mechanism in place for the gas business.

5. PROPERTY, PLANT AND EQUIPMENT

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

	March 31,	
	2014	2013
	(in millions of dollars)	
Plant and machinery	**$ 27,034**	$ 25,181
Property held for future use	**16**	24
Land and buildings	**2,075**	2,027
Assets in construction	**1,410**	1,380
Software and other intangibles	**637**	530
Total property, plant and equipment	**31,172**	29,142
Accumulated depreciation and amortization	**(7,297)**	(6,643)
Property, plant and equipment, net	**$ 23,875**	$ 22,499

6. DERIVATIVE CONTRACTS AND HEDGING

The Company utilizes derivative instruments to manage commodity price, interest and currency rate risk associated with its natural gas and electricity purchases and 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 to, and only in terms and volumes consistent with its core business.

Volumes

Volumes of outstanding commodity derivative contracts measured in dekatherms ("dths") and megawatt hours ("Mwhs") are as follows:

	Electric		Gas	
	March 31,		March 31,	
	2014	2013	**2014**	2013
	(in millions)		*(in millions)*	
Gas purchase contracts (dths)	-	-	**87**	59
Gas swap contracts (dths)	-	-	**50**	66
Gas option contracts (dths)	-	-	**23**	4
Gas future contracts (dths)	-	-	**20**	17
Electric swap contracts (Mwhs)	**7**	6	**-**	-
Total:	**7**	6	**180**	146

Amounts Recognized in the Accompanying Consolidated Balance Sheets:

	Asset Derivatives			Liability Derivatives		
	March 31,			March 31,		
	2014	2013		**2014**	2013	
	(in millions of dollars)			*(in millions of dollars)*		
Current assets:			Current liabilities:			
Rate recoverable contracts:			Rate recoverable contracts:			
Gas swap contracts	**$ 12**	$ 15	Gas swap contracts	**$ 4**	$ 6	
Gas future contracts	**3**	1	Gas future contracts	**1**	2	
Gas option contracts	**2**	1	Gas option contracts	**1**	-	
Gas purchase contracts	**11**	15	Gas purchase contracts	**36**	3	
Electric swap contracts	**36**	18	Electric swap contracts	**1**	-	
Electric option contracts	**1**	-	Electric option contracts	**-**	-	
Hedge contracts:			Hedge contracts:			
CCIRS	**5**	11	CCIRS	**-**	-	
	70	61		**43**	11	
Deferred charges and other assets:			Deferred credits and other liabilities:			
Rate recoverable contracts:			Rate recoverable contracts:			
Gas swap contracts	**-**	1	Gas swap contracts	**-**	-	
Gas future contracts	**-**	2	Gas future contracts	**-**	-	
Gas purchase contracts	**18**	4	Gas purchase contracts	**5**	7	
Electric swap contracts	**8**	6	Electric swap contracts	**9**	1	
Hedge contracts:			Hedge contracts:			
CCIRS	**-**	1	CCIRS	**-**	56	
	26	14		**14**	64	
Total	**$ 96**	$ 75	Total	**$ 57**	$ 75	

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 changes in fair value of the Company's contracts not subject to rate recovery are recorded within purchased gas in the accompanying consolidated statements of income.

Credit and Collateral

The Company is exposed to credit risk related to transactions entered into for commodity price, interest and currency 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 clearinghouses act as the counterparty to each trade. Transactions on the NYMEX must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX are significantly collateralized and have limited counterparty credit risk.

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

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 $29 million and $42 million as of March 31, 2014 and 2013, respectively.

The aggregate fair value of the Company's commodity derivative instruments with credit-risk-related contingent features that is in a liability position at March 31, 2014 and 2013 was $16.9 million and $5.0 million, respectively. The Company had no collateral posted for these instruments at March 31, 2014 or 2013. If the Company's credit rating were to be downgraded by one or two levels, it would not be required to post any additional collateral. If the Company's credit rating were to be downgraded by three levels, it would be required to post $18.0 million additional collateral to its counterparties.

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.

In relation to the Company's 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 additional collateral.

Offsetting Information for Derivatives Subject to Master Netting Arrangements

March 31, 2014
Gross Amounts Not Offset in the Balance Sheets
(in millions of dollars)

ASSETS: Description	Gross amounts of recognized assets *A*	Gross amounts offset in the Balance Sheets *B*	Net amounts of assets presented in the Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral received *Db*	Net amount *E=C-D*
Derivatives						
Gas swap contracts	$ 12	$ -	$ 12	$ -	$ -	$ 12
Gas future contracts	3	-	3	-	3	-
Gas option contracts	2	-	2	-	-	2
Gas purchase contracts	29	-	29	-	-	29
Electric swap contracts	44	-	44	-	3	41
Electric option contracts	1	-	1	-	-	1
CCIRS	5	-	5	-	-	5
Total	$ 96	$ -	$ 96	$ -	$ 6	$ 90

LIABILITIES: Description	Gross amounts of liabilities *A*	Gross amounts offset in the Balance Sheets *B*	Net amounts of presented in the Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral paid *Db*	Net amount *E=C-D*
Derivatives						
Gas swap contracts	$ 4	$ -	$ 4	$ -	$ -	$ 4
Gas future contracts	1	-	1	-	1	-
Gas option contracts	1	-	1	-	-	1
Gas purchase contracts	41	-	41	-	-	41
Electric swap contracts	10	-	10	-	-	10
Total	$ 57	$ -	$ 57	$ -	$ 1	$ 56

March 31, 2013
Gross Amounts Not Offset in the Balance Sheets
(in millions of dollars)

ASSETS: Description	Gross amounts of recognized assets *A*	Gross amounts offset in the Balance Sheets *B*	Net amounts of assets presented in the Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral received *Db*	Net *E=C-D*
Derivatives						
Gas swap contracts	$ 16	$ -	$ 16	$ -	$ -	$ 16
Gas future contracts	3	-	3	-	3	-
Gas option contracts	1	-	1	-	-	1
Gas purchase contracts	19	-	19	-	-	19
Electric swap contracts	24	-	24	-	-	24
CCIRS	12	-	12	-	-	12
Total	$ 75	$ -	$ 75	$ -	$ 3	$ 72

LIABILITIES: Description	Gross amounts of liabilities *A*	Gross amounts offset in the Balance Sheets *B*	liabilities presented in the Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral paid *Db*	Net *E=C-D*
Derivatives						
Gas swap contracts	$ 6	$ -	$ 6	$ -	$ -	$ 6
Gas future contracts	2	-	2	-	1	1
Gas purchase contracts	10	-	10	-	-	10
Electric swap contracts	1	-	1	-	-	1
CCIRS	56	-	56	-	6	50
Total	$ 75	$ -	$ 75	$ -	$ 7	$ 68

7. FAIR VALUE MEASUREMENTS

The following tables present assets and liabilities measured and recorded at fair value in the accompanying consolidated balance sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2014 and 2013:

	March 31, 2014			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Assets:				
Derivative contracts				
Gas swaps contracts	$ -	$ 12	$ -	$ 12
Gas futures contracts	3	-	-	3
Gas options contracts	-	-	2	2
Gas purchase contracts	-	1	28	29
Electric swaps contracts	-	44	-	44
Electric options contracts	-	-	1	1
CCIRS	-	5	-	5
Available-for-sale securities	113	124	-	237
Total	116	186	31	333
Liabilities:				
Derivative contracts				
Gas swaps contracts	-	4	-	4
Gas futures contracts	1	-	-	1
Gas options contracts	-	-	1	1
Gas purchase contracts	-	5	36	41
Electric swaps contracts	-	10	-	10
Total	1	19	37	57
Net assets	$ 115	$ 167	$ (6)	$ 276

	March 31, 2013			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Assets:				
Derivative contracts				
Gas swaps contracts	$ -	$ 16	$ -	$ 16
Gas futures contracts	3	-	-	3
Gas options contracts	-	-	1	1
Gas purchase contracts	-	1	18	19
Electric swaps contracts	-	24	-	24
CCIRS	-	12	-	12
Available-for-sale securities	134	115	-	249
Total	137	168	19	324
Liabilities:				
Derivative contracts				
Gas swaps contracts	-	6	-	6
Gas futures contracts	2	-	-	2
Gas purchase contracts	-	2	8	10
Electric swaps contracts	-	1	-	1
CCIRS	-	56	-	56
Total	2	65	8	75
Net assets	$ 135	$ 103	$ 11	$ 249

Derivative Contracts: 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 derivatives (e.g. natural gas futures traded on NYMEX).

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

The Company's Level 3 fair value derivative instruments consist of OTC gas option contracts and gas purchase contracts, which are valued based on internally-developed models. Industry-standard valuation techniques, such as the Black-Scholes pricing model, Monte Carlo simulation, and Financial Engineering Associates libraries are used for valuing such instruments. A derivative is designated Level 3 when it is valued based on a forward curve that is internally developed, extrapolated or derived from market observable curves with correlation coefficients less than 95%, where optionality is present, or if non-economic assumptions are made. The internally developed forward curves have a high level of correlation with Platts Mark-to-Market curves and are reviewed by the middle office. The Company considers non-performance risk and liquidity risk in the valuation of derivative contracts categorized in Level 2 and Level 3.

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

Changes in Level 3 Derivatives

	Years Ended March 31,	
	2014	**2013**
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 11**	$ 25
Transfers out of Level 3	**1**	(4)
Total gains or losses included in regulatory assets and liabilities	**(23)**	(17)
Settlements	**5**	7
Balance as of the end of the year	**$ (6)**	$ 11
The amount of total gains or losses for the year included in net income attributed to the change in unrealized gains or losses related to non-regulatory assets and liabilities at year-end	**$ -**	$ -

A transfer into Level 3 represents existing assets or liabilities that were previously categorized at a higher level for which the inputs became unobservable during the year. A transfer out of Level 3 represents assets and liabilities that were previously classified as Level 3 for which the inputs became observable based on the criteria discussed previously for classification in Level 2. These transfers, which are recognized at the end of each period, result from changes in the observability of forward curves from the beginning to the end of each reporting period. There were no transfers between Level 1 and Level 2, and no transfers into Level 3, during the years ended March 31, 2014 or 2013.

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 derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The forward curves used for financial reporting are

developed and verified by the middle office. The Company considers non-performance risk and liquidity risk in the valuation of derivative contracts categorized in Level 2 and Level 3.

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

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of March 31, 2014 Assets	(Liabilities)	Total	Valuation Technique(s)	Significant Unobservable Input	Range
		(in millions of dollars)					
Gas	Purchase Contracts	$ 28	$ (36)	$ (8)	Discounted Cash Flow	Forward Curve and LNG Forward Curve	$2.434-$98.98/Dth
Gas	Options Contracts	2	(1)	1	Discounted Cash Flow	Forward Curve	$(1.070)-$0.720/Dth
Electric	Options Contracts	1	-	1	Discounted Cash Flow	Implied Volatility	29%-65%
	Total	$ 31	$ (37)	$ (6)			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of March 31, 2013 Assets	(Liabilities)	Total	Valuation Technique(s)	Significant Unobservable Input	Range
		(in millions of dollars)					
Gas	Purchase Contracts	$ 18	$ (8)	$ 10	Discounted Cash Flow	Forward Curve	$3.816-$93.21/Dth
Gas	Options Contracts	1	-	1	Discounted Cash Flow	Forward Curve	$0.274-$0.352/Dth
	Total	$ 19	$ (8)	$ 11			

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 and gas and electric option derivatives are forward commodity prices, both gas and electric, implied volatility and valuation assumptions pertaining to the peaking gas deals based on the forward gas curves. A relative change in commodity price at various locations underlying the open positions can result in significantly different fair value estimates.

Other Fair Value Measurements

The Company's consolidated balance sheets reflect long-term debt at amortized cost. The fair value of the Company's long-term debt was based on quoted market prices when available, or estimated using quoted market prices for similar debt. The fair value of this debt at March 31, 2014 and 2013 was $9.9 billion and $10.4 billion, respectively.

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

8. EMPLOYEE BENEFITS

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

Pension Plans

The Pension Plans are comprised of both qualified and non-qualified plans. The qualified pension plans provide union employees, as well as all 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. The Company funds the qualified plans by contributing at least the minimum amount required under Internal Revenue Service ("IRS") regulations. The Company expects to contribute approximately $196 million to the Pension Plans during the year ended March 31, 2015.

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. The Company funds these plans based on the requirements of the various regulatory jurisdictions in which it operates. The Company expects to contribute approximately $181 million to the PBOP Plans during the year ended March 31, 2015.

Defined Contribution Plans

The Company also has several defined contribution pension plans (primarily 401(k) employee savings fund plans) that cover substantially all employees. In addition, employees may receive certain employer contributions, including matching contributions and a 15% discount on the purchase of National Grid plc common stock. Employer matching contributions of approximately $38 million and $30 million, respectively, were expensed in the years ended March 31, 2014 and 2013.

Components of Net Periodic Benefit Costs

	Pension Plans		PBOP Plans	
	Years Ended March 31,		**Years Ended March 31,**	
	2014	2013	**2014**	2013
	(in millions of dollars)			
Service cost, benefits earned during the year	**$ 134**	$ 133	**$ 73**	$ 68
Interest cost	**355**	361	**203**	207
Expected return on plan assets	**(443)**	(414)	**(170)**	(145)
Net amortization and deferral	**261**	275	**91**	111
Settlements/curtailments	**16**	7	**(140)**	(2)
Total cost	**$ 323**	$ 362	**$ 57**	$ 239

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

Amounts Recognized in AOCI and Regulatory Assets

	Pension Plans		PBOP Plans	
	Years Ended March 31,		**Years Ended March 31,**	
	2014	2013	**2014**	2013
	(in millions of dollars)			
Net actuarial loss	**$ (18)**	$ 150	**$ (319)**	$ 227
Prior service cost	**-**	11	**(31)**	-
Amortization of gain	**(267)**	(272)	**58**	(98)
Amortization of prior service cost	**(10)**	(9)	**(9)**	(11)
Total	**$ (295)**	$ (120)	**$ (301)**	$ 118
Included in regulatory assets	**$ (181)**	$ 22	**$ (62)**	$ 66
Included in AOCI	**(114)**	(142)	**(239)**	52
Total	**$ (295)**	$ (120)	**$ (301)**	$ 118

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

	Pension Plans		PBOP Plans		Expected Amortization
	Years Ended March 31,		**Years Ended March 31,**		**Year Ended March 31,**
	2014	2013	**2014**	2013	2015
	(in millions of dollars)				
Cumulative loss	**$ 1,681**	$ 1,966	**$ 644**	$ 905	**$ 306**
Prior service cost	**46**	56	**(23)**	17	**13**
Total	**$ 1,727**	$ 2,022	**$ 621**	$ 922	**$ 319**
Included in regulatory assets	**$ 886**	$ 1,067	**$ 397**	$ 459	
Included in accumulated other comprehensive income	**841**	955	**224**	463	
Total	**$ 1,727**	$ 2,022	**$ 621**	$ 922	

Reconciliation of Funded Status to Amount Recognized

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2014	2013	**2014**	2013
	(in millions of dollars)			
Change in benefit obligation:				
Benefit obligation as of the beginning of the year	**$ (7,724)**	$ (7,340)	**$ (4,589)**	$ (4,213)
Service cost	**(134)**	(133)	**(73)**	(68)
Interest cost on projected benefit obligation	**(355)**	(361)	**(203)**	(207)
Plan amendments	**-**	(11)	**31**	-
Net actuarial loss	**(157)**	(379)	**(103)**	(283)
Benefits paid	**357**	418	**190**	194
Actual Medicare Part D subsidy received	**-**	-	**(26)**	(33)
Curtailments and settlements	**141**	3	**304**	-
Divestitures	**-**	79	**-**	21
Benefit obligation as of the end of the year	**(7,872)**	(7,724)	**(4,469)**	(4,589)
Change in plan assets:				
Fair value of plan assets as of the beginning of the year	**6,654**	6,159	**2,302**	1,907
Actual return on plan assets	**591**	623	**287**	189
Company contributions	**279**	352	**303**	409
Benefits paid	**(357)**	(418)	**(190)**	(194)
Settlements	**(115)**	(3)	**-**	-
Divestitures	**-**	(59)	**-**	(9)
Fair value of plan assets as of the end of the year	**7,052**	6,654	**2,702**	2,302
Funded status	**$ (820)**	$ (1,070)	**$ (1,767)**	$ (2,287)

The benefit obligation shown above is the projected benefit obligation ("PBO") for the Pension Plans and the accumulated benefit obligation ("ABO") for the PBOP Plans. The Company is required to reflect the funded status of its Pension Plans above in terms of the PBO, which is higher than the ABO, because the PBO includes the impact of expected future compensation increases on the pension obligation. The Pension Plans had ABO balances that exceeded the fair value of plans assets as of March 31, 2014 and 2013. The aggregate ABO balances for the Pension Plans were $7.4 billion and $7.2 billion as of March 31, 2014 and 2013, respectively.

Amounts Recognized in the Accompanying Consolidated Balance Sheets

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2014	2013	**2014**	2013
	(in millions of dollars)			
Non-current assets	**$ 290**	$ 297	**$ 15**	$ -
Current liabilities	**(22)**	(23)	**(16)**	(11)
Non-current liabilities	**(1,088)**	(1,344)	**(1,766)**	(2,276)
Total	**$ (820)**	$ (1,070)	**$ (1,767)**	$ (2,287)

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2014:

(in millions of dollars) Years Ended March 31,	Pension Benefits	Postretirement Benefits
2015	$ 486	$ 199
2016	491	206
2017	497	213
2018	499	220
2019	498	226
Thereafter	2,510	1,223
Total	$ 4,981	$ 2,287

Assumptions Used for Employee Benefits Accounting

	Pension Plans		**PBOP Plans**	
	Years Ended March 31,		**Years Ended March 31,**	
	2014	2013	**2014**	2013
Benefit Obligations				
Discount rate	**4.80%**	4.70%	**4.80%**	4.70%
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	n/a
Expected return on plan assets	**7.00%**	6.75%-7.25%	**7.00% - 7.25%**	7.25%-7.50%
Net Periodic Benefit Costs				
Discount rate	**4.70%**	5.10%	**4.70%**	5.10%
Rate of compensation increase	**3.50%**	3.50%	**n/a**	n/a
Expected return on plan assets	**6.75% - 7.25%**	6.75%-7.25%	**7.25%-7.50%**	7.25%-7.50%

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,	
	2014	2013
Health care cost trend rate assumed for next year		
Pre 65	**8.00%**	8.00%
Post 65	**7.00%**	7.50%
Prescription	**7.00%**	8.25%
Rate to which the cost trend is assumed to decline (ultimate)	**5.00%**	5.00%
Year that rate reaches ultimate trend		
Pre 65	**2022**	2019
Post 65	**2021**	2018
Prescription	**2021**	2020

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

(in millions of dollars)	March 31, 2014
1% point increase	
Total of service cost plus interest cost	$ 51
Postretirement benefit obligation	642
1% point decrease	
Total of service cost plus interest cost	(41)
Postretirement benefit obligation	(542)

Plan Assets

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

The target asset allocations for the benefit plans as of March 31, 2014 and 2013 are as follows:

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2014	2013	**2014**	2013
U.S. equities	**20%**	20%	**39%**	39%
Global equities (including U.S.)	**7%**	7%	**6%**	6%
Global tactical asset allocation	**10%**	10%	**9%**	9%
Non-U.S. equities	**10%**	10%	**21%**	21%
Fixed income	**40%**	40%	**25%**	25%
Private equity	**5%**	5%	**0%**	0%
Real estate	**5%**	5%	**0%**	0%
Infrastructure	**3%**	3%	**0%**	0%
	100%	100%	**100%**	100%

Fair Value Measurements

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

	March 31, 2014			
	Level 1	**Level 2**	**Level 3**	**Total**
		(in millions of dollars)		
Pension Assets:				
Cash and cash equivalents	$ 5	$ 116	$ 1	$ 122
Accounts receivable	93	-	-	93
Accounts payable	(82)	-	-	(82)
Equity	846	1,796	318	2,960
Global tactical asset allocation	-	244	54	298
Fixed income securities	-	2,890	46	2,936
Preferred securities	2	-	-	2
Futures contracts	4	-	-	4
Private equity	-	-	409	409
Real estate	-	-	310	310
Total	**$ 868**	**$ 5,046**	**$ 1,138**	**$ 7,052**
PBOP Assets:				
Cash and cash equivalents	$ 49	$ 17	$ -	$ 66
Accounts receivable	6	-	-	6
Accounts payable	(5)	-	-	(5)
Equity	460	1,219	105	1,784
Global tactical asset allocation	72	98	24	194
Fixed income securities	2	647	-	649
Private equity	-	-	8	8
Total	**$ 584**	**$ 1,981**	**$ 137**	**$ 2,702**

	March 31, 2013			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Pension Assets:				
Cash and cash equivalents	$ 4	$ 102	$ -	$ 106
Accounts receivable	141	-	-	141
Accounts payable	(124)	-	-	(124)
Equity	988	1,778	56	2,822
Global tactical asset allocation	-	261	52	313
Fixed income securities	-	2,697	56	2,753
Preferred securities	6	-	-	6
Private equity	-	-	376	376
Real estate	-	-	261	261
Total	**$ 1,015**	**$ 4,838**	**$ 801**	**$ 6,654**
PBOP Assets:				
Cash and cash equivalents	$ 94	$ 42	$ -	$ 136
Accounts receivable	8	-	-	8
Accounts payable	(7)	-	-	(7)
Equity	419	1,030	22	1,471
Global tactical asset allocation	64	79	18	161
Fixed income securities	-	517	1	518
Private equity	-	-	15	15
Total	**$ 578**	**$ 1,668**	**$ 56**	**$ 2,302**

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

Accounts Receivable and Accounts Payable: Accounts receivable and accounts payable are classified in the same category as the investments to which they relate. Such amounts are short-term and settle within a few days of the measurement date.

Equity and Preferred Securities: Common stocks 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. Investments that are not publicly traded and valued using unobservable inputs are classified as Level 3 investments. Commingled funds with publicly quoted prices and active trading are classified as Level 1 investments. For investments in commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the net asset value (“NAV”) per fund share, derived from the underlying securities’ quoted prices in active markets, and they are classified as Level 2 investments. Investments in commingled funds with redemption restrictions and that use NAV are classified as Level 3 investments.

Global Tactical Asset Allocation: Assets held in global tactical asset allocation funds are managed by investment managers who use both top-down and bottom-up valuation methodologies to value asset classes, countries, industrial sectors, and individual securities in order to allocate and invest assets opportunistically. If the inputs used to measure a financial instrument fall within different levels of the fair value hierarchy within the commingled fund, the categorization is based on the lowest level input that is significant to the measurement of that financial instrument. The assets invested through commingled funds are classified as Level 2. Those which are open ended mutual funds with observable pricing are classified as Level 1. However, the underlying Level 3 assets that makeup these funds are classified in the same category as the investments to which they relate.

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. If prices are based on uncorroborated and unobservable inputs, then the investments are classified as Level 3 investments. Commingled funds with publicly quoted prices and active trading are classified as Level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, derived from the underlying securities' quoted prices in active markets, and are classified as Level 2 investments. Investments in commingled funds with redemption restrictions and that use NAV are classified as Level 3.

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. As a result, the Company classifies these investments as Level 3.

While management believes its valuation methodologies are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of Level 3 financial instruments could result in a different fair value measurement at the reporting date.

Changes in Level 3 Plan Investments

	Pension Plans		PBOP Plans	
	Years Ended March 31,		**Years Ended March 31,**	
	2014	2013	**2014**	2013
	(in millions of dollars)			
Balance as of the beginning of the year	**$ 801**	$ 804	**$ 56**	$ 73
Transfers out of Level 3	**(16)**	(4)	**(41)**	(24)
Transfers in to Level 3	**282**	6	**102**	27
Actual gain or loss on plan assets				
Realized gain	**37**	17	**3**	-
Unrealized gain	**56**	37	**(1)**	1
Purchases	**397**	296	**37**	188
Sales	**(419)**	(355)	**(19)**	(209)
Balance as of the end of the year	**$ 1,138**	$ 801	**$ 137**	$ 56

Other Benefits

The Company accrued $83.7 million and $74.6 million at March 31, 2014 and 2013, respectively, regarding workers compensation, auto and general insurance claims which have been incurred but not yet reported.

9. CAPITALIZATION

European Medium Term Note Program

At March 31, 2014, the Company had a Euro Medium Term Note program (the "Program") under which it is able to issue debt instruments ("Instruments") up to a total of the equivalent of 4 billion Euros. Instruments issued under the Program are admitted to trading on the London Stock Exchange. The Program commenced in December 2007 and is renewed annually, with the latest renewal of the Program expiring in December 2014. If the Program is not renewed in December 2014, it would preclude the issuance of new notes under this Program, but it would not impact the outstanding debt balances and their maturity dates. Instruments carry certain affirmative and negative covenants, including a restriction on the Company's ability to mortgage, pledge, charge or otherwise encumber its assets in order to secure, guarantee or indemnify other listed or quoted debt obligations, as well as cross-acceleration in the event of breach by the Company or its principal subsidiaries of other listed or quoted debt obligations. At March 31, 2014 and 2013, the Company was in compliance with all covenants. At March 31, 2014 and 2013, $842 million and $876 million, respectively, of these notes were issued and outstanding, excluding the impact of interest rate and currency swaps.

Notes Payable

At March 31, 2014 and 2013 the Company had outstanding $5.9 billion and $6.1 billion, respectively, of unsecured medium and long-term notes. In December 2012, Narragansett issued $250 million of unsecured long-term debt at 4.17% with a maturity date of December 10, 2042. In November 2012, Niagara Mohawk issued $400 million of unsecured long-term debt at 4.119% with a maturity date of November 28, 2042 and $300 million of unsecured long-term debt at 2.721% with a maturity date of November 28, 2022. The interest rates on the unsecured notes range from 3.296% to 9.750% and maturity dates range from October 2014 through December 2042.

Gas Facilities Revenue Bonds

Brooklyn Union has outstanding tax-exempt Gas Facilities Revenue Bonds ("GFRB") issued through the New York State Energy Research and Development Authority ("NYSERDA"). There are no sinking fund requirements for any of Brooklyn Union's GFRB. At March 31, 2014 and 2013, $641 million of GFRB were outstanding; $230 million of which are variable-rate,

auction rate bonds. The interest rate on the various variable rate series due starting December 1, 2020 through July 1, 2026 is reset weekly and ranged from 0.07% to 0.51% during the year ended March 31, 2014 and 0.14% to 2.17% during the year ended March 31, 2013. The GFRB are currently in auction rate mode and are backed by bond insurance. These bonds cannot be put back to Brooklyn Union and, in the case of a failed auction, the resulting interest rate on the bonds would revert to the maximum rate which depends on the current appropriate, short-term benchmark rates and the senior unsecured rating of the Brooklyn Union's bonds. The effect of the failed auctions on interest expense was not material for the years ended March 31, 2014 or 2013.

Promissory Notes to LIPA

KeySpan Corporation had previously issued $155 million of promissory notes to LIPA to support certain debt obligations assumed by LIPA. Following the expiration of the MSA on December 31, 2013, the debt was fully extinguished (refer to Note 17, "Discontinued Operations").

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 $51.6 million, respectively, of non-callable First Mortgage Bonds ("FMB"). These FMB indentures include, among other provisions, limitations on the issuance of long-term debt. Interest rates range from 6.34% to 9.63% and maturity dates range from April 2018 to April 2028.

State Authority Financing Bonds

At March 31, 2014, the Company had outstanding $1.2 billion of State Authority Financing Bonds. Of the $1.2 billion outstanding at March 31, 2014, approximately $716 million of these bonds were issued through NYSERDA and the remaining $484 million were issued through various other state agencies.

Approximately $605 million of State Authority Financing Bonds were issued to secure a like amount of tax-exempt revenue bonds issued by NYSERDA. Approximately $530 million of such securities bear interest at short-term adjustable interest rates (with an option to convert to other rates, including a fixed interest rate) ranging from 0.38% to 0.53% for the year ended March 31, 2014. The bonds are currently in auction rate mode and are backed by bond insurance. These bonds cannot be put back to the Company and, in the case of a failed auction, the resulting interest rate on the bonds would revert to the maximum rate which depends on the current appropriate, short-term benchmark rate and the senior secured rating of the Company or the bond insurer, whichever is greater. The effect on interest expense has not been material in either of the years ended March 31, 2014 or 2013.

The Company also has $75 million of 5.15% fixed rate pollution control revenue bonds issued through NYSERDA which are callable at par. Pursuant to agreements between NYSERDA and the Company, proceeds from such issues were used for the purpose of financing the construction of certain pollution control facilities at the Company's generation facilities (which the Company subsequently sold) or to refund outstanding tax-exempt bonds and notes.

Additionally, the Company has $41 million of 1999 Series A Pollution Control Revenue Bonds due October 1, 2028. The interest rate ranged from 0.15% to 1.35% for the year ended March 31, 2014, at which time the rate was 0.61%. The interest rate ranged from 0.25% to 1.60% for the year ended March 31, 2013, at which time the rate was 0.61%. Interest expense related to these notes for each of the years ended March 31, 2014 and 2013 was approximately $0.4 million and $0.5 million, respectively.

The Company also has outstanding $25 million variable rate 1997 Series A Electric Facilities Revenue Bonds due December 1, 2027. The interest rate on these bonds is reset weekly and ranged from 0.04% to 0.25% and from 0.10% to 0.27% during the years ended March 31, 2014 and 2013, respectively. The interest rate was 0.25% and 0.12% at March 31, 2014 and 2013, respectively. Interest expense related to these notes for each of the years ended March 31, 2014 and 2013 was approximately $0.1 million.

At March 31, 2014, the Company had outstanding $410 million of the Pollution Control Revenue Bonds in tax exempt commercial paper mode with maturity dates ranging from October 2015 to October 2022 and variable interest ranging from 0.29% to 0.50% for the year ended March 31, 2014. In addition, at March 31, 2014, the Company had $52 million of tax exempt Electric Revenue Bonds in commercial paper mode with varying maturity dates from March 2016 through August 2042 and variable interest rates ranging from 0.30% to 0.50% during the year ended March 31, 2014. The bonds were issued by the Massachusetts Development Finance Agency in connection with the Company's financing of its first and second underground and submarine cable projects. Sinking fund payments of $0.3 million were made during the year ended March 31, 2014.

At March 31, 2012, three of the Company's subsidiaries had a Standby Bond Purchase Agreement ("SBPA") totaling $500 million, which expires on November 20, 2015. This agreement was available to provide liquidity support for $483 million of the Company's long-term bonds in tax-exempt commercial paper mode. The Company has classified this 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. The Company, together with other affiliates of National Grid plc, has rights to issue debt under an $850 million syndicated revolving credit facility which can be drawn upon at any time until its maturity in November 2015 and may be used, if needed, to refinance the tax-exempt commercial paper on a long-term basis. This facility has a number of financial and non-financial covenants which the Company is obliged to meet. At March 31, 2014 and 2013, the Company was in compliance with all covenants.

Industrial Development Revenue Bonds

At March 31, 2014 and 2013, KeySpan Corporation had outstanding $128 million of 5.25% tax-exempt bonds due in June 2027. Of the amount, $53 million was issued through the Nassau County Industrial Development Authority for the construction of the Glenwood Energy electric-generation peaking plant and the balance of $75 million was issued by the Suffolk County Industrial Development Authority for the Port Jefferson electric-generation peaking plant. KeySpan Corporation has fully and unconditionally guaranteed the payment obligations with regard to these tax-exempt bonds.

Committed Facility Agreements

At March 31, 2014, the Company, NGNA, and National Grid plc have a committed revolving credit facility of $850 million which matures in November 2015. This facility, bearing a commitment fee of 0.21%, has not been drawn against and therefore there is no balance outstanding. The Company, NGNA, and National Grid plc can all draw on this facility in a variety of currencies as needed, but the aggregate borrowings across the group cannot exceed the $850 million limit. The terms of the facility restrict the borrowing of all U.S. subsidiaries of the Company to $18 billion excluding intercompany indebtedness. Additionally, this facility has a number of non-financial covenants which the Company is obliged to meet. At March 31, 2014 and 2013, the Company was in compliance with all covenants.

The Company and National Grid plc have two additional committed revolving credit facilities of $280 million and £155 million which mature in July 2017. These facilities, bear a commitment fee of 0.20% each, have not been drawn against and therefore there is no balance outstanding. The Company and National Grid plc can draw on these facilities in a variety of currencies as needed, but the aggregate borrowings across the group cannot exceed the $280 million and £155 million limit, respectively. The terms of the facilities restrict the borrowing of all U.S. subsidiaries of the Company to $18 billion excluding intercompany indebtedness. Additionally, these facilities have a number of non-financial covenants which the Company is obliged to meet. At March 31, 2014 and 2013, the Company was in compliance with all covenants.

Debt Maturities

The aggregate maturities of long-term debt for the years subsequent to March 31, 2014 are as follows:

(in millions of dollars)	
Years Ended March 31,	
2015	$ 633
2016	891
2017	511
2018	89
2019	36
Thereafter	6,679
Total	$ 8,839

The Company is obligated to meet certain financial and non-financial covenants. 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, 2014 and 2013 the Company was in compliance with all such covenants and restrictions.

Some of the Company's State Authority Financing Bonds, First Mortgage Bonds, and Notes Payable have sinking fund requirements which totaled $7 million during the years ended March 31, 2014 and 2013. The following table reflects the sinking fund repayment requirements for the years subsequent to March 31, 2014:

(in millions of dollars)	
Years Ended March 31,	
2015	$ 2
2016	2
2017	1
2018	1
2019	1
Thereafter	8
Total	$ 15

Commercial Paper and Revolving Credit Agreements

Commercial Paper

At March 31, 2014, the Company had two commercial paper programs totaling $4 billion; a $2 billion U.S. commercial paper program and a $2 billion Euro commercial paper program. In support of these programs, the Company was a named borrower under National Grid plc credit facilities with $1.4 billion available to the Company. These facilities support both the Parent's and the Company's commercial paper programs for ongoing working capital needs. The facilities expire in 2015 to 2017. At March 31, 2014 and 2013, there were $421 million and $625 million of borrowings outstanding on the U.S. commercial paper program and no borrowings outstanding on the Euro commercial paper program.

The credit facilities allow both the Parent and the Company to borrow in multi-currencies. The current annual commitment fees range from 0.20% to 0.21%. If for any reason the Company were not able to issue sufficient commercial paper or source funds from other sources, the facilities could be drawn upon to meet cash requirements. The facilities contain certain affirmative and negative operating covenants, including restrictions on the Company's utility subsidiaries' ability to mortgage, pledge, encumber or otherwise subject their utility property to any lien, as well as financial covenants that require the Company and the Parent to limit the total indebtedness in U.S. and non-U.S. subsidiaries to pre-defined limits. Violation of these covenants could result in the termination of the facilities and the required repayment of amounts borrowed thereunder, as well as possible cross defaults under other debt agreements. At March 31, 2014 and 2013, the Company was in compliance with all covenants.

10. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,	
	2014	2013
	(in millions of dollars)	
Current tax expense (benefit):		
Federal	**$ (18)**	$ (208)
State	**40**	53
Total current tax expense (benefit)	**22**	(155)
Deferred tax expense:		
Federal	**254**	388
State	**6**	45
Total deferred tax expense	**260**	433
Amortized investment tax credits [1]	**(5)**	(6)
Total deferred tax expense	**255**	427
Total income tax expense	**$ 277**	$ 272

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

Statutory Rate Reconciliation

The Company's effective tax rates for the years ended March 31, 2014 and 2013 were 36.3% and 39.5%, respectively. The following table presents a reconciliation of income tax expense at the federal statutory tax rate of 35% to the actual tax expense:

	Years Ended March 31,	
	2014	2013
	(in millions of dollars)	
Computed tax	**$ 267**	$ 241
Change in computed taxes resulting from:		
State income tax, net of federal benefit	**30**	62
Investment tax credit	**(5)**	(6)
Other items, net	**(15)**	(25)
Total	**10**	31
Federal and state income taxes	**$ 277**	$ 272

The Company is included in the NGNA and subsidiaries consolidated federal income tax return. The Company has joint and several liability for any potential assessments against the consolidated group. The Company also files unitary, combined, and separate state income tax returns.

In September 2013, the IRS issued final regulations, effective for tax years beginning in 2014, that provide guidance on the appropriate tax treatment of costs incurred to acquire, produce or improve tangible property, as well as routine maintenance and repair costs. Proposed regulations were issued addressing the tax treatment of asset dispositions. The Company has evaluated tax accounting method changes that may be elected or required by the final regulations. At March 31, 2014, $43.5 million of deferred tax liabilities have been classified as current in the Company's consolidated balance sheets, representing the cumulative adjustment expected to be reflected in income for tax purposes during the twelve

months ending March 31, 2015. The application of these regulations is not expected to have a material impact on the Company's financial position, results of operations, or cash flows.

On July 24, 2013, the Massachusetts legislature enacted into law transportation finance legislation which included significant tax changes affecting the classification of utility corporations. For tax years beginning on or after January 1, 2014, Massachusetts utility corporations will be taxed in the same manner as general business corporations. The state income tax rate increased from 6.5% to 8.0%. Also, any unitary net operating loss generated post-2013 and allocated to the utilities will be allowed as a carryforward tax attribute. As of March 31, 2014, all Massachusetts state deferred tax balances at the regulated utilities were remeasured to the 8% rate, resulting in an increase in deferred tax liabilities of $47 million with an offset to the regulatory deferred tax asset. The application of this legislation is not expected to have a material impact on the Company's financial position, results of operations, or cash flows.

On March 31, 2014, New York's legislature enacted as part of the 2014-15 budget package, legislation which included significant tax changes. For tax years beginning on or after January 1, 2016, the New York corporate franchise rate is reduced from 7.1% to 6.5%. Additionally, for tax years beginning on or after January 1, 2015, New York State will generally require combined reporting if the taxpayer is engaged in a unitary business and a 50% common ownership test is met. The Metropolitan Transportation Authority surcharge rate increased from 17% to 25.6% of the New York rate for taxable years beginning after 2014 and before 2016. For subsequent years, the rate is to be adjusted by the Commissioner of the New York State Department of Taxation and Finance. As of March 31, 2014, the Company remeasured its New York State deferred tax assets and liabilities based upon the enacted law that will apply when the corresponding state temporary differences are expected to be realized or settled. Specifically, the Company decreased its New York State deferred tax liability and income tax expense by $24.5 million and $3.1 million, respectively, with an offset of $27.6 million to the regulatory deferred tax liability.

Deferred Tax Components

	March 31,	
	2014	2013
	(in millions of dollars)	
Deferred tax assets:		
Pensions, PBOP and other employee benefits	**$ 1,514**	$ 1,821
Reserve - environmental response costs	**563**	580
Regulatory liabilities - other	**326**	398
Future federal benefit on state taxes	**176**	173
Net operating losses	**242**	297
Other items	**210**	274
Total deferred tax assets [1]	**3,031**	3,543
Deferred tax liabilities:		
Property related differences	**5,615**	5,248
Regulatory assets - pension and PBOP	**722**	875
Regulatory assets - environmental	**681**	692
Regulatory assets - other	**432**	479
Other items	**223**	249
Total deferred tax liabilities	**7,673**	7,543
Net deferred income tax liabilities	**4,642**	4,000
Deferred investment tax credits	**37**	45
Net deferred income tax liability and investment tax credits	**4,679**	4,045
Current portion of deferred income tax liabilities	**171**	193
Deferred income tax liabilities	**$ 4,850**	$ 4,238

[1] There was a valuation allowance of zero and $5.8 million for deferred tax assets at March 31, 2014 and 2013, respectively.

The following table presents the amounts and expiration dates of operating losses as of March 31, 2014:

Expiration of net operating losses:	Federal
	(in millions of dollars)
03/31/2033	$ 535
03/31/2034	509

Expiration of state and city net operating losses:	State of New York	City of New York
	(in millions of dollars)	
12/31/2024	$ 49	$ 38
12/31/2025	88	82
12/31/2026	24	-
12/31/2027	35	-
03/31/2028	47	7
03/31/2029	295	37
03/31/2030	70	28
03/31/2031	11	-
03/31/2032	41	10
03/31/2033	387	295
03/31/2034	90	-

Unrecognized Tax Benefits

As of March 31, 2014 and 2013, the Company's unrecognized tax benefits totaled $510 million and $662 million, respectively, of which $65 million and $80 million, respectively, would affect the effective tax rate, if recognized. The unrecognized federal tax benefits are included in other non-current liabilities in the accompanying consolidated balance sheets.

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

	Years Ended March 31,	
	2014	2013
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 662**	$ 713
Gross increases related to prior period	**52**	16
Gross decreases related to prior period	**(63)**	(77)
Gross increases related to current period	**53**	41
Gross decreases related to current period	**-**	(27)
Settlements with tax authorities	**(194)**	(4)
Balance as of the end of the year	**$ 510**	$ 662

As of March 31, 2014 and 2013, the Company has accrued for interest related to unrecognized tax benefits of $55.3 million and $71 million, respectively. During the years ended March 31, 2014 and 2013, the Company recorded interest expense of $12.4 million and $0.4 million, respectively. The Company recognizes interest related to unrecognized tax benefits in other interest, including affiliate interest and related penalties, if applicable, in other deductions, net in the accompanying consolidated statements of income. No tax penalties were recognized during the years ended March 31, 2014 and 2013.

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.

During fiscal year 2014, the IRS concluded its examination of the NGNA consolidated filing group's corporate income tax returns, which includes corporate income tax returns of KeySpan Corporation and subsidiaries for the short period ended August 24, 2007, and of NGNA and subsidiaries for the periods ended March 31, 2008 and 2009. These examinations were completed on March 27, 2014 and March 31, 2014, respectively, with an agreement on the majority of income tax issues for the years referenced above, as well as an acknowledgment that certain discrete items remain disputed. NGNA is in the process of appealing these disputed issues with the IRS Office of Appeals. The Company does not anticipate a change in its unrecognized tax positions in the next twelve months as a result of the appeals. However, pursuant to the Company's tax sharing agreement, the audit or appeals may result in a change to allocated tax.

The years ended March 31, 2010 through March 31, 2014 remain subject to examination by the IRS.

The Company is a member of the NGUSA Service Company Massachusetts unitary group since fiscal year ended March 31, 2010. The tax returns for the fiscal years ended March 31, 2010 through March 31, 2014 remain subject to examination by the State of Massachusetts.

The following table indicates the earliest tax year subject to examination:

Jurisdiction	Tax Year
Federal	August 24, 2007 *
Massachusetts	March 31, 2003
New York	December 31, 2003
New York City	December 31, 2003
New Hampshire	March 31, 2009

* The NGNA consolidated filing group is in the process of appealing certain disputed issues with the IRS Office of Appeals for the years ended March 31, 2008 through March 31, 2009.

The Company is in the process of appealing adjustments made by the Massachusetts Department of Revenue ("MADOR") for the years ended March 31, 2003 through March 31, 2005. The Company is currently under audit by the MADOR for years ended March 31, 2006 through March 31, 2008.

During the fiscal year, the Company settled examinations for KeySpan Corporation and subsidiaries income tax returns for the years 2000 through 2002, and Wayfinder Group Inc. for the year ended March 31, 2008 with the State of New York and made payments for tax and interest of $3.4 million and $4.3 million, respectively.

The State of New York is in the process of examining the Company's NYS income tax returns for KeySpan Gas East for the period January 1, 2003 through March 31, 2008, and for Brooklyn Union for the period January 1, 2007 through March 31, 2008. The tax returns for the years ended March 31, 2009 through March 31, 2014 remain subject to examination by the State of New York. The Company has filed New York ITC claims for the New York Gas Companies for the tax years ended December 31, 2002 through March 31, 2010. New York State has disallowed the claims for December 31, 2002 through December 31, 2006 upon audit, and also denied them on appeal to the New York Tax Tribunal, which decision was further appealed to the Supreme Court, Appellate Division. On June 6, 2013, the Company received an adverse decision from the Supreme Court, Appellate Division, and made tax and interest payments of $29.7 million and $19.9 million, respectively, during the year ended March 31, 2014.

New York State and New York City are in the process of an examining the returns of KeySpan Corporation and subsidiaries for the period January 1, 2003 through March 31, 2008 and January 1, 2003 through December 31, 2005, respectively.

The State of New York is in the process of examining the Niagara Mohawk Holdings Inc. and subsidiaries combined returns for the years ended March 31, 2006 through March 31, 2008.

11. GOODWILL

The following table represents the changes in the carrying amount of goodwill for the years ended March 31, 2014 and 2013:

	Years Ended March 31,	
	2014	2013
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 7,151**	$ 7,133
Consolidation of variable interest entity	**-**	20
Revaluation in relation to Granite State	**-**	(1)
Regulatory recovery	**-**	(1)
Balance as of the end of the year	**$ 7,151**	$ 7,151

In January 2013, the Company made an investment in Clean Line Energy Partners LLC ("Clean Line"). Clean Line is a development-stage entity engaged in the development of long distance, high voltage direct current transmission lines that connect wind farms and other renewable resources in remote parts of the United States with electric demand. The Company committed to a $40 million investment in Clean Line, of which the Company contributed $12.5 million during the year ended March 31, 2013 and contributed the remaining $27.5 million during the year ended March 31, 2014. Based on an analysis of the contractual terms and rights contained in the related agreements, the Company determined that under the applicable accounting standards, Clean Line is a variable interest entity and the Company has effective control over the entity. Therefore, as the primary beneficiary, the Company has consolidated Clean Line. Upon consolidation, the Company recognized approximately $20 million of goodwill.

Colonial Gas has authority from the DPU to recover $234.8 million of goodwill ($141.5 million of acquisition premium, plus tax of $93.3 million). The regulatory asset for the recovery of the acquisition premium was $208.4 million at March 31, 2014, and will be amortized on a straight-line basis as it is recovered through rates at $8.2 million per year through August 2039.

The net regulatory recovery adjustments of $1 million shown in the table above include, with respect to Colonial Gas: (1) a reclassification adjustment of $5 million from regulatory assets to goodwill in order to correct these balances and properly reflect the authorized recovery period of acquisition premium under DPU 10-55, and (2) a reclassification adjustment of ($6.0) million from goodwill to regulatory assets related to a ruling by the DPU in January 2013.

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.

On April 26, 2013, General Electric ("GE") filed a lawsuit against Niagara Mohawk seeking contribution under the Comprehensive Environmental Response, Compensation, and Liability Act for an unspecified portion of GE's alleged response costs incurred in remediating polychlorinated biphenyl ("PCB") contamination in the Hudson River. GE alleges that Niagara Mohawk's removal of the Fort Edward Dam in 1973 resulted in the migration of sediments, contaminated with PCBs released into the environment by GE, downstream of the former dam's location. On June 25, 2013, Niagara Mohawk answered GE's complaint denying liability. The parties executed a confidential settlement agreement on December 13, 2013. By stipulation of the parties and Court order, GE's claims against Niagara Mohawk were dismissed with prejudice on January 13, 2014.

Air

National Grid Generation'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 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. National Grid Generation'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 National Grid Generation to achieve its prior emission reductions in a cost-effective manner. Recently completed investments include the installation of enhanced NOx controls and efficiency improvement projects at certain of National Grid Generation'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. National Grid Generation 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, the Company 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 National Grid Generation's power plants will likely be required by the DEC at each of the Long Island power plants pursuant to Section 316 of the Clean Water Act to mitigate the plants' alleged cooling water system impacts to aquatic organisms. National Grid Generation is currently engaged in discussions with the DEC and environmental groups regarding the nature of capital upgrades or other mitigation measures necessary to reduce any impacts. Although these discussions have been productive and have led to mutually agreeable final permits at some of the plants, it is possible that the determination of required capital improvements and the issuance of final renewal permits for the remaining plants could involve adjudicatory hearings among National Grid Generation, the agency, and the environmental groups. Capital costs for expected mitigation requirements at the plants had been estimated on the order of approximately $100 million and do not anticipate a need for cooling towers at any of the plants. Depending on the outcome of the adjudicatory process, which could extend beyond the next fiscal year, ultimate costs could be substantially higher. Costs associated with any finally ordered capital improvements would be 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 a remediation at this location pursuant to Administrative Order on Consent ("ACO") with the New York State Department of Environmental Conservation ("DEC"). KeySpan intends to contest these proceedings vigorously.

On February 8, 2007, the Company received a Notice of Intent to File Suit from the AG against KeySpan and four other companies in connection with the cleanup of historical contamination found in certain lands located in Greenpoint, Brooklyn and in an adjoining waterway. KeySpan has previously agreed to remediate portions of the properties referenced in this notice and will work cooperatively with the DEC and AG to address environmental conditions associated with the remainder of the properties. KeySpan has entered into an ACO with the DEC for the land-based sites. The EPA assumed control of the waterway and, on September 29, 2010, listed this site on its National Priorities List of Superfund sites. The Company signed a consent decree with the EPA on July 7, 2011 and is currently performing a Remedial Investigation and Feasibility Study. At this time, the Company is unable to predict what effect, if any, the outcome of these proceedings will have on its consolidated financial position, results of operations, and cash flows.

Utility Sites

At March 31, 2014, the Company's total reserve for estimated MGP-related environmental matters is $1.3 billion. The potential high end of the range at March 31, 2014 is presently estimated at $2.0 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 regulatory asset of $1.7 billion and $1.8 billion on the consolidated balance sheets at March 31, 2014 and 2013, respectively.

Upon the acquisition of KeySpan by NGUSA, the Company recognized those environmental liabilities at fair value. The fair values included discounting of the reserve, which is being accreted over the period for which remediation is expected to occur. Following the acquisition of KeySpan, these environmental liabilities are recognized in accordance with the current accounting guidance for environmental obligations.

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 two non-utility sites for which it may have, or share, environmental remediation or ongoing maintenance responsibility. Expenditures incurred were approximately $2 million and $1 million for the years ended March 31, 2014 and 2013, respectively. The Company presently estimates the remaining cost of the environmental cleanup activities for these two non-utility sites will be approximately $24 million and $22 million, which has been accrued at March 31, 2014 and 2013, respectively. The Company's environmental obligation is net of a discount rate of 6.5%, and the undiscounted amount totaled $29 million and $27 million in liabilities at March 31, 2014 and 2013, 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 noted, depending upon 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 $121 million and $105 million for the years ended March 31, 2014 and 2013, respectively.

The future minimum lease payments for the years subsequent to March 31, 2014 are as follows:

(in millions of dollars) Years Ending March 31,	
2015	$ 97
2016	98
2017	98
2018	99
2019	86
Thereafter	404
Total	$ 882

Energy Purchase and Capital Expenditure 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. The Company's gas distribution subsidiaries are liable for these payments regardless of the level of services required from third-parties. Such charges are currently recovered from customers as gas costs. 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, 2014 are summarized in the table below:

(in millions of dollars) Years Ending March 31,	Energy Purchases	Capital Expenditures
2015	$ 2,087	$ 489
2016	859	46
2017	632	41
2018	483	50
2019	391	34
Thereafter	1,806	-
Total	$ 6,258	$ 660

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

Pursuant to the PSA, the Company is required to invest in capital improvements in accordance with prudent utility practice. Such investments may approach the range of $500 million to $590 million subject to certain provisions in the contract.

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, 2014, the following amounts would have to be paid by the Company in the event of non-payment by the primary obligor at the time payment is due:

Guarantees for Subsidiaries:		Amount of Exposure	Expiration Dates
		(in millions of dollars)	
Industrial Development Revenue Bonds	(i)	$ 128	June 2027
KeySpan Ravenswood LLC Lease	(ii)	387	May 2040
Reservoir Woods	(iii)	229	October 2029
Surety Bonds	(iv)	195	Revolving
Commodity Guarantees and Other	(v)	95	October 2015 - August 2042
Letters of Credit	(vi)	203	May 2014 - December 2014
		$ 1,237	

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

(i) KeySpan has fully and unconditionally guaranteed the payment obligations of its subsidiaries with regard to $128 million of Industrial Development Revenue Bonds issued through the Nassau County and Suffolk County Industrial Development Authorities for the construction of two electric-generation peaking plants on Long Island, New York. The face value of these notes is included in long-term debt in the accompanying consolidated balance sheets.

(ii) 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, 2014, the Company's obligation related to the lease was $387 million and is reflected in other non-current liabilities in the accompanying consolidated balance sheets.

(iii) The Company has fully and unconditionally guaranteed $229 million in lease payments through 2029 related to the lease of office facilities by its service company at Reservoir Woods in Waltham, Massachusetts.

(iv) 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.

(v) The Company has guaranteed commodity-related payments for certain subsidiaries. These guarantees are provided to third-parties to facilitate physical and financial transactions involved in the purchase and transportation of natural gas, oil and other petroleum products for gas and electric production and marketing activities. The guarantees cover actual purchases by these subsidiaries that are still outstanding as of March 31, 2014.

(vi) 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.

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.

The Company has guaranteed $210 million of an $800 million Millennium Pipeline construction loan. The $210 million represents the Company's proportionate share of the $800 million loan based on the Company's 26.25% ownership interest in the Millennium Pipeline project.

Long-Term Contracts for Renewable Energy

Town of Johnston Project

In June 2010, pursuant to 2009 Rhode Island legislation that required Narragansett to negotiate a contract for an electric generating project fueled by landfill gas from the Rhode Island Central Landfill Narragansett entered into a contract with Rhode Island LFG Genco for the Town of Johnston Project, a combined cycle power plant with an average output of 32 megawatts ("MW"). The facility reached commercial operation on May 28, 2013 and is being accounted for as an operating lease.

Deepwater Agreement

The 2009 law also required Narragansett to solicit proposals for a small scale renewable energy generation project of up to eight wind turbines with an aggregate nameplate capacity of up to 30 MW to benefit the Town of New Shoreham. The renewable energy generation project also included a transmission cable to be constructed between Block Island and the mainland of Rhode Island. On June 30, 2010, Narragansett entered into a 20-year Amended Power Purchase Agreement ("PPA") with Deepwater Wind Block Island LLC, which was approved by the RIPUC in August 2010. 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. On April 2, 2014, the Division issued its Consent Decision for Narragansett to execute the Facilities Purchase Agreement with Deepwater. Narragansett intends to make a filing with the FERC to recover the costs associated with the cable in transmission rates.

Legal Matters

The Company is subject to various legal proceedings, primarily injury claims, 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.

FERC ROE Complaints

On September 30, 2011, several state and municipal parties in New England, ("Complainants"), filed a complaint against certain New England Transmission Owners, ("NETOs") including NEP, to lower the base ROE for transmission rates in New England from 11.14% to 9.2 %. On August 6, 2013, a FERC Administrative Law Judge ("ALJ") issued an Initial Decision finding that the base ROE for the refund period and the prospective period should be 10.6% and 9.7%, respectively, prior to any adjustments in a final FERC order. The refund period is the 15-month period from October 1, 2011 through December 31, 2012; the prospective period begins when the FERC issues its final order. In response to the ALJ's Initial Decision, NEP recorded an estimated reduction to revenues of $7.1 million and an increase to interest expense of $0.2 million for the fiscal year ended March 31, 2013, reflecting an effective ROE of 10.6% for the portion that would be refunded to transmission customers for the refund period. On June 19, 2014, the FERC issued an order modifying the ALJ's findings and its previous methodology for establishing ROE. The FERC tentatively set the ROE at 10.57% and capped the ROE for incentive rates of return to 11.74% subject to further proceedings to establish and quantify growth rates applicable to the ROE. In response, NEP recorded an additional reduction to revenues of $1.2 million and an increase of $0.2 million to interest expense for the fiscal year ended March 31, 2014.

On December 27, 2012, a new ROE complaint was filed against the NETOs by a coalition of consumers seeking to lower the base ROE for New England transmission rates to 8.7% effective as of December 27, 2012. On June 19, 2014, the FERC issued an order setting the complaint for investigation and a trial-type, evidentiary hearing. The FERC stated that it expects parties to present evidence and any discounted cash flow analyses, as guided by the rulings found in FERC's June 19 order on the first complaint.

On July 31, 2014, a third ROE Complaint was filed against the NETOs by the Complainants. The FERC has not yet acted on this complaint.

Electric Services and LIPA Agreements

Effective May 23, 2013, National Grid Generation provides services to LIPA under an amended and restated PSA. Under the PSA, National Grid Generation has a revenue requirement of $418.6 million, a return on equity of 9.75% and a capital structure of 50% debt and 50% equity. The 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. National Grid Generation accounts for the PSA as an operating lease.

The PSA provides potential penalties to National Grid Generation 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 $4.0 million annually. Although the 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. National Grid Generation must, therefore, operate its generating facilities in a manner such that the Company can remain competitive with other producers of energy. To date, National Grid Generation 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 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. A monthly variable maintenance charge is billed for each unit of energy actually acquired from the generating facilities. The billings to LIPA under the PSA do not include a provision for fuel costs, as such fuel is owned by LIPA.

In June 2011, LIPA and National Grid Generation executed an amendment to the then-current PSA pursuant to which the parties agreed that LIPA would reduce purchases of capacity from specified generating facilities, specifically the Glenwood and Far Rockaway, New York steam facilities. The Company has retired these generating facilities and removed them from the PSA and is in the process of dismantling these facilities. As part of this amendment, National Grid Generation paid an Economic Equivalent Payment ("EEP") of $18.0 million which represented the economic benefit to LIPA which would have been realized under the original agreement. Half of the EEP was paid on July 3, 2012, with the remaining balance on May

28, 2013. The EEP was accrued on a straight-line basis over the 24-month term, from June 2011 through May 2013, as a reduction in operating revenues.

Pursuant to the EMA, the Company procured and managed fuel supplies for LIPA to fuel the Company's Long Island based generating facilities. In exchange for these services, the Company earned an annual fee of $750,000. The EMA expired on May 28, 2013. LIPA did not renew the EMA contract with the Company.

Decommissioning Nuclear Units

NEP has minority interests in three nuclear generating companies: Yankee Atomic Electric Company ("Yankee Atomic"), Connecticut Yankee Atomic Power Company ("Connecticut Yankee"), and Maine Yankee Atomic Power Company ("Maine Yankee") (together, the "Yankees"). These ownership interests are accounted for on the equity method. The Yankees operated nuclear generating units which have been permanently decommissioned. Spent nuclear fuel remains on each site, awaiting fulfillment by the U.S. Department of Energy ("DOE") of its statutory obligation to remove it. In addition, groundwater monitoring is ongoing at each site. Future estimated billings, which are included in other deferred liabilities and other current liabilities in the accompanying consolidated balance sheets, are as follows:

(in thousands of dollars)	The Company's Investment as of March 31, 2014				Future Estimated Billings to the Company	
Unit	%		Amount	Date Retired		Amount
Yankee Atomic	34.5	$	529	Feb 1992	$	3,877
Connecticut Yankee	19.5		303	Dec 1996		18,090
Maine Yankee	24.0		564	Aug 1997		10,947

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 liability and a regulatory asset reflecting the estimated future decommissioning billings from the Yankees.

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

Each of the Yankees brought litigation against the DOE for failure to remove their respective nuclear fuel stores as required by the Nuclear Waste Policy Act and contracts. Following a trial at the U.S. Court of Claims ("Claims Court") to determine the level of damages, on October 4, 2006, the Claims Court awarded the three companies an aggregate of $143 million for spent fuel storage costs that had been incurred through 2001 and 2002 (the "Phase I Litigation"). The Yankees had requested $176.3 million. The DOE appealed to the U.S. Court of Appeals for the Federal Circuit, which rendered an opinion generally supporting the Claims Court's decision and remanded the matter to it for further proceedings. In September, 2010, the Claims Court again awarded the companies an aggregate of approximately $143 million. The DOE again appealed and the Yankees cross-appealed. On May 18, 2012, the Court of Appeals again ruled in favor of the Yankees, awarding them an aggregate of approximately $160 million. The DOE sought reconsideration but, on September 5, 2012, the Court of Appeals for the Federal Circuit denied the petition for rehearing. The DOE elected not to file a petition for writ of certiorari seeking review by the U.S. Supreme Court and in January 2013 the awards were paid to the Yankees. As of March 2014, total net proceeds of $14.4 million have been refunded to NEP by Connecticut Yankee and Maine Yankee. Yankee Atomic did not provide a refund, but reduced monthly billing effective June 1, 2013.

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

On April 29, 2014, the Yankees submitted informational filings to the FERC in order to flow through the DOE Phase II proceeds to their Sponsor companies, including NEP, in accordance with financial analyses that were performed earlier this year and supported by stakeholders from Connecticut, Massachusetts and Maine. The filings will allow for the flow through of the proceeds to the Sponsors, including NEP, with a proposed rate effective date of June 1, 2014. NEP's aggregate share will be approximately $58 million, which is recorded in accounts receivable in the accompanying consolidated balance sheets. NEP will refund its aggregate share to its customers through the CTCs.

On August 15, 2013 the Yankees brought further litigation in the Claims Court to recover damages incurred 2009 through 2012.

The U.S. Congress and the DOE have effectively terminated budgetary support for the proposed long-term spent fuel storage facility at Yucca Mountain in Nevada and the DOE took actions designed to prevent its construction. However, on August 12, 2013 the U.S. Court of Appeals for the District of Columbia Circuit directed the Nuclear Regulatory Commission ("NRC") to resume the Yucca Mountain licensing process despite insufficient funding to complete it. On October 28, 2013, the Circuit Court denied the NRC's petition for rehearing. On November 18, 2013, NRC ordered its staff to resume work on its Yucca Mountain safety report. A Blue Ribbon Commission ("BRC") charged with advising the DOE regarding alternatives to disposal at Yucca Mountain issued its final report on January 26, 2012. In the report, the BRC recommended that priority be given to removal of spent fuel from shutdown reactor sites. 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, 2014 and 2013, Niagara Mohawk had a liability of $168 million, recorded in other non-current liabilities in the accompanying consolidated balance sheets, 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. Niagara Mohawk cannot predict the impact that the recent actions of the DOE and the U.S. government will have on the ability to dispose of the spent nuclear fuel and waste.

Storm Costs Recovery

In October 2012, SuperStorm Sandy hit the northeastern U.S. affecting energy supply to customers in the Company's service territory. Total costs associated with gas customer service restoration from this storm (including capital expenditures) were approximately $204.1 million through March 31, 2014, for the New York Gas Companies.

The Company has recorded an "other receivable" in the accompanying consolidated balance sheets in the amount of $58 million and $67 million as of March 31, 2014 and 2013, respectively, relating to claims filed against property damage and business interruption insurance policies, net of insurance deductibles and allowance. As of March 31, 2014, the Company has received $83.4 million from its insurers.

Total costs from SuperStorm Sandy associated with electricity customers' service restoration charged to LIPA through March 31, 2014, were approximately $668 million. The Company had outstanding accounts receivable from LIPA related to costs incurred in connection with SuperStorm Sandy of $88.4 million and $328.6 million at March 31, 2014 and 2013, respectively.

14. RELATED PARTY TRANSACTIONS

Accounts Receivable from and Accounts Payable to Affiliates

The Company engages in various transactions with National Grid plc 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 payables to and receivables from certain of its affiliates in the ordinary course of business. At March 31, 2014 and 2013, the Company had net outstanding accounts receivable from affiliates and accounts payable to affiliates balances as follows:

	Accounts Receivable from Affiliates		Accounts Payable to Affiliates	
	March 31,		March 31,	
	2014	2013	**2014**	2013
	(in millions of dollars)		*(in millions of dollars)*	
NGNA	**$ -**	$ -	**$ -**	$ 87
National Grid plc	**-**	-	**60**	36
Other	**2**	13	**3**	-
Total	**$ 2**	$ 13	**$ 63**	$ 123

Advances from Affiliates

In August 2009, the Company and KeySpan Corporation 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 1.4%. At March 31, 2014 and 2013, the Company had $750 million and zero outstanding 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. These advances do not bear interest. At March 31, 2014 and 2013, the Company had $1.4 billion and zero outstanding advances from NGNA under this agreement.

Holding Company Charges

The Company received charges from National Grid Commercial Holdings Limited (an affiliated company in the U.K.) for certain corporate and administrative services provided by the corporate functions of National Grid plc to its U.S. subsidiaries. For the years ended March 31, 2014 and 2013, the effect on net income was $52 million before tax and $34 million after tax.

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, 2014 and 2013 is as follows:

		Shares Outstanding		Amount		
		March 31,		**March 31,**		Call
Series	Company	**2014**	2013	**2014**	2013	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 New York State. 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 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%.

In August 2012, by written consent of the Company's shareholders, the annual dividend payment date on the series A through E preferred stock was changed from September 30 to August 24. As a result, the amount of the preferred stock dividend for the series A through E preferred stock was adjusted during the year ended March 31, 2013.

A summary of preferred stock is as follows:

	Shares Outstanding		Amount (par)		Amount (additional paid-in capital)	
	March 31,		March 31,		March 31,	
Series	**2014**	2013	**2014**	2013	**2014**	2013
	(in millions of dollars, except per share and number of shares data)					
$0.10 par value -						
Series A	**51**	51	**$ -**	$ -	**$ 400**	$ 400
Series B	**40**	40	**-**	-	**315**	315
Series C	**96**	96	**-**	-	**750**	750
Series D	**79**	79	**-**	-	**616**	616
Series E	**1**	1	**-**	-	**10**	10
Series F	**648**	648	**-**	-	**5,368**	5,368
Total	**915**	915	**$ -**	$ -	**$ 7,459**	$ 7,459

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, 2014, the Parent had 3.9 billion of ordinary shares issued with 123,948,354 held as treasury shares. The aggregate dilution resulting from executive share-based incentives will not exceed 5% in any 10-year period for executive share-based incentives and will not exceed 10% in any 10-year period for all employee incentives. This is reviewed by the Remuneration Committee and currently, the Parent has excess headroom of 4.10% and 7.99% 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 three parts as follows: (i) 50% of the units awarded are subject to annualized growth in the Parent's earnings per share ("EPS") over a general index of retail prices over a period of three years; (2) 25% of the units awarded will vest based upon the Parent's Total Shareholder Return ("TSR") compared to that of the Financial Times Stock Exchange ("FTSE") 100 over a period of three years; and (3) 25% of the units awarded are subject to the average achieved regulatory ROE. Under the PSP, performance conditions are split into two parts as follows: (1) 50% of the units awarded are subject to annualized growth in the Parent's EPS over a general index of retail prices over a period of three years; and (2) 50% of the units awarded will vest based upon the Parent's TSR compared to that of the FTSE 100 over a period of three years. Units under both plans generally vest at the end of the performance period.

A Monte Carlo simulation model has been used to estimate the fair value for the TSR portion of the awards. For the EPS and ROE portions of the awards, the fair value of the award is determined using the stock price as quoted per the London Stock Exchange or the price for the American Depository Shares as quoted on the New York Stock Exchange as of the earlier of the reporting date or vesting date.

The following assumptions were used to calculate the fair value of the TSR portion of the awards issued during the fiscal year ended March 31, 2014:

	2014	2013
Expected volatility	**18.39%**	12.72% - 14.48%
Expected term	**3 years**	3 years
Risk free rates	**0.66%**	0.07% - 0.26%

The EPS portions of the awards are classified as liability awards as they are each indexed to a factor that is not a market, performance, or service condition. Therefore, the changes in the fair value of the EPS portions of the awards are reflected within net income. The TSR and ROE portions of the awards are classified as equity awards as they are indexed to market conditions and are expensed over the performance period.

The following table summarizes the stock based compensation expense recognized by the Company for the years ended March 31, 2014 and 2013:

	Units	**Weighted Average Grant Date Fair Value**
Non-vested as of March 31, 2012	1,015,540	$ 42.19
Vested	119,468	45.53
Granted	272,274	48.29
Forfeited/Cancelled	222,401	42.97
Non-vested as of March 31, 2013	945,945	40.36
Vested	183,275	46.37
Granted	247,891	55.96
Forfeited/Cancelled	89,829	49.00
Non-vested as of March 31, 2014	920,732	$ 49.92

The total expense recognized for non-vested awards was $19.0 million and $24.7 million for the years ended March 31, 2014 and 2013 respectively, and will vest over three years. The total tax benefit recorded was approximately $7.6 million and $9.9 million as of March 31, 2014 and 2013 respectively. Total expense expected to be recognized by the Parent in future periods for non-vested awards outstanding as of March 31, 2014 is $9.0 million, $4.7 million, and $1.4 million for the years ended March 31, 2015, 2016, and 2017 respectively.

17. DISCONTINUED OPERATIONS

On December 8, 2010, the Company and Liberty Energy entered into a stock purchase agreement which was subsequently amended and restated on January 21, 2011, pursuant to which the Company sold and Liberty Energy purchased all of the common stock of Granite State and EnergyNorth. The parties received FERC approval in July 2011 and New Hampshire Public Utilities Commission approval in May 2012. Granite State and EnergyNorth were sold on July 3, 2012 for proceeds of $294 million. The results of Granite State and EnergyNorth are reflected as discontinued operations in the accompanying consolidated statements of income for the year ended March 31, 2013.

On December 15, 2011, LIPA announced that it was not renewing the MSA contract beyond its expiration on December 31, 2013. During the year ended March 31, 2013, the MSA contract represented approximately 9.9% of the Company's annual revenue and 1.2% of its operating income. In addition, the loss of the contract resulted in 1,950 employees transferring to a new employer. The results of the MSA are reflected as discontinued operations in the accompanying consolidated financial statements for the years ended March 31, 2014 and 2013.

Following the expiration of the MSA, the Company entered into a Settlement and Release Agreement ("SRA") with LIPA. Under the terms of this SRA, LIPA (1) fully released the Company from its obligations under certain promissory notes payable to LIPA, and (2) agreed to make a one-time lump sum payment to the Company of $91.5 million. In return, the Company fully released LIPA from certain claims for reimbursement of pension and PBOP costs. As a result, the Company recorded a gain of approximately $231.0 million, primarily related to the extinguishment of debt and recognition of a receivable for the lump sum cash payment (which was received from LIPA in April 2014).

In addition, a $97.0 million net settlement gain and a $43.0 million net curtailment gain were recognized for the employees who transferred to a new employer. The new employer had assumed responsibility for the transferred employees' obligations under the PBOP.

The reconciliation below highlights the major classes of line items constituting income before income taxes of discontinued operations for Granite State, EnergyNorth and the MSA for the years ended March 31, 2014 and 2013:

	Years Ended March 31,	
	2014	2013
	(in millions of dollars)	
Major classes of line items constituting income before income taxes of discontinued operations		
Revenue	**$ 476**	$ 1,288
Purchased electricity	**-**	(8)
Purchased gas		(8)
Operations and maintenance	**(601)**	(1,267)
Other expenses	**(19)**	(12)
Loss before income taxes from discontinued operations	**(144)**	(7)
Gain (loss) on disposal of discontinued operations	**371**	(34)
Total income (loss) before income taxes from discontinued operations	**227**	(41)
Income tax expense (benefit)	**94**	(27)
Income (loss) from discontinued operations, net of taxes	**$ 133**	$ (14)

The reconciliation below highlights the carrying values of assets and liabilities of the discontinued operations that are disclosed in the accompanying consolidated balance sheets for the MSA at March 31, 2014 and 2013:

	March 31,	
	2014	2013
	(in millions of dollars)	
Carrying values of assets included in the discontinued operations:		
Cash and cash equivalents	**$ -**	$ 1
Accounts receivable	**219**	96
Allowance for doubtful accounts	**(70)**	(33)
Unbilled revenues	**2**	336
Inventory	**-**	16
Property, plant, and equipment, net	**-**	28
Deferred income tax assets	**29**	9
Other assets that are not major	**2**	26
Total assets classified as discontinued operations in the consolidated balance sheets	**$ 182**	$ 479
Carrying values of liabilities included in the discontinued operations:		
Accounts payable	**$ 20**	$ 146
Taxes accrued	**2**	5
Long-term debt	**-**	155
Other liabilities that are not major	**15**	22
Total liabilties classified as discontinued operations in the consolidated balance sheets	**$ 37**	$ 328

18. SUBSEQUENT EVENTS

In September 2014, Niagara Mohawk issued $500 million of unsecured long-term debt at 3.508% with a maturity date of October 1, 2024 and $400 million of unsecured long-term debt at 4.278% with a maturity date of October 1, 2034.

nationalgrid

National Grid USA and Subsidiaries

Consolidated Financial Statements

For the years ended March 31, 2015 and 2014

NATIONAL GRID USA AND SUBSIDIARIES

TABLE OF CONTENTS

Independent Auditor's Report

To the Board of Directors of
National Grid USA

We have audited the accompanying consolidated financial statements of National Grid USA (the "Company"), which comprise the consolidated balance sheets as of March 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, cash flows, capitalization, and changes in shareholders' equity for the years then ended.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

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

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

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of National Grid USA at March 31, 2015 and 2014, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

September 17, 2015

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

	Years Ended March 31,	
	2015	2014
Operating revenues:		
Electric services	**$ 7,138**	$ 7,177
Gas distribution	**5,164**	5,355
Other	**29**	24
Total operating revenues	**12,331**	12,556
Operating expenses:		
Purchased electricity	**2,514**	2,503
Purchased gas	**2,179**	2,360
Operations and maintenance	**4,563**	4,541
Depreciation and amortization	**952**	896
Other taxes	**1,002**	1,063
Total operating expenses	**11,210**	11,363
Operating income	**1,121**	1,193
Other income and (deductions):		
Interest on long-term debt	**(393)**	(400)
Other interest, including affiliate interest	**(89)**	(47)
Income from equity investments	**41**	35
Other deductions, net	**(62)**	(18)
Total other deductions, net	**(503)**	(430)
Income before income taxes	**618**	763
Income tax expense	**201**	277
Income from continuing operations	**417**	486
Income from discontinued operations, net of taxes	**12**	133
Net income	**429**	619
Net loss attributable to non-controlling interest	**18**	20
Dividends paid on preferred stock	**-**	(597)
Net income attributable to common and preferred shares	**$ 447**	$ 42

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,	
	2015	2014
Net income	**$ 429**	$ 619
Other comprehensive income (loss), net of taxes:		
Unrealized gains on securities	**6**	4
Change in pension and other postretirement obligations	**(238)**	212
Unrealized losses on hedges	**(1)**	(2)
Total other comprehensive (loss) income	**(233)**	214
Comprehensive income	**$ 196**	$ 833
Less: comprehensive loss attributable to non-controlling interest	**18**	20
Comprehensive income attributable to common and preferred shares	**$ 214**	$ 853
Related tax (expense) benefit:		
Unrealized gains on securities	**$ (4)**	$ (3)
Change in pension and other postretirement obligations	**167**	(148)
Unrealized losses on hedges	**1**	1
Total tax benefit (expense)	**$ 164**	$ (150)

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,	
	2015	2014
Operating activities:		
Net income	**$ 429**	$ 619
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**952**	896
Regulatory amortizations	**120**	50
Provision for deferred income taxes	**209**	255
Bad debt expense	**218**	136
Loss (income) from equity investments, net of dividends received	**6**	(10)
Goodwill impairment	**22**	-
Allowance for equity funds used during construction	**(19)**	(27)
Amortization of debt discount and issuance costs	**9**	10
Net postretirement benefits expense	**166**	113
Net environmental remediation payments	**(103)**	(136)
Share based compensation	**15**	-
Changes in operating assets and liabilities:		
Accounts receivable and other receivable, net, and unbilled revenues	**74**	(718)
Accounts receivable from/payable to affiliates, net	**(9)**	(49)
Inventory	**(46)**	45
Regulatory assets and liabilities, net	**(4)**	45
Derivative contracts	**130**	22
Prepaid and accrued taxes	**(91)**	(33)
Accounts payable and other liabilities	**(46)**	(89)
Renewable energy certificate obligations, net	**52**	89
Other, net	**67**	7
Net cash provided by operating activities	**2,151**	1,225
Investing activities:		
Capital expenditures	**(2,440)**	(1,960)
Changes in restricted cash and special deposits	**(22)**	53
Cost of removal and other	**(150)**	(206)
Net cash used in investing activities	**(2,612)**	(2,113)
Financing activities:		
Preferred stock dividends	**-**	(597)
Payments on long-term debt	**(728)**	(304)
Proceeds from long-term debt	**900**	-
Payment of debt issuance costs	**(5)**	-
Commercial paper issued (paid)	**161**	(204)
Affiliated money pool borrowing and receivables/payables, net	**4**	-
Advances from affiliates	**(1,093)**	2,171
Equity infusion from Parent	**-**	1,000
Other	**5**	34
Net cash (used in) provided by financing activities	**(756)**	2,100
Net (decrease) increase in cash and cash equivalents	**(1,217)**	1,212
Net cashflow from discontinued operations - operating	**96**	(352)
Net cashflow from discontinued operations - investing	**-**	28
Cash and cash equivalents, beginning of year	**1,571**	683
Cash and cash equivalents, end of year	**$ 450**	$ 1,571
Supplemental disclosures:		
Interest paid	**$ (390)**	$ (457)
Income taxes refunded (paid)	**22**	(108)
Significant non-cash items:		
Capital-related accruals included in accounts payable	**231**	161
Long Island Power Authority settlement	**-**	371

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,	
	2015	2014
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 450**	$ 1,571
Restricted cash and special deposits	**190**	168
Accounts receivable	**2,641**	2,761
Allowance for doubtful accounts	**(361)**	(300)
Other receivable	**-**	58
Accounts receivable from affiliates	**2**	2
Unbilled revenues	**567**	620
Inventory	**397**	344
Regulatory assets	**667**	571
Derivative contracts	**45**	70
Current portion of deferred income tax assets, net	**242**	171
Prepaid taxes	**182**	145
Other	**91**	125
Current assets related to discontinued operations	**70**	153
Total current assets	**5,183**	6,459
Equity investments	**190**	194
Property, plant and equipment, net	**25,671**	23,875
Other non-current assets:		
Regulatory assets	**4,921**	4,322
Goodwill	**7,129**	7,151
Derivative contracts	**30**	26
Postretirement benefits asset	**189**	305
Financial investments	**494**	476
Other	**127**	141
Other non-current assets related to discontinued operations	**-**	29
Total other non-current assets	**12,890**	12,450
Total assets	**$ 43,934**	$ 42,978

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,	
	2015	2014
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 1,393**	$ 1,339
Accounts payable to affiliates	**54**	63
Advances from affiliates	**1,078**	2,171
Commercial paper	**582**	421
Current portion of long-term debt	**638**	633
Taxes accrued	**47**	21
Customer deposits	**120**	98
Interest accrued	**133**	134
Regulatory liabilities	**627**	524
Derivative contracts	**270**	43
Renewable energy certificate obligations	**166**	123
Payroll and benefits accruals	**252**	228
Other	**177**	191
Current liabilities related to discontinued operations	**21**	37
Total current liabilities	**5,558**	6,026
Other non-current liabilities:		
Regulatory liabilities	**2,864**	2,688
Asset retirement obligations	**81**	87
Deferred income tax liabilities, net	**4,892**	4,850
Postretirement benefits	**3,839**	2,872
Environmental remediation costs	**1,336**	1,341
Derivative contracts	**54**	14
Other	**864**	892
Total other non-current liabilities	**13,930**	12,744
Commitments and contingencies (Note 14)		
Capitalization:		
Shareholders' equity	**16,232**	16,000
Long-term debt	**8,214**	8,208
Total capitalization	**24,446**	24,208
Total liabilities and capitalization	**$ 43,934**	$ 42,978

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,	
			2015	2014
Shareholders' equity attributable to common and preferred shares			**$ 16,218**	$ 15,988
Non-controlling interest in subsidiaries			**14**	12
Long-term debt:	Interest Rate	Maturity Date		
European Medium Term Note	Variable	June 2015 - January 2016	**588**	842
Notes Payable	2.72% - 9.75%	October 2015 - December 2042	**6,338**	5,948
Gas Facilities Revenue Bonds	Variable	December 2020 - July 2026	**230**	230
Gas Facilities Revenue Bonds	4.7% - 6.95%	April 2020 - July 2026	**411**	411
First Mortgage Bonds	6.82% - 9.63%	April 2018 - April 2028	**125**	127
State Authority Financing Bonds	Variable	October 2015 - August 2042	**1,033**	1,153
Industrial Development Revenue Bonds	5.25%	June 2027	**128**	128
Total debt			**8,853**	8,839
Unamortized debt (discount) premium			**(1)**	2
Current portion of long-term debt			**(638)**	(633)
Long-term debt			**8,214**	8,208
Total capitalization			**$ 24,446**	$ 24,208

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)

				Accumulated Other Comprehensive Income (Loss)						
	Common Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest	Total
Balance as of March 31, 2013	**$ -**	**$ 35**	**$ 13,110**	**$ (2)**	**$ (864)**	**$ -**	**$ (866)**	**$ 2,426**	**$ 26**	**$ 14,731**
Net income	-	-	-	-	-	-	-	639	(20)	619
Other comprehensive income (loss):										
Unrealized gains on securities, net of $3 tax expense	-	-	-	4	-	-	4	-	-	4
Change in pension and other postretirement obligations, net of $148 tax expense	-	-	-	-	212	-	212	-	-	212
Unrealized losses on hedges, net of $1 tax benefit	-	-	-	-	-	(2)	(2)	-	-	(2)
Total comprehensive income										833
Equity infusion from Parent	-	-	1,000	-	-	-	-	-	-	1,000
Parent loss tax allocation	-	-	1	-	-	-	-	-	-	1
Share based compensation	-	-	33	-	-	-	-	-	-	33
Preferred stock dividends	-	-	-	-	-	-	-	(597)	-	(597)
Other equity transactions with non-controlling interest	-	-	(7)	-	-	-	-	-	6	(1)
Balance as of March 31, 2014	**$ -**	**$ 35**	**$ 14,137**	**$ 2**	**$ (652)**	**$ (2)**	**$ (652)**	**$ 2,468**	**$ 12**	**$ 16,000**
Net income	-	-	-	-	-	-	-	447	(18)	429
Other comprehensive income (loss):										
Unrealized gains on securities, net of $4 tax expense	-	-	-	6	-	-	6	-	-	6
Change in pension and other postretirement obligations, net of $167 tax benefit	-	-	-	-	(238)	-	(238)	-	-	(238)
Unrealized losses on hedges, net of $1 tax benefit	-	-	-	-	-	(1)	(1)	-	-	(1)
Total comprehensive income										196
Parent loss tax allocation	-	-	5	-	-	-	-	-	-	5
Share based compensation	-	-	15	-	-	-	-	-	-	15
Other equity transactions with non-controlling interest	-	-	(4)	-	-	-	-	-	20	16
Balance as of March 31, 2015	**$ -**	**$ 35**	**$ 14,153**	**$ 8**	**$ (890)**	**$ (3)**	**$ (885)**	**$ 2,915**	**$ 14**	**$ 16,232**

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, 2015 and 2014.

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 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").

In addition, the Company has certain subsidiaries which have provided operational and energy management services and continue to supply capacity to and produce energy for the use of customers of the Long Island Power Authority ("LIPA"), on Long Island, New York. The services provided to LIPA were, or continue to be, provided through the following contractual arrangements. The Power Supply Agreement ("PSA"), which was amended and restated for a maximum term of 15 years in October 2012, provides LIPA with electric generating capacity, energy conversion and ancillary services from the Company's Long Island generating units. The Energy Management Agreement ("EMA"), which expired on May 28, 2013, provided management of all aspects of fuel supply for the Company's Long Island generating facilities. The Management Service Agreement ("MSA"), which expired on December 31, 2013, provided operation, maintenance and construction services, and significant administrative services relating to the Long Island electric transmission and distribution system. The results of the MSA are reflected as discontinued operations in the accompanying consolidated financial statements for the years ended March 31, 2015 and 2014.

Other Services and Investments

The Company's Energy Services business includes companies that provide energy-related services to customers located primarily within the northeastern United States ("U.S."). These services comprise the operation, maintenance, and design of energy systems for commercial and industrial customers.

The Company's Energy Investments business consists of gas production and development investments such as natural gas pipelines, as well as certain other domestic energy-related investments. Through the Company's wholly-owned subsidiary, National Grid LNG, it owns a 600,000 barrel liquefied natural gas ("LNG") storage and receiving facility 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") and a 20.4% interest in Iroquois Gas Transmission System, which are 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 14, "Commitments and Contingencies" under "Decommissioning Nuclear Units."

On August 14, 2015, the Company entered into an agreement to exchange its 20.4% interest in Iroquois Gas Transmission System to Dominion Midstream Partners, LP ("DM") in exchange for approximately 6.8 million common units (representing

approximately a 15% interest) in DM. DM owns, operates, develops and acquires natural gas import, storage, regasification, transportation and related assets, including a preferred equity interest in the Cove Point LNG facility in Lusby, Maryland and ownership of Carolina Gas Transmission ("CGT") in Cayce, South Carolina. Cove Point provides LNG import, storage and transportation services to the Mid-Atlantic marketplace and CGT is an interstate natural gas transportation company delivering natural gas to wholesale and direct industrial customers throughout South Carolina. This exchange transaction is expected to close by September 30, 2015.

Through its indirect wholly-owned subsidiary, National Grid Generation Ventures LLC, the Company owns a 50% interest in Island Park Energy Center LLC, formed to construct, install, hold, own, protect, finance, manage, operate and maintain projects consisting of the repowering of the E.F. Barrett Steam Unit and Barrett CT Units all located in Nassau County, New York.

Additionally, National Grid Generation Ventures LLC owns a 50% interest in three LLCs (LI Solar Generation LLC, LI Energy Storage System LLC, and LI Peaker Generation LLC). These LLCs were formed to jointly respond to LIPA's Request for Proposals ("RFP's") for Generation, Energy Storage and Demand Response Resources, and to jointly develop, construct, install, hold, own, protect, finance, manage, operate and maintain the respective RFP projects (none were awarded) or future proposals for similar projects.

Grid NY LLC, a direct wholly-owned subsidiary of Keyspan Corporation, was formed pursuant to the articles of organization filed 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 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.

Management recorded out-of-period adjustments during the current fiscal year that resulted in an increase to net income from continuing operations of $6.8 million (net of income taxes). The adjustments primarily related to a $51.4 million increase to net income for the correction of the Company's methodology for accruing Niagara Mohawk and Narragansett property taxes, which were previously accrued on a calendar year basis; a $23.6 million increase to net income related to the correction of the Company's tax accounting for employee variable pay tax deduction, offset by an $18.1 million decrease to net income resulting from the recognition of a previously unrecognized regulatory liability for the Brooklyn Union and Niagara Mohawk Net Utility Plant Trackers; a $35.8 million decrease to net income resulting from the correction of the Company's accounting for its revenue decoupling mechanism ("RDM") related to the unbilled component of revenue; a $6.4 million decrease to net income to correct the timing of recognition of rate resets and true-ups related to billings to LIPA under the terms of the PSA; a $5.3 million decrease to net income to correct the valuation of the liability associated

with a historical lease agreement of KeySpan Corporation; combined with various other immaterial corrections totaling a decrease of $2.6 million. The adjustments primarily impacted operating revenues, other taxes and income tax expense. Management has concluded that the impact of recording these adjustments was not material to the current fiscal year or any prior period.

The Company has evaluated subsequent events and transactions through September 17, 2015, 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, 2015.

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 these cases, the subsidiaries defer costs (as regulatory assets) or recognize obligations (as regulatory liabilities) if it is probable that such amounts will be recovered from, or refunded to, customers through future rates. Regulatory assets and liabilities are amortized to the consolidated statements of income consistent with the treatment of the related costs in the ratemaking process. Iroquois' transmission assets are regulated by the Federal Energy Regulatory Commission ("FERC") and its rates are filed with the FERC.

Revenue Recognition

Electric and Gas Distribution Revenue

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

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

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

Transmission Revenue

Transmission revenues 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 14, "Commitments and Contingencies" under "Electric Services and LIPA Agreements."

Other Revenues

Revenues earned for service and maintenance contracts associated with commercial energy systems are recognized as earned or over the life of the service contract, as appropriate.

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, 2015 and 2014 were $107.2 million and $103.4 million, respectively.

Gas distribution revenues include the collection of excise taxes and the related expense is included in other taxes in the accompanying consolidated statements of income.

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 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 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 company determines its current and deferred taxes based on the separate return method. The Company settles its current tax liability or benefit each year with NGNA pursuant to a tax sharing arrangement between NGNA and its subsidiaries. Tax benefits attributable to the tax attributes of other group companies and allocated by NGNA are treated as capital contributions.

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 primarily consists of deposits held by the New York Independent System Operator ("NYISO") and by the ISO New England ("ISO-NE") and cash collateral related to derivative contracts. Special deposits primarily consist of health care claims deposits. The Company had restricted cash of $169 million and $144 million and special deposits of $21 million and $24 million at March 31, 2015 and 2014, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

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

Inventory

Inventory is comprised of materials and supplies, emission credits, renewable energy certificates ("RECs"), and gas in storage. Materials and supplies are stated at the lower of weighted average cost or market and are expensed or capitalized as used. The Company's policy is to write-off obsolete inventory; there were no material write-offs of obsolete inventory for the years ended March 31, 2015 or 2014. Emission credits are comprised of sulfur dioxide, nitrogen oxide ("NOx"), and carbon dioxide credits. Emission credits are held primarily for consumption or may be sold to third-party purchasers. RECs are used to measure compliance with renewable energy standards and 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.

At March 31, 2015 and 2014, the Company had materials and supplies of $158 million and $150 million, emission credits of $44 million and $28 million, gas in storage of $149 million and $111 million, and purchased RECs of $46 million and $55 million, respectively.

Derivative Contracts

The Company uses derivative contracts to manage commodity price risk, as well as interest and foreign currency rate risk. All derivative contracts are recorded in the accompanying consolidated balance sheets at their fair value. Qualifying derivative contracts may be designated as either cash flow hedges or fair value hedges.

Commodity Derivative Contracts

All commodity costs, including the impact of derivative contracts, are passed on to customers through the Company's commodity rate adjustment mechanisms. Therefore, gains or losses on the settlement of these contracts are initially deferred and then refunded to, or collected from, customers consistent with regulatory requirements.

Certain non-trading contracts for the physical purchase of natural gas and electricity qualify for the normal purchase normal sale exception and are accounted for upon settlement. If the Company were to determine that a contract for which it elected the normal purchase normal sale exception no longer qualifies, the Company would recognize the fair value of the contract in accordance with the regulatory accounting described above.

Financing Derivative Contracts

Treasury related derivative contracts may qualify as either fair value hedges or cash flow hedges. The Company has entered into cross-currency and interest rate swaps ("CCIRS") to protect against changes in the fair value of fixed-rate borrowings due to movements in market interest rates. The Company has designated these instruments as fair value hedging relationships. For qualifying fair value hedges, all changes in the fair value of the derivative financial instrument and changes in the fair value of the item in relation to the risk being hedged are recognized in the consolidated statements of income. If the hedge relationship is terminated, the fair value adjustment to the hedged item continues to be reported as part of the basis of the item and is amortized to the consolidated statements of income as a yield adjustment over the remainder of the hedging period. At March 31, 2015 and 2014, the Company held no CCIRS designated in fair value hedging relationships.

The Company continually assesses the cost relationship between fixed and variable rate debt and periodically enters into CCIRS to convert the terms of the underlying debt obligations from fixed rate to variable rate or variable rate to fixed rate. Payments made, or received, on these derivative contracts are recognized as an adjustment to interest expense as incurred. The Company has designated these instruments as cash flow hedges. For qualifying cash flow hedges, the effective portion of a derivative's gain or loss is reported in other comprehensive income, net of related tax effects, and the ineffective portion is reported in earnings. Amounts in accumulated other comprehensive income ("AOCI") are reclassified into earnings in the same period or periods during which the hedged transaction affects earnings.

As of March 31, 2015 the Company had $538 million of foreign currency debt and $2 million of current derivative assets and $159 million of non-current derivative liabilities designated in cash flow hedging relationships, with $2.3 million recognized in other comprehensive income for the year ended March 31, 2015. As of March 31, 2014, the Company had $792 million of foreign currency debt and $5 million of current derivative assets designated in cash flow hedging relationships, with $4.5 million recognized in other comprehensive income for the year ended March 31, 2014. The Company expects $0.1 million in other comprehensive income will be reclassified into earnings within the next twelve months. For the years ended March 31, 2015 and 2014, the Company recorded ineffectiveness related to cash flow hedges of $3 million (loss) and $2 million (loss), respectively.

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

Power Purchase Agreements

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

Fair Value Measurements

The Company measures derivatives and available-for-sale securities at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The following is the fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access as of the reporting date;

- Level 2: inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data; and
- Level 3: unobservable inputs, such as internally-developed forward curves and pricing models for the asset or liability due to little or no market activity for the asset or liability with low correlation to observable market inputs.

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

Property, Plant and Equipment

Property, plant and equipment is stated at original cost. The cost of repairs and maintenance is charged to expense and the cost of renewals and betterments that extend the useful life of property, plant and equipment is capitalized. The capitalized cost of additions to property, plant and equipment includes costs such as direct material, labor and benefits, and an allowance for funds used during construction ("AFUDC") 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 and average service lives for the years ended March 31, 2015 and 2014 are as follows:

	Electric		**Gas**		**Common**	
	Years Ended March 31,		**Years Ended March 31,**		**Years Ended March 31,**	
	2015	2014	**2015**	2014	**2015**	2014
Composite rates	**2.7%**	2.8%	**2.9%**	2.9%	**4.8%**	5.3%
Average service lives	48 years	48 years	**46 years**	46 years	**35 years**	36 years

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 and $1.6 billion at March 31, 2015 and 2014, respectively.

Allowance for Funds Used During Construction

In accordance with applicable accounting guidance, the regulated subsidiaries record AFUDC, which represents the debt and equity costs of financing the construction of new property, plant and equipment. AFUDC equity is reported in the consolidated statements of income as non-cash income in other deductions, net, and AFUDC debt is reported as a non-cash offset to other interest, including affiliate interest. After construction is completed, the Company is permitted to recover these costs through their inclusion in rate base and corresponding depreciation expense. The Company recorded AFUDC related to equity of $19 million and $27 million for the years ended March 31, 2015 and 2014, respectively. The Company recorded AFUDC related to debt of $6 million and $13 million for the years ended March 31, 2015 and 2014, respectively. The average AFUDC rates for the years ended March 31, 2015 and 2014 were 2.7% and 4.5%, respectively.

In addition, approximately $0.8 million and $1.2 million of interest was capitalized for construction of non-regulated projects during the years ended March 31, 2015 and 2014, respectively.

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. Goodwill is tested for impairment using a two-step approach. The first step compares the estimated fair value of each reporting unit with its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, then goodwill is considered not impaired. If the carrying value exceeds the estimated fair value, then a second step is performed to determine the implied fair value of goodwill. If the carrying value of goodwill exceeds its implied fair value, then an impairment charge equal to the difference is recorded.

The fair value of each reporting unit was calculated in the annual goodwill impairment test for the year ended March 31, 2015 utilizing both income and market approaches, except as it pertains to Clean Line Energy Partners LLC ("Clean Line") as described in Note 12, "Goodwill."

- To estimate fair value utilizing the income approach, the Company used a discounted cash flow methodology incorporating its most recent business plan forecasts together with a projected terminal year calculation. Key assumptions used in the income approach were: (a) expected cash flows for the period from April 1, 2015 to March 31, 2020; (b) a discount rate of 5.2%, which was based on the Company's best estimate of its after-tax weighted-average cost of capital; and (c) a terminal growth rate of 2.25%, based on the Company's expected long-term average growth rate in line with estimated long-term U.S. economic inflation.

- To estimate fair value utilizing the market approach, the Company followed a market comparable methodology. Specifically, the Company applied a valuation multiple of earnings before interest, taxes, depreciation and amortization ("EBITDA"), derived from data of publicly-traded benchmark companies, to business operating data. Benchmark companies were selected based on comparability of the underlying business and economics. Key assumptions used in the market approach included the selection of appropriate benchmark companies and the selection of an EBITDA multiple of 11, which the Company believes is appropriate based on comparison of its business with the benchmark companies.

The Company determined the fair value of the business using 50% weighting for each valuation methodology, as it believes that each methodology provides equally valuable information. Based on the resulting fair value from the annual analyses, the Company determined that no adjustment of the goodwill carrying value was required at March 31, 2015 or 2014, except in relation to Clean Line as described in Note 12, "Goodwill."

Prior to 2015, the Company utilized an annual impairment assessment date of January 31. Management has determined that the use of January 1 as its annual impairment assessment date is preferable to January 31 because it facilitates a more timely evaluation in advance of the Company's fiscal year end of March 31. The movement of the date has not resulted in a substantive change in the timing of recording any potential impairment.

Available-For-Sale Securities

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

Asset Retirement Obligations

Asset retirement obligations are recognized for legal obligations associated with the retirement of property, plant and equipment, primarily associated with the Company's 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 has a legal obligation to dismantle the Glenwood and Far Rockaway facilities and remediate the associated sites. These facilities were shut down and decommissioning began in July 2012; demolition and remediation activities at Glenwood and Far Rockaway were completed in July 2015 and in August 2015, respectively.

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

	Years Ended March 31,	
	2015	2014
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 87**	$ 105
Accretion expense	**5**	6
Liabilities settled	**(11)**	(24)
Balance as of the end of the year	**$ 81**	$ 87

At March 31, 2015, the Company carried out a revaluation study that resulted in a net upward revaluation in estimated cost related to the asset retirement obligations. These increases were due to changes in remediation cost and enhanced asset replacement programs.

Accretion expense for the Company's regulated subsidiaries is deferred as part of the Company's asset retirement obligation regulatory asset as management believes it is probable that such amounts will be collected in future rates.

Employee Benefits

The Company has defined benefit pension and postretirement benefit other than pension ("PBOP") plans for its employees. The Company recognizes all pension and PBOP plans' funded status in the accompanying consolidated balance sheets as a net liability or asset with an offsetting adjustment to AOCI in shareholders' equity. In the case of regulated entities, the cost of providing these plans is recovered through rates; therefore, the net funded status is offset by a regulatory asset or liability. The Company measures and records its pension and PBOP funded status at the year-end date. Pension and PBOP plan assets are measured at fair value, using the year-end market value of those assets.

Supplemental Executive Retirement Plans

The Company has corporate assets included in financial investments in the accompanying consolidated balance sheets 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 with increases and decreases in the value of these assets recorded in the accompanying consolidated statements of income.

New and Recent Accounting Guidance

Accounting Guidance Adopted in Fiscal Year 2015

Reclassifications From Accumulated Other Comprehensive Income

In February 2013, the FASB issued ASU 2013-02, "Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income," to improve the reporting of reclassifications out of AOCI. The amendments require an entity to provide information either on the face of the consolidated financial statements or in a single footnote on significant amounts reclassified out of AOCI and the related income statement line items to the extent an amount is reclassified in its entirety to net income. For significant items not reclassified to net income in their entirety, an

entity is required to cross-reference to other disclosures that provide additional information. For non-public entities, the amendments are effective prospectively for reporting periods beginning after December 15, 2013. Early adoption is permitted. The Company adopted this guidance effective April 1, 2014 with no impact on its financial position, results of operations or cash flows.

Accounting Guidance Not Yet Adopted

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

In August 2014, the FASB issued amendments on reporting about an entity's ability to continue as a going concern in ASU No. 2014-15, "Presentation of Financial Statements – Going Concern (Subtopic 205 - 40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern." The amendments provide guidance about management's responsibility to evaluate whether there is substantial doubt surrounding an entity's ability to continue as a going concern. If management concludes that substantial doubt exists, the amendments also require additional disclosures relating to management's evaluation and conclusion. The amendments are effective for the annual reporting period ending after December 15, 2016 and interim periods thereafter. The application of this guidance is not expected to have a material impact on the Company's financial position, results of operations and cash flows.

Revenue Recognition

In May 2014, the FASB and the International Accounting Standards Board jointly issued a new revenue recognition standard ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." The objective of the new guidance is to provide a single comprehensive revenue recognition model for all contracts with customers to improve comparability. The standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services in an amount that reflects the consideration the entity expects to receive. The new guidance must be adopted using either a full retrospective approach or a modified retrospective approach. For non-public entities, the new guidance is effective for periods beginning after December 15, 2018, with early adoption permitted for periods beginning after December 15, 2017. The Company is currently evaluating the impact of the new guidance on its financial position, results of operations and cash flows.

3. REGULATORY ASSETS AND LIABILITIES

The Company records regulatory assets and liabilities that result from the ratemaking process. The following table presents the regulatory assets and regulatory liabilities recorded in the accompanying consolidated balance sheets.

	March 31,	
	2015	2014
	(in millions of dollars)	
Regulatory assets		
Current:		
Derivative contracts	**$ 113**	$ 16
Energy efficiency	**55**	23
Gas costs adjustment	**131**	287
Rate adjustment mechanisms	**87**	72
Renewable energy certificates	**120**	91
Revenue decoupling mechanism	**72**	20
Transmission service	**63**	38
Other	**26**	24
Total	**667**	571
Non-current:		
Environmental response costs	**1,732**	1,739
Postretirement benefits	**2,070**	1,476
Storm costs	**339**	319
Other	**780**	788
Total	**4,921**	4,322
Regulatory liabilities		
Current:		
CTC decommissioning rebate	**-**	58
Derivative contracts	**22**	50
Energy efficiency	**130**	146
Gas costs adjustment	**72**	50
Profit sharing	**46**	38
Rate adjustment mechanisms	**179**	68
Revenue decoupling mechanism	**119**	66
Temporary state assessment	**46**	-
Other	**13**	48
Total	**627**	524
Non-current:		
Carrying charges	**145**	60
Cost of removal	**1,683**	1,617
Environmental response costs	**145**	104
Postretirement benefits	**145**	220
Temporary state assessment	**-**	111
Other	**746**	576
Total	**2,864**	2,688
Net regulatory assets	**$ 2,097**	$ 1,681

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.

CTC decommissioning rebate: Represents the U.S. Department of Energy ("DOE") litigation awards for spent fuel storage costs that had been incurred through 2001 and 2008. These decommissioning rebates will be returned to customers through CTC charges.

Derivative contracts: The Company evaluates open derivative contracts for regulatory deferral by determining if they are probable of recovery from, or refund to, customers through future rates. Derivative contracts that qualify for regulatory deferral 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 its 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 sites with which it may be associated. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates.

The regulatory liability primarily represents the amount of customer contributions and insurance proceeds recovered to pay for costs to investigate and perform certain remediation activities at sites with which it may be associated as well as the excess of amounts received in rates over the Company's actual site investigation and remediation ("SIR") costs.

Gas costs adjustment: The Company's gas regulated subsidiaries are 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 amount in regulatory assets primarily represents the excess costs of the Company's pension and PBOP plans over amounts received in rates that are deferred to a regulatory asset to be recovered in future periods and the non-cash accrual of net actuarial gains and losses. The amount in regulatory liabilities 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, the 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 in the accompanying consolidated balance sheet will be refunded to customers over the next year.

Rate adjustment mechanisms: The Company's regulated subsidiaries are subject to a number of rate adjustment mechanisms such as for commodity costs, whereby an asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered or differences between actual revenues and targeted amounts as approved by the applicable state regulatory bodies.

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

Revenue decoupling mechanism: Revenue decoupling mechanisms allow for the periodic adjustment of delivery rates as a result of the reconciliation between allowed revenue per customer and actual revenue per customer. Any difference

between the allowed revenue per customer and the actual revenue per customer is recorded as a regulatory asset or regulatory liability.

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

Temporary state assessment: In June 2009, the NYPSC authorized utilities to recover the costs required for payment of the Temporary State Energy & Utility Service Conservation Assessment ("Temporary State Assessment"), including carrying charges. The Temporary State Assessment is subject to reconciliation over a five year period which began July 1, 2009.

On June 18, 2014, the NYPSC issued an order authorizing certain utilities, including Brooklyn Union and KeySpan Gas East ("The New York Gas Companies"), to recover the Temporary State Assessment subject to reconciliation, including carrying charges, from July 1, 2014 through June 30, 2017. As of March 31, 2015, the New York Gas Companies over-collected on these costs. The New York Gas Companies are required to net any deferred over-collected amounts against the amount to be collected during fiscal years 2014 and 2015 as well as the first payment relating to fiscal years 2015 and 2016.

On September 13, 2013 and August 7, 2013, Niagara Mohawk submitted a compliance filing (updated from June 14, 2013) proposing to maintain the currently effective surcharge. On June 18, 2014, a final order implementing a revised Temporary State Assessment resulted in a $2.7 million and $3.9 million credit to electric and gas customers, respectively, for rates effective July 1, 2014 through June 30, 2015.

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

The Company records carrying charges on all regulatory balances (with the exception of derivative contracts, cost of removal, environmental response costs, renewable energy certificates, and regulatory deferred tax balances), for which cash expenditures have been made and are subject to recovery, or for which cash has been collected and is subject to refund. Carrying charges are not recorded on items for which expenditures have not yet been made.

4. RATE MATTERS

Niagara Mohawk

March 2013 Electric and Gas Filing

In March 2013 the NYPSC issued a final order regarding Niagara Mohawk's electric and gas base rate filing made on April 27, 2012. The term of the new rate plan is from April 1, 2013 through March 31, 2016 and provides for an electric revenue requirement of $1,338.3 million in the first year, $1,395.9 million in the second year, and $1,432.5 million in the third year. It also provides for a gas revenue requirement of $307.4 million in the first year, $314.7 million in the second year, and $322 million in the third year.

Transmission Return on Equity Complaint

On September 11, 2012, the New York Association of Public Power ("NYAPP") filed a complaint against the Company, seeking to have the base ROE for transmission service of 11.5%, which includes a NYISO participation incentive adder, lowered to 9.49%. Similarly, on November 2, 2012 the Municipal Electric Utilities Association ("MEUA") filed a complaint to lower the Company's ROE to 9.25% including the NYISO participation adder. The MEUA complaint also challenged certain aspects of the Company's transmission formula rate. On February 6, 2014, the NYAPP filed a further complaint to reduce the ROE used in calculating rates for transmission service under the NYISO Open Access Transmission Tariff ("OATT") to 9.36%, inclusive of the 50 basis point adder for participation in the NYISO, with a corresponding overall weighted cost of capital of 6.60%. On February 24, 2015, the parties filed a Settlement Agreement which reduces the ROE used in calculating

rates for transmission service under the NYISO OATT to 10.3%, inclusive of incentive adders, from November 2, 2012, until the date of a FERC order accepting the Settlement Agreement, and prospectively thereon. The Settlement Agreement also provides for a one-time refund of $180,000 plus interest on that amount calculated at the FERC rate pursuant to 18 C.F.R. §35.19a(a)(2)(iii) from November 2, 2012, until the date the refund is provided, along with a one-time refund of $200,000 without interest for the non-ROE transmission formula rate issues raised in the MEUA complaint. Any change in the ROE would not have an impact on net income as the retail rate plan fully reconciles any increase or decrease in wholesale transmission revenue under the FERC Transmission Service Charge rate through a Transmission Revenue Adjustment Clause mechanism. On May 13, 2015, the FERC issued a letter order approving the Company's Transmission ROE settlement without any modification.

Wholesale Transmission Service Charge

On December 6, 2013, Niagara Mohawk submitted a filing for FERC approval of revisions to its Wholesale Transmission Service Charge ("TSC Rate") under the NYSIO OATT to recover its RSS costs under two agreements with NRG to support the reliability of Niagara Mohawk's transmission system while transmission reinforcements are constructed. On February 4, 2014 the FERC allowed the RSS charges to become effective in TSC Rates as of July 1, 2013, subject to refund and further consideration of the matter by the FERC. On March 19, 2015, the FERC issued two orders relating to the Company's December 6, 2013 filing of proposed tariff revisions to the TSC Rate. In the first order, the FERC set for hearing and settlement judge procedures the justness and reasonableness of the Company's proposed Wholesale TSC formula rate revisions and the Dunkirk RSS charges. In the second order, the FERC rejected a request for rehearing filed by the MEUA regarding the FERC's decision to accept the December 6, 2013 amendment for filing retroactive to July 1, 2013. The FERC held the hearing on the first order in abeyance pending the outcome of settlement proceedings before a settlement judge.

Dunkirk RSS Agreement Extension

On May 18, 2015, the NYPSC approved a seven-month extension of the existing RSS agreement between the Company and Dunkirk. The approval extends the end date of the RSS from May 31, 2015 to December 31, 2015, and provides for recovery of the RSS costs under the surcharge mechanism currently in place. The extension is needed to address reliability issues until the Company's Five Mile Road substation and associated reconductoring projects are in service (estimated at December 31, 2015).

Management Audit

In February 2011, the NYPSC selected Overland Consulting Inc., ("Overland") to perform a management audit of NGUSA's affiliate cost allocations, policies and procedures. Niagara Mohawk and the New York Gas Companies disputed certain of Overland's final audit conclusions and the NYPSC ordered that further proceedings be conducted to address what, if any, ratemaking adjustments were necessary. On September 5, 2014, the NYPSC approved a settlement that resolves all outstanding issues relating to the audit and provides for no rate adjustments for the Company.

Gas Management Audit

In February 2013, the NYPSC initiated a comprehensive management and operational audit of NGUSA's New York gas businesses, including Niagara Mohawk and the New York Gas Companies, pursuant to the Public Service Law requirement that major electric and gas utilities undergo an audit every five years. The audit commenced in August 2013 and the NYPSC issued an audit findings repot in October 2014. The audit findings found that NGUSA's New York gas businesses performed well in providing reliable gas service, and strength in operations, network planning, project management, work management, load forecasting, supply procurement and customer systems support. Also included were 31 recommendations for improvement, including: reconstituting the boards of directors of NGUSA and the gas companies in New York to include more objective oversight; establishing stronger reporting authority between the New York jurisdictional president and operational organizations; preparing a true strategic plan for NGUSA's New York gas business operations to serve as a road map for investments, programs and operations to build upon the state energy plan and energy initiatives; developing a five-year, integrated, system-wide plan that includes all gas reliability work, mandated replacements, growth projects and system planning work: enhancing internal service level agreements to promote

accountability for performance and costs; and undertaking a full accounting of all costs associated with NGUSA's SAP enterprise wide system. In November 2014, the Company filed joint audit implementation plans addressing each of the audit recommendations. On May 14, 2015, the NYPSC issued an order accepting without modifications the joint implementation plans and directing NGUSA's New York gas businesses to execute the plans.

Operations Audit

In August 2013, the NYPSC initiated an operational audit 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 Niagara Mohawk and the New York Gas Companies. On December 19, 2013, the NYPSC selected Overland to conduct the audit, which commenced in February 2014. At the time of the issuance of these consolidated financial statements, the Company has not received the final audit findings and cannot predict the outcome of this 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 Niagara Mohawk. On June 26, 2014, the NYPSC selected The Liberty Consulting Group to conduct the audit. At the time of the issuance of these consolidated financial statements, Niagara Mohawk cannot predict the outcome of this operational audit.

Recovery of Deferral Costs Relating to Emergency Order

On January 28, 2014, Niagara Mohawk filed a petition requesting a waiver of Rule 46.3.2 of its tariff. Rule 46.3.2 describes the manner in which Niagara Mohawk calculates its supply-related Mass Market Adjustment ("MMA"). Niagara Mohawk proposed the waiver of the rule to mitigate adverse financial impacts anticipated from a significant and unusual increase in electric commodity prices for its mass market customers.

On that same date, the NYPSC issued, on an emergency basis pursuant to the State Administrative Procedure Act §202(6), an Emergency Order granting Niagara Mohawk's waiver request (the "Emergency Order"). In the Emergency Order, the NYPSC waived the requirements of Rule 46.3.2 and approved deferral treatment of the costs and associated carrying charges related to the one-time credit provided via the waiver. However, the NYPSC denied, pending further review and consideration of public comments, Niagara Mohawk's request to recover such deferral over a six-month period beginning May 2014.

The NYPSC issued another order on April 25, 2014 permanently approving the Emergency Order and authorizing Niagara Mohawk to collect $33.3 million, plus carrying charges at the customer deposit rate, over a six-month period commencing with the June 2014 billing period. The deferral recovery will be performed in a manner consistent with the method that was used to provide the benefit to the mass market customers, through an adjustment to the MMA as calculated by NYISO load zone.

Petition for Authorization to Defer an Actuarial Experience Pension Settlement Loss for the Year Ending March 31, 2014

On February 28, 2014 and August 13, 2014 the Company filed petitions seeking authorization to defer $14.1 million related to a pension settlement loss incurred during the year ending March 31, 2014.

Commodity Rate Mechanism Changes

On October 23, 2014, the NYPSC approved tariff revisions filed by Niagara Mohawk that modified several components of Rule 46 – Supply Service Charges of Niagara Mohawk's tariff, NYPSC No. 220-Electricity. The revisions provide Niagara Mohawk with a measure of flexibility to manage significant volatility resulting from the reconciliation of commodity costs, like those experienced in January and March of 2014 due to the unanticipated extreme cold weather, for its residential and small commercial customers ("mass market customers"). The tariff revisions went into effect October 29, 2014 and will

allow for more flexibility in the timing of Niagara Mohawk's reconciliation of revenues and expenses for mass market customers.

The New York Gas Companies

General Rate Case

KeySpan Gas East has been subject to a rate plan with a primary term of five years (2008-2012), which remains in effect until modified by the NYPSC. Under this rate plan, base delivery rates include an allowed ROE of 9.8% with a 45% equity ratio in the capital structure.

On June 13, 2013, the NYPSC approved a rate plan extension covering Brooklyn Union's 2013 and 2014 rate years. Brooklyn Union's revenue requirements for both years have been modified as follows: (i) there is no change in base delivery rates, other than those previously approved by the NYPSC in the rate plan extension, (ii) the allowed ROE has decreased from 9.8% to 9.4%, and (iii) the common equity ratio in the capital structure has increased from 45% to 48%.

Capital Investment

On June 13, 2014, KeySpan Gas East filed a petition with the NYPSC to implement a three year capital investment program that would allow KeySpan Gas East to invest more than $700 million in gas infrastructure projects designed to enhance the safety and reliability of its gas systems and promote gas growth, while maintaining base delivery rates.

On December 15, 2014, KeySpan Gas East received an order which authorizes it to replace leak prone pipe up to its forecasted budget of $211.7 million for calendars years 2015 and 2016. KeySpan Gas East is allowed to establish a 21-month surcharge mechanism beginning April 2, 2015 through December 31, 2016, which will be capped at $10 million and $13.4 million, respectively, to address KeySpan Gas East's capital needs for replacement of leak prone pipe, while minimizing future customer bill impacts. KeySpan Gas East was authorized to spend up to its forecasted budget of $202.7 million for calendar years 2015 and 2016 for its Neighborhood Expansion and other related programs. KeySpan Gas East is directed to establish a new deferral mechanism that allows it to defer the pre-tax revenue requirements associated with its capital spending program up to a maximum capital expenditure of $202.7 million made in calendar years 2015 and 2016. KeySpan Gas East's existing city/state deferral mechanism was eliminated as of January 1, 2015 and the non-growth deferral mechanism is continued. The order also included additional obligations and filing requirements.

Capital Reconciliation Mechanism Petition

In June 2015, Brooklyn Union submitted a petition to the NYPSC requesting a modification to the Capital Expenditures and Net Utility Plant and Depreciation Expense Reconciliation Mechanism ("Capital Reconciliation Mechanism") in its current rate plan. The Capital Reconciliation Mechanism is a downward only net utility plant reconciliation mechanism that permits a cumulative, two-year reconciliation for the two years ended December 31, 2014 and annual reconciliations thereafter. While Brooklyn Union implemented and largely completed its capital program for 2013 and 2014, its ability to launch certain programs was hampered by Superstorm Sandy and its aftermath. The impact of these delays and other related issues was a deferred liability, which was offset against the regulatory asset recorded in relation to the primary term of the rate plan. The requested modification to the Capital Reconciliation Mechanism would provide for an additional two year reconciliation period (calendar years 2015 and 2016) to complete more capital projects and facilitate Brooklyn Union's plan to invest in its distribution system infrastructure.

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

2009 Capital Investments Audit

The DPU approved an RDM arising from the 2009 distribution rate case filed by the Massachusetts Electric Companies. As part of their RDM provision, the Massachusetts Electric Companies file a report by July 1st of each year on their capital investment for the prior calendar year. In connection with the Massachusetts Electric Companies' first capital expenditure

("CapEx") filing made in July 2010, the DPU opened a proceeding in March 2011, as requested by the Massachusetts Attorney General's Office ("Attorney General"), for an independent audit of the Massachusetts Electric Companies' 2009 capital investments which, in part, formed the basis for the Massachusetts Electric Companies' RDM rate. On July 31, 2014, the DPU issued an order approving the sole respondent's bid to perform the CapEx audit. The CapEx audit is currently underway. The Massachusetts Electric Companies cannot currently predict the outcome of this proceeding.

Cost Recovery

In addition to the rates and tariffs put into effect following its most recent rate case, Massachusetts Electric continues to be authorized to recover costs associated with the procurement of electricity for its customers, all transmission costs, and costs charged by Massachusetts Electric's affiliate NEP, for stranded costs associated with NEP's former electric generation investments.

DPU Audit Settlement Agreement

In the general rate case involving the Company's Massachusetts gas distribution subsidiaries, the DPU opened an investigation to address the allocation and assignment of costs to the gas affiliates by the NGUSA service companies. The audit was later expanded to include the Massachusetts Electric Companies. The Massachusetts Electric Companies, the Massachusetts Gas Companies and the Attorney General's Office executed a Settlement Agreement that the DPU approved on July 25, 2014. As a result of the approval of the Settlement, there is no need for an audit, and both the Massachusetts Gas and Massachusetts Electric Companies will implement reporting and review practices similar to those in place for their New York affiliates, and NGUSA contributed $1 million to the Massachusetts Association for Community Action that will be used for the benefit of the Massachusetts Electric Companies' electric customers and the customers of its Massachusetts gas distribution affiliates who are eligible for fuel assistance.

Storm Management Audit

In January 2011, the DPU opened an investigation into the Massachusetts Electric Companies' preparation and response to a December 2010 winter storm. The DPU has the authority to issue fines not to exceed approximately $0.3 million for each violation for each day that the violation persists. On September 22, 2011, the DPU approved a settlement between Massachusetts Electric Companies and the Attorney General that included a $1.2 million refund to customers. The DPU also investigated the Massachusetts Electric Companies' response to Tropical Storm Irene and the October 2011 winter storm in a consolidated proceeding. On December 11, 2012, the DPU issued an order in which it assessed the Massachusetts Electric Companies a penalty of $18.7 million associated with the Massachusetts Electric Companies' performance in responding to these two weather events, consisting of $8.1 million for Tropical Storm Irene and $10.6 million for the October 2011 winter storm. The Massachusetts Electric Companies appealed this ruling and on September 4, 2014 the Court affirmed all but two violations, reducing the penalty by $0.9 million. The Massachusetts Electric Companies had recorded the original penalty and credited customers during March 2013. In addition, in the December 11, 2012 order, the DPU ordered a management audit of the Massachusetts Electric Companies' emergency planning, outage management, and restoration. The auditors have completed their audit, and submitted their Final Report to the DPU on July 9, 2014. The DPU adopted the auditor's thirty recommendations, which include items such as improving emergency response training and tracking of training, designating additional personnel for storm roles, and considering the expanded use of technology and communication tools. The Massachusetts Electric Companies have already implemented some of the recommendations and are in the process of implementing the remaining recommendations.

Storm Cost Recovery

The Massachusetts Electric Companies have deferred incremental storm costs of approximately $146 million as of March 31, 2015, net of customer contributions of approximately $95 million to the Massachusetts Electric Companies' Storm Contingency Fund, to restore power associated with several major weather events occurring since January 2010, pending ultimate approval by the DPU to charge its deferred costs to the Massachusetts Electric Companies' Storm Contingency Fund. This amount represents approximately $241 million of deferred storm costs, excluding net carrying costs of

approximately $40 million. The deferred incremental storm cost and carrying cost amounts have been reduced by approximately $21 million and $2 million, respectively, to reflect the impact of estimated billings to Verizon for vegetation management costs as a result of the DPU's order regarding the December 2008 Storm. On March 5, 2013, the Massachusetts Electric Companies filed with the DPU a request for accelerated funding for the Massachusetts Electric Companies' Storm Contingency Fund of $40 million per year over a period of up to five years, or $200 million. On May 3, 2013, the DPU approved $40 million annually for up to three years, or $120 million. This is in addition to $4.3 million that the Massachusetts Electric Companies recover annually in base rates for the Storm Contingency Fund. In its ruling, the DPU also directed the Massachusetts Electric Companies to submit two filings of all documentation supporting its storm costs for DPU review and approval. The Massachusetts Electric Companies submitted the first filing for $128 million of costs on May 31, 2013 for qualifying storms that occurred during calendar years 2010 and 2011. On September 30, 2014, the Massachusetts Electric Companies submitted its second filing supporting $94 million of storm costs (net of $7 million of vegetation management costs billable to Verizon) that were incurred for storm events which occurred during calendar year 2012 through February 2013 and two additional storm events occurring in February and March 2013. In its September 30, 2014 filing, the Massachusetts Electric Companies also updated the costs related to the calendar year 2010 and 2011 storm events to exclude $10 million of vegetation management costs billed to Verizon. The Massachusetts Electric Companies cannot currently predict the outcome of any proceedings related to storm recovery.

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

2010 Service Quality Report

On December 30, 2013, the DPU issued an order on Massachusetts Electric's calendar year 2010 Service Quality Report, ordering that Massachusetts Electric refund to customers a net penalty of $6.7 million. On January 21, 2014, Massachusetts Electric filed a Motion for Clarification/Reconsideration regarding a portion of the penalty amount related to Circuit Average Interruption Frequency Index which totaled $2.7 million. In addition, Massachusetts Electric filed a proposal to credit customers the $6.7 million penalty along with a proposed tariff that would allow for recovery of the $2.7 million if the DPU ruled in favor of Massachusetts Electric regarding the Motion for Clarification/Reconsideration. On May 21, 2014, the DPU denied Massachusetts Electric's motion.

The Massachusetts Gas Companies

General Rate Case

In November 2010, the DPU issued an order in the Massachusetts Gas Companies' 2010 rate case approving a revenue increase of $58 million based upon a 9.75% ROE and a 50% equity ratio. The Massachusetts Gas Companies filed two motions in response. These motions resulted in a final revenue increase of $65.3 million reflected in rates effective February 1, 2013.

PBOP Carrying Charges

On June 1, 2011, in conjunction with the DPU's annual investigation of Boston Gas' calendar year 2009 pension and PBOP rate reconciliation mechanism, the Massachusetts Attorney General ("AG") argued that Boston Gas be obligated to provide carrying charges to the benefit of customers on its PBOP liability balances related to its 2003 to 2006 rate reconciliation filings. In August 2010, the DPU ordered Boston Gas to provide carrying charges on its PBOP liability balances on its 2007 and 2008 rate reconciliation filings, but the order was silent about providing carrying charges prior to those years. On

August 29, 2014, the DPU ordered Boston Gas to provide carrying charges on its 2003 to 2006 PBOP liability balances in its next annual pension and PBOP reconciliation filing. On September 15, 2014, the 2014-2015 Pension Adjustment Factor filing was finalized and Boston Gas recorded an $8.3 million reduction to the regulatory asset in the accompanying consolidated financial statements.

Gas System Enhancement Plan

On April 30, 2015, the DPU approved the Massachusetts Gas Companies' first Gas System Enhancement Plan for calendar year 2015 and the associated factors ("GSEAFs"). The approved GSEAFs are designed to provide concurrent recovery of the revenue requirement associated with the Massachusetts Gas Companies' capital costs for the replacement of eligible leak prone pipe and ancillary equipment pursuant to the 2014 Gas Leaks Act passed in Massachusetts. This new program will replace the currently effective Targeted Infrastructure Replacement Program. The approved GSEAFs are designed to recover from all firm sales and transportation customers a surcharge of approximately $9.7 million.

New England Power

Stranded Cost Recovery

Under settlement agreements approved by state commissions and the FERC, NEP is permitted to recover stranded costs (those costs associated with its former generating investments (nuclear and non-nuclear) and related contractual commitments that were not recovered through the sale of those investments). NEP earns an ROE of approximately 11% on stranded cost recovery. NEP will recover its remaining non-nuclear stranded costs through 2020. See the "Decommissioning Nuclear Units" in Note 14 "Commitments and Contingencies," for a discussion of ongoing costs associated with decommissioned nuclear units.

Transmission Return on Equity

NEP's transmission rates applicable to transmission service through October 15, 2014 reflect a base ROE of 11.14% applicable to NEP's transmission facilities, plus an additional 0.5% Regional Transmission Organization ("RTO") participation adder applicable to transmission facilities included under the Regional Network Service ("RNS") rate. Approximately 70% of the NEP's transmission facilities are included under RNS rates. NEP earns an additional 1% ROE incentive adder on RNS-related transmission facilities approved under the RTO's Regional System Plan and placed in service on or before December 31, 2008. It also earns a 1.25% ROE incentive on its portion of New England East-West Solution ("NEEWS") as described below. Effective as of October 16, 2014, the FERC issued a series of orders as the result of a ROE complaint case (see the "FERC ROE Complaints" in Note 14, "Commitments and Contingencies") reducing NEP's base ROE to 10.57%. The FERC also established a maximum ROE such that the aforementioned incentives, taken together, may not exceed a cap of 11.74%.

New England East-West Solution

In September 2008, NEP, its affiliate Narragansett, and Northeast Utilities jointly filed an application with the FERC to recover financial incentives for the NEEWS, pursuant to the FERC's Transmission Pricing Policy Order No. 679. Effective November 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. 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 April 11, 2013, the RIPUC issued an order approving the agreement among the Rhode Island Division of Public Utilities and Carriers, the Department of the Navy, and Narragansett, which provided for an increase in electric base distribution revenue of $21.5 million and an increase in gas base distribution revenue of $11.3 million based on a 9.5% allowed ROE and a common equity ratio of approximately 49.1%, effect retroactively on February 1, 2013. The order also included reinstatement of base rate recovery of storm fund contributions and implementation of a Pension Adjustment Mechanism for pension and PBOP expenses for the electric business identical to the mechanism in place for the gas business.

5. PROPERTY, PLANT AND EQUIPMENT

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

	March 31,	
	2015	2014
	(in millions of dollars)	
Plant and machinery	**$ 28,980**	$ 27,034
Property held for future use	**15**	16
Land and buildings	**2,108**	2,075
Assets in construction	**1,581**	1,410
Software and other intangibles	**792**	637
Total property, plant and equipment	**33,476**	31,172
Accumulated depreciation and amortization	**(7,805)**	(7,297)
Property, plant and equipment, net	**$ 25,671**	$ 23,875

6. DERIVATIVE CONTRACTS AND HEDGING

The Company utilizes derivative contracts to manage commodity price, interest and currency rate risk associated with its natural gas and electricity purchases and 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 contracts measured in dekatherms ("dths") and megawatt hours ("mwhs") are as follows:

	Electric		Gas	
	March 31,		March 31,	
	2015	2014	**2015**	2014
	(in millions)		*(in millions)*	
Gas swap contracts (dths)	**-**	-	**65**	50
Gas future contracts (dths)	**-**	-	**20**	20
Gas option contracts (dths)	**-**	-	**4**	23
Gas purchase contracts (dths)	**-**	-	**55**	87
Electric swap contracts (mwhs)	**11**	7	**-**	-
Total	**11**	7	**144**	180

Amounts Recognized in the Accompanying Consolidated Balance Sheets

	Asset Derivatives			Liability Derivatives		
	March 31,			March 31,		
	2015	2014		**2015**	2014	
	(in millions of dollars)			*(in millions of dollars)*		
Current assets:			Current liabilities:			
Rate recoverable contracts:			Rate recoverable contracts:			
Gas swap contracts	**$ 2**	$ 12	Gas swap contracts	**$ 37**	$ 4	
Gas future contracts	**-**	3	Gas future contracts	**11**	1	
Gas option contracts	**-**	2	Gas option contracts	**-**	1	
Gas purchase contracts	**18**	11	Gas purchase contracts	**10**	36	
Electric swap contracts	**23**	36	Electric swap contracts	**51**	1	
Electric option contracts	**-**	1	Electric option contracts	**1**	-	
Contracts not subject to rate recovery:			Contracts not subject to rate recovery:			
Gas swap contracts	**-**	-	Gas swap contracts	**1**	-	
Hedge contracts:			Hedge contracts:			
CCIRS	**2**	5	CCIRS	**159**	-	
	45	70		**270**	43	
Other non-current assets:			Other non-current liabilities:			
Rate recoverable contracts:			Rate recoverable contracts:			
Gas swap contracts	**-**	-	Gas swap contracts	**3**	-	
Gas future contracts	**-**	-	Gas future contracts	**6**	-	
Gas purchase contracts	**22**	18	Gas purchase contracts	**8**	5	
Electric swap contracts	**8**	8	Electric swap contracts	**37**	9	
	30	26		**54**	14	
Total	**$ 75**	$ 96	Total	**$ 324**	$ 57	

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 changes in fair value of the Company's contracts not subject to rate recovery are recorded within purchased gas in the accompanying consolidated statements of income.

Credit and Collateral

The Company is exposed to credit risk related to transactions entered into for commodity price, interest and currency 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 clearinghouses act as the counterparty to each trade. Transactions on the NYMEX must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX are significantly collateralized and have limited counterparty credit risk.

The credit policy for commodity transactions is managed and monitored by the Executive Energy Risk Management Committee ("EERC"), which is responsible for approving risk management policies and objectives for risk assessment, control and valuation, and the monitoring and reporting of risk exposures. The 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 EERC is chaired by the Global Tax and Treasury Director and reports to the Finance Committee. The EPRMC is chaired by the Vice President of U.S. Treasury and reports to the EERC.

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 contracts, 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 $54 million and an asset of $26 million as of March 31, 2015 and 2014, respectively.

The aggregate fair value of the Company's commodity derivative contracts with credit-risk-related contingent features that are in a liability position at March 31, 2015 and 2014 was $98.3 million and $16.9 million, respectively. The Company had $12.1 million at March 31, 2015 and zero collateral posted for these instruments at March 31, 2014. If the Company's credit rating were to be downgraded by one level, it would be required to post $13.6 million additional collateral to its counterparties at March 31, 2015. If the Company's credit rating were to be downgraded by two levels, it would be required to post $23.6 million additional collateral to its counterparties at March 31, 2015. If the Company's credit rating were to be downgraded by three levels, it would be required to post $96.5 million and $18 million additional collateral to its counterparties at March 31, 2015 and 2014, 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.

In relation to the Company's 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 additional collateral.

Offsetting Information for Derivatives Subject to Master Netting Arrangements

March 31, 2015
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 contracts						
Gas swap contracts	$ 2	$ -	$ 2	$ -	$ -	$ 2
Gas purchase contracts	40	-	40	-	-	40
Electric swap contracts	31	-	31	-	-	31
CCIRS	2	-	2	-	-	2
Total	$ 75	$ -	$ 75	$ -	$ -	$ 75

LIABILITIES:	Gross amounts of recognized liabilities *A*	Gross amounts offset in the Consolidated Balance Sheets *B*	Net amounts of presented in the Consolidated Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral paid *Db*	Net amount *E=C-D*
Derivative contracts						
Gas swap contracts	$ 41	$ -	$ 41	$ -	$ -	$ 41
Gas future contracts	17	-	17	-	17	-
Gas purchase contracts	18	-	18	-	-	18
Electric swap contracts	88	-	88	-	12	76
Electric option contracts	1	-	1	-	-	1
CCIRS	159	-	159	-	115	44
Total	$ 324	$ -	$ 324	$ -	$ 144	$ 180

March 31, 2014
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 contracts						
Gas swap contracts	$ 12	$ -	$ 12	$ -	$ -	$ 12
Gas future contracts	3	-	3	-	3	-
Gas option contracts	2	-	2	-	-	2
Gas purchase contracts	29	-	29	-	-	29
Electric swap contracts	44	-	44	-	3	41
Electric option contracts	1	-	1	-	-	1
CCIRS	5	-	5	-	-	5
Total	$ 96	$ -	$ 96	$ -	$ 6	$ 90

LIABILITIES:	Gross amounts of recognized liabilities *A*	Gross amounts offset in the Consolidated Balance Sheets *B*	Net amounts of presented in the Consolidated Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral paid *Db*	Net amount *E=C-D*
Derivative contracts						
Gas swap contracts	$ 4	$ -	$ 4	$ -	$ -	$ 4
Gas future contracts	1	-	1	-	1	-
Gas option contracts	1	-	1	-	-	1
Gas purchase contracts	41	-	41	-	-	41
Electric swap contracts	10	-	10	-	-	10
Total	$ 57	$ -	$ 57	$ -	$ 1	$ 56

7. FAIR VALUE MEASUREMENTS

The following tables present assets and liabilities measured and recorded at fair value in the accompanying consolidated balance sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2015 and 2014:

	March 31, 2015			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Assets:				
Derivative contracts				
Gas swap contracts	$ -	$ 2	$ -	$ 2
Gas purchase contracts	-	-	40	40
Electric swap contracts	-	31	-	31
CCIRS	-	2	-	2
Available-for-sale securities	125	133	-	258
Total	125	168	40	333
Liabilities:				
Derivative contracts				
Gas swap contracts	-	41	-	41
Gas future contracts	17	-	-	17
Gas purchase contracts	-	-	18	18
Electric swap contracts	-	88	-	88
Electric option contracts	-	-	1	1
CCIRS	-	159	-	159
Total	17	288	19	324
Net assets (liabilities)	$ 108	$ (120)	$ 21	$ 9

	March 31, 2014			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Assets:				
Derivative contracts				
Gas swap contracts	$ -	$ 12	$ -	$ 12
Gas future contracts	3	-	-	3
Gas option contracts	-	-	2	2
Gas purchase contracts	-	1	28	29
Electric swap contracts	-	44	-	44
Electric option contracts	-	-	1	1
CCIRS	-	5	-	5
Available-for-sale securities	113	124	-	237
Total	116	186	31	333
Liabilities:				
Derivative contracts				
Gas swap contracts	-	4	-	4
Gas future contracts	1	-	-	1
Gas option contracts	-	-	1	1
Gas purchase contracts	-	5	36	41
Electric swap contracts	-	10	-	10
Total	1	19	37	57
Net assets (liabilities)	$ 115	$ 167	$ (6)	$ 276

Derivative Contracts: The Company's Level 1 fair value derivative contracts 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 derivatives (e.g. natural gas futures traded on NYMEX).

The Company's Level 2 fair value derivative contracts primarily consist of over-the-counter ("OTC") interest and currency swap transactions, and gas swap contracts with pricing inputs obtained from the New York Mercantile Exchange 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 contracts. 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 contracts primarily consist of OTC gas option contracts and gas purchase contracts, which are valued based on internally-developed models. Industry-standard valuation techniques, such as the Black-Scholes pricing model, Monte Carlo simulation, and Financial Engineering Associates libraries are used for valuing such instruments. A derivative is designated Level 3 when it is valued based on a forward curve that is internally developed, extrapolated or derived from market observable curves with correlation coefficients less than 95%, where optionality is present, or if non-economic assumptions are made. The internally developed forward curves have a high level of correlation with Platts Mark-to-Market curves and are reviewed by the middle office. The Company considers non-performance risk and liquidity risk in the valuation of derivative contracts categorized in Level 2 and Level 3.

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

Changes in Level 3 Derivative Contracts

	Years Ended March 31,	
	2015	**2014**
	(in millions of dollars)	
Balance as of the beginning of the year	**$ (6)**	$ 11
Transfers out of Level 3	**5**	1
Total gains or losses included in regulatory assets and liabilities	**(17)**	(23)
Settlements	**39**	5
Balance as of the end of the year	**$ 21**	$ (6)
The amount of total gains or losses for the year included in net income attributed to the change in unrealized gains or losses related to non-regulatory assets and liabilities at year-end	**$ -**	$ -

A transfer into Level 3 represents existing assets or liabilities that were previously categorized at a higher level for which the inputs became unobservable during the year. A transfer out of Level 3 represents assets and liabilities that were previously classified as Level 3 for which the inputs became observable based on the criteria discussed previously for classification in Level 2. These transfers, which are recognized at the end of each period, result from changes in the observability of forward curves from the beginning to the end of each reporting period. There were no transfers between Level 1 and Level 2, and no transfers into Level 3, during the years ended March 31, 2015 or 2014.

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 derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The forward curves used for financial reporting are developed and verified by the middle office. The Company considers non-performance risk and liquidity risk in the valuation of derivative contracts 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, 2015 Assets	(Liabilities)	Total	Valuation Technique(s)	Significant Unobservable Input	Range
		(in millions of dollars)					
Gas	Option contracts	$ -	$ -	$ -	Discounted Cash Flow	Forward Curve Implied Volatility	$0.27-$0.29/dth 34%-41%
Gas	Purchase contracts	35	(18)	17	Discounted Cash Flow	Forward Curve LNG Forward Curve	$0.96-$11.47/dth
Gas	Cross commodity contracts	5	-	5	Discounted Cash Flow	Forward Curve	$17.47-$378.51/dth
Electric	Option contracts	-	(1)	(1)	Discounted Cash Flow	Implied Volatility	30%-69%
	Total	$ 40	$ (19)	$ 21			

Commodity	Level 3 Position	Fair Value as of March 31, 2014 Assets	(Liabilities)	Total	Valuation Technique(s)	Significant Unobservable Input	Range
		(in millions of dollars)					
Gas	Option contracts	$ 2	$ (1)	$ 1	Discounted Cash Flow	Forward Curve Implied Volatility	$(1.07)-$0.72/dth 29%-31%
Gas	Purchase contracts	25	(36)	(11)	Discounted Cash Flow	Forward Curve LNG Forward Curve	$2.43-$17.31/dth $6.62-$11.01/dth
Gas	Cross commodity contracts	3	-	3	Discounted Cash Flow	Forward Curve	$43.19-$98.98/dth
Electric	Option contracts	1	-	1	Discounted Cash Flow	Implied Volatility	29%-65%
	Total	$ 31	$ (37)	$ (6)			

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 and gas and electric option derivatives are forward commodity prices, both gas and electric, implied volatility and valuation

assumptions pertaining to the peaking gas deals based on the forward gas curves. A relative change in commodity price at various locations underlying the open positions can result in significantly different fair value estimates.

Other Fair Value Measurements

The Company's consolidated balance sheets reflect long-term debt at amortized cost. The fair value of the Company's long-term debt was based on quoted market prices when available, or estimated using quoted market prices for similar debt. The fair value of this debt at March 31, 2015 and 2014 was $10.2 billion and $9.9 billion, respectively.

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

8. EMPLOYEE BENEFITS

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

Pension Plans

The Pension Plans are comprised of both qualified and non-qualified plans. The qualified pension plans provide union employees, as well as all 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. The Company funds the qualified plans by contributing at least the minimum amount required under Internal Revenue Service ("IRS") regulations. The Company expects to contribute $291 million to the Pension Plans during the year ending March 31, 2016.

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. The Company funds these plans based on the requirements of the various regulatory jurisdictions in which it operates. The Company expects to contribute $148 million to the PBOP Plans during the year ending March 31, 2016.

Defined Contribution Plans

The Company also has several defined contribution pension plans (primarily 401(k) employee savings fund plans) that cover substantially all employees. In addition, employees may receive certain employer contributions, including matching contributions and a 15% discount on the purchase of National Grid plc common stock. Employer matching contributions of approximately $41 million and $38 million, respectively, were expensed in the years ended March 31, 2015 and 2014.

Components of Net Periodic Benefit Costs

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2015	2014	**2015**	2014
	(in millions of dollars)			
Service cost	**$ 119**	$ 134	**$ 62**	$ 73
Interest cost	**368**	355	**203**	203
Expected return on plan assets	**(473)**	(443)	**(190)**	(170)
Amortization of prior service cost, net	**7**	9	**6**	8
Amortization of net actuarial loss	**237**	252	**61**	83
Settlements/curtailments	**-**	16	**-**	(140)
Total cost	**$ 258**	$ 323	**$ 142**	$ 57

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

Amounts Recognized in AOCI and Regulatory Assets

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2015	2014	**2015**	2014
	(in millions of dollars)			
Net actuarial loss (gain) on liabilities	**$ 998**	$ (18)	**$ 501**	$ (319)
Net actuarial (gain) loss on assets	**(205)**	-	**62**	-
Prior service cost (credit)	**2**	-	**-**	(31)
Amortization of net actuarial (loss) gain	**(237)**	(267)	**(61)**	58
Amortization of prior service cost, net	**(7)**	(10)	**(6)**	(9)
Total	**$ 551**	$ (295)	**$ 496**	$ (301)
Included in regulatory assets	**$ 261**	$ (181)	**$ 380**	$ (62)
Included in AOCI	**290**	(114)	**116**	(239)
Total	**$ 551**	$ (295)	**$ 496**	$ (301)

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

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2015	2014	**2015**	2014
			(in millions of dollars)	
Net actuarial loss	**$ 2,237**	$ 1,681	**$ 1,146**	$ 644
Prior service cost (credit)	**41**	46	**(29)**	(23)
Total	**$ 2,278**	$ 1,727	**$ 1,117**	$ 621
Included in regulatory assets	**$ 1,147**	$ 886	**$ 777**	$ 397
Included in AOCI	**1,131**	841	**340**	224
Total	**$ 2,278**	$ 1,727	**$ 1,117**	$ 621

The amount of net actuarial loss and prior service cost to be amortized from regulatory assets during the year ended March 31, 2016 for the Pension Plans and PBOP Plans is $419 million and $2 million, respectively.

Reconciliation of Funded Status to Amount Recognized

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2015	2014	**2015**	2014
		(in millions of dollars)		
Change in benefit obligation:				
Benefit obligation as of the beginning of the year	**$ (7,872)**	$ (7,724)	**$ (4,469)**	$ (4,589)
Service cost	**(119)**	(134)	**(62)**	(73)
Interest cost on projected benefit obligation	**(368)**	(355)	**(203)**	(203)
Plan amendments	**(2)**	-	**-**	31
Net actuarial loss	**(998)**	(157)	**(501)**	(103)
Benefits paid	**425**	357	**197**	190
Settlements/curtailments	**-**	141	**-**	304
Other	**-**	-	**(29)**	(26)
Benefit obligation as of the end of the year	**(8,934)**	(7,872)	**(5,067)**	(4,469)
Change in plan assets:				
Fair value of plan assets as of the beginning of the year	**7,052**	6,654	**2,702**	2,302
Actual return on plan assets	**678**	591	**128**	287
Company contributions	**197**	279	**194**	303
Benefits paid	**(425)**	(357)	**(197)**	(190)
Settlements	**-**	(115)	**-**	-
Fair value of plan assets as of the end of the year	**7,502**	7,052	**2,827**	2,702
Funded status	**$ (1,432)**	$ (820)	**$ (2,240)**	$ (1,767)

The benefit obligation shown above is the projected benefit obligation ("PBO") for the Pension Plans and the accumulated benefit obligation ("ABO") for the PBOP Plans. The Company is required to reflect the funded status of its Pension Plans above in terms of the PBO, which is higher than the ABO, because the PBO includes the impact of expected future compensation increases on the pension obligation. The Pension Plans had ABO balances that exceeded the fair value of plans assets as of March 31, 2015 and 2014. The aggregate ABO balances for the Pension Plans were $8.5 billion and $7.4 billion as of March 31, 2015 and 2014, respectively.

Amounts Recognized in the Accompanying Consolidated Balance Sheets

	Pension Plans March 31,		PBOP Plans March 31,	
	2015	2014	**2015**	2014
	(in millions of dollars)			
Non-current assets	**$ 179**	$ 290	**$ 10**	$ 15
Current liabilities	**(23)**	(22)	**(16)**	(16)
Non-current liabilities	**(1,588)**	(1,088)	**(2,234)**	(1,766)
Total	**$ (1,432)**	$ (820)	**$ (2,240)**	$ (1,767)

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2015:

(in millions of dollars) Years Ending March 31,	Pension Plans	PBOP Plans
2016	$ 493	$ 197
2017	505	204
2018	513	211
2019	517	217
2020	521	223
Thereafter	2,683	1,199
Total	$ 5,232	$ 2,251

Assumptions Used for Employee Benefits Accounting

	Pension Plans Years Ended March 31,		PBOP Plans Years Ended March 31,	
	2015	2014	**2015**	2014
Benefit Obligations:				
Discount rate	**4.10%**	4.80%	**4.10%**	4.80%
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	3.50%
Expected return on plan assets	**6.25%**	7.00%	**6.25% - 6.75%**	7.00% - 7.25%
Net Periodic Benefit Costs:				
Discount rate	**4.80%**	4.70%	**4.80%**	4.70%
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	3.50%
Expected return on plan assets	**7.00%**	6.75% - 7.25%	**7.00%-7.25%**	7.25%-7.50%

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.

Mortality assumptions are used to estimate life expectancies of plan participants and the expected period over which they will receive pension benefits. The mortality assumption is composed of a base table that represents the current expectation

of life expectancy of the population and an improvement scale that anticipates future improvements in life expectancy. In October 2014, the Society of Actuaries ("SOA") issued updated mortality tables (RP-2014) and a mortality improvement scale (MP-2014), which reflect longer life expectancies than previously projected.

The Company's pension and PBOP obligations as of March 31, 2015 reflect a change in the underlying mortality assumption consistent with the SOA study. These changes resulted in an increase in the projected benefit obligation of $390 million as of March 31, 2015.

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,	
	2015	2014
Health care cost trend rate assumed for next year		
Pre 65	**8.00%**	8.00%
Post 65	**6.50%**	7.00%
Prescription	**6.50%**	7.00%
Rate to which the cost trend is assumed to decline (ultimate)	**5.00%**	5.00%
Year that rate reaches ultimate trend		
Pre 65	**2022**	2022
Post 65	**2022**	2021
Prescription	**2022**	2021

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

(in millions of dollars)	**March 31, 2015**
1% point increase	
Total of service cost plus interest cost	$ 48
Postretirement benefit obligation	750
1% point decrease	
Total of service cost plus interest cost	(39)
Postretirement benefit obligation	(631)

Plan Assets

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

The target asset allocations for the benefit plans as of March 31, 2015 and 2014 are as follows:

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2015	2014	**2015**	2014
U.S. equities	**20%**	20%	**39%**	39%
Global equities (including U.S.)	**7%**	7%	**6%**	6%
Global tactical asset allocation	**10%**	10%	**9%**	9%
Non-U.S. equities	**10%**	10%	**21%**	21%
Fixed income	**40%**	40%	**25%**	25%
Private equity	**5%**	5%	**0%**	0%
Real estate	**5%**	5%	**0%**	0%
Infrastructure	**3%**	3%	**0%**	0%
	100%	100%	**100%**	100%

Fair Value Measurements

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

	March 31, 2015			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Pension Assets:				
Cash and cash equivalents	$ 19	$ 107	$ -	$ 126
Accounts receivable	138	-	-	138
Accounts payable	(139)	-	-	(139)
Equity	887	1,907	315	3,109
Global tactical asset allocation	-	-	323	323
Fixed income securities	-	3,000	128	3,128
Preferred securities	1	29	-	30
Futures contracts	-	4	-	4
Private equity	-	-	413	413
Real estate	-	77	293	370
Total	$ 906	$ 5,124	$ 1,472	$ 7,502
PBOP Assets:				
Cash and cash equivalents	$ 39	$ 10	$ -	$ 49
Accounts receivable	5	-	-	5
Accounts payable	(1)	-	-	(1)
Equity	428	1,336	116	1,880
Global tactical asset allocation	69	-	132	201
Fixed income securities	2	684	-	686
Private equity	-	-	7	7
Total	$ 542	$ 2,030	$ 255	$ 2,827

	March 31, 2014			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Pension Assets:				
Cash and cash equivalents	$ 5	$ 116	$ 1	$ 122
Accounts receivable	93	-	-	93
Accounts payable	(82)	-	-	(82)
Equity	846	1,796	318	2,960
Global tactical asset allocation	-	244	54	298
Fixed income securities	-	2,890	46	2,936
Preferred securities	2	-	-	2
Futures contracts	4	-	-	4
Private equity	-	-	409	409
Real estate	-	-	310	310
Total	$ 868	$ 5,046	$ 1,138	$ 7,052
PBOP Assets:				
Cash and cash equivalents	$ 49	$ 17	$ -	$ 66
Accounts receivable	6	-	-	6
Accounts payable	(5)	-	-	(5)
Equity	460	1,219	105	1,784
Global tactical asset allocation	72	98	24	194
Fixed income securities	2	647	-	649
Private equity	-	-	8	8
Total	$ 584	$ 1,981	$ 137	$ 2,702

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

Accounts Receivable and Accounts Payable: Accounts receivable and accounts payable are classified in the same category as the investments to which they relate. Such amounts are short-term and settle within a few days of the measurement date.

Equity and Preferred Securities: Common stocks, preferred stocks, and real estate investment trusts are valued using the official close of the primary market on which the individual securities are traded. Equity securities are primarily comprised of securities issued by public companies in domestic and foreign markets plus investments in commingled funds, which are valued on a daily basis. The Company can exchange shares of the publicly traded securities and the fair values are primarily sourced from the closing prices on stock exchanges where there is active trading, in which case they are classified as Level 1 investments. If there is less active trading, then the publicly traded securities would typically be priced using observable data, such as bid and ask prices, and these measurements are classified as Level 2 investments. Investments that are not publicly traded and valued using unobservable inputs are classified as Level 3 investments. Commingled funds with publicly quoted prices and active trading are classified as Level 1 investments. For investments in commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the net asset value ("NAV") per fund share, derived from the underlying securities' quoted prices in active markets, and they are

classified as Level 2 investments. Investments in commingled funds with redemption restrictions and that use NAV are classified as Level 3 investments.

Global Tactical Asset Allocation: Assets held in global tactical asset allocation funds are managed by investment managers who use both top-down and bottom-up valuation methodologies to value asset classes, countries, industrial sectors, and individual securities in order to allocate and invest assets opportunistically. If the inputs used to measure a financial instrument fall within different levels of the fair value hierarchy within the commingled fund, the categorization is based on the lowest level input that is significant to the measurement of that financial instrument. The assets invested through commingled funds are classified as Level 2. Those which are open ended mutual funds with observable pricing are classified as Level 1. However, the underlying Level 3 assets that makeup these funds are classified in the same category as the investments to which they relate.

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. If prices are based on uncorroborated and unobservable inputs, then the investments are classified as Level 3 investments. Commingled funds with publicly quoted prices and active trading are classified as Level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, derived from the underlying securities' quoted prices in active markets, and are classified as Level 2 investments. Investments in commingled funds with redemption restrictions and that use NAV are classified as Level 3.

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. As a result, the Company classifies these investments as Level 3.

While management believes its valuation methodologies are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of Level 3 financial instruments could result in a different fair value measurement at the reporting date.

Changes in Level 3 Plan Investments

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2015	2014	**2015**	2014
	(in millions of dollars)			
Balance as of the beginning of the year	**$ 1,138**	$ 801	**$ 137**	$ 56
Transfers out of Level 3	**(444)**	(16)	**(32)**	(41)
Transfers into Level 3	**457**	282	**50**	102
Actual gain or loss on plan assets:				
Realized gain	**85**	37	**9**	3
Unrealized gain (loss)	**84**	56	**17**	(1)
Purchases	**506**	397	**101**	37
Sales	**(354)**	(419)	**(27)**	(19)
Balance as of the end of the year	**$ 1,472**	$ 1,138	**$ 255**	$ 137

Other Benefits

At March 31, 2015 and 2014, the Company had accrued workers compensation, auto, and general insurance claims which have been incurred but not yet reported of $82.7 million and $83.7 million, respectively.

9. ACCUMULATED OTHER COMPREHENSIVE INCOME

The following table represents the changes in the Company's AOCI for the year ended March 31, 2015:

	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total
	(in millions of dollars)			
Balance as of the beginning of the year	$ 2	$ (652)	$ (2)	$ (652)
Other comprehensive income (loss) before reclassifications:				
Unrecognized net acturial loss (net of $0, $219, and $0 tax benefit, respectively)	-	(313)	-	(313)
Gain on investment (net of $9, $0, and $0 tax expense, respectively)	13	-	-	13
Amounts reclassified from other comprehensive income (loss):				
Amortization of net actuarial loss (net of $0, $52, and $0 tax expense, respectively) [2]	-	75	-	75
Amortization of treasury lock (net of $0, $0, and $1 tax benefit, respectively) [1]	-	-	(1)	(1)
Gain on investment (net of $5, $0, and $0 tax benefit, respectively) [2]	(7)	-	-	(7)
Net current period other comprehensive income (loss)	6	(238)	(1)	(233)
Balance as of the end of the year	$ 8	$ (890)	$ (3)	$ (885)

[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.

10. CAPITALIZATION

European Medium Term Note Program

At March 31, 2015, the Company had a Euro Medium Term Note program (the "Program") under which it is able to issue debt instruments ("Instruments") up to a total of the equivalent of 4 billion Euros. Instruments issued under the Program are admitted to trading on the London Stock Exchange. The Program commenced in December 2007 and is renewed annually, with the latest renewal of the Program expiring in December 2015. If the Program is not renewed in December 2015, it would preclude the issuance of new notes under this Program, but it would not impact the outstanding debt balances and their maturity dates. Instruments carry certain affirmative and negative covenants, including a restriction on the Company's ability to mortgage, pledge, charge or otherwise encumber its assets in order to secure, guarantee or indemnify other listed or quoted debt obligations, as well as cross-acceleration in the event of breach by the Company or its principal subsidiaries of other listed or quoted debt obligations. At March 31, 2015 and 2014, the Company was in compliance with all covenants. At March 31, 2015 and 2014, $588 million and $842 million, respectively, of these notes were issued and outstanding, excluding the impact of interest rate and currency swaps.

Notes Payable

At March 31, 2015 and 2014 the Company had outstanding $6.3 billion and $5.9 billion, respectively, of unsecured medium and long-term notes. In September 2014, Niagara Mohawk issued $500 million of unsecured long-term debt at 3.508% with a maturity date of October 1, 2024 and $400 million of unsecured long-term debt at 4.278% with a maturity date of October 1, 2034. The interest rates on the unsecured notes range from 2.721% to 9.750% and maturity dates range from October 2015 through December 2042.

Gas Facilities Revenue Bonds

Brooklyn Union has outstanding tax-exempt Gas Facilities Revenue Bonds ("GFRB") issued through the New York State Energy Research and Development Authority ("NYSERDA"). There are no sinking fund requirements for any of Brooklyn Union's GFRB. At March 31, 2015 and 2014, $641 million of GFRB were outstanding; $230 million of which are variable-rate, auction rate bonds. The interest rate on the various variable rate series due starting December 1, 2020 through July 1, 2026 is reset weekly and ranged from 0.07% to 0.44% during the year ended March 31, 2015 and 0.07% to 0.51% during the year ended March 31, 2014. The GFRB are currently in auction rate mode and are backed by bond insurance. These bonds cannot be put back to Brooklyn Union and, in the case of a failed auction, the resulting interest rate on the bonds would revert to the maximum rate which depends on the current appropriate, short-term benchmark rates and the senior unsecured rating of the Brooklyn Union's bonds. The effect of the failed auctions on interest expense was not material for the years ended March 31, 2015 or 2014.

Promissory Notes to LIPA

KeySpan Corporation had previously issued $155 million of promissory notes to LIPA to support certain debt obligations assumed by LIPA. Following the expiration of the MSA on December 31, 2013, the debt was fully extinguished (refer to Note 18, "Discontinued Operations").

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 $50 million, respectively, of non-callable First Mortgage Bonds ("FMB"). These FMB indentures include, among other provisions, limitations on the issuance of long-term debt. Interest rates range from 6.82% to 9.63% and maturity dates range from April 2018 to April 2028.

State Authority Financing Bonds

At March 31, 2015, the Company had outstanding $1 billion of State Authority Financing Bonds. Of the $1 billion outstanding at March 31, 2015, approximately $571 million of these bonds were issued through NYSERDA and the remaining $462 million were issued through various other state agencies.

Approximately $605 million of State Authority Financing Bonds were issued to secure a like amount of tax-exempt revenue bonds issued by NYSERDA. Approximately $430 million of such securities bear interest at short-term adjustable interest rates (with an option to convert to other rates, including a fixed interest rate) ranging from 0.37% to 0.45% for the year ended March 31, 2015. The bonds are currently in auction rate mode and are backed by bond insurance. These bonds cannot be put back to the Company and, in the case of a failed auction, the resulting interest rate on the bonds would revert to the maximum rate which depends on the current appropriate, short-term benchmark rate and the senior secured rating of the Company or the bond insurer, whichever is greater. The effect on interest expense has not been material in either of the years ended March 31, 2015 or 2014.

The Company also has $75 million of 5.15% fixed rate pollution control revenue bonds issued through NYSERDA which are callable at par. Pursuant to agreements between NYSERDA and the Company, proceeds from such issues were used for the purpose of financing the construction of certain pollution control facilities at the Company's generation facilities (which the Company subsequently sold) or to refund outstanding tax-exempt bonds and notes.

Additionally, the Company has $41 million of 1999 Series A Pollution Control Revenue Bonds due October 1, 2028. The interest rate ranged from 0.10% to 1.44% for the year ended March 31, 2015, at which time the rate was 0.90%. The interest rate ranged from 0.15% to 1.35% for the year ended March 31, 2014, at which time the rate was 0.61%. Interest expense related to these notes for each of the years ended March 31, 2015 and 2014 was approximately $0.4 million.

The Company also has outstanding $25 million variable rate 1997 Series A Electric Facilities Revenue Bonds due December 1, 2027. The interest rate on these bonds is reset weekly and ranged from 0.13% to 0.28% and from 0.04% to 0.25% during the years ended March 31, 2015 and 2014, respectively. The interest rate was 0.13% and 0.25% at March 31, 2015 and 2014, respectively. Interest expense related to these notes for each of the years ended March 31, 2015 and 2014 was approximately $0.1 million.

At March 31, 2015, the Company had outstanding $410 million of the Pollution Control Revenue Bonds in tax exempt commercial paper mode with maturity dates ranging from October 2015 to October 2022 and variable interest ranging from 0.07% to 0.46% for the year ended March 31, 2015. In addition, at March 31, 2015, the Company had $52 million of tax exempt Electric Revenue Bonds in commercial paper mode with varying maturity dates from March 2016 through August 2042 and variable interest rates ranging from 0.06% to 0.38% during the year ended March 31, 2015. The bonds were issued by the Massachusetts Development Finance Agency in connection with the Company's financing of its first and second underground and submarine cable projects. Sinking fund payments of $0.3 million were made during the year ended March 31, 2015.

At March 31, 2012, three of the Company's subsidiaries had a Standby Bond Purchase Agreement ("SBPA") totaling $500 million, which expires on November 20, 2015. In November 2014, the SBPA agreement was renewed and is due to expire on November 20, 2019. This agreement was available to provide liquidity support for $463 million of the Company's long-term bonds in tax-exempt commercial paper mode. The Company has classified this 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. The Company, together with other affiliates of the Parent, has rights to issue debt under an $850 million syndicated revolving credit facility which can be drawn upon at any time until its maturity in November 2015 and may be used, if needed, to refinance the tax-exempt commercial paper on a long-term basis. This facility has a number of financial and non-financial covenants which the Company is obliged to meet. At March 31, 2015 and 2014, the Company was in compliance with all covenants.

Industrial Development Revenue Bonds

At March 31, 2015 and 2014, Genco had outstanding $128 million of 5.25% tax-exempt bonds due June 1, 2027. Of this amount, $53 million was issued through the Nassau County Industrial Development Authority for the construction of the Glenwood electric-generation peaking plant and the balance of $75 million was issued by the Suffolk County Industrial Development Authority for the Port Jefferson electric-generation peaking plant. KeySpan Corporation has fully and unconditionally guaranteed the payment obligations with regard to these tax-exempt bonds.

Committed Facility Agreements

At March 31, 2015, the Company, NGNA, and the Parent have a committed revolving credit facility of $850 million which matures in November 2015. This facility has not been drawn against. The Company, NGNA, and the Parent can all draw on this facility in a variety of currencies as needed, but the aggregate borrowings across the group cannot exceed the $850 million limit. The terms of the facility restrict the borrowing of all U.S. subsidiaries of the Company to $18 billion excluding intercompany indebtedness. Additionally, this facility has a number of non-financial covenants which the Company is obliged to meet. At March 31, 2015 and 2014, NGNA and the Parent were in compliance with all covenants.

The Company and the Parent have two additional committed revolving credit facilities of $280 million and £155 million which mature in July 2017. These facilities have not been drawn against. The Company and the Parent can draw on these facilities in a variety of currencies as needed, but the aggregate borrowings across the group cannot exceed the $280 million and £155 million limit, respectively. The terms of the facilities restrict the borrowing of all U.S. subsidiaries of the Company to $18 billion excluding intercompany indebtedness. Additionally, these facilities have a number of non-financial covenants which NGNA and the Parent were obliged to meet. At March 31, 2015 and 2014, the Company was in compliance with all covenants.

On May 29, 2015, new facilities totaling £1.7 billion were signed, replacing the committed facilities of $850 million and $280 million and part of the £155 million facility. The £155 million facility was reduced to £30 million.

Debt Maturities

The aggregate maturities of long-term debt for the years subsequent to March 31, 2015 are as follows:

(in millions of dollars) Years Ending March 31,		
2016	$	638
2017		511
2018		89
2019		36
2020		1,008
Thereafter		6,571
Total	$	8,853

The Company is obligated to meet certain financial and non-financial covenants. 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, 2015 and 2014, the Company was in compliance with all such covenants and restrictions.

Some of the Company's State Authority Financing Bonds, First Mortgage Bonds, and Notes Payable have sinking fund requirements which totaled $1 million and $7 million during the years ended March 31, 2015 and 2014, respectively. The following table reflects the sinking fund repayment requirements for the years subsequent to March 31, 2015:

(in millions of dollars) Years Ending March 31,	
2016	$ 2
2017	1
2018	1
2019	1
2020	1
Thereafter	8
Total	$ 14

Commercial Paper and Revolving Credit Agreements

At March 31, 2015, the Company had two commercial paper programs totaling $4 billion; a $2 billion U.S. commercial paper program and a $2 billion Euro commercial paper program. In support of these programs, the Company was a named borrower under National Grid plc credit facilities with $1.4 billion available to the Company. These facilities support both the Parent's and the Company's commercial paper programs for ongoing working capital needs. The facilities expire in 2015 to 2017. At March 31, 2015 and 2014, there were $486 million and $421 million of borrowings outstanding on the U.S. commercial paper program and $96 million outstanding on the Euro commercial paper program.

The credit facilities allow both the Parent and the Company to borrow in multi-currencies. The current annual commitment fees range from 0.20% to 0.21%. If for any reason the Company were not able to issue sufficient commercial paper or source funds from other sources, the facilities could be drawn upon to meet cash requirements. The facilities contain certain affirmative and negative operating covenants, including restrictions on the Company's utility subsidiaries' ability to mortgage, pledge, encumber or otherwise subject their utility property to any lien, as well as financial covenants that require the Company and the Parent to limit the total indebtedness in U.S. and non-U.S. subsidiaries to pre-defined limits. Violation of these covenants could result in the termination of the facilities and the required repayment of amounts borrowed thereunder, as well as possible cross defaults under other debt agreements. At March 31, 2015 and 2014, the Company was in compliance with all covenants.

11. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,	
	2015	2014
	(in millions of dollars)	
Current tax expense (benefit):		
Federal	**$ (61)**	$ (18)
State	**53**	40
Total current tax (benefit) expense	**(8)**	22
Deferred tax expense (benefit):		
Federal	**229**	254
State	**(15)**	6
Total deferred tax expense	**214**	260
Amortized investment tax credits [1]	**(5)**	(5)
Total deferred tax expense	**209**	255
Total income tax expense	**$ 201**	$ 277

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

Statutory Rate Reconciliation

The Company's effective tax rates for the years ended March 31, 2015 and 2014 are 32.4% and 36.3%, respectively. The following table presents a reconciliation of income tax expense at the federal statutory tax rate of 35% to the actual tax expense:

	Years Ended March 31,	
	2015	2014
	(in millions of dollars)	
Computed tax	**$ 217**	$ 267
Change in computed taxes resulting from:		
Audit and related reserve movements	**(20)**	6
Investment tax credits	**(5)**	(5)
State income tax, net of federal benefit	**25**	30
Other items, net	**(16)**	(21)
Total	**(16)**	10
Federal and state income taxes	**$ 201**	$ 277

The Company is included in the NGNA and subsidiaries consolidated federal income tax return. The Company has joint and several liability for any potential assessments against the consolidated group. The Company also files unitary, combined, and separate state income tax returns.

In September 2013, the U.S. Department of the Treasury issued final tangible property regulations which provide guidance for the application of IRC §162(a) and IRC §263(a) to amounts paid to acquire, produce, or improve tangible property. In August 2014, the U.S. Department of the Treasury also finalized the depreciable property disposition regulations. Both sets of regulations become effective for tax years beginning on or after January 1, 2014, which, for the Company, is the fiscal year ended March 31, 2015. The Company intends to adopt these regulations with its fiscal year 2015 federal tax return and has estimated a favorable §481(a) adjustment of $122 million related to dispositions of depreciable property and an unfavorable §481(a) adjustment of $74 million related to repairs deduction following casualty loss.

On July 24, 2013, the Massachusetts legislature enacted into law transportation finance legislation which included significant tax changes affecting the classification of utility corporations. For tax years beginning on or after January 1, 2014, Massachusetts utility corporations will be taxed in the same manner as general business corporations. The state income tax rate increased from 6.5% to 8%. Also, any unitary net operating loss generated post-2013 and allocated to the utilities will be allowed as a carryforward tax attribute. As of March 31, 2014, all Massachusetts state deferred tax balances at the regulated utilities were remeasured to the 8% rate, resulting in an increase in deferred tax liabilities of $47 million with an offset to the regulatory deferred tax asset.

On March 31, 2014, New York's legislature enacted, as part of the 2014-15 budget package, legislation which included significant tax changes. For tax years beginning on or after January 1, 2016, the New York corporate franchise rate is reduced from 7.1% to 6.5%. Additionally, for tax years beginning on or after January 1, 2015, New York state will generally require combined reporting if the taxpayer is engaged in a unitary business and a 50% common ownership test is met. As of March 31, 2014, the Company remeasured its New York state deferred tax assets and liabilities based upon the enacted law that will apply when the corresponding state temporary differences are expected to be realized or settled. Specifically to reflect the decrease in tax rate, the Company decreased its New York state deferred tax liability by $24.5 million with an offset of $27.6 million to regulatory liabilities and $3.1 million to income tax expense. During the year ended March 31, 2015, the Company updated the impact of the tax rate change and adjusted its New York state deferred tax liability by $2.7 million with an offset of $0.9 million to regulatory liabilities and $3.6 million to income tax expense.

Deferred Tax Components

	March 31,	
	2015	2014
	(in millions of dollars)	
Deferred tax assets:		
Environmental remediation costs	**$ 587**	$ 563
Future federal benefit on state taxes	**166**	176
Net operating losses	**555**	242
Postretirement benefits and other employee benefits	**1,738**	1,514
Regulatory liabilities - other	**531**	326
Other items	**410**	210
Total deferred tax assets [1]	**3,987**	3,031
Deferred tax liabilities:		
Property related differences	**6,208**	5,615
Regulatory assets - environmental response costs	**713**	681
Regulatory assets - postretirement benefits	**729**	722
Regulatory assets - other	**648**	432
Other items	**304**	223
Total deferred tax liabilities	**8,602**	7,673
Net deferred income tax liabilities	**4,615**	4,642
Deferred investment tax credits	**35**	37
Net deferred income tax liabilities and investment tax credits	**4,650**	4,679
Current portion of deferred income tax assets, net	**(242)**	(171)
Deferred income tax liabilities, net	**$ 4,892**	$ 4,850

(1) There were no valuation allowances for deferred tax assets at March 31, 2015 or 2014.

The following table presents the amounts and expiration dates of net operating losses as of March 31, 2015:

Expiration of net operating losses:	Federal	State of Massachusetts
	(in millions of dollars)	
3/31/2029	$ 198	$ -
3/31/2030	78	-
3/31/2032	114	-
3/31/2033	535	-
3/31/2034	573	-
3/31/2035	444	435

Expiration of state and city net operating losses:	State of New York	City of New York
	(in millions of dollars)	
3/31/2035	$ 1,185	$ 282

Unrecognized Tax Benefits

As of March 31, 2015 and 2014, the Company's unrecognized tax benefits totaled $522 million and $510 million, respectively, of which $57.6 million and $54.2 million, respectively, would affect the effective tax rate, if recognized. The unrecognized tax benefits are included in other non-current liabilities in the accompanying consolidated balance sheets.

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

	Years Ended March 31,	
	2015	2014
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 510**	$ 662
Gross increases - tax positions in prior periods	**15**	52
Gross decreases - tax positions in prior periods	**(45)**	(63)
Gross increases - current period tax positions	**47**	53
Gross decreases - current period tax positions	**-**	-
Settlements with tax authorities	**(5)**	(194)
Balance as of the end of the year	**$ 522**	$ 510

As of March 31, 2015 and 2014, the Company has accrued for interest related to unrecognized tax benefits of $43.5 million and $55.3 million, respectively. During the years ended March 31, 2015 and 2014, the Company recorded interest expense of $10.5 million and $12.4 million, respectively. The Company recognizes interest related to unrecognized tax benefits in other interest, including affiliate interest and related penalties, if applicable, in other deductions, net, in the accompanying consolidated statements of income. No tax penalties were recognized during the years ended March 31, 2015 or 2014.

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.

During the year ended March 31, 2014, the IRS concluded its examination of the NGNA consolidated filing group's corporate income tax returns, which includes corporate income tax returns of KeySpan Corporation and subsidiaries for the short period ended August 24, 2007, and of NGNA and subsidiaries for the periods ended March 31, 2008 and 2009. These examinations were completed on March 27, 2014 and March 31, 2014, respectively, with an agreement on the majority of income tax issues for the years referenced above, as well as an acknowledgment that certain discrete items remain disputed. NGNA is in the process of appealing these disputed issues with the IRS Office of Appeals. The Company does not anticipate a change in its unrecognized tax positions in the next twelve months as a result of the appeals. However, pursuant to the Company's tax sharing agreement, the audit or appeals may result in a change to allocated tax. The tax returns for the years ended March 31, 2010 through March 31, 2015 remain subject to examination by the IRS.

The Company is a member of the NGUSA Service Company Massachusetts unitary group since the fiscal year ended March 31, 2010. The tax returns for the fiscal years ended March 31, 2010 through March 31, 2015 remain subject to examination by the state of Massachusetts.

The Company is in the process of appealing certain adjustments made by the Massachusetts Department of Revenue ("MADOR") for the years ended March 31, 2001 through March 31, 2005. The Company is currently under audit by the MADOR for the years ended March 31, 2006 through March 31, 2008.

The state of New York is in the process of examining the Company's New York state income tax returns for KeySpan Gas East for the period January 1, 2003 through March 31, 2008 and for Brooklyn Union for the period January 1, 2007 through March 31, 2008. The tax returns for the years ended March 31, 2009 through March 31, 2015 remain subject to examination by the state of New York.

New York state and New York City are in the process of an examining the returns of KeySpan Corporation and subsidiaries for the period January 1, 2003 through March 31, 2008 and January 1, 2003 through December 31, 2005, respectively.

During the year ended March 31, 2015, the state of New York concluded its examination of the Niagara Mohawk Holdings Inc. and subsidiaries combined returns for the years ended March 31, 2006 through March 31, 2008. The examination did not result in adjustments to the Company's taxable income. The tax returns for the years ended March 31, 2009 through March 31, 2015 remain subject to examination by the state of New York.

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

Jurisdiction	Tax Year
Federal	August 24, 2007 *
Massachusetts	March 31, 2003 *
New York	December 31, 2003
New York City	December 31, 2003
New Hampshire	March 31, 2009

* The KeySpan consolidated filing group for the tax year ended August 24, 2007 and the NGNA consolidated filing group for the fiscal years ended March 31, 2008 and 2009, are in the process of appealing certain disputed issues with the IRS Office of Appeals. The Company is also in the process of appealing certain disputed issues with the Massachusetts Department of Revenue for the years ended March 31, 2003 through March 31, 2005.

12. GOODWILL

The following table represents the changes in the carrying amount of goodwill for the years ended March 31, 2015 and 2014:

	Years Ended March 31,	
	2015	2014
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 7,151**	$ 7,151
Impairment in Clean Line	**(22)**	-
Balance as of the end of the year	**$ 7,129**	$ 7,151

In January 2013, the Company made an investment in Clean Line. Clean Line is a development-stage entity engaged in the development of long distance, high voltage direct current transmission lines that connect wind farms and other renewable resources in remote parts of the U.S. with electric demand. The Company initially committed to a $40 million investment in Clean Line, of which the Company contributed $12.5 million during the year ended March 31, 2013 and contributed the remaining $27.5 million during the year ended March 31, 2014. Based on an analysis of the contractual terms and rights contained in the related agreements, the Company determined that under the applicable accounting standards, Clean Line is a variable interest entity and the Company has effective control over the entity. Therefore, as the primary beneficiary, the Company has consolidated Clean Line. Upon consolidation, the Company recognized approximately $20 million of goodwill.

The fair value of the Clean Line reporting unit was calculated in the annual goodwill impairment test for the year ended March 31, 2015 solely utilizing the income approach. Due to the fact that Clean Line is only at the development stage of its life cycle, its discounted cash flow model has been prepared using specific assumptions, rather than the general assumptions used in relation to National Grid's longstanding operating companies as discussed in Note 2, "Summary of Significant Accounting Policies" under "Goodwill." The annual impairment test yielded a negative implied fair value of goodwill for the Clean Line reporting unit, and an impairment of $22 million has been recognized for the year ended March 31, 2015.

13. 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 New York State 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. Recently completed 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 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 power plants will likely be required by the DEC at each of the Long Island power plants pursuant to Section 316 of the Clean Water Act to mitigate the plants' alleged cooling water system impacts to aquatic organisms. Genco is currently engaged in discussions with the DEC and environmental groups regarding the nature of capital upgrades or other mitigation measures necessary to reduce any impacts. Although these discussions have been productive and have led to mutually agreeable final permits at some of the plants, it is possible that the determination of required capital improvements and the issuance of final renewal permits for the remaining plants could involve adjudicatory hearings among Genco, the agency, and the environmental groups. Capital costs for expected mitigation requirements at the plants had been estimated at approximately $76 million and do not anticipate a need for cooling towers at any of the plants. Depending on the outcome of the adjudicatory process, which could extend beyond the next fiscal year, ultimate costs could be substantially higher. Costs associated with any finally ordered capital improvements would be 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 a remediation at this location pursuant to Administrative Order on Consent ("ACO") with the DEC. KeySpan intends to contest these proceedings vigorously.

On February 8, 2007, the Company received a Notice of Intent to File Suit from the AG against KeySpan and four other companies in connection with the cleanup of historical contamination found in certain lands located in Greenpoint, Brooklyn and in an adjoining waterway. KeySpan has previously agreed to remediate portions of the properties referenced in this notice and will work cooperatively with the DEC and AG to address environmental conditions associated with the remainder of the properties. KeySpan has entered into an ACO with the DEC for the land-based sites. The EPA assumed control of the waterway and, on September 29, 2010, listed this site on its National Priorities List of Superfund sites. The Company signed a consent decree with the EPA on July 7, 2011 and is currently performing a Remedial Investigation and Feasibility Study. At this time, the Company is unable to predict what effect, if any, the outcome of these proceedings will have on its consolidated financial position, results of operations, and cash flows.

Utility Sites

At March 31, 2015, the Company's total reserve for estimated MGP-related environmental matters is $1.3 billion. The potential high end of the range at March 31, 2015 is presently estimated at $2.1 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 regulatory asset of $1.7 billion on the consolidated balance sheets at March 31, 2015 and 2014.

Upon the acquisition of KeySpan by NGUSA, the Company recognized those environmental liabilities at fair value. The fair values included discounting of the reserve, which is being accreted over the period for which remediation is expected to occur. Following the acquisition, these environmental liabilities are recognized in accordance with the current accounting guidance for environmental obligations.

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 were approximately $1 million and $2 million for the years ended March 31, 2015 and 2014, respectively. The Company presently estimates the remaining cost of the environmental cleanup activities for these non-utility sites will be approximately $26 million and $24 million, which has been accrued at March 31, 2015 and 2014, respectively. The Company's environmental obligation is net of a discount rate of 6.5%, and the undiscounted amount totaled $32 million and $29 million in liabilities as of March 31, 2015 and 2014, 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 noted, depending upon 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.

14. 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 $97 million and $121 million for the years ended March 31, 2015 and 2014, respectively.

The future minimum lease payments for the years subsequent to March 31, 2015 are as follows:

(in millions of dollars)	
Years Ending March 31,	
2016	$ 98
2017	98
2018	98
2019	84
2020	58
Thereafter	363
Total	$ 799

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. The Company's gas distribution subsidiaries are liable for these payments regardless of the level of services required from third-parties. Such charges are currently recovered from customers as gas costs. 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, 2015 are summarized in the table below:

(in millions of dollars) Years Ending March 31,	Energy Purchases	Capital Expenditures
2016	$ 1,801	$ 407
2017	898	60
2018	666	60
2019	502	45
2020	420	30
Thereafter	2,070	-
Total	$ 6,357	$ 602

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

Financial Guarantees

The Company has guaranteed the principal and interest payments on certain outstanding debt of its subsidiaries. Additionally, the Company has issued financial guarantees in the normal course of business, on behalf of its subsidiaries, to various third-party creditors. At March 31, 2015, 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
Industrial Development Revenue Bonds	(i)	$ 128	June 2027
KeySpan Ravenswood LLC Lease	(ii)	350	May 2040
Reservoir Woods	(iii)	212	October 2029
Surety Bonds	(iv)	218	Revolving
Commodity Guarantees and Other	(v)	95	October 2015 - August 2042
Letters of Credit	(vi)	198	July 2015 - February 2016
NY Transco Parent Guaranty	(vii)	842	None
		$ 2,043	

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

(i) KeySpan has fully and unconditionally guaranteed the payment obligations of its subsidiaries with regard to $128 million of Industrial Development Revenue Bonds issued through the Nassau County and Suffolk County Industrial Development Authorities for the construction of two electric-generation peaking plants on Long Island, New York. The face value of these notes is included in long-term debt in the accompanying consolidated balance sheets.

(ii) 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, 2015, the Company's obligation related to the lease was $151 million and is reflected in other non-current liabilities in the accompanying consolidated balance sheets.

(iii) The Company has fully and unconditionally guaranteed $229 million in lease payments through 2029 related to the lease of office facilities by its service company at Reservoir Woods in Waltham, Massachusetts.

(iv) 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.

(v) The Company has guaranteed commodity-related payments for certain subsidiaries. These guarantees are provided to third-parties to facilitate physical and financial transactions involved in the purchase and transportation of natural gas, oil and other petroleum products for gas and electric production and marketing activities. The guarantees cover actual purchases by these subsidiaries that are still outstanding as of March 31, 2015.

(vi) 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.

(vii) 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 LLC Agreement.

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

Town of Johnston Project

In June 2010, pursuant to a 2009 Rhode Island law that required Narragansett to negotiate a contract for an electric generating project fueled by landfill gas from the Rhode Island Central Landfill Narragansett entered into a contract with Rhode Island LFG Genco for the Town of Johnston Project, a combined cycle power plant with an average output of 32 megawatts ("MW"). The facility reached commercial operation on May 28, 2013 and is being accounted for as an operating lease.

Deepwater Agreement

The 2009 Rhode Island law also required Narragansett to solicit proposals for a small scale renewable energy generation project of up to eight wind turbines with an aggregate nameplate capacity of up to 30 MW to benefit the Town of New Shoreham. The renewable energy generation project also included a transmission cable to be constructed between Block Island and the mainland of Rhode Island. On June 30, 2010, Narragansett entered into a 20-year Amended Power Purchase Agreement ("PPA") with Deepwater Wind Block Island LLC, which was approved by the RIPUC in August 2010. 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, Narragansett filed with the FERC to recover the costs associated with the cable in transmission rates. On September 2, 2014, the FERC approved all four agreements required to implement NGUSA's cost recovery for the project, with no conditions. The agreements went into effect on September 30, 2014. On January 30, 2015, Narragansett closed on its purchase of the Transmission Facilities from Deepwater.

The Renewable Energy Growth Program

The Renewable Energy ("RE") Growth Program was established pursuant to Chapter 26.6 of Title 39 of the Rhode Island General Laws under the recently-enacted Clean Energy Jobs Program Act (the "Act") to encourage growth of renewable generation in Rhode Island by 160 MW. Pursuant to the Act, Narragansett is required to purchase the output generated by eligible Distributed Generation projects that have been selected for participation in the RE Growth Program and to compensate program applicants in the form of Performance Based Incentive ("PBI") Payments. Participants will be subject to the terms and conditions of the RE Growth Program tariffs approved by the RIPUC and will be compensated via PBI Payments pursuant to those tariffs, which will be in effect for up to 20 years. The Act provides for the recovery of the incremental costs incurred by Narragansett associated with the implementation and administration of the RE Growth Program from all retail delivery service customers through a fixed monthly charge per customer. Costs eligible for recovery include the PBI Payments less the net proceeds from the sale of the energy and the RE Certificates generated by each project into the market, plus all incremental administrative costs. In addition, the Act authorizes Narragansett to earn 1.75% of the total PBI Payments as remuneration.

Legal Matters

The Company is subject to various legal proceedings, primarily injury claims, 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.

FERC ROE Complaints

On September 30, 2011, several state and municipal parties in New England, ("Complainants"), filed a complaint against certain New England Transmission Owners, ("NETOs") including NEP, to lower the base ROE for transmission rates in New England from 11.14% to 9.2 %. On August 6, 2013, a FERC Administrative Law Judge ("ALJ") issued an Initial Decision finding that the base ROE for the refund period and the prospective period should be 10.6% and 9.7%, respectively, prior to any

adjustments in a final FERC order. The refund period is the 15-month period from October 1, 2011 through December 31, 2012; the prospective period begins when the FERC issues its final order. In response to the ALJ's Initial Decision, NEP recorded an estimated reduction to revenues of $7.1 million and an increase to interest expense of $0.2 million for the fiscal year ended March 31, 2013, reflecting an effective ROE of 10.6% for the portion that would be refunded to transmission customers for the refund period. On June 19, 2014, the FERC issued Opinion No. 531, an initial order modifying the ALJ's findings and its previous methodology for establishing ROE. The FERC tentatively set the ROE at 10.57% and capped the ROE for incentive rates of return to 11.74% subject to further proceedings to establish and quantify growth rates applicable to the ROE. In response, NEP recorded an additional reduction to revenues of $1.2 million and an increase of $0.2 million to interest expense for the fiscal year ended March 31, 2014.

On October 16, 2014, the FERC issued a final order in Opinion No. 531-A establishing a 10.57% base ROE for the NETOs effective as of October 16, 2014 and capped the ROE, including incentives, at 11.74%. The FERC also directed that refunds be issued to transmission customers taking service during the 15-month refund period from October 1, 2011 through December 31, 2012 to reflect these reductions. On March 3, 2015, the FERC issued an Order on Rehearing, Opinion No. 531-B, affirming the 10.57% base ROE and clarifying that the 11.74% maximum ROE applies to all individual transmission projects with ROE incentives previously granted by the FERC. A further compliance filing will be submitted to the FERC shortly to clarify the applications of the 11.74% ROE cap.

On December 27, 2012, a second ROE complaint was filed against the NETOs by a coalition of consumers seeking to lower the base ROE for New England transmission rates to 8.7% effective as of December 27, 2012. On June 19, 2014, the FERC issued an order setting the complaint for investigation and a trial-type, evidentiary hearing. The FERC stated that it expects parties to present evidence and any discounted cash flow analyses, as guided by the rulings found in FERC's June 19 order on the first complaint. The FERC's order also established a 15-month refund period for the second complaint beginning on December 27, 2012. In its order setting the complaint for hearing, the FERC noted that, if the case is fully litigated, the FERC expects to issue its final decision no earlier than April 30, 2016.

On July 31, 2014, a third ROE Complaint was filed against the NETOs by the Complainants. The FERC has not yet acted on this complaint.

Electric Services and LIPA Agreements

Effective May 28, 2013, Genco provides services to LIPA under an amended and restated PSA. Under the PSA, Genco has a revenue requirement of $418.6 million, a ROE of 9.75% and a capital structure of 50% debt and 50% equity. The 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 PSA as an operating lease.

The 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 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 the Company 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 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. A monthly variable maintenance charge is billed for each unit of energy actually acquired from the generating facilities. The billings to LIPA under the PSA do not include a provision for fuel costs, as such fuel is owned by LIPA.

In June 2011, LIPA and Genco executed an amendment to the then-current PSA pursuant to which the parties agreed that LIPA would reduce purchases of capacity from specified generating facilities, specifically the Glenwood and Far Rockaway, New York steam facilities. The Company has retired these generating facilities and removed them from the PSA and is in the process of dismantling these facilities. As part of this amendment, Genco paid an Economic Equivalent Payment ("EEP") of

$18 million which represented the economic benefit to LIPA which would have been realized under the original agreement. Half of the EEP was paid on July 3, 2012, with the remaining balance on May 28, 2013. The EEP was accrued on a straight-line basis over the 24-month term, from June 2011 through May 2013, as a reduction in operating revenues.

Pursuant to the EMA, the Company procured and managed fuel supplies for LIPA to fuel the Company's Long Island based generating facilities. In exchange for these services, the Company earned an annual fee of $750,000. The EMA expired on May 28, 2013. LIPA did not renew the EMA contract with the Company.

Decommissioning Nuclear Units

NEP has minority interests in three nuclear generating companies: Yankee Atomic Electric Company ("Yankee Atomic"), Connecticut Yankee Atomic Power Company ("Connecticut Yankee"), and Maine Yankee Atomic Power Company ("Maine Yankee") (together, the "Yankees"). These ownership interests are accounted for on the equity method. The Yankees operated nuclear generating units which have been permanently shut down and physically decommissioned. Spent nuclear fuel remains on each site, awaiting fulfillment by the DOE of its statutory and contractual obligation to remove it. Future estimated billings, which are included in other non-current liabilities and other current liabilities in the accompanying consolidated balance sheets, are as follows:

(in thousands of dollars)	NEP's Investment as of March 31, 2015			Future Estimated Billings to the Company
Unit	%	Amount	Date Retired	Amount
Yankee Atomic	34.5	$ 520	Feb 1992	$ 3,685
Connecticut Yankee	19.5	317	Dec 1996	14,921
Maine Yankee	24.0	593	Aug 1997	7,913

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 liability and a regulatory asset reflecting the estimated future decommissioning billings from the Yankees.

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

Each of the Yankees brought litigation against the DOE for failure to remove their respective nuclear fuel stores as required by the Nuclear Waste Policy Act and contracts. Following a trial at the U.S. Court of Claims ("Claims Court") to determine the level of damages, on October 4, 2006, the Claims Court awarded the three companies an aggregate of $143 million for spent fuel storage costs that had been incurred through 2001 and 2002 (the "Phase I Litigation"). The Yankees had requested $176.3 million. The DOE appealed to the U.S. Court of Appeals for the Federal Circuit, which rendered an opinion generally supporting the Claims Court's decision and remanded the matter to it for further proceedings. In September, 2010, the Claims Court again awarded the companies an aggregate of approximately $143 million. The DOE again appealed and the Yankees cross-appealed. On May 18, 2012, the Court of Appeals again ruled in favor of the Yankees, awarding them an aggregate of approximately $160 million. The DOE sought reconsideration but, on September 5, 2012, the Court of Appeals for the Federal Circuit denied the petition for rehearing. The DOE elected not to file a petition for writ of certiorari seeking review by the U.S. Supreme Court and in January 2013 the awards were paid to the Yankees. As of March 31, 2015, total net proceeds of $20.9 million have been refunded to NEP by Connecticut Yankee and Maine Yankee. Yankee Atomic

did not provide a refund, but reduced monthly billing effective June 1, 2013. The Company will refund its share to its customers through the CTCs.

On December 14, 2007, the Yankees brought further litigation in the Claims Court to recover subsequent damages incurred through 2008 (the "Phase II Litigation"). A Claims Court trial took place in October 2011. On November 1, 2013, the judge awarded the Yankees an aggregate of $235.4 million in damages for the Phase II Litigation. The DOE elected not to seek appellate review and the awards were paid to the Yankees. As of March 31, 2015 total net proceeds of $57.9 million have been refunded to the Company by the Yankees. The Company will refund its share of the net proceeds to its customers through the CTCs.

On August 15, 2013 the Yankees brought further litigation in the Claims Court to recover damages incurred from 2009 through 2012.

The U.S. Congress and the DOE have effectively terminated budgetary support for the proposed long-term spent fuel storage facility at Yucca Mountain in Nevada and the DOE took actions designed to prevent its construction. However, on August 12, 2013 the U.S. Court of Appeals for the District of Columbia Circuit directed the Nuclear Regulatory Commission ("NRC") to resume the Yucca Mountain licensing process despite insufficient funding to complete it. On October 28, 2013, the Circuit Court denied the NRC's petition for rehearing. On November 18, 2013, NRC ordered its staff to resume work on its Yucca Mountain safety report. A Blue Ribbon Commission ("BRC") charged with advising the DOE regarding alternatives to disposal at Yucca Mountain issued its final report on January 26, 2012. In the report, the BRC recommended that priority be given to removal of spent fuel from shutdown reactor sites. 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, 2015 and 2014, Niagara Mohawk had a liability of $168 million, recorded in other non-current liabilities in the accompanying consolidated balance sheets, 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. Niagara Mohawk cannot predict the impact that the recent actions of the DOE and the U.S. government will have on the ability to dispose of the spent nuclear fuel and waste.

SuperStorm Sandy

In October 2012, SuperStorm Sandy hit the northeastern U.S. affecting energy supply to customers in the Company's service territory. Total costs associated with gas customer service restoration from this storm (including capital expenditures) through March 31, 2014 were approximately $204.1 million for the New York Gas Companies.

The Company had recorded an "other receivable" in the accompanying consolidated balance sheets in the amount of $58 million as of March 31, 2014, relating to claims filed against its property damage insurance policy, net of insurance deductibles, allowances, and advance payments received. In December 2014, the Company reached a final settlement with its insurers for $155 million (inclusive of advance payments of $83.4 million), and received final payment for the remaining amounts due. This resulted in the Company recognizing a gain of $11.1 million for the year ended March 31, 2015, recorded as a reduction to operations and maintenance expense in the accompanying consolidated statements of income.

15. RELATED PARTY TRANSACTIONS

Accounts Receivable from and Accounts Payable to Affiliates

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

The Company records short-term receivables from, and payables to, certain of its affiliates in the ordinary course of business. A summary of net outstanding accounts receivable from affiliates and accounts payable to affiliates is as follows:

	Accounts Receivable from Affiliates		Accounts Payable to Affiliates	
	March 31,		March 31,	
	2015	2014	**2015**	2014
	(in millions of dollars)		*(in millions of dollars)*	
National Grid plc	**$ -**	$ -	**$ 52**	$ 60
Other	**2**	2	**2**	3
Total	**$ 2**	$ 2	**$ 54**	$ 63

Advances from Affiliates

In August 2009, the Company and KeySpan Corporation 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 1.4%. At March 31, 2015 and 2014, the Company had zero and $750 million outstanding 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 was amended and restated to February 2014 to increase the borrowing capacity to $3 billion. These advances do not bear interest. At March 31, 2015 and 2014, the Company had $1.1 billion and $1.4 billion outstanding advances from NGNA under this agreement.

Holding Company Charges

The Company received charges from National Grid Commercial Holdings Limited (an affiliated company in the U.K.) 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, 2015 and 2014, the effect on net income was $45 million and $52 million before taxes and $27 million and $34 million after taxes.

16. 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, 2015 and 2014 is as follows:

		Shares Outstanding		Amount		
		March 31,		March 31,		Call
Series	Company	**2015**	2014	**2015**	2015	**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 New York state. 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 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%.

A summary of preferred stock is as follows:

	Shares Outstanding		Amount (par)		Amount (additional paid-in capital)	
	March 31,		March 31,		March 31,	
Series	**2015**	2014	**2015**	2014	**2015**	2014
	(in millions of dollars, except per share and number of shares data)					
$0.10 par value -						
Series A	**51**	51	**$ -**	$ -	**$ 400**	$ 400
Series B	**40**	40	**-**	-	**315**	315
Series C	**96**	96	**-**	-	**750**	750
Series D	**79**	79	**-**	-	**616**	616
Series E	**1**	1	**-**	-	**10**	10
Series F	**648**	648	**-**	-	**5,368**	5,368
Total	**915**	915	**$ -**	$ -	**$ 7,459**	$ 7,459

17. 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, 2015, the Parent had 3.9 billion of ordinary shares issued with 152,945,477 held as treasury shares. The aggregate dilution resulting from executive share-based incentives will not exceed 5% in any ten year period for executive share-based incentives and will not exceed 10% in any ten year period for all employee incentives. This is reviewed by the Remuneration Committee and currently, the Parent has excess headroom of 4.12% and 7.95%, 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 three parts as follows: (i) 50% of the units awarded are subject to annualized growth in the Parent's earnings per share ("EPS") over a general index of retail prices over a period of three years; (2) 25% of the units awarded will vest based upon the Parent's Total Shareholder Return ("TSR") compared to that of the Financial Times Stock Exchange ("FTSE") 100 over a period of three years; and (3) 25% of the units awarded are subject to the average achieved regulatory ROE. Under the PSP, performance conditions are split into two parts as follows: (1) 50% of the units awarded are subject to annualized growth in the Parent's EPS over a general index of retail prices over a period of three years; and (2) 50% of the units awarded will vest based upon the Parent's TSR compared to that of the FTSE 100 over a period of three years. Units under both plans generally vest at the end of the performance period.

A Monte Carlo simulation model has been used to estimate the fair value for the TSR portion of the awards. For the EPS and ROE portions of the awards, the fair value of the award is determined using the stock price as quoted per the London Stock Exchange or the price for the American Depository Shares as quoted on the New York Stock Exchange as of the earlier of the reporting date or vesting date.

The following table summarizes the stock based compensation expense recognized by the Company for the years ended March 31, 2015 and 2014:

	Units	Weighted Average Grant Date Fair Value
Non-vested as of March 31, 2013	945,945	$ 40.36
Vested	183,275	46.37
Granted	247,891	55.96
Forfeited/Cancelled	89,829	49.00
Non-vested as of March 31, 2014	920,732	49.92
Vested	351,669	45.95
Granted	408,730	68.26
Forfeited/Cancelled	122,169	55.86
Non-vested as of March 31, 2015	855,624	$ 60.65

The total expense recognized for non-vested awards was $15.5 million and $19 million for the years ended March 31, 2015 and 2014, respectively, and will vest over three years. The total tax benefit recorded was approximately $6.2 million and $7.6 million as of March 31, 2015 and 2014, respectively. Total expense expected to be recognized by the Parent in future periods for non-vested awards outstanding as of March 31, 2015 is $12 million, $8.5 million, and $2.8 million for the years ended March 31, 2016, 2017, and 2018, respectively.

18. DISCONTINUED OPERATIONS

On December 15, 2011, LIPA announced that it was not renewing the MSA contract beyond its expiration on December 31, 2013. The loss of the contract resulted in 1,950 employees transferring to a new employer. The results of the MSA are reflected as discontinued operations in the accompanying consolidated financial statements for the years ended March 31, 2015 and 2014.

Following the expiration of the MSA, the Company entered into a Settlement and Release Agreement ("SRA") with LIPA. Under the terms of this SRA, LIPA (1) fully released the Company from its obligations under certain promissory notes payable to LIPA, and (2) agreed to make a one-time lump sum payment to the Company of $91.5 million. In return, during the year ended March 31, 2014, the Company fully released LIPA from certain claims for reimbursement of pension and PBOP costs. As a result, the Company recorded a gain of approximately $231 million, primarily related to the extinguishment of debt and recognition of a receivable for the lump sum cash payment during the year ended March 31, 2014.

In addition, during the year ended March 31, 2014, a $97 million net settlement gain and a $43 million net curtailment gain were recognized for the employees who transferred to a new employer. The new employer had assumed responsibility for the transferred employees' obligations under the PBOP.

The reconciliation below highlights the financial statements line items within income from discontinued operations, net of taxes for the MSA for the years ended March 31, 2015 and 2014:

	Years Ended March 31,	
	2015	2014
	(in millions of dollars)	
Operating revenues	**$ 97**	$ 476
Operations and maintenance	**(69)**	(601)
Other expenses	**(8)**	(19)
Other deductions	**(2)**	-
Income (loss) before income taxes	**18**	(144)
Gain on disposal of discontinued operations	**-**	371
Total income before income taxes	**18**	227
Income tax (benefit) expense	**6**	94
Income from discontinued operations, net of taxes	**$ 12**	$ 133

The reconciliation below highlights the carrying values of assets and liabilities related to discontinued operations that are disclosed in the accompanying consolidated balance sheets for the MSA at March 31, 2015 and 2014:

	March 31,	
	2015	2014
	(in millions of dollars)	
Assets		
Accounts receivable	**$ 100**	$ 219
Allowance for doubtful accounts	**(70)**	(70)
Unbilled revenues	**11**	2
Deferred income tax assets	**29**	29
Other	**-**	2
Total assets related to discontinued operations	**$ 70**	$ 182
Liabilities		
Accounts payable	**$ 20**	$ 20
Taxes accrued	**1**	2
Other	**-**	15
Total liabilities related to discontinued operations	**$ 21**	$ 37

nationalgrid

National Grid USA and Subsidiaries

Consolidated Financial Statements

For the years ended March 31, 2016 and 2015

NATIONAL GRID USA AND SUBSIDIARIES

TABLE OF CONTENTS

Independent Auditor's Report

To the Board of Directors
of National Grid USA

We have audited the accompanying consolidated financial statements of National Grid USA and its subsidiaries (the Company), which comprise the consolidated balance sheets and statements of capitalization as of March 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, cash flows, and changes in shareholders' equity for the years then ended.

Management's Responsibility for the Consolidated Financial Statements

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

Auditor's Responsibility

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

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

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of National Grid USA and its subsidiaries as of March 31, 2016 and 2015, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

September 26, 2016

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

	Years Ended March 31,	
	2016	2015
Operating revenues:		
Electric services	**$ 6,667**	$ 7,142
Gas distribution	**4,316**	5,234
Other	**25**	64
Total operating revenues	**11,008**	12,440
Operating expenses:		
Purchased electricity	**1,948**	2,514
Purchased gas	**1,301**	2,201
Operations and maintenance	**4,282**	4,608
Depreciation and amortization	**1,006**	953
Other taxes	**1,099**	1,087
Total operating expenses	**9,636**	11,363
Operating income	**1,372**	1,077
Other income and (deductions):		
Interest on long-term debt	**(386)**	(393)
Other interest, including affiliate interest	**(80)**	(74)
Income from equity investments	**33**	41
Gain on sale of assets	**76**	-
Unrealized gains on investment in Dominion Midstream Partners, LP	**53**	-
Other deductions, net	**(12)**	(79)
Total other deductions, net	**(316)**	(505)
Income before income taxes	**1,056**	572
Income tax expense	**402**	200
Income from continuing operations	**654**	372
(Loss) income from discontinued operations, net of taxes	**(13)**	10
Net income	**641**	382
Net loss attributable to non-controlling interest	**-**	18
Dividends paid on preferred stock	**(1,179)**	-
Net (loss) income attributable to common shares	**$ (538)**	$ 400

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,	
	2016	2015
Net income	**$ 641**	$ 382
Other comprehensive income (loss), net of taxes:		
Unrealized (losses) gains on securities	**(4)**	6
Change in pension and other postretirement obligations	**42**	(238)
Unrealized gains (losses) on hedges	**1**	(1)
Total other comprehensive income (loss)	**39**	(233)
Comprehensive income	**$ 680**	$ 149
Less: comprehensive loss attributable to non-controlling interest	**-**	18
Comprehensive income attributable to common and preferred shares	**$ 680**	$ 167
Related tax (expense) benefit:		
Unrealized losses (gains) on securities	**$ 3**	$ (4)
Change in pension and other postretirement obligations	**(29)**	167
Unrealized (gains) losses on hedges	**-**	1
Total tax (expense) benefit	**$ (26)**	$ 164

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,	
	2016	2015
Operating activities:		
Net income	**$ 641**	$ 382
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**1,006**	953
Regulatory amortizations	**115**	120
Provision for deferred income taxes	**345**	214
Bad debt expense	**191**	218
(Income) loss from equity investments, net of dividends received	**(9)**	6
Gain on sale of assets	**(76)**	-
Unrealized gains on investment in Dominion Midstream Partners, LP	**(53)**	-
Goodwill impairment	**-**	22
Allowance for equity funds used during construction	**(19)**	(19)
Amortization of debt discount and issuance costs	**12**	9
Net postretirement benefits expense	**1**	170
Net environmental remediation payments	**(118)**	(103)
Share based compensation	**21**	15
Changes in operating assets and liabilities:		
Accounts receivable and other receivable, net, and unbilled revenues	**566**	74
Accounts receivable from/payable to affiliates, net	**(36)**	(9)
Inventory	**(35)**	(46)
Regulatory assets and liabilities, net	**(3)**	(57)
Derivative instruments	**(110)**	130
Prepaid and accrued taxes	**31**	(12)
Accounts payable and other liabilities	**(190)**	(2)
Renewable energy certificate obligations, net	**(43)**	52
Other, net	**5**	66
Net cash provided by operating activities	**2,242**	2,183
Investing activities:		
Capital expenditures	**(2,572)**	(2,433)
Changes in restricted cash and special deposits	**97**	(22)
Cost of removal and other	**(175)**	(150)
Net cash used in investing activities	**(2,650)**	(2,605)
Financing activities:		
Preferred stock dividends	**(1,179)**	-
Payments on long-term debt	**(866)**	(728)
Proceeds from long-term debt	**1,221**	900
Payment of debt issuance costs	**-**	(5)
Commercial paper (paid) issued	**(284)**	161
Affiliated money pool borrowing and receivables/payables, net	**-**	4
Advances from affiliates	**1,979**	(1,093)
Payments on sale/leaseback arrangement	**(41)**	(41)
Other	**-**	5
Net cash provided by (used in) financing activities	**830**	(797)
Net increase (decrease) in cash and cash equivalents	**422**	(1,219)
Net cashflow from discontinued operations - operating	**12**	98
Net cashflow from discontinued operations - investing	**-**	-
Net cashflow from discontinued operations - financing	**-**	-
Cash and cash equivalents, beginning of year	**450**	1,571
Cash and cash equivalents, end of year	**$ 884**	$ 450
Supplemental disclosures:		
Interest paid	**$ (381)**	$ (390)
Income taxes (paid) refunded	**(4)**	22
Significant non-cash items:		
Capital-related accruals included in accounts payable	**181**	95

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,	
	2016	2015
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 884**	$ 450
Restricted cash and special deposits	**93**	190
Accounts receivable	**2,080**	2,641
Allowance for doubtful accounts	**(406)**	(361)
Accounts receivable from affiliates	**28**	2
Unbilled revenues	**416**	567
Inventory	**481**	397
Regulatory assets	**712**	656
Derivative instruments	**15**	37
Prepaid taxes	**156**	182
Other	**82**	91
Current assets related to discontinued operations	**21**	41
Total current assets	**4,562**	4,893
Equity investments	**125**	190
Property, plant and equipment, net	**27,464**	25,595
Other non-current assets:		
Regulatory assets	**4,850**	4,903
Goodwill	**7,129**	7,129
Derivative instruments	**5**	15
Postretirement benefits asset	**187**	189
Financial investments	**693**	494
Other	**143**	127
Other non-current assets related to discontinued operations	**37**	29
Total other non-current assets	**13,044**	12,886
Total assets	**$ 45,195**	$ 43,564

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,	
	2016	2015
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 1,211**	$ 1,393
Accounts payable to affiliates	**44**	54
Advances from affiliates	**3,057**	1,078
Commercial paper	**298**	582
Current portion of long-term debt	**940**	638
Taxes accrued	**47**	46
Customer deposits	**121**	120
Interest accrued	**120**	133
Regulatory liabilities	**569**	631
Derivative instruments	**94**	262
Renewable energy certificate obligations	**193**	166
Payroll and benefits accruals	**276**	252
Other	**166**	177
Current liabilities related to discontinued operations	**23**	21
Total current liabilities	**7,159**	5,553
Other non-current liabilities:		
Regulatory liabilities	**3,020**	2,861
Asset retirement obligations	**94**	81
Deferred income tax liabilities, net	**4,989**	4,600
Postretirement benefits	**3,712**	3,839
Environmental remediation costs	**1,295**	1,336
Derivative instruments	**41**	39
Other	**891**	864
Total other non-current liabilities	**14,042**	13,620
Commitments and contingencies (Note 14)		
Capitalization:		
Shareholders' equity	**15,700**	16,177
Long-term debt	**8,294**	8,214
Total capitalization	**23,994**	24,391
Total liabilities and capitalization	**$ 45,195**	$ 43,564

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, 2016	March 31, 2015
Shareholders' equity attributable to common and preferred shares			**$ 15,691**	$ 16,163
Non-controlling interest in subsidiaries			**9**	14
Long-term debt:	Interest Rate	Maturity Date		
European Medium Term Note	Variable	June 2015 - January 2016	**-**	588
Notes Payable	2.72% - 9.75%	January 2016 - March 2046	**7,328**	6,338
Promissory Notes to National Grid North America Inc.	3.13% - 3.25%	June 2027 - April 2028	**227**	-
Gas Facilities Revenue Bonds	Variable	December 2020 - July 2026	**230**	230
Gas Facilities Revenue Bonds [1]	4.7% - 6.95%	April 2020 - July 2026	**411**	411
First Mortgage Bonds	6.82% - 9.63%	April 2018 - April 2028	**124**	125
State Authority Financing Bonds	Variable	June 2015 - August 2042	**918**	1,033
Industrial Development Revenue Bonds [2]	5.25%	June 2027	**-**	128
Total debt			**9,238**	8,853
Unamortized debt discount			**(4)**	(1)
Current portion of long-term debt			**(940)**	(638)
Long-term debt			**8,294**	8,214
Total capitalization			**$ 23,994**	$ 24,391

[1] During March 2016, The Brooklyn Union Gas Company issued Notice of Optional Redemption letters to the bond holders of the fixed interest rate gas facilities revenue bonds. The Brooklyn Union Gas Company fully repaid these bonds during April 2016 as disclosed in Note 19, "Subsequent Events." Hence these bonds are classified within current portion of long-term debt.

[2] On November 20, 2015, National Grid Generation LLC redeemed this debt as disclosed in Note 10, "Capitalization."

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

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

				Accumulated Other Comprehensive Income (Loss)						
	Common Stock	Cumulative Preferred Stock	Additional Paid-in Capital	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Hedging Activity	Total Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest	Total
Balance as of March 31, 2014	**$ -**	**$ 35**	**$ 14,137**	**$ 2**	**$ (652)**	**$ (2)**	**$ (652)**	**$ 2,460**	**$ 12**	**$ 15,992**
Net income	-	-	-	-			-	400	(18)	382
Other comprehensive income (loss):										
Unrealized gains on securities, net of $4 tax expense	-	-	-	6	-	-	6	-	-	6
Change in pension and other postretirement obligations, net of $167 tax benefit	-	-	-	-	(238)	-	(238)	-	-	(238)
Unrealized losses on hedges, net of $1 tax benefit	-	-	-	-	-	(1)	(1)	-	-	(1)
Total comprehensive income										149
Parent loss tax allocation	-	-	5	-	-	-	-	-	-	5
Share based compensation	-	-	15	-	-	-	-	-	-	15
Other equity transactions with non-controlling interest	-	-	(4)	-	-	-	-	-	20	16
Balance as of March 31, 2015	**$ -**	**$ 35**	**$ 14,153**	**$ 8**	**$ (890)**	**$ (3)**	**$ (885)**	**$ 2,860**	**$ 14**	**$ 16,177**
Net income	-	-	-	-			-	641	-	641
Other comprehensive income:										
Unrealized losses on securities, net of $3 tax benefit	-	-	-	(4)	-	-	(4)	-	-	(4)
Change in pension and other postretirement obligations, net of $29 tax expense	-	-	-	-	42	-	42	-	-	42
Unrealized gains on hedges, net of $0 tax expense	-	-	-	-	-	1	1	-	-	1
Total comprehensive income										680
Share based compensation	-	-	21	-	-	-	-	-	-	21
Preferred stock dividends	-	-	-	-	-	-	-	(1,179)	-	(1,179)
Other equity transactions with non-controlling interest	-	-	6	-	-	-	-	-	(5)	1
Balance as of March 31, 2016	**$ -**	**$ 35**	**$ 14,180**	**$ 4**	**$ (848)**	**$ (2)**	**$ (846)**	**$ 2,322**	**$ 9**	**$ 15,700**

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, 2016 and 2015.

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 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").

In addition, the Company has certain subsidiaries which have provided operational and energy management services and continue to supply capacity to and produce energy for the use of customers of the Long Island Power Authority ("LIPA") on Long Island, New York. The services provided to LIPA were, or continue to be, provided through the following contractual arrangements. The Power Supply Agreement ("PSA"), which was amended and restated for a maximum term of 15 years in October 2012, provides LIPA with electric generating capacity, energy conversion, and ancillary services from the Company's Long Island generating units. The Management Service Agreement ("MSA"), which expired on December 31, 2013, provided operation, maintenance and construction services, and significant administrative services relating to the Long Island electric transmission and distribution system. The results of the MSA are reflected as discontinued operations in the accompanying consolidated financial statements for the years ended March 31, 2016 and 2015.

Other Services and Investments

The Company's Energy Services business includes companies that provide energy-related services to customers located primarily within the northeastern United States ("U.S."). These services comprise the operation, maintenance, and design of energy systems for commercial and industrial customers.

The Company's Energy Investments business consists of gas production and 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 14, "Commitments and Contingencies" under "Decommissioning Nuclear Units."

On September 29, 2015, the Company contributed its 20.4% interest in Iroquois Gas Transmission System L.P., which was accounted for under the equity method of accounting, to Dominion Midstream Partners, LP ("DM") in exchange for approximately 6.8 million common units (representing approximately a 9% interest) of DM. DM was formed to grow a portfolio of natural gas terminaling, processing, storage, and transportation assets. The transaction resulted in a gain on sale of assets of $74 million. The Company has elected the fair value option with respect to its investment in DM and as

such, any changes in the fair value of these common units are recorded as unrealized gains on investment in Dominion Midstream Partners, LP in the accompanying consolidated statements of income. The Company's investment in DM is included within financial investments in the accompanying consolidated balance sheets.

On October 13, 2015, through its indirect wholly-owned subsidiary, National Grid Technologies, the Company entered into agreements with and became a limited partner of Energy Impact Fund LP ("the Fund"), which is a Delaware limited partnership set up to engage in private equity and venture capital investing, primarily through acquiring, holding, and disposing of equity securities issued by companies focused on energy impact technologies. The Fund has an initial term of 10 years and the Company has made a capital commitment of $50 million to the Fund. For the year ended March 31, 2016, the Company has made multiple capital contributions totaling $1.1 million.

Through its indirect wholly-owned subsidiary, National Grid Generation Ventures LLC, the Company owns a 50% interest in Island Park Energy Center LLC, formed to construct, install, hold, own, protect, finance, manage, operate, and maintain projects consisting of the repowering of the E.F. Barrett Steam Unit and Barrett CT Units all located in Nassau County, New York.

Additionally, National Grid Generation Ventures LLC owns a 50% interest in three LLCs (LI Solar Generation LLC, LI Energy Storage System LLC, and LI Peaker Generation LLC). These LLCs were formed to jointly respond to LIPA's Request for Proposals ("RFPs") for Generation, Energy Storage, and Demand Response Resources and to jointly develop, construct, install, hold, own, protect, finance, manage, operate, and maintain the respective RFP projects (none were awarded) or future proposals for similar projects.

Grid NY LLC, a direct wholly-owned subsidiary of KeySpan Corporation, was formed pursuant to the articles of organization filed 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. From October 10, 2014 to the year ended March 31, 2016, the Company has made multiple capital contributions totaling $1.6 million. In May 2016, the Company has made two additional capital contributions totaling $31.7 million for the purchase of the Indian Point Reliability Contingency Projects which included the Ramapo Rock Tavern and Staten Island Unbottling Projects.

Through its wholly-owned subsidiary, National Grid Algonquin LLC ("NGA"), the Company entered into an agreement in September 2015 to participate in a project ("Access Northeast") with Eversource Energy and Spectra Energy Corporation to enhance the Algonquin and Maritimes & Northeast pipeline systems and construct new LNG storage tanks and vaporization facilities in Acushnet, Massachusetts that will be connected to the Algonquin gas pipeline.

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 and has not elected to account for such investments at fair value. 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 26, 2016, 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, 2016, except as described in Note 19, "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. Movements in regulatory assets and liabilities are reflected in the consolidated statements of income consistent with the treatment of the related costs in the ratemaking processes that exist at the different operating companies.

Revenue Recognition

Electric and Gas Distribution Revenue

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

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

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

Transmission Revenue

Transmission revenues 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 14, "Commitments and Contingencies" under "Electric Services and LIPA Agreements."

Other Revenues

Revenues earned for service and maintenance contracts associated with commercial energy systems are recognized as earned or over the life of the service contract, as appropriate.

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, 2016 and 2015 were $101.1 million and $107.2 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 effects of tax positions are recognized in the consolidated financial statements when it is more likely than not that the position taken, or expected to be taken, in a tax return will be sustained upon examination by taxing authorities based on the technical merits of the position. The financial effect of changes in tax laws or rates is accounted for in the period of enactment. Deferred investment tax credits are amortized over the useful life of the underlying property.

NGNA files consolidated federal tax returns including all of the activities of its subsidiaries. Each subsidiary determines its current and deferred taxes based on the separate return method, modified by benefits-for-loss allocation pursuant to a tax sharing agreement between NGNA and its subsidiaries. To the extent that the consolidated return group settles cash differently than the amount reported as realized under the benefit-for-loss allocation, the difference is accounted for as either a capital contribution or as a distribution.

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 health care claims deposits and deposits held by the New York Independent System Operator

("NYISO") and by the ISO New England, Inc. ("ISO-NE"). The Company had restricted cash of $44 million and $41 million and special deposits of $49 million and $149 million at March 31, 2016 and 2015, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

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

Inventory

Inventory is comprised of materials and supplies, emission credits, renewable energy certificates ("RECs"), and gas in storage. Materials and supplies are stated at the lower of weighted average cost or market and are expensed or capitalized as used. The Company's policy is to write-off obsolete inventory; there were no material write-offs of obsolete inventory for the years ended March 31, 2016 or 2015. Emission credits are comprised of sulfur dioxide, nitrogen oxide ("NOx"), and carbon dioxide credits. Emission credits are valued at the lower of weighted average cost or market and are held primarily for consumption or may be sold to third-party purchasers. RECs are stated at cost and used to measure compliance with renewable energy standards. RECs are held primarily for consumption.

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

The Company had materials and supplies of $180 million and $158 million, emission credits of $23 million and $44 million, purchased RECs of $117 million and $46 million, and gas in storage of $161 million and $149 million at March 31, 2016 and 2015, respectively.

Derivative Instruments

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

The effective portion of the change in fair value of a cash flow hedge is recorded in accumulated other comprehensive income ("AOCI"), net of related tax effects, and the ineffective portion is reported in earnings. For the years ended March 31, 2016 and 2015, the Company recorded ineffectiveness related to cash flow hedges of $0.5 million (loss) and $3 million (loss), respectively. Amounts in AOCI are reclassified into earnings in the same period or periods during which the hedged item affects earnings. The effective portion of the change in the fair value of a fair value hedge is offset in the consolidated statements of income by changes in the hedged item. If the hedge relationship is terminated, the fair value adjustment to the hedged item continues to be reported as part of the basis of the item and is amortized to the consolidated statements of income as a yield adjustment over the remainder of the hedging period. For activity subject to regulatory accounting, gains and losses on derivative instruments are reflected as regulatory assets or liabilities, to be collected from, or refunded to, customers consistent with the regulatory requirements.

The Company has certain non-trading instruments for the physical purchase of electricity that qualify for the normal purchase normal sale exception and are accounted for upon settlement. If the Company were to determine that a contract

no longer qualifies for the normal purchase normal sale exception, then the Company would recognize the fair value of the contract in accordance with the regulatory accounting described above.

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

Power Purchase Agreements

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

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: as discussed in Note 2, under "New and Recent Accounting Guidance," 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 and average service lives for the years ended March 31, 2016 and 2015 are as follows:

	Electric		Gas		Common	
	Years Ended March 31,		Years Ended March 31,		Years Ended March 31,	
	2016	2015	**2016**	2015	**2016**	2015
Composite rates	**2.7%**	2.7%	**2.8%**	2.9%	**5.5%**	4.8%
Average service lives	**48 years**	48 years	**46 years**	46 years	**34 years**	35 years

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, 2016 and 2015.

Allowance for Funds Used During Construction

In accordance with applicable accounting guidance, the regulated subsidiaries record AFUDC, which represents the debt and equity costs of financing the construction of new property, plant and equipment. AFUDC equity is reported in the consolidated statements of income as non-cash income in other deductions, net, and AFUDC debt is reported as a non-cash offset to other interest, including affiliate interest. After construction is completed, the Company is permitted to recover these costs through their inclusion in rate base and corresponding depreciation expense. The Company recorded AFUDC related to equity of $19 million for each of the years ended March 31, 2016 and 2015 and AFUDC related to debt of $10 million and $6 million for the years ended March 31, 2016 and 2015, respectively. The average AFUDC rates for the years ended March 31, 2016 and 2015 were 3.3% and 2.7%, respectively.

In addition, approximately $10 million and $2 million of interest was capitalized for construction of non-regulated projects during the years ended March 31, 2016 and 2015, respectively.

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. Goodwill is tested for impairment using a two-step approach. The first step compares the estimated fair value of each reporting unit with its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, then goodwill is considered not impaired. If the carrying value exceeds the estimated fair value, then a second step is performed to determine the implied fair value of goodwill. If the carrying value of goodwill exceeds its implied fair value, then an impairment charge equal to the difference is recorded.

The fair value of each reporting unit was calculated in the annual goodwill impairment test for the year ended March 31, 2016 utilizing both income and market approaches. The Company uses a 50% weighting for each valuation methodology, as it believes that each methodology provides equally valuable information. Based on the resulting fair value from the annual analyses, the Company determined that no adjustment of the goodwill carrying value was required at March 31, 2016 or 2015, except as in relation to Clean Line Energy Partners LLC ("Clean Line") as described in Note 12, "Goodwill."

Available-For-Sale Securities

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

Asset Retirement Obligations

Asset retirement obligations are recognized for legal obligations associated with the retirement of property, plant and equipment, primarily associated with the Company's 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 following table represents the changes in the Company's asset retirement obligations:

	Years Ended March 31,	
	2016	2015
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 81**	$ 87
Accretion expense	**4**	5
Liabilities settled	**(4)**	(11)
Revisions to present values of estimated cash flows	**13**	-
Balance as of the end of the year	**$ 94**	$ 81

At March 31, 2015, certain of the Company's subsidiaries carried out a revaluation study that resulted in a revaluation in estimated cost related to the asset retirement obligations due to changes in remediation cost and enhanced asset replacement programs. These revaluations resulted in no net impact. At March 31, 2016, certain of the Company's subsidiaries carried out a revaluation study that resulted in a net upward revaluation in estimated costs related to the asset retirement obligations. These increases were due to changes in remediation cost and systematic measurement of these regulatory obligations.

Accretion expense for the Company's regulated subsidiaries is deferred as part of the Company's asset retirement obligation regulatory asset as management believes it is probable that such amounts will be collected in future rates.

Employee Benefits

The Company has defined benefit pension and postretirement benefit other than pension ("PBOP") plans for its employees. The Company recognizes all pension and PBOP plans' funded status in the accompanying consolidated balance sheets as a net liability or asset with an offsetting adjustment to AOCI in shareholders' equity. In the case of regulated entities, the cost of providing these plans is recovered through rates; therefore, the net funded status is offset by a regulatory asset or liability. The Company measures and records its pension and PBOP funded status at the year-end date. Pension and PBOP plan assets are measured at fair value, using the year-end market value of those assets.

Supplemental Executive Retirement Plans

The Company has corporate assets included in financial investments in the accompanying consolidated balance sheets 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 with increases and decreases in the value of these assets recorded in the accompanying consolidated statements of income.

New and Recent Accounting Guidance

Accounting Guidance Adopted in Fiscal Year 2016

The new accounting guidance that was adopted for fiscal year 2016 had no material impact on the results of operations, cash flows, or financial position of the Company.

Presentation of Financial Statements – Balance Sheet Classification of Deferred Taxes

In November 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-17, "Balance Sheet Classification of Deferred Taxes." The new guidance requires that all deferred tax assets and liabilities, along with any related valuation allowance be classified as non-current in the balance sheets; the new guidance does not change the existing requirement of prohibiting the offsetting of deferred tax liabilities from one jurisdiction against deferred tax assets of another jurisdiction. The Company early adopted this guidance, retrospectively, effective April 1, 2015.

Fair Value Measurement – Investments Measured at Net Asset Value ("NAV")

In May 2015, the FASB issued ASU 2015-07, "Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities that Calculate New Asset Value per Share (or its equivalent)." The new guidance requires that the valuation of investments using NAV, as a practical expedient to fair value should be excluded from the fair value hierarchy. The Company early adopted this guidance, retrospectively, effective April 1, 2015.

Accounting Guidance Not Yet Adopted

The Company is currently evaluating the impact of recently issued accounting guidance on the presentation, results of operations, cash flows, and financial position of the Company.

Derivative instruments

In March 2016, the FASB issued ASU 2016-05, "Effect of Derivative Contract Novations on Existing Hedge Accounting Relationship." The new guidance clarifies that a change in the counterparty to a derivative contract, in and of itself, does not require the de-designation of a hedging relationship. However, an entity still needs to evaluate whether it is probable that the counterparty will perform under the contract as part of its ongoing effectiveness assessment for hedge accounting. The new guidance, which can be applied either on a prospective basis or on a modified retrospective basis, is effective for non-public entities for periods beginning after December 15, 2017, with early adoption permitted.

Leases

In February 2016, the FASB issued a new lease accounting standard, ASU 2016-02, "Leases (Topic 842)." The key objective of the new standard is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Lessees will need to recognize a right-of-use asset and a lease liability for virtually all of their leases (other than leases that meet the definition of a short-term lease). For income statement purposes, a dual model has been retained, with leases to be designated as operating leases or finance leases. Expenses will be recognized on a straight-line basis for operating leases, and a front-loaded basis for finance leases. For non-public entities, the new standard is effective for periods beginning after December 15, 2019, with early adoption permitted. The new standard must be adopted using a modified retrospective transition, and provides for certain practical expedients.

Financial Instruments – Classification and Measurement

In January 2016, the FASB issued ASU 2016-01, "Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities." The new guidance principally affects the accounting for equity investments and financial

liabilities where the fair value option has been elected, as well as the disclosure requirements for financial instruments. The new guidance is effective for non-public entities for periods beginning after December 15, 2018, with early adoption permitted for periods beginning after December 15, 2017.

Revenue Recognition

In August 2015, the FASB issued ASU 2015-14, "Revenue from Contracts with Customers – Deferral of the Effective Date." The new standard defers by one year the effective date of ASU 2014-09 "Revenue from Contracts with Customers (Topic 606)." The underlying principle of "Revenue from Contracts with Customers" is that an entity will recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to, in exchange for those goods or services. The new guidance must be adopted using either a full retrospective approach or a modified retrospective approach. For non-public entities, the new guidance is effective for periods beginning after December 15, 2018, with early adoption permitted for periods beginning after December 15, 2016.

Further, in March 2016, the FASB issued ASU 2016-08, which clarifies the implementation guidance on principal versus agent considerations. In May 2016, the FASB issued ASU 2016-12, providing additional clarity on various aspects of Topic 606, including a) Assessing the Collectibility 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. The effective date and transition requirements for the amendments in these updates are the same as the effective date and transition requirements of ASU 2014-09.

Measurement of Inventory

In July 2015, the FASB issued ASU 2015-11, "Simplifying the Measurement of Inventory." The new guidance requires that inventory be measured at the lower of cost and net realizable value (other than inventory measured using "last-in, first out" and the "retail inventory method"). The new guidance, which must be applied prospectively, is effective for non-public entities for periods beginning after December 15, 2016, with early adoption permitted.

Intangibles – Goodwill and Other – Internal-Use Software, Customer's Accounting for Fees Paid in a Cloud Computing Arrangement

In April 2015, the FASB issued ASU 2015-05 "Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement." The amendments provide guidance to customers about whether a cloud computing arrangement includes a software license. If a cloud computing arrangement includes a software license, then the customer should account for the software license element of the arrangement consistent with the acquisition of other software licenses. If a cloud computing arrangement does not include a software license, the customer should account for the arrangement as a service contract. The guidance will not change GAAP for a customer's accounting for service contracts. In addition, all software licenses within the scope of Subtopic 350-40 will be accounted for consistent with other licenses of intangible assets. For non-public entities, the new guidance is effective for annual periods beginning after December 15, 2015, and interim periods in annual periods beginning after December 15, 2016, with early adoption permitted.

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

In April 2015, the FASB issued ASU 2015-03, "Simplifying the Presentation of Debt Issuance Costs." The new guidance requires that debt issuance costs related to term loans, be presented in the balance sheets as a direct deduction from the carrying value of debt. The new guidance, which requires retrospective application, is effective for fiscal years beginning after December 15, 2015, and interim periods within fiscal years beginning after December 15, 2016, with early adoption permitted.

Consolidation

In February 2015, the FASB issued ASU 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis." The new guidance eliminates entity specific consolidation guidance for limited partnerships. It also revises other aspects of the consolidation analysis, including how kick-out rights, fee arrangements and related parties are assessed. The new guidance, which requires either modified retrospective or full retrospective basis application, is effective for periods beginning after December 15, 2016, with early adoption permitted.

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

In August 2014, the FASB issued amendments on reporting about an entity's ability to continue as a going concern in ASU 2014-15, "Presentation of Financial Statements – Going Concern (Subtopic 205 - 40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern." The amendments provide guidance about management's responsibility to evaluate whether there is substantial doubt surrounding an entity's ability to continue as a going concern. If management concludes that substantial doubt exists, the amendments require additional disclosures relating to management's evaluation and conclusion. The amendments are effective for the annual reporting period ending after December 15, 2016 and interim periods thereafter.

Financial Statement Revision

During 2016, management determined that certain accounting transactions were not properly recorded in the Company's previously issued consolidated financial statements. The Company has corrected the accounting by revising the prior period consolidated financial statements presented herein, the impacts of which are described below. The Company concluded that the corrections were not material to any prior periods.

During the Company's review, it identified the following errors which required correction:

- Open work orders within capital work in progress that were inappropriately classified as capital instead of expense. A cumulative adjustment of $40 million (net of income taxes) was recorded, of which $25 was recorded as a decrease to opening retained earnings (as of March 31, 2014) and $15 million was recorded as a decrease to net income with the correction recorded within operations and maintenance expense for the year ended March 31, 2015.
- A gas costs deferral for the year ended March 31, 2014 that had not reversed into the subsequent fiscal year. An adjustment of $10 million (net of income taxes) was recorded as a decrease to net income with the correction recorded within purchased gas for the year ended March 31, 2015.
- Other miscellaneous account balances that were improperly recorded in the previously issued financial statements. A cumulative adjustment of $12 million (net of income taxes) was recorded, of which $17 million was recorded as a decrease to opening retained earnings (as of March 31, 2014) and $5 million was recorded as an increase to net income for the year ended March 31, 2015.
- An error in the amount of capital-related accruals included in accounts payable of $21 million as well as the classification of payments on sales/leaseback arrangement of $41 million.

There were also a number of items identified during the preparation of the March 31, 2015 financial statements that were recorded and previously disclosed as out of period adjustments. As part of the current year revision, these out of period adjustments were also corrected and recorded. These relate to:

- A correction of the methodology for accruing property taxes for certain subsidiaries, which were previously accrued on a calendar year basis. An adjustment of $51 million (net of income taxes) was recorded as an increase to opening retained earnings (as of March 31, 2014) and a decrease to net income with the correction recorded within other taxes for the year ended March 31, 2015.
- A $45 million (net of income taxes) correction for errors in the deferrals associated with various regulatory assets and liabilities (primarily related to RDM, Net Utility Plant Tracker, and Electric Supply Reconciliation Mechanism).

This was recorded as a decrease to opening retained earnings (as of March 31, 2014) and an increase to net income with the correction recorded within operating revenues for the year ended March 31, 2015.

- Various adjustments to the Company's tax provision (primarily related to the correction of the tax accounting for employee variable pay tax deduction, the transfer of Narragansett pension tracker amounts from AOCI to non-current regulatory assets during the year ended March 31, 2013, and the accounting related to a settlement with the New York State Department of Taxation and Finance's examination of the Company's corporate income tax returns for the years ended December 31, 2000 through 2002). A cumulative adjustment of $8 million was recorded, of which $28 million was recorded as an increase to opening retained earnings (as of March 31, 2014) and $20 million was recorded as a decrease to net income for the year ended March 31, 2015.

These errors, in conjunction with the impact of the aforementioned items, resulted in an understatement in net cash provided by operating activities of $32 million, an overstatement in net cash used in investing activities of $7 million, an understatement in net cash used in financing activities of $41 million, and an understatement in net cashflow from discontinued operations - operating of $2 million for the year ended March 31, 2015.

The following table shows the amounts previously reported as revised:

	As Previously Reported [1]	Adjustments	As Revised
		(in millions of dollars)	
Consolidated Statement of Income	**March 2015**		**March 2015**
Operating revenues	$ 12,361	$ 79	$ 12,440
Operating expenses	11,234	129	11,363
Operating income	1,127	(50)	1,077
Total other deductions, net	(509)	4	(505)
Income before income taxes	618	(46)	572
Income tax expense	201	(1)	200
Income from discontinued operations, net of taxes	12	(2)	10
Net income	447	(47)	400
Consolidated Statement of Cash Flows	**March 2015**		**March 2015**
Net cash provided by operating activities	$ 2,151	$ 32	$ 2,183
Net cash used in investing activities	(2,612)	7	(2,605)
Net cash provided by financing activities	(756)	(41)	(797)
Net cashflow from discontinued operations - operating	96	2	98

	As Previously Reported [1]	Adjustments	As Revised
		(in millions of dollars)	
Consolidated Balance Sheet	**March 2015**		**March 2015**
Total current assets	$ 4,910	$ (17)	$ 4,893
Property, plant and equipment, net	25,671	(76)	25,595
Total other non-current assets	13,093	(17)	13,076
Total assets	43,674	(110)	43,564
Total current liabilities	5,556	(3)	5,553
Total other non-current liabilities	13,672	(52)	13,620
Total liabilities	19,228	(55)	19,173
Retained Earnings			
March 31, 2015	2,915	(55)	2,860
March 31, 2014	2,468	(8)	2,460
Shareholders' equity			
March 31, 2015	16,232	(55)	16,177
March 31, 2014	16,000	(8)	15,992

[1] During 2016, the Company early adopted ASU 2015-17 "Balance Sheet Classification of Deferred Taxes" retrospectively (as discussed in Note 11, "Income Taxes"). This change in accounting policy resulted in the reclassification of balances reported at March 31, 2015.

3. REGULATORY ASSETS AND LIABILITIES

The Company records regulatory assets and liabilities that result from the ratemaking process. The following table presents the regulatory assets and regulatory liabilities recorded in the accompanying consolidated balance sheets:

	March 31,	
	2016	2015
	(in millions of dollars)	
Regulatory assets		
Current:		
Derivative instruments	**$ 120**	$ 113
Energy efficiency	**59**	55
Gas costs adjustment	**121**	120
Rate adjustment mechanisms	**119**	87
Renewable energy certificates	**77**	120
Revenue decoupling mechanism	**131**	72
Transmission service	**57**	63
Other	**28**	26
Total	**712**	656
Non-current:		
Environmental response costs	**1,711**	1,732
Postretirement benefits	**1,980**	2,063
Storm costs	**307**	327
Other	**852**	781
Total	**4,850**	4,903
Regulatory liabilities		
Current:		
Energy efficiency	**195**	128
Gas costs adjustment	**86**	77
Profit sharing	**54**	46
Rate adjustment mechanisms	**146**	179
Revenue decoupling mechanism	**62**	119
Temporary state assessment	**9**	46
Other	**17**	36
Total	**569**	631
Non-current:		
Carrying charges	**169**	139
Cost of removal	**1,702**	1,683
Environmental response costs	**195**	145
Postretirement benefits	**112**	145
Other	**842**	749
Total	**3,020**	2,861
Net regulatory assets	**$ 1,973**	$ 2,067

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 charges 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 sites with which it may be associated. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates.

The regulatory liability primarily represents the amount of customer contributions and insurance proceeds recovered to pay for costs to investigate and perform certain remediation activities at sites with which it may be associated as well as 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 deferred to a regulatory asset 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 in the accompanying consolidated balance sheets will be refunded to customers over the next year.

Rate adjustment mechanisms: The Company is subject to a number of rate adjustment mechanisms such as for commodity costs, whereby an asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered or differences between actual revenues and targeted amounts as approved by the applicable state regulatory bodies.

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

Revenue decoupling mechanism: Revenue decoupling mechanisms allow for the periodic adjustment of delivery rates as a result of the reconciliation between allowed revenue and actual revenue. Any difference between the allowed revenue and the actual revenue is recorded as a regulatory asset or regulatory liability.

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

Temporary state assessment: In June 2009, the NYPSC authorized utilities to recover the costs required for payment of the Temporary State Energy & Utility Service Conservation Assessment ("Temporary State Assessment"), including carrying charges. The Temporary State Assessment is subject to reconciliation over a five year period which began July 1, 2009.

On June 18, 2014, the NYPSC issued an order authorizing certain utilities, including Brooklyn Union and KeySpan Gas East ("The New York Gas Companies"), to recover the Temporary State Assessment subject to reconciliation, including carrying charges, from July 1, 2014 through June 30, 2017. As of March 31, 2016, the New York Gas Companies over-collected on these costs. The New York Gas Companies are required to net any deferred over-collected amounts against the amount to be collected during fiscal years 2014 and 2015 as well as the first payment relating to fiscal years 2015 and 2016.

On September 13, 2013 and August 7, 2013, Niagara Mohawk submitted a compliance filing (updated from June 14, 2013) proposing to maintain the currently effective surcharge. On June 18, 2014, a final order implementing a revised Temporary State Assessment resulted in a $2.7 million and $3.9 million credit to electric and gas customers, respectively, for rates effective July 1, 2014 through June 30, 2015.

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

The Company records carrying charges on all regulatory balances (with the exception of derivative instruments, cost of removal, environmental response costs, RECs, and regulatory deferred tax balances), for which cash expenditures have been made and are subject to recovery, or for which cash has been collected and is subject to refund. Carrying charges are not recorded on items for which expenditures have not yet been made.

4. RATE MATTERS

Niagara Mohawk

March 2013 Electric and Gas Filing

In March 2013, the NYPSC issued a final order regarding Niagara Mohawk's electric and gas base rate filing made on April 27, 2012. The original term of the rate plan was from April 1, 2013 through March 31, 2016, and provided for electric delivery rate revenue of $1,338.3 million in the first year, $1,395.9 million in the second year, and $1,432.5 million in the third year. It also provided for gas delivery rate revenue of $307.4 million in the first year, $314.7 million in the second year, and $322 million in the third year. On December 21, 2015, Niagara Mohawk filed a Petition with the NYPSC seeking authorization to recover approximately $150 million in revenue requirements associated with a proposed two-year, $1.4 billion capital spending program for Niagara Mohawk's electric and gas operations in fiscal years 2017 and 2018. The Petition proposed that the revenue requirement be fully funded by existing regulatory deferrals and proposed no increase in customer rates. The Petition also proposed on extension of the existing rate plan which expired in March 2016 through March 2018.

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

Transmission Return on Equity ("ROE") Complaint

On September 11, 2012, the New York Association of Public Power ("NYAPP") filed a complaint against Niagara Mohawk, seeking to have the base ROE for transmission service of 11.5%, which includes a NYISO participation incentive adder, lowered to 9.49%. Similarly, on November 2, 2012 the Municipal Electric Utilities Association ("MEUA") filed a complaint to lower Niagara Mohawk's ROE to 9.25% including the NYISO participation adder. The MEUA also challenges certain aspects of Niagara Mohawk's transmission formula rate. On February 6, 2014, the NYAPP filed a further complaint against Niagara

Mohawk seeking an order effective February 6, 2014 to reduce the ROE used in calculating rates for transmission service under the NYISO Open Access Transmission Tariff ("OATT") to 9.36%, inclusive of the 50 basis point adder for participation in the NYISO, with a corresponding overall weighted cost of capital of 6.6%. On September 8, 2014, the FERC issued orders consolidating the first and second complaints and setting the consolidated complaints and the third complaint for hearing and settlement procedures.

On February 24, 2015, Niagara Mohawk filed an Offer of Settlement and Settlement Agreement ("Settlement") resolving all issues in the complaints and setting the ROE at 10.3%, inclusive of any incentive adders, effective November 2, 2012. The Settlement also provided for various refunds, and separate payments of $200,000 and $180,000 to certain customers. On May 13, 2015, the FERC approved the Offer of Settlement, and on June 12, 2015, Niagara Mohawk filed tariff revisions to implement the new 10.3% ROE negotiated in the settlement. Niagara Mohawk subsequently provided all refunds required by the Settlement and on September 30, 2015 filed a Refund Report with the FERC which concluded this FERC proceeding.

Wholesale Transmission Service Charge

On December 6, 2013, Niagara Mohawk submitted a filing for FERC approval of revisions to its Wholesale Transmission Service Charge ("TSC Rate") under the NYSIO OATT to recover its Reliability Support Services ("RSS") costs under two agreements with NRG Energy Inc. to support the reliability of Niagara Mohawk's transmission system while transmission reinforcements are constructed. On February 4, 2014 the FERC allowed the RSS charges to become effective in TSC Rates as of July 1, 2013, subject to refund and further consideration of the matter by the FERC. On March 19, 2015, the FERC issued two orders relating to Niagara Mohawk's December 6, 2013 filing of proposed tariff revisions to the TSC Rate. In the first order, the FERC set for hearing and settlement judge procedures the justness and reasonableness of Niagara Mohawk's proposed Wholesale TSC formula rate revisions and the Dunkirk RSS charges. In the second order, the FERC rejected a request for rehearing filed by the MEUA regarding the FERC's decision to accept the December 6, 2013 amendment for filing retroactive to July 1, 2013. The FERC held the hearing on the first order in abeyance pending the outcome of settlement proceedings before a settlement judge. The parties agreed to the terms of a settlement which was filed with the settlement judge on September 11, 2015 and certified by the settlement judge to the FERC on October 19, 2015. Under the terms of the settlement, Niagara Mohawk will include the costs of the Dunkirk RSS agreements, including the costs associated with extending the 2013 Dunkirk RSS agreement through the end of 2015, less $35 million, in the TSC Rate. The $35 million reduction to the revenue requirement impact of the Dunkirk RSS agreements will be implemented through a billing adjustment included in Niagara Mohawk's 2016 annual TSC informational update filing. Any change in revenues received from wholesale transmission customers resulting from the settlement agreement will be offset by revenues from retail electric distribution customers through the Transmission Revenue Adjustment Clause mechanism.

Gas Management Audit

In February 2013, the NYPSC initiated a comprehensive management and operational audit of NGUSA's New York gas businesses, including Niagara Mohawk and the New York Gas Companies, pursuant to the Public Service Law requirement that major electric and gas utilities undergo an audit every five years. The audit commenced in August 2013 and the NYPSC issued an audit findings report in October 2014. The audit findings found that the Company's operations performed well in providing reliable gas service, and strength in operations, network planning, project management, work management, load forecasting, supply procurement and customer systems support. Also included were 31 recommendations for improvement, including: reconstituting the boards of directors of NGUSA and the gas companies in New York to include more objective oversight; establishing stronger reporting authority between the New York jurisdictional president and operational organizations; preparing a true strategic plan for NGUSA's New York operations to serve as a road map for investments, programs and operations to build upon the state energy plan and energy initiatives; developing a five-year, integrated, system-wide plan that includes all gas reliability work, mandated replacements, growth projects and system planning work; enhancing internal service level agreements to promote accountability for performance and costs; and undertaking a full accounting of all costs associated with NGUSA's SAP enterprise wide system. In November 2014, NGUSA's New York gas businesses filed joint audit implementation plans addressing each of the audit recommendations. On May 14, 2015, the NYPSC issued an order accepting without modifications the joint implementation plans and directing NGUSA's New York gas businesses to execute the plans.

Operations Audit

In August 2013, the NYPSC initiated an operational audit 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 Niagara Mohawk and the New York Gas Companies. On December 19, 2013, the NYPSC selected Overland to conduct the audit, which commenced in February 2014. On April 20, 2016, the NYPSC released Overland's audit report publicly and adopted the majority of recommendations in the report. The audit report found that the Company, in general, is meeting its 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 May 26, 2016, the NYPSC issued a Notice Seeking Comments on the draft customer service recommendations that were not addressed in the previous order. The Company filed comments on the draft recommendations on July 20, 2016.

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 Niagara Mohawk and the New York Gas Companies. On June 26, 2014, the NYPSC selected The Liberty Consulting Group to conduct the audit. At the time of the issuance of these consolidated financial statements, the Company cannot predict the outcome of this operational audit.

Recovery of Deferral Costs Relating to Emergency Order

On January 28, 2014, Niagara Mohawk filed a petition requesting a waiver of Rule 46.3.2 of its tariff. Rule 46.3.2 describes the manner in which Niagara Mohawk calculates its supply-related Mass Market Adjustment ("MMA"). Niagara Mohawk proposed the waiver of the rule to mitigate adverse financial impacts anticipated from a significant and unusual increase in electric commodity prices for its mass market customers.

On that same date, the NYPSC issued, on an emergency basis pursuant to the State Administrative Procedure Act §202(6), an Emergency Order granting Niagara Mohawk's waiver request (the "Emergency Order"). In the Emergency Order, the NYPSC waived the requirements of Rule 46.3.2 and approved deferral treatment of the costs and associated carrying charges related to the one-time credit provided via the waiver. However, the NYPSC denied, pending further review and consideration of public comments, Niagara Mohawk's request to recover such deferral over a six-month period beginning May 2014.

The NYPSC issued another order on April 25, 2014 permanently approving the Emergency Order and authorizing Niagara Mohawk to collect $33.3 million, plus carrying charges at the customer deposit rate, over a six-month period commencing with the June 2014 billing period. The deferral recovery will be performed in a manner consistent with the method that was used to provide the benefit to the mass market customers, through an adjustment to the MMA as calculated by NYISO load zone.

Petition for Authorization to Defer an Actuarial Experience Pension Settlement Loss for the Year Ending March 31, 2014

On February 28, 2014 and August 13, 2014, Niagara Mohawk filed petitions seeking authorization to defer $14.1 million related to a pension settlement loss incurred during the year ending March 31, 2014.

The New York Gas Companies

General Rate Case

KeySpan Gas East has been subject to a rate plan with a primary term of five years (2008-2012), which remains in effect until modified by the NYPSC. Under this rate plan, base delivery rates include an allowed ROE of 9.8% with a 45% equity ratio in the capital structure.

On June 13, 2013, the NYPSC approved a rate plan extension covering Brooklyn Union's 2013 and 2014 rate years. Brooklyn Union's revenue requirements for both years have been modified as follows: (i) there is no change in base delivery rates, other than those previously approved by the NYPSC in the rate plan extension, (ii) the allowed ROE decreased from 9.8% to 9.4%, and (iii) the common equity ratio in the capital structure increased from 45% to 48%.

Rate Case Filing

On January 29, 2016, the New York Gas Companies filed to adjust its base gas rates, which, if adopted, would be effective from January 1, 2017. The filing seeks to increase gas delivery base revenues. On June 17, 2016, the New York Gas Companies filed for a month-extension in the suspension period in the proceedings with a make whole provision, such that new rates would become effective February 1, 2017. On July 21, 2016, to allow additional time for the parties to conduct settlement discussions and finalize a joint proposal, the New York Gas Companies requested an additional one-month extension in the suspension period, subject to a make whole, such that new rates would become effective no later than March 1, 2017.

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 Joint Proposal is supported by several parties, including Department of Public Service Staff and the City of New York. It is expected that the NYPSC will issue an order on the Joint Proposal in December or January and that new rates would go into effect in either January or February. The Joint Proposal includes a make whole provision that, if approved, is designed to ensure the New York Gas Companies are restored to the same financial position by December 31, 2017 as if new rates went into effect beginning January 1, 2017.

Capital Investment

On June 13, 2014, KeySpan Gas East filed a petition with the NYPSC to implement a three year capital investment program that would allow KeySpan Gas East to invest more than $700 million in gas infrastructure projects designed to enhance the safety and reliability of its gas systems and promote gas growth, while maintaining base delivery rates.

On December 15, 2014, KeySpan Gas East received an order which authorizes it to replace leak prone pipe up to its forecasted budget of $211.7 million for calendars years 2015 and 2016. KeySpan Gas East is allowed to establish a 21-month surcharge mechanism beginning April 2, 2015 through December 31, 2016, which will be capped at $10 million and $13.4 million, respectively, to address KeySpan Gas East's capital needs for replacement of leak prone pipe, while minimizing future customer bill impacts. KeySpan Gas East was authorized to spend up to its forecasted budget of $202.7 million for calendar years 2015 and 2016 for its Neighborhood Expansion and other related programs. KeySpan Gas East is directed to establish a new deferral mechanism that allows it to defer the pre-tax revenue requirements associated with its capital spending program up to a maximum capital expenditure of $202.7 million made in calendar years 2015 and 2016. KeySpan Gas East's existing city/state deferral mechanism was eliminated as of January 1, 2015 and the non-growth deferral mechanism is continued. The order also included additional obligations and filing requirements.

Management Audit

In February 2011, the NYPSC selected Overland Consulting Inc., ("Overland") to perform a management audit of NGUSA's affiliate cost allocations, policies, and procedures. The New York Gas Companies disputed certain of Overland's final audit conclusions and the NYPSC ordered that further proceedings be conducted to address what, if any, ratemaking adjustments were necessary. On September 5, 2014, the NYPSC approved a settlement that resolves all outstanding issues relating to the audit and establishes a $24.7 million regulatory liability.

Capital Reconciliation Mechanism Petition

In June 2015, Brooklyn Union submitted a petition to the NYPSC requesting a modification to the Capital Expenditures and Net Utility Plant and Depreciation Expense Reconciliation Mechanism ("Capital Reconciliation Mechanism") in its current rate plan. The Capital Reconciliation Mechanism is a downward only net utility plant reconciliation mechanism that permits

a cumulative, two-year reconciliation for the two years ended December 31, 2014 and annual reconciliations thereafter. While Brooklyn Union implemented and largely completed its capital program for 2013 and 2014, its ability to launch certain programs was hampered by SuperStorm Sandy and its aftermath. The impact of these delays and other related issues was a deferred liability, which was offset against the regulatory asset recorded in relation to the primary term of the rate plan. Brooklyn Union requested a modification to the Capital Reconciliation Mechanism to extend the reconciliation period for two years (calendar years 2015 and 2016) to complete more capital projects and facilitate Brooklyn Union's plan to invest in its distribution system infrastructure. On October 19, 2015, the NYPSC issued an order granting the requested two year extension to the reconciliation period.

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

Electric Rate Case Filing

On November 6, 2015, the Massachusetts Electric Companies filed a one-year rate plan, requesting an increase in base distribution revenue of approximately $211.3 million to take effect from October 1, 2016, which was updated to $205.5 million on April 29, 2016, $202.8 million on June 3, 2016, and $201.9 million on July 25, 2016. The updated rate case filing requests an annualized net increase in distribution revenue of approximately $133.2 million. Approximately $28 million of the increase is associated with higher personal property taxes, and $10 million of the increase to increase funding to the Massachusetts Electric Companies' Storm Contingency Fund to more adequately address mobilization and restoration activities incurred in connection with responding to significant weather events experienced by the Massachusetts Electric Companies since their last rate case in 2009. The increase also reflects the impact of net plant additions since December 31, 2008, the end of the test year in the Massachusetts Electric Companies' last general rate case, as well as its investment in five solar generating facilities placed into service since that time; however, the Massachusetts Electric Companies have been recovering a portion of their investments through recovery mechanisms outside of base distribution rates, and such recovery shall end when recovery commences through base distribution rates, as approved by the DPU. The Massachusetts Electric Companies have also requested revisions to their capital investment recovery mechanism to better align the eligible capital investment with its recent and future plans for capital investment in its distribution system to ensure safe and reliable service to its customers. The Company cannot currently predict the outcome of this case.

2009 Capital Investment Audit

The DPU approved an RDM arising from the 2009 distribution rate case filed by the Massachusetts Electric Companies. As part of their RDM provision, the Massachusetts Electric Companies file a report by July 1 of each year on their capital investment for the prior calendar year. In connection with the Massachusetts Electric Companies' first capital expenditure ("CapEx") filing made in July 2010, the DPU opened a proceeding in March 2011, as requested by the Massachusetts Office of the Attorney General ("Attorney General"), for an independent audit of Massachusetts Electric Companies' 2009 capital investments which, in part, formed the basis for the Massachusetts Electric Companies' RDM rate. The auditor issued its Final Audit Report on August 5, 2015, certifying that the CapEx filing and supporting documentation demonstrated that the costs requested for recovery were supported by source documents and were properly allocable to the Massachusetts Electric Companies. On February 28, 2016, the DPU issued an order generally accepting the auditor's audit report and certification and directing the Massachusetts Electric Companies to implement the following recommendations: (1) perform a review of work orders on equipment energized in 2008 but recorded as in-service in 2009 for accounting purposes; (2) develop a detailed written policy describing the process of data extraction, the categorizing of projects, and any other steps used in producing the CapEx filing, including documentation of key controls, checkpoints and approvals; and (3) eliminate the lag time between energizing equipment and recording it in the Massachusetts Electric Companies' accounting system as in-service and to correct the Massachusetts Electric Companies' accounts for errors associated with manual adjustments associated with in-service dates of assets. The Massachusetts Electric Companies have completed the first recommendation and are currently on track to implement the remaining recommendations by January 2017.

Storm Management Audit

In the December 11, 2012 order, the DPU ordered a management audit of the Massachusetts Electric Companies' emergency planning, outage management, and restoration. The auditors submitted their Final Report to the DPU on July 9,

2014. The DPU adopted the auditor's thirty recommendations, which include items such as improving emergency response training and tracking of training, designating additional personnel for storm roles, and considering the expanded use of technology and communication tools. The Massachusetts Electric Companies have already implemented some of the recommendations and are in the process of implementing the remaining recommendations.

Storm Cost Recovery

The Massachusetts Electric Companies have deferred incremental storm costs to respond to and restore power associated with several major weather events occurring since January 2010, pending ultimate approval by the DPU to charge its deferred costs to the Massachusetts Electric Companies' Storm Contingency Fund. The deferred incremental storm cost and carrying cost amounts have been reduced to reflect the impact of actual and estimated billings to Verizon for vegetation management costs as a result of the DPU's order regarding the December 2008 ice storm. On May 3, 2013, following a request by the Massachusetts Electric Companies for accelerated funding for the Massachusetts Electric Companies' Storm Contingency Fund, the DPU approved a Storm Fund Replenishment Factor ("SFRF") of $40 million annually for up to three years, or $120 million. This is in addition to $4.3 million that the Massachusetts Electric Companies recover annually in base rates for the Storm Contingency Fund. In its ruling, the DPU also directed the Massachusetts Electric Companies to submit two filings of all documentation supporting their storm costs for DPU review and approval. The first filing for $128 million of costs relating to qualifying storms that occurred during calendar years 2010 and 2011 was made on May 31, 2013 (later updated to exclude vegetation management costs billed to Verizon) and the second filing for $94 million of storm costs (net of vegetation management costs billable to Verizon) related to storm events that occurred during calendar year 2012 through March 2013 was made on September 30, 2014. In its September 30, 2014 filing, the Massachusetts Electric Companies also requested an extension of the SFRF through June 2018 to eliminate the deficit in the Storm Contingency Fund created by storm events experienced through March 2013. On April 13, 2016, the DPU extended the SFRF for three additional months until August 4, 2016, unless otherwise ordered, while its prudency review is ongoing. The Company cannot currently predict the outcome of any proceedings related to storm recovery.

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

As part of the November 2015 Electric Rate Case Filing, the Massachusetts Electric Companies proposed a further extension of the approximately $47 million in total SFRF recoveries to August 2019, or fourteen months beyond the June 2018 date proposed in the pending storm cost proceeding.

Gas Transportation and Storage Contracts

On January 15, 2016, the Massachusetts Electric Companies filed petitions with the DPU for approval of: (1) two long-term gas transportation and storage services agreements with Algonquin Gas Transmission, LLC on the proposed Access Northeast pipeline (together, the "ANE Contracts"); (2) two long-term transportation agreements with Tennessee Gas Pipeline, LLC on the proposed Northeast Energy Direct pipeline (together, the "NED Contracts"); (3) an Electric Reliability Service Program ("ERSP") to set parameters for the release of capacity and sale of LNG supply available by virtue of the ANE and NED Contracts; and (4) Long-Term Gas Transportation and Storage Contracts tariffs, which would allow for recovery of the costs associated with the agreements executed by the Massachusetts Electric Companies for the provision of interstate pipeline transportation and gas storage services to electric generation facilities in the region, as well as an innovation incentive for the Massachusetts Electric Companies equal to 2.75% of the annual fixed contract payments under the proposed ANE and NED Contracts. Both pipelines are designed to provide increased natural gas deliverability to the New England markets. If approved by the DPU, the Massachusetts Electric Companies would release their capacity on these

pipelines to the electric market in accordance with an Electric Reliability Service tariff, which is subject to approval by the FERC, and in accordance with the state-approved ERSP, in order to improve the reliability and cost of electric supply for its electric retail customers. As a result of receiving an April 21, 2016 termination notice on the NED Contracts from Tennessee Gas Pipeline, LLC, on April 26, 2016, the Massachusetts Electric Companies submitted a motion to withdraw their request for DPU approval of the NED Contracts, which the DPU granted on April 27, 2016. The estimated estimates levelized annual net benefits from the ANE project by itself are $1.1 billion per year from 2019 through 2038 for electric customers in New England under normal weather conditions. There will be DPU hearings on the contracts, with a decision expected by the fall of 2016.

The Massachusetts Gas Companies

General Rate Case

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

Gas System Enhancement Plan

On April 30, 2015 and April 29, 2016, the DPU approved the Massachusetts Gas Companies' 2015 and 2016 Gas System Enhancement Plans (''GSEP'') for calendar year 2015 and 2016, respectively, and the associated gas system enhancement adjustment factors ("GSEAFs"). The approved GSEAFs are designed to provide concurrent recovery of the revenue requirement associated with the Massachusetts Gas Companies' capital costs for the replacement of eligible leak prone pipe and ancillary equipment pursuant to the Massachusetts 2014 Gas Leaks Act. This program replaced the Targeted Infrastructure Replacement ("TIR") Program in 2015, however recovery of the revenue requirement TIR Program investment will continue until recovery commences through new base distribution rates. The approved GSEAFs are designed to recover from all firm sales and transportation customers a revenue requirement of approximately $28.9 million and $9.7 million for 2016 and 2015, respectively. Also on April 29, 2016, the Massachusetts Electric Companies submitted their first GSEP reconciliation filing for 2015, which reconciled the 2015 revenue requirement on 2015 actual GSEP capital investment with revenue billed through the GSEAFs, and proposed to credit customers $3.3 million as a result of this reconciliation effective November 1, 2016.

New England Power

Stranded Cost Recovery

Under settlement agreements approved by state commissions and the FERC, NEP is permitted to recover stranded costs (those costs associated with its former generating investments (nuclear and non-nuclear) and related contractual commitments that were not recovered through the sale of those investments). NEP earns a ROE of approximately 11% on stranded cost recovery. NEP will recover its remaining non-nuclear stranded costs through 2020. See the "Decommissioning Nuclear Units" section in Note 14 "Commitments and Contingencies," for a discussion of ongoing costs associated with decommissioned nuclear units.

Transmission Return on Equity

NEP's transmission rates applicable to transmission service through October 15, 2014 reflect a base ROE of 11.14% applicable to NEP's transmission facilities, plus an additional 0.5% Regional Transmission Organization ("RTO") participation adder applicable to transmission facilities included under the Regional Network Service ("RNS") rate. Approximately 70% of the NEP's transmission facilities are included under RNS rates. NEP earns an additional 1% ROE incentive adder on RNS-related transmission facilities approved under the RTO's Regional System Plan and placed in service on or before December 31, 2008. It also earns a 1.25% ROE incentive on its portion of New England East-West Solution ("NEEWS") as described below. 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 14, "Commitments and Contingencies") reducing NEP's base ROE to 10.57%. The

FERC also established a maximum ROE such that the aforementioned incentives, taken together, may not exceed a cap of 11.74%.

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.

New England East-West Solution

In September 2008, NEP, its affiliate 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%), (2) 100% construction work in progress in rate base, and (3) recovery of plant abandoned for reasons beyond the companies' control. 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

The RIPUC approved a settlement agreement among the 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. The settlement also included reinstatement of base rate recovery of storm fund contributions and implementation of a Pension Adjustment Mechanism for pension and PBOP expenses for the electric business identical to the mechanism in place for the gas business.

5. PROPERTY, PLANT AND EQUIPMENT

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

	March 31,	
	2016	2015
	(in millions of dollars)	
Plant and machinery	**$ 30,890**	$ 28,980
Property held for future use	**15**	15
Land and buildings	**2,227**	2,108
Assets in construction	**1,477**	1,513
Software and other intangibles	**991**	792
Total property, plant and equipment	**35,600**	33,408
Accumulated depreciation and amortization	**(8,136)**	(7,813)
Property, plant and equipment, net	**$ 27,464**	$ 25,595

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,	
	2016	2015	**2016**	2015
	(in millions)		*(in millions)*	
Gas future contracts (dths)	**-**	-	**14**	20
Gas option contracts (dths)	**-**	-	**16**	4
Gas purchase contracts (dths)	**-**	-	**44**	55
Gas swap contracts (dths)	**-**	-	**76**	65
Electric swap contracts (mwhs)	**12**	11	**-**	-
Total	**12**	11	**150**	144

Amounts Recognized in the Accompanying Consolidated Balance Sheets

	Asset Derivatives			Liability Derivatives		
	March 31,			March 31,		
	2016	2015		**2016**	2015	
	(in millions of dollars)			*(in millions of dollars)*		
Current assets:			Current liabilities:			
Rate recoverable contracts:			Rate recoverable contracts:			
Gas future contracts	**$ 1**	$ -	Gas future contracts	**$ 12**	$ 11	
Gas purchase contracts	**1**	14	Gas purchase contracts	**2**	6	
Gas swap contracts	**5**	2	Gas swap contracts	**16**	37	
Electric option contracts	**-**	-	Electric option contracts	**-**	1	
Electric swap contracts	**2**	19	Electric swap contracts	**63**	47	
Contracts not subject to rate recovery:			Contracts not subject to rate recovery:			
Gas swap contracts	**-**	-	Gas swap contracts	**-**	1	
Hedge contracts:			Hedge contracts:			
Cross-currency & interest rate swaps	**-**	2	Cross-currency & interest rate swaps	**-**	159	
Foreign exchange forward contracts	**6**	-	Foreign exchange forward contracts	**1**	-	
	15	37		**94**	262	
Other non-current assets:			Other non-current liabilities:			
Rate recoverable contracts:			Rate recoverable contracts:			
Gas future contracts	**-**	-	Gas future contracts	**2**	6	
Gas purchase contracts	**2**	15	Gas purchase contracts	**-**	1	
Gas swap contracts	**-**	-	Gas swap contracts	**2**	3	
Electric capacity contracts	**3**	-	Electric capacity contracts	**-**	-	
Electric option contracts	**-**	-	Electric option contracts	**1**	-	
Electric swap contracts	**-**	-	Electric swap contracts	**36**	29	
	5	15		**41**	39	
Total	**$ 20**	$ 52	Total	**$ 135**	$ 301	

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 changes in fair value of the Company's contracts not subject to rate recovery are recorded within purchased gas in the accompanying consolidated statements of income.

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 $83.6 million and $54 million as of March 31, 2016 and 2015, respectively.

The aggregate fair value of the Company's commodity derivative instruments with credit-risk-related contingent features that are in a liability position at March 31, 2016 and 2015 was $111.8 million and $98.3 million, respectively. The Company had $29 million and $12.1 million collateral posted for these instruments at March 31, 2016 and 2015, respectively. At March 31, 2016, 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 $9.6 million, $22.1 million, or $84.5 million, respectively. At March 31, 2015, 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 $13.6 million, $23.6 million, or $96.5 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, 2016
Gross Amounts Not Offset in the Consolidated Balance Sheets
(in millions of dollars)

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

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

March 31, 2015
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	$ 29	$ -	$ 29	$ -	$ -	$ 29
Gas swap contracts	2	-	2	-	-	2
Electric swap contracts	19	-	19	-	-	19
Cross-currency & interest rate swaps	2	-	2	-	-	2
Total	$ 52	$ -	$ 52	$ -	$ -	$ 52

LIABILITIES:	Gross amounts of recognized liabilities *A*	Gross amounts offset in the Consolidated Balance Sheets *B*	Net amounts of presented in the Consolidated Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral paid *Db*	Net amount *E=C-D*
Derivative instruments						
Gas future contracts	$ 17	$ -	$ 17	$ -	$ 17	$ -
Gas purchase contracts	7	-	7	-	-	7
Gas swap contracts	41	-	41	-	-	41
Electric option contracts	1	-	1	-	-	1
Electric swap contracts	76	-	76	-	12	64
Cross-currency & interest rate swaps	159	-	159	-	115	44
Total	$ 301	$ -	$ 301	$ -	$ 144	$ 157

7. FAIR VALUE MEASUREMENTS

The following tables present assets and liabilities measured and recorded at fair value in the accompanying consolidated balance sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2016 and 2015:

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

	March 31, 2015			
	Level 1	Level 2	Level 3	Total
		(in millions of dollars)		
Assets:				
Derivative instruments				
Gas purchase contracts	$ -	$ -	$ 29	$ 29
Gas swap contracts	-	2	-	2
Electric swap contracts	-	19	-	19
Cross-currency & interest rate swaps	-	2	-	2
Available-for-sale securities	125	133	-	258
Total	125	156	29	310
Liabilities:				
Derivative instruments				
Gas future contracts	17	-	-	17
Gas purchase contracts	-	-	7	7
Gas swap contracts	-	41	-	41
Electric options contracts	-	-	1	1
Electric swap contracts	-	76	-	76
Cross-currency & interest rate swaps	-	159	-	159
Total	17	276	8	301
Net assets (liabilities)	$ 108	$ (120)	$ 21	$ 9

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

The Company's Level 3 fair value derivative instruments primarily consist of OTC gas option contracts and gas purchase contracts, which are valued based on internally-developed models. Industry-standard valuation techniques, such as the Black-Scholes pricing model, Monte Carlo simulation, and Financial Engineering Associates libraries are used for valuing such instruments. A derivative is designated Level 3 when it is valued based on a forward curve that is internally developed, extrapolated, or derived from market observable curves with correlation coefficients less than 95%, where optionality is present, or if non-economic assumptions are made. The internally developed forward curves have a high level of correlation with Platts Mark-to-Market curves and are reviewed by the middle office. The Company considers non-performance risk and liquidity risk in the valuation of derivative instruments categorized in Level 2 and Level 3.

Available-for-sale securities: Available-for-sale securities are included in financial investments in the accompanying consolidated balance sheets 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 Dominion Midstream Partners, LP: The Company's Level 2 Investment in DM is valued based on Level 1 quoted market prices for DM common units, combined with a discount to the quoted market price which is calculated using Level 2 inputs, to reflect restrictions on the transfer of the units and resulting lack of marketability.

Changes in Level 3 Derivative Instruments

	Years Ended March 31,	
	2016	2015
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 21**	$ (6)
Transfers out of Level 3	**-**	5
Total gains or losses included in regulatory assets and liabilities	**(25)**	(17)
Settlements	**7**	39
Balance as of the end of the year	**$ 3**	$ 21
The amount of total gains or losses for the year included in net income attributed to the change in unrealized gains or losses related to non-regulatory assets and liabilities at year-end	**$ -**	$ -

A transfer into Level 3 represents existing assets or liabilities that were previously categorized at a higher level for which the inputs became unobservable during the year. A transfer out of Level 3 represents assets and liabilities that were previously classified as Level 3 for which the inputs became observable based on the criteria discussed previously for classification in Level 2. These transfers, which are recognized at the end of each period, result from changes in the observability of forward curves from the beginning to the end of each reporting period. There were no transfers between Level 1 and Level 2, and no transfers into Level 3, during the years ended March 31, 2016 or 2015.

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivative instruments valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility, and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The forward curves used for financial reporting are developed and verified by the middle office.

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

Commodity	Level 3 Position	Fair Value as of March 31, 2015 Assets	(Liabilities)	Total	Valuation Technique(s)	Significant Unobservable Input	Range
		(in millions of dollars)					
Gas	Purchase contracts	24	(7)	17	Discounted Cash Flow	Forward Curve LNG Forward Curve	$0.96-$11.47/dth
Gas	Cross commodity contracts	5	-	5	Discounted Cash Flow	Forward Curve	$17.47-$378.51/dth
Electric	Option contracts	-	(1)	(1)	Discounted Cash Flow	Implied Volatility	30%-69%
	Total	$ 29	$ (8)	$ 21			

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 and gas and electric option derivative instruments are forward commodity prices (both gas and electric), implied volatility, and valuation assumptions pertaining to peaking gas deals based on forward gas curves. A relative change in commodity price at various locations underlying the open positions can result in significantly different fair value estimates.

Other Fair Value Measurements

The Company's consolidated balance sheets reflect long-term debt at amortized cost. The fair value of the Company's long-term debt was based on quoted market prices when available, or estimated using quoted market prices for similar debt. The fair value of this debt at March 31, 2016 and 2015 was $10.2 billion.

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

8. EMPLOYEE BENEFITS

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

Pension Plans

The Pension Plans are comprised of both qualified and non-qualified plans. The qualified pension plans provide substantially all union employees, as well as all non-union employees hired before January 1, 2011, with a retirement benefit. Supplemental, non-qualified, non-contributory executive retirement programs provide additional defined pension benefits to certain eligible executives. The Company funds the qualified plans by contributing at least the minimum amount required under Internal Revenue Service ("IRS") regulations. The Company expects to contribute $316 million to the Pension Plans during the year ending March 31, 2017.

PBOP Plans

The Company's PBOP Plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must contribute to the cost of their coverage. The Company funds these plans based on the requirements of the various regulatory jurisdictions in which it operates. The Company expects to contribute $342 million to the PBOP Plans during the year ending March 31, 2017.

Defined Contribution Plans

The Company also has several defined contribution pension plans (primarily 401(k) employee savings fund plans) that cover substantially all employees. In addition, employees may receive certain employer contributions, including matching contributions and a 15% discount on the purchase of National Grid plc common stock. Employer matching contributions of approximately $46 million and $41 million were expensed in the years ended March 31, 2016 and 2015, respectively.

Components of Net Periodic Benefit Costs

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2016	2015	**2016**	2015
	(in millions of dollars)			
Service cost	**$ 136**	$ 119	**$ 77**	$ 62
Interest cost	**355**	368	**198**	203
Expected return on plan assets	**(448)**	(473)	**(185)**	(190)
Amortization of prior service cost (credit), net	**7**	7	**(5)**	6
Amortization of net actuarial loss	**295**	237	**103**	61
Total cost	**$ 345**	$ 258	**$ 188**	$ 142

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

Amounts Recognized in AOCI and Regulatory Assets

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2016	2015	**2016**	2015
	(in millions of dollars)			
Net actuarial loss (gain)	**$ 261**	$ 793	**$ (34)**	$ 563
Prior service cost	**-**	2	**-**	-
Amortization of net actuarial gain	**(295)**	(237)	**(103)**	(61)
Amortization of prior service (cost) credit, net	**(7)**	(7)	**5**	(6)
Total	**$ (41)**	$ 551	**$ (132)**	$ 496
Included in regulatory assets	**$ (20)**	$ 261	**$ (81)**	$ 380
Included in AOCI	**(21)**	290	**(51)**	116
Total	**$ (41)**	$ 551	**$ (132)**	$ 496

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

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

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2016	2015	**2016**	2015
	(in millions of dollars)			
Net actuarial loss	**$ 2,203**	$ 2,237	**$ 1,009**	$ 1,146
Prior service cost (credit)	**34**	41	**(24)**	(29)
Total	**$ 2,237**	$ 2,278	**$ 985**	$ 1,117
Included in regulatory assets	**$ 1,127**	$ 1,147	**$ 697**	$ 777
Included in AOCI	**1,110**	1,131	**288**	340
Total	**$ 2,237**	$ 2,278	**$ 985**	$ 1,117

The amount of expected net actuarial loss and prior service credit to be amortized from regulatory assets and AOCI during the year ended March 31, 2017 for the Pension Plans and PBOP Plans is $109 million and $8million, respectively.

Reconciliation of Funded Status to Amount Recognized

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2016	2015	**2016**	2015
	(in millions of dollars)			
Change in benefit obligation:				
Benefit obligation as of the beginning of the year	**$ (8,934)**	$ (7,872)	**$ (5,067)**	$ (4,469)
Service cost	**(136)**	(119)	**(77)**	(62)
Interest cost	**(355)**	(368)	**(198)**	(203)
Net actuarial gain (loss)	**190**	(998)	**279**	(501)
Benefits paid	**457**	425	**211**	197
Settlements/curtailments	**-**	-	**(22)**	-
Other	**-**	(2)	**-**	(29)
Benefit obligation as of the end of the year	**(8,778)**	(8,934)	**(4,874)**	(5,067)
Change in plan assets:				
Fair value of plan assets as of the beginning of the year	**7,502**	7,052	**2,827**	2,702
Actual (loss) return on plan assets	**(3)**	678	**(60)**	128
Company contributions	**341**	197	**170**	194
Benefits paid	**(457)**	(425)	**(211)**	(197)
Fair value of plan assets as of the end of the year	**7,383**	7,502	**2,726**	2,827
Funded status	**$ (1,395)**	$ (1,432)	**$ (2,148)**	$ (2,240)

The benefit obligation shown above is the projected benefit obligation ("PBO") for the Pension Plans and the accumulated benefit obligation ("ABO") for the PBOP Plans. The Company is required to reflect the funded status of its Pension Plans above in terms of the PBO, which is higher than the ABO, because the PBO includes the impact of expected future compensation increases on the pension obligation. The Pension Plans had ABO balances that exceeded the fair value of plans assets as of March 31, 2016 and 2015. The aggregate ABO balances for the Pension Plans were $8.4 billion and $8.5 billion as of March 31, 2016 and 2015, respectively.

Amounts Recognized in the Accompanying Consolidated Balance Sheets

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2016	2015	**2016**	2015
	(in millions of dollars)			
Non-current assets	**$ 179**	$ 179	**$ 8**	$ 10
Current liabilities	**(23)**	(23)	**(11)**	(16)
Non-current liabilities	**(1,551)**	(1,588)	**(2,145)**	(2,234)
Total	**$ (1,395)**	$ (1,432)	**$ (2,148)**	$ (2,240)

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to March 31, 2016:

(in millions of dollars) Years Ending March 31,	Pension Plans	PBOP Plans
2017	$ 526	$ 197
2018	533	207
2019	535	216
2020	538	226
2021	541	237
Thereafter	2,737	1,325
Total	$ 5,410	$ 2,408

Assumptions Used for Employee Benefits Accounting

	Pension Plans		PBOP Plans	
	Years Ended March 31,		Years Ended March 31,	
	2016	2015	**2016**	2015
Benefit Obligations:				
Discount rate	**4.25%**	4.10%	**4.25%**	4.10%
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	3.50%
Expected return on plan assets	**6.25%-6.5%**	6.25%	**6.25%-6.75**	6.25% - 6.75%
Net Periodic Benefit Costs:				
Discount rate	**4.10%**	4.80%	**4.10%**	4.80%
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	3.50%
Expected return on plan assets	**6.25%**	7.00%	**6.25%-6.75%**	7.00% - 7.25%

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,	
	2016	2015
Health care cost trend rate assumed for next year		
Pre 65	**7.50%**	8.00%
Post 65	**6.25%**	6.50%
Prescription	**11.00%**	6.50%
Rate to which the cost trend is assumed to decline (ultimate)	**4.50%**	5.00%
Year that rate reaches ultimate trend		
Pre 65	**2025**	2022
Post 65	**2024**	2022
Prescription	**2025**	2022

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

(in millions of dollars)	March 31, 2016
1% point increase	
Total of service cost plus interest cost	$ 57
Postretirement benefit obligation	807
1% point decrease	
Total of service cost plus interest cost	(45)
Postretirement benefit obligation	(669)

Plan Assets

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

The target asset allocations for the benefit plans as of March 31, 2016 and 2015 are as follows:

	Pension Plans		PBOP Plans	
	March 31,		March 31,	
	2016	2015	**2016**	2015
U.S. equities	**20%**	20%	**40%**	39%
Global equities (including U.S.)	**7%**	7%	**6%**	6%
Global tactical asset allocation	**10%**	10%	**8%**	9%
Non-U.S. equities	**10%**	10%	**21%**	21%
Fixed income	**40%**	40%	**25%**	25%
Private equity	**5%**	5%	**-**	-
Real estate	**5%**	5%	**-**	-
Infrastructure	**3%**	3%	**-**	-
	100%	100%	**100%**	100%

Fair Value Measurements

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

	March 31, 2016				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in millions of dollars)		
Pension Assets:					
Cash and cash equivalents	$ 13	$ 61	$ -	$ 92	$ 166
Accounts receivable	108	-	-	-	108
Accounts payable	(105)	-	-	-	(105)
Convertible securities	-	1	-	-	1
Equity	939	223	-	1,878	3,040
Global tactical asset allocation	-	-	-	373	373
Fixed income securities	-	2,798	-	138	2,936
Preferred securities	1	23	-	-	24
Futures contracts	-	(2)	-	-	(2)
Private equity	-	-	-	445	445
Real estate	-	-	-	397	397
Total	$ 956	$ 3,104	$ -	$ 3,323	$ 7,383
PBOP Assets:					
Cash and cash equivalents	$ 35	$ 13	$ -	$ 2	$ 50
Accounts receivable	28	-	-	-	28
Accounts payable	(25)	-	-	-	(25)
Equity	423	84	-	1,220	1,727
Global tactical asset allocation	72	-	-	189	261
Fixed income securities	3	675	-	-	678
Futures contracts	-	1	-	-	1
Private equity	-	-	-	6	6
Total	$ 536	$ 773	$ -	$ 1,417	$ 2,726

	March 31, 2015				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in millions of dollars)		
Pension Assets:					
Cash and cash equivalents	$ 19	$ 53	$ -	$ 78	$ 150
Accounts receivable	116	-	-	-	116
Accounts payable	(142)	-	-	-	(142)
Equity	958	229	-	1,923	3,110
Global tactical asset allocation	-	-	-	349	349
Fixed income securities	-	2,955	-	147	3,102
Preferred securities	1	29	-	-	30
Futures contracts	-	4	-	-	4
Private equity	-	-	-	413	413
Real estate	-	-	-	370	370
Total	$ 952	$ 3,270	$ -	$ 3,280	$ 7,502
PBOP Assets:					
Cash and cash equivalents	$ 39	$ 10	$ -	$ 1	$ 50
Accounts receivable	5	-	-	-	5
Accounts payable	(2)	-	-	-	(2)
Equity	446	83	-	1,303	1,832
Global tactical asset allocation	70	-	-	179	249
Fixed income securities	3	683	-	-	686
Private equity	-	-	-	7	7
Total	$ 561	$ 776	$ -	$ 1,490	$ 2,827

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

Cash and cash equivalents: Cash and cash equivalents that can be priced daily are classified as Level 1. Active reserve funds, reserve deposits, commercial paper, repurchase agreements, and commingled cash equivalents are classified as Level 2. Cash and cash equivalents invested in the Employee Benefit Temporary Investment Funds and JPMorgan Chase Bank Liquidity Funds are excluded from the fair value hierarchy. Such instruments are generally valued using a curve methodology that includes observable inputs such as money market rates for specific instruments, programs, currencies and maturity points obtained from a variety of market makers, reflective of current trading levels. The methodologies consider an instrument's days to final maturity to generate a yield based on the relevant curve for the instrument.

Accounts receivable and accounts payable: Accounts receivable and accounts payable are classified in the same category as the investments to which they relate. Such amounts are short-term and settle within a few days of the measurement date.

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

Global tactical asset allocation: Assets held in global tactical asset allocation funds are managed by investment managers who use both top-down and bottom-up valuation methodologies to value asset classes, countries, industrial sectors, and individual securities in order to allocate and invest assets opportunistically. If the inputs used to measure a financial instrument fall within different levels of the fair value hierarchy within the commingled fund, the categorization is based on the lowest level input that is significant to the measurement of that financial instrument. Those which are open ended mutual funds with observable pricing are classified as Level 1. Investments with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

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

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

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

Other Benefits

At March 31, 2016 and 2015, the Company had accrued workers compensation, auto, and general insurance claims which have been incurred but not yet reported of $90.7 million and $82.7 million, respectively.

9. ACCUMULATED OTHER COMPREHENSIVE INCOME

The following table represents the changes in the Company's AOCI for the years ended March 31, 2016 and 2015:

	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, 2014	$ 2	$ (652)	$ (2)	$ (652)
Other comprehensive income (loss) before reclassifications:				
Unrecognized net acturial loss (net of $219 tax benefit)	-	(313)	-	(313)
Gain on investment (net of $9 tax expense)	13	-	-	13
Amounts reclassified from other comprehensive income (loss):				
Amortization of net actuarial loss (net of $52 tax expense) [2]	-	75	-	75
Amortization of treasury lock (net of $1 tax benefit) [1]	-	-	(1)	(1)
Gain on investment (net of $5 tax benefit) [2]	(7)	-	-	(7)
Net current period other comprehensive income (loss)	6	(238)	(1)	(233)
Balance as of March 31, 2015	$ 8	$ (890)	$ (3)	$ (885)
Other comprehensive income (loss) before reclassifications:				
Unrecognized net acturial loss (net of $42 tax benefit)	-	(61)	-	(61)
Gain on investment (net of $1 tax expense)	2	-	-	2
Amounts reclassified from other comprehensive income (loss):				
Amortization of net actuarial loss (net of $71 tax expense) [2]	-	103	-	103
Amortization of treasury lock (net of $0 tax benefit) [1]	-	-	1	1
Gain on investment (net of $4 tax benefit) [2]	(6)	-	-	(6)
Net current period other comprehensive income (loss)	(4)	42	1	39
Balance as of March 31, 2016	**$ 4**	**$ (848)**	**$ (2)**	**$ (846)**

[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 ended March 31, 2017.

10. CAPITALIZATION

The aggregate maturities of long-term debt for the years subsequent to March 31, 2016 are as follows:

(in millions of dollars) Years Ending March 31,		
2017	$	940
2018		106
2019		54
2020		1,026
2021		346
Thereafter		6,766
Total	$	9,238

Sinking fund repayment requirements related to certain of the Company's Promissory Notes to NGNA and First Mortgage Bonds for the years subsequent to March 31, 2016 are as follows:

(in millions of dollars) Years Ending March 31,		
2017	$	19
2018		19
2019		19
2020		19
2021		19
Thereafter		144
Total	$	239

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, 2016 and 2015, the Company was in compliance with all such covenants.

Significant Debt Covenants and Facilities

European Medium Term Note Program

The Company previously issued debt instruments ("instruments") under a Euro Medium Term Note program (the "Program") under which it was able to issue instruments up to a total of the equivalent of 4 billion Euros. Such instruments issued under the Program were admitted to trading on the London Stock Exchange. The Program commenced in December 2007 and was renewed annually until December 2015. The non-renewal of the Program precludes the issuance of new instruments under the Program, but does not impact the outstanding debt balances and their maturity dates. As of March 31, 2016, the Company had no outstanding debt balances under the Program.

Gas Facilities Revenue Bonds

Brooklyn Union has outstanding tax-exempt Gas Facilities Revenue Bonds ("GFRB") issued through the New York State Energy Research and Development Authority ("NYSERDA"). At March 31, 2016 and 2015, $641 million of GFRB were outstanding; $230 million of which are variable-rate, auction rate bonds. The GFRB currently in auction rate mode are backed by bond insurance. These bonds cannot be put back to Brooklyn Union and, in the case of a failed auction, the

resulting interest rate on the bonds would revert to the maximum auction rate which depends on the current appropriate, short-term benchmark rates and the senior unsecured rating of the Brooklyn Union's bonds. The effect of the failed auctions on interest on long-term debt was not material for the years ended March 31, 2016 or 2015.

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 $49 million, respectively, of non-callable First Mortgage Bonds ("FMB"). These FMB indentures include, among other provisions, limitations on the issuance of long-term debt.

State Authority Financing Bonds

At March 31, 2016, the Company had outstanding $918 million of State Authority Financing Bonds, of which, approximately $495 million were issued through NYSERDA and the remaining $423 million were issued through various other state agencies.

Approximately $429 million of State Authority Financing Bonds were issued to secure a like amount of tax-exempt revenue bonds issued by NYSERDA. These securities bear interest at short-term adjustable interest rates (with an option to convert to other rates, including a fixed interest rate). The bonds are currently in auction rate mode and are backed by bond insurance. These bonds cannot be put back to Niagara Mohawk and, in the case of a failed auction, the resulting interest rate on the bonds would revert to the maximum rate which depends on the current appropriate, short-term benchmark rate and the senior secured rating of Niagara Mohawk or the bond insurer, whichever is greater. The effect on interest on long-term debt has not been material in either of the years ended March 31, 2016 or 2015. Additionally, Genco has $41 million of 1999 Series A Pollution Control Revenue Bonds due October 1, 2028. Genco also has outstanding $25 million of variable rate 1997 Series A Electric Facilities Revenue Bonds due December 1, 2027.

Additionally, at March 31, 2016, NEP had outstanding $372 million of Pollution Control Revenue Bonds in tax-exempt commercial paper mode and Nantucket had $51 million of Electric Revenue Bonds in tax exempt commercial paper mode. The Electric Revenue Bonds were issued by the Massachusetts Development Finance Agency in connection with Nantucket's financing of its first and second underground and submarine cable projects. Sinking fund payments of $0.4 million were made during the year ended March 31, 2016.

Standby Bond Purchase Agreement

Two of the Company's subsidiaries have a Standby Bond Purchase Agreement ("SBPA"), which expires on November 20, 2019. This agreement provides liquidity support for $423 million of the Company's long-term bonds in tax-exempt commercial paper mode. The Company has classified this 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, 2016, the Company, NGNA, and the Parent have a committed revolving credit facility of £1.7 billion which matures in May 2021. This facility has not been drawn against. The Company, NGNA, and the Parent can all draw on this facility in a variety of currencies as needed, but the aggregate borrowings across the group cannot exceed the £1.7 billion limit. The terms of the facility restrict the borrowing of all U.S. subsidiaries of the Company to $25 billion excluding intercompany indebtedness. Additionally, this facility has a number of non-financial covenants which the Company is obliged to meet. At March 31, 2016 and 2015, NGNA and the Parent were in compliance with all covenants.

Commercial Paper and Revolving Credit Agreements

At March 31, 2016, the Company had two commercial paper programs totaling $4 billion; a $2 billion U.S. commercial paper program and a $2 billion Euro commercial paper program. In support of these programs, the Company was a named

borrower under National Grid plc credit facilities with $1.4 billion available to the Company. These facilities support both the Parent's and the Company's commercial paper programs for ongoing working capital needs. The facilities expire in 2018 and 2021. At March 31, 2016 and 2015, there were $179 million and $486 million of borrowings outstanding on the U.S. commercial paper program and $119 million and $96 million outstanding on the Euro commercial paper program, respectively.

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

Significant Debt Issuances and Redemptions

Notes Payable

At March 31, 2016 and 2015 the Company had outstanding $7.3 billion and $6.3 billion, respectively, of unsecured medium and long-term notes with various interest rates and maturity dates. In March 2016, Brooklyn Union issued $500 million of unsecured senior long-term debt at 3.407% with a maturity date of March 10, 2026 and $500 million of unsecured senior long-term debt at 4.504% with a maturity date of March 10, 2046. In September 2014, Niagara Mohawk issued $500 million of unsecured long-term debt at 3.508% with a maturity date of October 1, 2024 and $400 million of unsecured long-term debt at 4.278% with a maturity date of October 1, 2034.

Industrial Development Revenue Bonds

At March 31, 2015, Genco had outstanding $128 million of 5.25% tax-exempt bonds due June 1, 2027. Of this amount, $53 million was issued through the Nassau County Industrial Development Authority for the construction of the Glenwood electric-generation peaking plant and the balance of $75 million was issued by the Suffolk County Industrial Development Authority for the Port Jefferson electric-generation peaking plant. KeySpan fully and unconditionally guaranteed the payment obligations with regard to these tax-exempt bonds. On November 20, 2015, Genco redeemed the $128 million of Industrial Development Revenue Bonds and KeySpan was relieved of all related guarantee obligations.

State Authority Financing Bonds

At March 31, 2015, Niagara Mohawk had outstanding $75 million of 5.15% fixed rate pollution control revenue bonds issued through NYSERDA callable at par. On June 30, 2015, Niagara Mohawk redeemed the bond at par prior to maturity.

Intercompany Loans

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

11. INCOME TAXES

Components of Income Tax Expense

	Years Ended March 31,	
	2016	2015
	(in millions of dollars)	
Current tax expense (benefit):		
Federal	**$ 1**	$ (57)
State	**56**	43
Total current tax expense (benefit)	**57**	(14)
Deferred tax expense (benefit):		
Federal	**338**	230
State	**12**	(11)
Total deferred tax expense (benefit)	**350**	219
Amortized investment tax credits [1]	**(5)**	(5)
Total deferred tax expense	**345**	214
Total income tax expense	**$ 402**	$ 200

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

Statutory Rate Reconciliation

The Company's effective tax rates for the years ended March 31, 2016 and 2015 are 38% and 34.8%, respectively. The following table presents a reconciliation of income tax expense at the federal statutory tax rate of 35% to the actual tax expense:

	Years Ended March 31,	
	2016	2015
	(in millions of dollars)	
Computed tax	**$ 370**	$ 201
Change in computed taxes resulting from:		
Investment tax credits	**(5)**	(5)
State income tax, net of federal benefit	**45**	20
Other items, net	**(8)**	(16)
Total	**32**	(1)
Total income tax expense	**$ 402**	$ 200

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.

During the period there was no material change in the Company's deferred tax liability for the decrease in the tax rate from 7.1% to 6.5% applicable to New York entities beginning with the year ended March 31, 2017. Likewise there was no material change in the Company's deferred tax liability for the increase in the Metropolitan Transportation Authority surcharge from 25.6% to 28%.

On August 26, 2016, the IRS issued Revenue Procedure 2016-48 that enables the Company to claim prior year's unclaimed bonus depreciation in its federal income tax return for the year ended March 31, 2016. The Company does not believe that adoption of this procedure will have a material impact on its results of operations, financial position, or cash flows.

Deferred Tax Components

	March 31,	
	2016	2015
	(in millions of dollars)	
Deferred tax assets:		
Environmental remediation costs	**$ 545**	$ 587
Future federal benefit on state taxes	**171**	159
Net operating losses	**812**	574
Postretirement benefits and other employee benefits	**1,673**	1,728
Regulatory liabilities - other	**590**	543
Other items	**535**	445
Total deferred tax assets [1]	**4,326**	4,036
Deferred tax liabilities:		
Property related differences	**6,803**	6,187
Regulatory assets - environmental response costs	**682**	713
Regulatory assets - postretirement benefits	**718**	729
Regulatory assets - other	**724**	626
Other items	**358**	346
Total deferred tax liabilities	**9,285**	8,601
Net deferred income tax liabilities	**4,959**	4,565
Deferred investment tax credits	**30**	35
Deferred income tax liabilities, net	**$ 4,989**	$ 4,600

[1] The Company established a valuation allowance for deferred tax assets in the amount of $6 million related to expiring charitable contribution carryforwards at March 31, 2016. There was no valuation allowance for deferred tax assets at March 31, 2015.

As a result of retrospective adoption of ASU 2015-17, the Company adjusted its current portion of deferred income tax assets, net and non-current deferred income tax liabilities, net by $242 million as of March 31, 2015.

Net Operating Losses

The following table presents the amounts and expiration dates of net operating losses as of March 31, 2016:

Expiration of net operating losses:	Federal	State of New York	New York City	State of Massachusetts
		(in millions of dollars)		
3/31/2029	$ 198	$ -	$ -	$ -
3/31/2030	78	-	-	-
3/31/2032	114	-	-	-
3/31/2033	535	-	-	-
3/31/2034	573	-	-	9
3/31/2035	504	1,181 (1)	286 (1)	222
3/31/2036	531	327	81	140

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

Unrecognized Tax Benefits

As of March 31, 2016 and 2015, the Company's unrecognized tax benefits totaled $552 million and $522 million, respectively, of which $60 million and $58 million, respectively, would affect the effective tax rate, if recognized. The unrecognized tax benefits are included in other non-current liabilities in the accompanying consolidated balance sheets.

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

	Years Ended March 31,	
	2016	2015
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 522**	$ 510
Gross increases - tax positions in prior periods	**18**	15
Gross decreases - tax positions in prior periods	**(23)**	(45)
Gross increases - current period tax positions	**35**	47
Settlements with tax authorities	**-**	(5)
Balance as of the end of the year	**$ 552**	$ 522

As of March 31, 2016 and 2015, the Company has accrued for interest related to unrecognized tax benefits of $79 million and $43 million, respectively. During the years ended March 31, 2016 and 2015, the Company recorded interest expense of $36 million and $11 million, respectively. The Company recognizes interest related to unrecognized tax benefits in other interest, including affiliate interest and related penalties, if applicable, in other deductions, net in the accompanying consolidated statements of income. During the year ended March 31, 2016 and 2015, the Company recognized tax penalties in the amount of $0.6 million 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, excluding the impact of the potential settlement with the state of New York, the Company does not believe any such increases or decreases would be material to its results of operations, financial position, or cash flows.

The Company is included in NGNA and subsidiaries' administrative appeal with the IRS related to the issues disputed in the examination cycles for the years ended August 24, 2007, March 31, 2008, and March 31, 2009. Pursuant to the Company's tax sharing agreement, the appeals may result in a change to allocated tax. During the period, the IRS commenced its next

examination cycle which includes income tax returns for the years ended March 31, 2010 through March 31, 2012. The examination is not expected to conclude until December 2017. The income tax returns for the years ended March 31, 2013 through March 31, 2016 remain subject to examination by the IRS.

The Company is included in NGNA and subsidiaries' appeal with the Massachusetts Department of Revenue ("MADOR") related to issues disputed in examination cycles for the years ended March 31, 2001 through March 31, 2005. In September 2016, the appeal related to examination cycles ended March 2001 through March 2002 was denied. In March 2016, the state of Massachusetts concluded its examination of NGNA and subsidiaries' tax returns for the years ended March 31, 2006 through March 31, 2008. The Company is appealing certain adjustments made by the MADOR disputed in this examination cycle. The income tax returns for the years ended March 31, 2009 through March 31, 2016 remain subject to examination by the state of Massachusetts.

The state of New York is in the process of examining the Company's NYS income tax returns. The following table presents the subsidiaries and years currently under examination. The income tax returns for the subsequent years through March 31, 2016 remain subject to examination by the state of New York.

Companies	Years Under Examination
KeySpan Corporation and Subsidiaries	December 31, 2003 through March 31, 2008
KeySpan Gas East	December 31, 2003 through March 31, 2008
Brooklyn Union	August 24, 2007 through March 31, 2008
National Grid Development Holdings, Inc.	March 31, 2009 through March 31, 2012
National Grid Services, Inc.	March 31, 2009 through March 31, 2012
Genco	March 31, 2009 through March 31, 2012
Niagara Mohawk Holdings, Inc.	March 31, 2009 through March 31, 2012

In August 2015, KeySpan Corporation received a preliminary audit report from the state of New York with a proposed increase to state taxable income primarily related to the interest deductions attributable to subsidiary capital. The Company has established a tax reserve of $8 million, net of federal benefit, related to this audit.

In June 2016, the New York Gas Companies received preliminary audit reports with proposed changes to state taxable income primarily related to transition property depreciation deduction. Brooklyn Union conducted an internal review of the audit report, agreed with its findings, and will enter into settlement discussions with the state of New York in the next fiscal year. KeySpan Gas East had previously established a reserve for uncertain tax position for the years under examination. Within the next twelve months, KeySpan Gas East may adjust the tax reserves following the internal review of the audit report and settlement discussions with the state of New York. The range of the reasonably possible change in recognition of tax benefit is estimated to be between zero and $2 million.

The City of New York is in the process of examining the income tax returns of KeySpan Corporation and Subsidiaries and National Grid Services, Inc. for the years ended December 31, 2003 through December 31, 2005, and March 2012 through March 2014, respectively. The income tax returns for the subsequent years through March 31, 2016 remain subject to examination by the City of New York.

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

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

12. GOODWILL

The following table represents the changes in the carrying amount of goodwill for the years ended March 31, 2016 and 2015:

	Years Ended March 31,	
	2016	2015
	(in millions of dollars)	
Balance as of the beginning of the year	**$ 7,129**	$ 7,151
Impairment in Clean Line	**-**	(22)
Balance as of the end of the year	**$ 7,129**	$ 7,129

In January 2013, the Company made an investment in Clean Line. Clean Line is a development-stage entity engaged in the development of long distance, high voltage direct current transmission lines that connect wind farms and other renewable resources in remote parts of the U.S. with electric demand. Based on an analysis of the contractual terms and rights contained in the related agreements, the Company determined that under the applicable accounting standards, Clean Line is a variable interest entity and the Company has effective control over the entity. Therefore, as the primary beneficiary, the Company has consolidated Clean Line.

The fair value of the Clean Line reporting unit was calculated in the annual goodwill impairment test for the year ended March 31, 2015 solely utilizing the income approach. Due to the fact that Clean Line is only at the development stage of its life cycle, its discounted cash flow model was prepared using specific assumptions, rather than the general assumptions used in relation to the Company's longstanding operating companies. The annual impairment test yielded a negative implied fair value of goodwill for the Clean Line reporting unit, and an impairment of $22 million was recognized for the year ended March 31, 2015.

13. 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 New York State 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 has developed a compliance strategy to address anticipated future requirements and is closely monitoring the regulatory developments to identify any necessary changes to its compliance strategy. At this time, Genco is unable to predict what effect, if any, these future requirements will have on its consolidated financial position, results of operations, and cash flows.

Water

Additional capital expenditures associated with the renewal of the surface water discharge permits for Genco's steam electric power plants have been required by the DEC pursuant to Section 316 of the Clean Water Act to mitigate the plants' alleged cooling water system impacts to aquatic organisms. Final permits have been issued for Port Jefferson and Northport. Capital improvements have been completed at Port Jefferson and are in the engineering phase for Northport. The Company continues to engage in discussions with the DEC regarding the nature of capital upgrades or other mitigation measures necessary to reduce any impacts at E.F. Barrett. Total capital costs for these improvements at Northport and E.F. Barrett are estimated to be approximately $76 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 a remediation at this location pursuant to Administrative Order on Consent ("ACO") with the DEC. KeySpan intends to contest these proceedings vigorously.

On February 8, 2007, the Company received a Notice of Intent to File Suit from the AG against KeySpan and four other companies in connection with the cleanup of historical contamination found in certain lands located in Greenpoint, Brooklyn and in an adjoining waterway. KeySpan has previously agreed to remediate portions of the properties referenced in this notice and will work cooperatively with the DEC and AG to address environmental conditions associated with the remainder of the properties. KeySpan has entered into an ACO with the DEC for the land-based sites. The EPA assumed control of the waterway and, on September 29, 2010, listed this site on its National Priorities List of Superfund sites. The Company signed a consent decree with the EPA on July 7, 2011 and is currently performing a Remedial Investigation and Feasibility Study. At this time, the Company is unable to predict what effect, if any, the outcome of these proceedings will have on its consolidated financial position, results of operations, and cash flows.

Utility Sites

At March 31, 2016 and 2015, the Company's total reserve for estimated MGP-related environmental matters is $1.3 billion. The potential high end of the range at March 31, 2016 is presently estimated at $1.9 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 $1.5 billion on the consolidated balance sheets at March 31, 2016 and 2015.

Expenditures incurred were approximately $115 million and $102 million for the years ended March 31, 2016 and 2015, respectively.

Upon the acquisition of KeySpan by NGUSA, the Company recognized those environmental liabilities at fair value. The fair values included discounting of the reserve, which is being accreted over the period for which remediation is expected to occur. Following the acquisition, these environmental liabilities are recognized in accordance with the current accounting guidance for environmental obligations.

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 were approximately $3 million and $1 million for the years ended March 31, 2016 and 2015, respectively. The Company estimated the remaining cost of the environmental remediation activities at non-utility sites were $30 million and $26 million at March 31, 2016 and 2015, respectively. The Company's environmental obligation is discounted at a rate of 6.5%, and the undiscounted amount of environmental liabilities at March 31, 2016 and 2015 was $36 million and $32, 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. Where the Company has regulatory recovery, it believes that the obligations imposed on it because of the environmental laws will not have a material impact on its results of operations or financial position.

14. 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 $99 million and $97 million for the years ended March 31, 2016 and 2015, respectively.

The future minimum lease payments for the years subsequent to March 31, 2016 are as follows:

(in millions of dollars)		
Years Ending March 31,		
2017	$	98
2018		99
2019		85
2020		60
2021		61
Thereafter		356
Total	$	759

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, 2016 are summarized in the table below:

(in millions of dollars) Years Ending March 31,	Energy Purchases	Capital Expenditures
2017	$ 1,538	$ 423
2018	841	76
2019	632	69
2020	498	49
2021	432	38
Thereafter	2,104	-
Total	$ 6,045	$ 655

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

Financial Guarantees

The Company has guaranteed the principal and interest payments on certain outstanding debt of its subsidiaries. Additionally, the Company has issued financial guarantees in the normal course of business, on behalf of its subsidiaries, to various third-party creditors. At March 31, 2016, 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)	$ 315	May 2040
Reservoir Woods	(ii)	196	October 2029
Surety Bonds	(iii)	222	Revolving
Commodity Guarantees and Other	(iv)	98	November 2027 - January 2042
Letters of Credit	(v)	338	May 2016 - February 2017
NY Transco Parent Guaranty	(vi)	842	None
National Grid Algonqin LLC	(vii)	103	December 2021
		$ 2,114	

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, 2016, the Company's obligation related to the lease was $120 million and is

reflected in other non-current liabilities in the accompanying consolidated balance sheets.

(ii) The Company has fully and unconditionally guaranteed $196 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, 2016.

(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 LLC Agreement.

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

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

Town of Johnston Project

In June 2010, pursuant to a 2009 Rhode Island law that required Narragansett to negotiate a contract for an electric generating project fueled by landfill gas from the Rhode Island Central Landfill Narragansett entered into a contract with Rhode Island LFG Genco for the Town of Johnston Project, a combined cycle power plant with an average output of 32 megawatts ("MW"). The facility reached commercial operation on May 28, 2013 and is being accounted for as an operating lease.

Deepwater Agreement

The 2009 Rhode Island law also required Narragansett to solicit proposals for a small scale renewable energy generation project of up to eight wind turbines with an aggregate nameplate capacity of up to 30 MW to benefit the Town of New Shoreham. The renewable energy generation project also included a transmission cable to be constructed between Block Island and the mainland of Rhode Island. On June 30, 2010, Narragansett entered into a 20-year Amended Power Purchase Agreement ("PPA") with Deepwater Wind Block Island LLC, which was approved by the RIPUC in August 2010. 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 the Company and Block Island Power Company through transmission rates. On September 2, 2014, the FERC accepted all four agreements thus approving cost recovery for the Project, with no conditions, that will apply to the Company's costs as well as those of NEP. The agreements went into effect on September 30, 2014. On January 30, 2015, Narragansett closed on its purchase of the Transmission Facilities from Deepwater.

Annual Solicitations

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

- First Solicitation: On July 28, 2011, the RIPUC approved a 15-year PPA with Orbit Energy Rhode Island, LLC for a 3.2 MW anaerobic digester biogas project.
- Second Solicitation: On May 11, 2012, the RIPUC approved a 15-year PPA with Black Bear Development Holdings, LLC for a 3.9 MW run-of-river hydroelectric plant located in Orono, Maine. The facility reached commercial operation on November 22, 2013.
- Third Solicitation: On October 25, 2013, the RIPUC approved a 15-year PPA with Champlain Wind, LLC for a 48 MW land-based wind project located in Carroll Plantation and Kossuth Township, Maine.
- 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.

The Renewable Energy Growth Program

The Renewable Energy ("RE") Growth Program was established pursuant to Chapter 26.6 of Title 39 of the Rhode Island General Laws under the recently-enacted Clean Energy Jobs Program Act (the "Act") to encourage growth of renewable generation in Rhode Island by 160 MW. Pursuant to the Act, Narragansett is required to purchase the output generated by eligible Distributed Generation projects that have been selected for participation in the RE Growth Program and to compensate program applicants in the form of Performance Based Incentive ("PBI") Payments. Participants will be subject to the terms and conditions of the RE Growth Program tariffs approved by the RIPUC and will be compensated via PBI

Payments pursuant to those tariffs, which will be in effect for up to 20 years. The Act provides for the recovery of the incremental costs incurred by Narragansett associated with the implementation and administration of the RE Growth Program from all retail delivery service customers through a fixed monthly charge per customer. Costs eligible for recovery include the PBI Payments less the net proceeds from the sale of the energy and the RECs generated by each project into the market, plus all incremental administrative costs. In addition, the Act authorizes Narragansett to earn 1.75% of the total PBI Payments as remuneration.

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.

FERC ROE Complaints

On September 30, 2011, several state and municipal parties in New England, ("Complainants"), filed a complaint against certain New England Transmission Owners, ("NETOs") including NEP, to lower the base ROE for transmission rates in New England from 11.14% to 9.2 %. On August 6, 2013, a FERC Administrative Law Judge ("ALJ") issued an Initial Decision finding that the base ROE for the refund period and the prospective period should be 10.6% and 9.7%, respectively, prior to any adjustments in a final FERC order. The refund period is the 15-month period from October 1, 2011 through December 31, 2012; the prospective period begins when the FERC issues its final order. In response to the ALJ's Initial Decision, NEP recorded an estimated reduction to revenues of $7.1 million and an increase to interest expense of $0.2 million for the year ended March 31, 2013, reflecting an effective ROE of 10.6% for the portion that would be refunded to transmission customers for the refund period. On June 19, 2014, the FERC issued Opinion No. 531, an initial order modifying the ALJ's findings and its previous methodology for establishing ROE. The FERC tentatively set the ROE at 10.57% and capped the ROE for incentive rates of return to 11.74% subject to further proceedings to establish and quantify growth rates applicable to the ROE. In response, NEP recorded an additional reduction to revenues of $1.2 million and an increase of $0.2 million to interest expense for the fiscal year ended March 31, 2014.

On October 16, 2014, the FERC issued a final order in Opinion No. 531-A establishing a 10.57% base ROE for the NETOs effective as of October 16, 2014 and capped the ROE, including incentives, at 11.74%. The FERC also directed that refunds be issued to transmission customers taking service during the 15-month refund period from October 1, 2011 through December 31, 2012 to reflect these reductions. On March 3, 2015, the FERC issued an Order on Rehearing, Opinion No. 531-B, affirming the 10.57% base ROE and clarifying that the 11.74% maximum ROE applies to all individual transmission projects with ROE incentives previously granted by the FERC. On July 18, 2015, the FERC approved an amended tariff compliance filing submitted by the NETOs in response to Opinion No. 531-B. This order constitutes final FERC action on the first ROE complaint. By December 31, 2015, the Company's total refund obligation of approximately $9.2 million for the periods October 1, 2011 through December 31, 2012, and October 16, 2014 through December 31, 2014, was returned to customers, followed by refund compliance reports submitted to the FERC. The NETOs, including the Company, have appealed certain aspects of the FERC's orders in the first ROE complaint to the U.S. Court of Appeals for the DC Circuit. At this time, the Company is unable to predict the outcome of the appeal.

On December 27, 2012, a second ROE complaint was filed against the NETOs by a coalition of consumers seeking to lower the base ROE for New England transmission rates to 8.7% effective as of December 27, 2012. On June 19, 2014, the FERC issued an order setting the complaint for investigation and a trial-type, evidentiary hearing. The FERC stated that it expects parties to present evidence and any discounted cash flow analyses, as guided by the rulings found in FERC's June 19 order on the first complaint. The FERC's order also established a 15-month refund period for the second complaint beginning on December 27, 2012. In its order setting the complaint for hearing, the FERC noted that, if the case is fully litigated, the FERC expected to issue its final decision no earlier than April 30, 2016.

On July 31, 2014, a third ROE complaint was filed against the NETOs by complainants seeking to lower the base ROE for New England transmission rates to 8.84% effective as of July 31, 2014. On November 24, 2014, the FERC issued an order consolidating this complaint with the second ROE complaint discussed above, setting both matters for investigation and a

trial-type, evidentiary hearing on a consolidated basis. The FERC's order established a 15-month refund period for the third ROE complaint beginning on July 31, 2014 and determined that it would be appropriate for the parties to litigate a separate ROE for the two separate refund periods established by each of the complaints. In its order consolidating the complaints and setting them for hearing, the FERC noted that, if the case is fully litigated, the FERC expects to issue its final decision by September 30, 2016. Hearings in this proceeding were held in February 2016. On March 25, 2016, an Administrative Law Judge ("ALJ") released his decision on the second and third ROE complaints. The ALJ found that the NETOs base ROE should be reduced to 9.59% for the first period at issue (December 27, 2012 through March 26, 2014), but the ROE should be increased to 10.90% for the second period (July 31, 2014 through October 30, 2015, and prospectively after the FERC issues an order on this decision). The new ROEs resulting from the second and third ROE complaints will not go into effect until the FERC issues an order addressing the ALJ's decision.

On April 29, 2016, a group of Massachusetts municipal customers filed a fourth ROE complaint at the FERC arguing that the FERC should reduce the NETOs base ROE to 8.61% and should cap the NETOs' total ROE, including any ROE incentives, at 11.24%. On June 3, 2016, the NETOs filed an answer to this complaint. On September 20, 2016, the FERC issued an order setting the fourth ROE complaint for hearing and settlement proceedings.

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 the Company's, current RNS and Local Network Service ("LNS") formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. The FERC explained that the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates. Accordingly, the FERC established hearing and settlement judge procedures to develop just and reasonable formula rate protocols to be included in the ISO-NE Tariff and to examine the justness and reasonableness of the RNS and LNS rates. The matter is currently in settlement procedures. At this time, the Company is unable to predict and estimate any impact to earnings.

Electric Services and LIPA Agreements

Effective May 28, 2013, Genco provides services to LIPA under an amended and restated PSA. Under the PSA, Genco has a revenue requirement of $418.6 million, a ROE of 9.75% and a capital structure of 50% debt and 50% equity. The 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 PSA as an operating lease.

The 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 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 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. A monthly variable maintenance charge is billed for each unit of energy actually acquired from the generating facilities. The billings to LIPA under the PSA do not include a provision for fuel costs, as such fuel is owned by LIPA.

Decommissioning Nuclear Units

NEP has minority interests in three nuclear generating companies: Yankee Atomic Electric Company ("Yankee Atomic"), Connecticut Yankee Atomic Power Company ("Connecticut Yankee"), and Maine Yankee Atomic Power Company ("Maine

Yankee") (together, the "Yankees"). These ownership interests are accounted for on the equity method. The Yankees operated nuclear generating units which 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 other non-current liabilities and other current liabilities in the accompanying consolidated balance sheets, are as follows:

(in thousands of dollars)	NEP's Investment as of March 31, 2016			Future Estimated Billings to the Company
Unit	%	Amount	Date Retired	Amount
Yankee Atomic	34.5	$ 512	Feb 1992	$ 5,819
Connecticut Yankee	19.5	331	Dec 1996	17,165
Maine Yankee	24.0	621	Aug 1997	6,528

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 liability and a regulatory asset reflecting the estimated future decommissioning billings from the Yankees.

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

Each of the Yankees brought litigation against the DOE for failure to remove their respective nuclear fuel stores as required by the Nuclear Waste Policy Act and contracts. Following a trial at the U.S. Court of Claims ("Claims Court") to determine the level of damages, on October 4, 2006, the Claims Court awarded the three companies an aggregate of $143 million for spent fuel storage costs that had been incurred through 2001 and 2002 (the "Phase I Litigation"). The Yankees had requested $176.3 million. The DOE appealed to the U.S. Court of Appeals for the Federal Circuit, which rendered an opinion generally supporting the Claims Court's decision and remanded the matter to it for further proceedings. In September, 2010, the Claims Court again awarded the companies an aggregate of approximately $143 million. The DOE again appealed and the Yankees cross-appealed. On May 18, 2012, the U.S. Court of Appeals for the Federal Circuit again ruled in favor of the Yankees, awarding them an aggregate of approximately $160 million. The DOE sought reconsideration but, on September 5, 2012, the U.S. Court of Appeals for the Federal Circuit denied the petition for rehearing. The DOE elected not to file a petition for writ of certiorari seeking review by the U.S. Supreme Court and in January 2013 the awards were paid to the Yankees. As of March 31, 2016, total net proceeds of $25.6 million have been refunded to NEP by Connecticut Yankee and Maine Yankee. Yankee Atomic did not provide a refund, but reduced monthly billing effective June 1, 2013. The Company refunds its share to its customers through the CTCs. The remaining amount to be refunded is included within regulatory liabilities in the accompanying consolidated balance sheets.

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

On April 29, 2014, the Yankees submitted informational filings to the FERC in order to flow through the DOE Phase II Litigation proceeds to their Sponsor companies, including the Company, in accordance with financial analyses that were performed earlier that year and supported by stakeholders from Connecticut, Massachusetts, and Maine. The filings

allowed for the flow through of the proceeds to the Sponsors, including the Company, with a rate effective date of June 1, 2014. As of March 31, 2016, total net proceeds of $57.8 million have been refunded to the Company by the Yankees. The Company refunds its share of the net proceeds to its customers through the CTCs.

On August 15, 2013 the Yankees brought further litigation (the "Phase III Litigation") in the Claims Court to recover damages incurred from 2009 through 2012. On March 25, 2016, the judge awarded the Yankees an aggregate of $76.8 million in damages for the Phase III Litigation which is about 98.6% of the damages sought. The DOE elected not to seek appellate review.

The U.S. Congress and the DOE have effectively terminated budgetary support for the proposed long-term spent fuel storage facility at Yucca Mountain in Nevada and the DOE took actions designed to prevent its construction. However, on August 12, 2013 the U.S. Court of Appeals for the DC Circuit ("DC Circuit Court") directed the Nuclear Regulatory Commission ("NRC") to resume the Yucca Mountain licensing process despite insufficient funding to complete it. On October 28, 2013, the DC Circuit Court denied the NRC's petition for rehearing. On November 18, 2013, NRC ordered its staff to resume work on its Yucca Mountain safety report. A Blue Ribbon Commission ("BRC") charged with advising the DOE regarding alternatives to disposal at Yucca Mountain issued its final report on January 26, 2012. In the report, the BRC recommended that priority be given to removal of spent fuel from shutdown reactor sites. 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, 2016 and 2015, Niagara Mohawk had a liability of $168 million, recorded in other non-current liabilities in the accompanying consolidated balance sheets, 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. Niagara Mohawk cannot predict the impact that the recent actions of the DOE and the U.S. government will have on the ability to dispose of the spent nuclear fuel and waste.

SuperStorm Sandy

In October 2012, SuperStorm Sandy hit the northeastern U.S. affecting energy supply to customers in the Company's service territory. Total costs associated with gas customer service restoration from this storm (including capital expenditures) through March 31, 2014 were approximately $204.1 million for the New York Gas Companies.

In December 2014, the Company reached a final settlement with its insurers for $155 million (inclusive of advance payments of $83.4 million), and received final payment for the remaining amounts due. This resulted in the Company recognizing a gain of $11.1 million for the year ended March 31, 2015, recorded as a reduction to operations and maintenance expense in the accompanying consolidated statements of income.

15. RELATED PARTY TRANSACTIONS

Accounts Receivable from and Accounts Payable to Affiliates

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

The Company records short-term receivables from, and payables to, certain of its affiliates in the ordinary course of business. A summary of net outstanding accounts receivable from affiliates and accounts payable to affiliates is as follows:

	Accounts Receivable from Affiliates		Accounts Payable to Affiliates	
	March 31,		March 31,	
	2016	2015	**2016**	2015
	(in millions of dollars)		*(in millions of dollars)*	
National Grid plc	**$ -**	$ -	**$ 44**	$ 52
NGNA	**28**	-	**-**	-
Other	**-**	2	**-**	2
Total	**$ 28**	$ 2	**$ 44**	$ 54

Advances from Affiliates

In August 2009, the Company and KeySpan entered into an agreement with the Parent, whereby either party can collectively borrow up to $3 billion from time to time for working capital needs. These advances bear interest rates of London Interbank Offered Rate plus 1.4%. At March 31, 2016 and 2015 there were no 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, 2016 and 2015, the Company had $3.1 billion and $1.1 billion outstanding advances from NGNA under this agreement.

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, 2016 and 2015, the effect on net income was $32 million and $45 million before taxes and $19 million and $27 million after taxes.

16. 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, 2016 and 2015 is as follows:

		Shares Outstanding		Amount		
		March 31,		March 31,		Call
Series	Company	**2016**	2015	**2016**	2015	**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 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 year ended March 31, 2016, Company declared and made dividend payments of $1.2 billion to NGNA in relation to the series A through E preferred stock.

A summary of preferred stock is as follows:

	Shares Outstanding		Amount (par)		Amount (additional paid-in capital)	
	March 31,		March 31,		March 31,	
Series	**2016**	2015	**2016**	2015	**2016**	2015
	(in millions of dollars, except per share and number of shares data)					
$0.10 par value -						
Series A	**51**	51	**$ -**	$ -	**$ 400**	$ 400
Series B	**40**	40	-	-	**315**	315
Series C	**96**	96	-	-	**750**	750
Series D	**79**	79	-	-	**616**	616
Series E	**1**	1	-	-	**10**	10
Series F	**648**	648	-	-	**5,368**	5,368
Total	**915**	915	**$ -**	$ -	**$ 7,459**	$ 7,459

17. 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, 2016, the Parent had 3.9 billion of ordinary shares issued with 179,065,924 held as treasury shares. The aggregate dilution resulting from executive share-based incentives will not exceed 5% in any ten year period for executive share-based incentives and will not exceed 10% in any ten year period for all employee incentives. This is reviewed by the Remuneration Committee and currently, the Parent has excess headroom of 4.01% and 7.98%, respectively.

The number of units within each award is subject to change depending upon the Parent's ability to meet the stated performance targets. Under the LTPP, performance conditions are split into three parts as follows: (i) 50% of the units awarded are subject to annualized growth in the Parent's earnings per share ("EPS") over a general index of retail prices over a period of three years; (2) 25% of the units awarded will vest based upon the Parent's Total Shareholder Return ("TSR") compared to that of the Financial Times Stock Exchange ("FTSE") 100 over a period of three years; and (3) 25% of the units awarded are subject to the average achieved regulatory ROE. Under the PSP, performance conditions are split into two parts as follows: (1) 50% of the units awarded are subject to annualized growth in the Parent's EPS over a general index of retail prices over a period of three years; and (2) 50% of the units awarded will vest based upon the Parent's TSR compared to that of the FTSE 100 over a period of three years. Units under both plans generally vest at the end of the performance period.

A Monte Carlo simulation model has been used to estimate the fair value for the TSR portion of the awards. For the EPS and ROE portions of the awards, the fair value of the award is determined using the stock price as quoted per the London Stock Exchange or the price for the American Depository Shares as quoted on the New York Stock Exchange as of the earlier of the reporting date or vesting date.

The following table summarizes the stock based compensation expense recognized by the Company for the years ended March 31, 2016 and 2015:

	Units	Weighted Average Grant Date Fair Value
Non-vested as of March 31, 2014	920,732	$ 49.92
Vested	351,669	45.95
Granted	408,730	68.26
Forfeited/Cancelled	122,169	55.86
Non-vested as of March 31, 2015	855,624	60.65
Vested	192,265	58.41
Granted	471,613	66.05
Forfeited/Cancelled	121,787	53.41
Non-vested as of March 31, 2016	1,013,185	$ 66.48

The total expense recognized for non-vested awards was $15.7 million and $15.5 million for the years ended March 31, 2016 and 2015, respectively, and will vest over three years. The total tax benefit recorded was approximately $6.3 million and $6.2 million as of March 31, 2016 and 2015, respectively. Total expense expected to be recognized by the Parent in future periods for non-vested awards outstanding as of March 31, 2016 is $17.9 million, $11.9 million, and $2.3 million for the years ended March 31, 2017, 2018, and 2019, respectively.

18. DISCONTINUED OPERATIONS

On December 15, 2011, LIPA announced that it was not renewing the MSA contract beyond its expiration on December 31, 2013. The loss of the contract resulted in 1,950 employees transferring to a new employer. The results of the MSA are reflected as discontinued operations in the accompanying consolidated financial statements for the years ended March 31, 2016 and 2015.

The reconciliation below highlights the financial statements line items within (loss) income from discontinued operations, net of taxes for the MSA for the years ended March 31, 2016 and 2015:

	Years Ended March 31,	
	2016	2015
	(in millions of dollars)	
Operating revenues	**$ 51**	$ 97
Operations and maintenance	**(67)**	(69)
Other taxes	**(2)**	(8)
Other deductions, net	**(5)**	(2)
Total (loss) income before income taxes	**(23)**	18
Income tax (benefit) expense	**(10)**	8
(Loss) income from discontinued operations, net of taxes	**$ (13)**	$ 10

During the year ended March 31, 2016 bad debt expense of $20 million was recorded in order to adjust the accounts receivable to reflect the probability of collection.

The reconciliation below highlights the carrying values of assets and liabilities related to discontinued operations that are disclosed in the accompanying consolidated balance sheets for the MSA at March 31, 2016 and 2015:

	March 31,	
	2016	2015
	(in millions of dollars)	
Assets		
Accounts receivable	**$ 100**	$ 100
Allowance for doubtful accounts	**(90)**	(70)
Unbilled revenues	**11**	11
Deferred income tax assets	**37**	29
Total assets related to discontinued operations	**$ 58**	$ 70
Liabilities		
Accounts payable	**$ 22**	$ 20
Taxes accrued	**1**	1
Total liabilities related to discontinued operations	**$ 23**	$ 21

19. SUBSEQUENT EVENTS

In August 2016, KeySpan Gas East issued $700 million of unsecured long-term debt at 2.742% with a maturity date of August 1, 2026. Additionally, Massachusetts Electric issued $500 million of unsecured long-term debt at 4.004% with a maturity date of August 1, 2046.

On July 29, 2016, NEP filed a 204 application with the FERC requesting an increase in its short-term borrowing limit from $750 million to $1.5 billion. This increase will provide a source of funding for NEP while it pursues long-term financing authority in Massachusetts, New Hampshire, and Vermont.

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

The following table shows the bonds that have been fully paid subsequent to March 2016:

	Interest Rate	Maturity Date	March 31. 2016
Gas Facilities Revenues Bonds:			*(in millions of dollars)*
1993A and 1993B	6.37%	April 1, 2020	$ 75
1996	5.50%	January 1, 2021	154
2005A	4.70%	February 1, 2024	82
1991A and 1991B	6.95%	July 1, 2026	100
Total debts			$ 411