National Grid North America Inc. and Subsidiaries

(formerly National Grid Holdings Inc.)
Consolidated Financial Statements
For the years ended March 31, 2013 and March 31, 2012

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES

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Independent Auditor's Report

To the Shareholder and Board of Directors of National Grid North America Inc. and Subsidiaries:

We have audited the accompanying consolidated financial statements of National Grid North America Inc. 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 shareholder's equity for the years then ended.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of 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 North America Inc. 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 30, 2013

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	March 31, 2013	March 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 1,186**	$ 796
Restricted cash	**162**	108
Accounts receivable	**2,303**	1,732
Allowance for doubtful accounts	**(310)**	(367)
Other receivable	**67**	-
Accounts receivable from affiliates	**13**	33
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**	191
Prepaid taxes	**300**	4
Prepaid and other current assets	**241**	331
Current assets held for sale	**-**	72
Total current assets	**5,975**	4,668
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	**$ 41,220**	$ 39,056

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

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars)

	March 31, 2013	March 31, 2012
LIABILITIES AND CAPITALIZATION		
Current liabilities:		
Accounts payable	**$ 1,519**	$ 1,189
Accounts payable to affiliates	**45**	48
Commercial paper	**665**	-
Other tax liabilities	**34**	34
Current portion of long-term debt	**1,063**	645
Taxes accrued	**112**	35
Customer deposits	**108**	123
Interest accrued	**185**	170
Regulatory liabilities	**459**	398
Derivative contracts	**11**	135
Payroll and benefits accruals	**272**	274
Other current liabilities	**200**	193
Current liabilities held for sale	**-**	34
Total current liabilities	**4,673**	3,278
Deferred credits and other liabilities:		
Regulatory liabilities	**2,592**	2,526
Asset retirement obligations	**105**	119
Deferred income tax liabilities	**4,191**	3,755
Postretirement benefits	**3,643**	3,675
Environmental remediation costs	**1,370**	1,386
Derivative contracts	**95**	57
Other deferred liabilities	**1,030**	1,367
Deferred liabilities held for sale	**-**	200
Total deferred credits and other liabilities	**13,026**	13,085
Capitalization:		
Shareholder's equity	**8,509**	7,907
Long-term debt	**15,012**	14,786
Total capitalization	**23,521**	22,693
Total liabilities and capitalization	**$ 41,220**	$ 39,056

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

NATIONAL GRID NORTH AMERICA INC. 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	**5,251**	4,321
Depreciation and amortization	**859**	801
Impairment of intangibles 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	**11,505**	11,141
Operating income	**1,096**	1,148
Other income and (deductions):		
Interest on long-term debt	**(403)**	(340)
Other interest expense, including affiliate interest	**(139)**	(231)
Equity income in subsidiaries	**36**	27
Gain on sale of investments	**-**	9
Other (deductions) income, net	**(14)**	45
Total deductions	**(520)**	(490)
Income before income taxes	**576**	658
Income taxes:		
Current	**(318)**	(81)
Deferred	**424**	436
Income tax expense	**106**	355
Income from continuing operations	**470**	303
Net (loss) income from discontinued operations, net of taxes	**(7)**	105
Net income	**463**	408
Net loss (income) attributable to non-controlling interest	**1**	(2)
Net income attributable to common shares	**$ 464**	$ 406

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

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions of dollars)

	Years Ended March 31,	
	2013	2012
Net income	**$ 463**	$ 408
Other comprehensive income (loss):		
Foreign currency translation, net of $1 tax expense	**1**	1
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	**(4)**	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 into net income, net of $61 tax expense and $23 tax benefit	**87**	(34)
Other comprehensive income (loss)	**58**	(206)
Comprehensive income	**521**	202
Less: comprehensive loss (income) attributable to non-controlling interest	**1**	(2)
Comprehensive income attributable to National Grid North America Inc.	**$ 522**	$ 200

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

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions of dollars)

	Years Ended March 31,	
	2013	2012
Operating activities:		
Net income	**$ 463**	$ 408
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	**424**	436
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	**14**	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	**(1,145)**	434
Materials and supplies and gas in storage	**111**	(99)
Accounts payable and accrued expenses	**347**	(250)
Prepaid and accrued taxes	**(222)**	212
Accounts receivable from/accounts payable to affiliates, net	**17**	(9)
Other liabilities	**(330)**	(446)
Regulatory assets and liabilities, net	**71**	(534)
Derivatives, net	**(67)**	149
Other, net	**69**	(224)
Net cash provided by continuing operating activities	**809**	1,995
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	**(54)**	(19)
Cost of removal and other	**(214)**	(131)
Net cash used in continuing investing activities	**(1,783)**	(1,756)
Financing activities:		
Payments of long-term debt	**(545)**	(1,867)
Proceeds from long-term debt	**1,684**	2,213
Commercial paper issued (paid)	**665**	(735)
Changes in advance from affiliates	**(500)**	(500)
Other	**61**	(6)
Net cash provided by (used in) continuing financing activities	**1,365**	(895)
Net increase (decrease) in cash and cash equivalents from continuing operations	**391**	(656)
Net cashflow from discontinued operations - operating	**4**	(47)
Net cashflow from discontinued operations - investing	**(5)**	7
Cash and cash equivalents, beginning of year	**796**	1,492
Cash and cash equivalents, end of year	**$ 1,186**	$ 796
Supplemental disclosures:		
Interest paid	**$ (527)**	$ (452)
Income taxes paid	**(128)**	(132)
Supplemental non-cash items:		
Capital-related accruals included in accounts payable	**84**	100
Settlement of intercompany debt	**-**	(2,081)
Issuance of intercompany debt	**-**	2,081

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

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
(in millions of dollars)

			March 31,	
			2013	2012
Shareholder's equity attributable to common and preferred shares			**$ 8,483**	$ 7,898
Non-controlling interest in subsidiaries			**26**	9
Long-term debt:	**Interest Rate**	**Maturity Date**		
European Medium Term Note	Variable	December 2013 - February 2018	**1,517**	845
Notes Payable	1.19% - 9.75%	April 2013 - December 2042	**7,113**	6,179
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	August 2013 - August 2027	**5,203**	6,153
Total debt			**16,084**	15,430
Other			**(9)**	1
Current maturities			**(1,063)**	(645)
Total long-term debt			**15,012**	14,786
Total capitalization			**$ 23,521**	$ 22,693

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

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY
(in millions of dollars, except per share and number of shares data)

	Common 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	Additional Paid-in Capital	Retained Earnings	Foreign Currency Translation	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	1,353	$ -	372,638	$ 35	$ 7,098	$ 1,422	$ (141)	$ (9)	$ (702)	$ (5)	$ (857)	$ 10	$ 7,708
Net income	-	-	-	-	-	408	-	-	-	-	-	-	408
Comprehensive income (loss):													
Foreign currency translation, net of $1 tax expense	-	-	-	-	-	-	1	-	-	-	1	-	1
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													202
											-		
Issuance of Golden Shares (par value $1 per share)	-	-	3	-	-	-	-	-	-	-	-	-	-
Net earnings attributable to non-controlling interest	-	-	-	-	-	(2)	-	-	-	-	-	(1)	(3)
											-		
Balance as of March 31, 2012	1,353	$ -	372,641	$ 35	$ 7,098	$ 1,828	$ (140)	$ (3)	$ (922)	$ 2	$ (1,063)	$ 9	$ 7,907
Net income	-	-	-	-	-	464	-	-	-	-	-	(1)	463
Comprehensive income (loss):													
Foreign currency translation, net of $1 tax benefit	-	-	-	-	-	-	1	-	-	-	1	-	1
Unrealized gains on securities, net of $0 tax expense	-	-	-	-	-	-	-	1	-	-	1	-	1
Unrealized losses on hedges, net of $1 tax benefit	-	-	-	-	-	-	-	-	-	(4)	(4)	-	(4)
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													521
Share based compensation	-	-		-	63	-	-	-	-	-	-	-	63
Consolidation of variable interest entity	-	-		-	-	-	-	-	-	-	-	22	22
Other equity transactions with non-controlling interest	-	-	-	-	-	-	-	-	-	-	-	(4)	(4)
											-		
Balance as of March 31, 2013	1,353	$ -	372,641	$ 35	$ 7,161	$ 2,292	$ (139)	$ (2)	$ (862)	$ (2)	$ (1,005)	$ 26	$ 8,509

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

NATIONAL GRID NORTH AMERICA INC. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

A. Nature of Operations

National Grid North America Inc. (referred to as "NGNA", the "Company", "we", "us", and "our"), formerly National Grid Holdings Inc., is a Delaware corporation that was created on May 16, 2001 to finance acquisitions in the United States ("US"). The Company is an indirectly-owned subsidiary of National Grid plc (the "Parent"), a public limited company incorporated under the laws of England and Wales. It is the intermediate holding company of National Grid USA ("NGUSA") and acts as a funding company on behalf of the Parent for certain subsidiaries' borrowings.

NGUSA 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 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 30, 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" and Note 16, "Subsequent Event."

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. Each included subsidiary settles its current tax liability or benefit each year with NGNA pursuant to a tax sharing arrangement between NGNA and its included subsidiaries.

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	$ (39)	$ (42)	$ (81)
Income from continuing operations	$ 360	$ (57)	$ 303
Net income from discontinued operations, net of taxes	48	57	105
Net income	$ 408	$ -	$ 408

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 transactions. Under current rate orders, the Company is required to return 90% of margins earned from such optimization transactions 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 capital expenditures to the amounts permitted in rates. The mechanism provides for a two way (upward and downward) tracker for City and State Construction ("CSC") related expenditures and a one way (downward only) tracker for all other capital expenditures. Brooklyn Union and KeySpan Gas East defer the full revenue requirement equivalent of CSC expenditures above or below the CSC rate allowance and defer the revenue requirement equivalent of any other unspent capital expenses below the rate allowance for all other capital expenditures. Brooklyn Union's recent rate settlement, discussed below, eliminated the CSC tracker effective January 1, 2013. The effect of the tracker is to adjust the Company's return on common equity capital ("ROE") for the difference between actual capital expenditures and the amount provided in rates.

Cost of removal: The Company's depreciation expense includes estimated costs to remove property, plant and equipment, which is 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.

Environmental 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.

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 computation of its ROE. If the level of earned common equity in the applicable rate year exceeds 10.5%, the company is required to defer a portion of the revenue equivalent associated with any over earnings for the benefit of customers. Brooklyn Union's recent rate settlement modified its ROE and revenue sharing mechanism for the rate year beginning January 1, 2013, as described below.

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

Postretirement benefits: The amount in regulatory assets primarily represents the excess costs of the Company's pension and postretirement benefits 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.

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 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:

<u>New England Power</u>

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.

<u>Massachusetts Electric and Nantucket (the "Massachusetts Electric Companies")</u>

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.

<u>National Grid Generation</u>

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 $2.6 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	**87**	22
	14	42		**95**	57
Total	**$ 75**	$ 94	Total	**$ 106**	$ 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	**(66)**	(13)
	$ (65)	$ (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 is $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 $18.8 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 $56.8 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	96	8	106
Net assets	$ 149	$ 65	$ 11	$ 225

	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. The Company 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 Assets	(Liabilities)	Total	Valuation Technique(s)	Significant Unobservable Input	Range
		(millions of dollars)					
Physical							
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 $17.9 billion and $15.4 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	**$ (323)**	$ (129)
State	**5**	48
Total current tax benefit	**(318)**	(81)
Deferred tax expense (benefit):		
Federal	**376**	378
State	**54**	64
	430	442
Amortized investment tax credits [1]	**(6)**	(6)
Total deferred tax expense	**424**	436
Total income tax expense	**$ 106**	$ 355

[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	**$ 201**	$ 230
Change in computed taxes resulting from:		
Audit and related reserve movements	**(115)**	73
State income tax, net of federal benefit	**39**	63
Investment tax credit	**(6)**	(6)
Other items, net	**(13)**	(5)
Total	**(95)**	125
Federal and state income taxes	**$ 106**	$ 355

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	**221**	204
Net operating losses	**176**	26
Allowance for uncollectible accounts	**130**	154
Other items	**155**	182
Subtotal deferred tax assets	**2,991**	2,912
Less: valuation allowance	**(15)**	(49)
Total deferred tax assets	**2,976**	2,863
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	**272**	96
Total deferred tax liabilities	**6,997**	6,382
Net deferred income tax liabilities	**4,021**	3,519
Deferred investment tax credits	**45**	45
Net deferred income tax liability and investment tax credit	**4,066**	3,564
Current portion of net deferred income tax asset	**125**	191
Non-current deferred income tax liability	**$ 4,191**	$ 3,755

Included in "Future federal benefit on state taxes" is a deferred tax asset related to future deductions on Massachusetts unitary returns recorded at $98 million as of March 31, 2013 and March 31, 2012. There is a valuation allowance of $13 million and $20 million against this deferred tax asset as of March 31, 2013 and March 31, 2012, respectively. After March 31, 2013, the state of Massachusetts passed new legislation, as a result of which, the Company anticipates that it will release the valuation allowance against this asset.

Also included in "Other items" are deferred tax assets relating to net operating losses in the state of Massachusetts of $2 million and $29 million as of March 31, 2013 and March 31, 2012, respectively, representing approximately $30 million and $366 million of net operating losses carried forward in the state of Massachusetts. A valuation allowance has been established for the full amount of these loss carry forwards 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.

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	$	543

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
03/31/2032		33		10
03/31/2033		57		1

The Company files a consolidated federal income tax return with its subsidiaries, all of which have joint and several liability for any potential assessments against the consolidated group.

As of March 31, 2013 and March 31, 2012, the Company's unrecognized tax benefits totaled $986 million and $1,114 million, respectively, of which $310 million and $417 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	**$**	**1,114**	$	1,142
Gross increases related to prior period		**33**		60
Gross decreases related to prior period		**(204)**		(148)
Gross increases related to current period		**59**		63
Gross decreases related to current period		**(12)**		(3)
Settlements with tax authorities		**(4)**		-
Balance at the end of the year	**$**	**986**	$	1,114

As of March 31, 2013 and March 31, 2012, the Company has accrued for interest related to unrecognized tax benefits of $82 million and $90 million, respectively. During the years ended March 31, 2013 and March 31, 2012, the Company recorded interest income of $5.4 million and $4 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, and reversed $115 million of uncertain tax positions.

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 certain 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 $87 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, $1.5 billion 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 $7.1 billion and $6.2 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.

On August 9, 2011, the Company entered into two loan agreements with Bank of Tokyo-Mitsubishi UFJ, Ltd. for $250 million with an interest rate of LIBOR plus a margin spread of 0.7%, maturing on August 9, 2013 and $500 million with an interest rate of LIBOR plus a margin spread of 0.9%, maturing on October 29, 2014. On August 19, 2011, the Company entered into a term loan agreement with the Mizuho Corporate Bank, Ltd. for $250 million with an interest rate of LIBOR plus a margin spread of 0.7%, maturing on August 19, 2013.

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

As of March 31, 2013 and March 31, 2012, NGNA's debt was in the form of intercompany loans from the Parent and other affiliated-entities obtained to fund the acquisition of various entities. The intercompany loans are paid back by NGNA from the dividends it receives from NGUSA.

In October 2010, NGNA transferred 266 shares of preferred stock in its subsidiary, NGUSA, to an affiliated company, National Grid Luxembourg 5 Sarl ("Lux 5"), in exchange for the release of NGNA's obligations under an intercompany note with a carrying value of $2,081 million. The preferred shares were transferred together with an agreement by NGNA to repurchase them in August 2011 for consideration consisting of the issuance of an intercompany note with a principal value of $1,681 million with terms substantially consistent with those of the released $2,081 million note, a cash amount of $400 million (representing a previously scheduled principal payment) and a further cash payment equivalent to interest that would have been due on the released note had it remained outstanding.

In accordance with the agreement in August 2011, the preferred shares were repurchased by NGNA in exchange for the issuance of a note with a face value of $1,681 million and cash of $447 million, which represented the scheduled principal payment of $400 million and a payment equivalent to interest of $47 million. This transaction has been treated as a continuation of the original $2,081 million intercompany note because payments under the repurchase of preferred shares and the note issued in August 2011 are equivalent to the payments under the original intercompany note.

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.

The following table summarizes the terms of the Company's intercompany loans as of March 31, 2013 and March 31, 2012:

(in millions of dollars)			March 31,	
			2013	2012
Due to:	**Interest Rate**	**Maturity Date**	**Amounts**	
National Grid Lux Investments Ltd	0.53% to 2.2% over LIBOR	Aug 2011 - Aug 2027	**$ 3,222**	$ 3,622
National Grid plc	0.6% to 0.9% over LIBOR	Nov 2011 - Nov 2015	**-**	500
National Grid US Partner 1 Limited	1.05% to 1.56% over LIBOR	Feb 2012 - Aug 2016	**300**	350
National Grid Twenty Five Ltd	2.00% to 2.3% over LIBOR	Aug 2014 - Aug 2018	**1,681**	1,681
Total			**$ 5,203**	$ 6,153

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	$ 1,063
2015	1,929
2016	1,752
2017	1,311
2018	839
Thereafter	9,190
Total	$ 16,084

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 $665 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.

he 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

NGUSA has guaranteed the principal and interest payments on certain outstanding debt of its subsidiaries. Additionally, NGUSA 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 NGUSA 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) NGUSA 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) NGUSA 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) NGUSA 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) NGUSA 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) NGUSA 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

In August 2009, NGUSA 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.

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 NGNA 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 the Company's 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.

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)			
			(Revised)	
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.”

Note 16. Subsequent Event

During June 2013, the Company entered into a new bank loan for $762.6 million. This 18-month loan contains an option to extend for a further year. The loan was originally borrowed in sterling, but swapped to USD at a fixed rate of 1.1325%.