nationalgrid

National Grid Holdings Inc. and Subsidiaries

Consolidated Financial Statements

For the years ended March 31, 2011 and March 31, 2010

NATIONAL GRID HOLDINGS INC. AND SUBSIDIARIES

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Report of Independent Auditors

To the Stockholder and Board of Directors of
National Grid Holdings Inc:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, retained earnings, capitalization and cash flows present fairly, in all material respects, the financial position of National Grid Holdings Inc. and its subsidiaries at March 31, 2011 and March 31, 2010, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

October 26, 2011

NATIONAL GRID HOLDINGS INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars, except per share and number of shares data)

	March 31, 2011	March 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	**$ 1,499**	$ 769
Restricted cash	**141**	230
Accounts receivable	**2,275**	2,350
Allowance for doubtful accounts	**(409)**	(389)
Unbilled revenues	**701**	614
Gas in storage, at average cost	**197**	275
Materials and supplies, at average cost	**163**	178
Derivative contracts	**26**	40
Regulatory assets	**779**	986
Current deferred income tax assets	**216**	115
Prepaid and other current assets	**489**	963
Current assets related to assets held for sale	**67**	59
Total current assets	**6,144**	6,190
Equity investments	**181**	148
Property, plant, and equipment, net	**20,126**	19,058
Deferred charges		
Regulatory assets	**4,785**	5,547
Goodwill	**7,133**	7,275
Intangible assets, net	**118**	136
Derivative contracts	**143**	130
Other deferred charges	**476**	542
Deferred assets related to assets held for sale	**438**	517
Total deferred charges	**13,093**	14,147
Total assets	**$ 39,544**	$ 39,543

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

NATIONAL GRID HOLDINGS INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions of dollars, except per share and number of shares data)

	March 31, 2011	2010
LIABILITIES AND CAPITALIZATION		
Current liabilities		
Accounts payable	**$ 1,306**	$ 1,314
Accounts payable to affiliates	**24**	30
Commercial paper	**735**	-
Current portion of long-term debt	**1,717**	2,694
Taxes accrued	**57**	601
Customer deposits	**96**	101
Interest accrued	**134**	206
Regulatory liabilities	**212**	150
Intercompany moneypool	**500**	-
Current portion of accrued Yankee nuclear plant costs	**15**	15
Derivative contracts	**117**	218
Payroll and benefits accruals	**322**	201
Other current liabilities	**243**	292
Liabilities related to assets held for sale	**22**	31
Total current liabilities	**5,500**	5,853
Deferred credits and other liabilities		
Regulatory liabilities	**2,893**	2,736
Asset retirement obligations	**69**	70
Deferred income tax liabilities	**3,472**	3,183
Postretirement benefits and other reserves	**2,987**	3,704
Environmental remediation costs	**1,305**	1,312
Derivative contracts	**161**	239
Other deferred liabilities	**1,880**	1,495
Liabilities related to assets held for sale	**202**	185
Total deferred credits and other liabilities	**12,969**	12,924
Capitalization		
Common stock, par value $.10 per share, issued and outstanding 1,353 shares	**-**	-
Cumulative preferred stock (see Note 13)	**35**	35
Additional paid-in capital	**7,098**	7,098
Retained earnings	**1,422**	1,082
Accumulated other comprehensive loss	**(857)**	(949)
Total shareholders' equity	**7,698**	7,266
Non-controlling interest	**10**	16
Total equity	**7,708**	7,282
Long-term debt	**13,367**	13,484
Total capitalization	**21,075**	20,766
Total liabilities and capitalization	**$ 39,544**	$ 39,543

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

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

	Years Ended March 31, 2011	2010
Operating Revenues:		
Gas distribution	$ 5,738	$ 5,621
Electric services	7,545	7,401
Other	64	143
Total revenues	13,347	13,165
Operating expenses:		
Gas purchased for resale	3,114	3,134
Electricity purchased for resale	2,373	2,461
Operations and maintenance	4,180	3,888
Amortization of regulatory assets, stranded costs and rate plan deferrals	689	657
Other taxes	963	921
Depreciation and amortization	820	785
Impairment of intangibles and property, plant and equipment	70	18
Contract termination charges and nuclear shutdown charges	17	20
Total operating expenses	12,226	11,884
Operating income	1,121	1,281
Other income and (deductions)		
Interest on long-term debt	(328)	(312)
Other interest expense, including affiliate interest	(245)	(368)
Equity income in subsidiaries	23	26
Gain on disposal of assets	46	5
Other income, net	47	88
Total deductions, net	(457)	(561)
Income before income taxes and non-controlling interest	664	720
Income taxes:		
Current	177	(392)
Deferred	83	871
Total income taxes	260	479
Income from continuing operations before non-controlling interest	404	241
(Loss) income from discontinued operations, net of taxes	(60)	12
Net income	344	253
Net income attributable to non-controlling interest	(4)	(4)
Net income attributable to NGHI	$ 340	$ 249

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

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

	Years Ended March 31,	
	2011	2010
Operating activities:		
Net income attributable to NGHI	**$ 340**	$ 249
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**820**	785
Amortization of regulatory assets, stranded costs and rate plan deferrals	**689**	657
Impairment of intangibles and property, plant and equipment	**70**	18
Provision for deferred income taxes	**83**	871
Equity loss in subsidiaries, net of dividends received	**(9)**	3
Loss from discontinued operations, net of taxes	**60**	(12)
Other non-cash items	**24**	(55)
Net prepayments and other amortizations	**(260)**	14
Net pension and other postretirement payments	**(91)**	(290)
Net environmental payments	**(115)**	(219)
Changes in operating assets and liabilities:		
Accounts receivable, net	**19**	187
Storage and materials	**91**	194
Accounts payable and accrued expenses	**(18)**	218
Prepaid taxes and accruals	**306**	(382)
Accounts payable to affiliates, net	**(6)**	(41)
Other, net	**286**	55
Net cash provided by continuing operating activities	**2,289**	2,252
Investing activities:		
Capital expenditures	**(1,691)**	(1,577)
Net proceeds from disposal of subsidiary assets	**31**	10
Derivative margin calls	**50**	59
Restricted cash	**39**	(55)
Other, including cost of removal	**(153)**	(135)
Net cash used in continuing investing activities	**(1,724)**	(1,698)
Financing activities:		
Payments on long-term debt	**(2,344)**	(978)
Proceeds from long-term debt	**1,258**	2,600
Commercial paper issuance	**735**	-
Changes in intercompany moneypool	**500**	(1,875)
Debt issuance cost	**(3)**	(15)
Net cash provided by (used in) continuing financing activities	**146**	(268)
Net increase in cash and cash equivalents	**711**	286
Net cashflow from discontinued operations - operating	**49**	76
Net cashflow from discontinued operations - investing	**(30)**	(21)
Cash and cash equivalents, beginning of year	**769**	428
Cash and cash equivalents, end of year	**$ 1,499**	$ 769
Supplemental disclosures of cash flow information:		
Interest paid	$ 552	$ 687
Taxes paid (refunded)	$ 12	$ (406)
Capital-related accruals included in accounts payable	$ (23)	$ 50

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

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

	Years Ended March 31,	
	2011	2010
Net income attributable to NGHI	**$ 340**	$ 249
Other comprehensive income (loss), net of taxes:		
Foreign currency translation	**(3)**	(32)
Unrealized (losses) gains on investments	**(5)**	13
Unrealized losses on hedges	**-**	(7)
Change in pension and other postretirement obligations	**(18)**	17
Reclassification adjustment for gains included in net income	**118**	74
Change in other comprehensive loss	**92**	65
Total comprehensive income	**$ 432**	$ 314
Related tax expense (benefit):		
Foreign currency translation	**$ (2)**	$ (21)
Unrealized (losses) gains on investments	**(1)**	9
Unrealized losses on hedges	**-**	(5)
Change in pension and other postretirement obligations	**(4)**	11
Reclassification adjustment for gains included in net income	**43**	49
Total tax expense	**$ 36**	$ 43

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS
(in millions of dollars)

	Years Ended March 31,	
	2011	2010
Retained earnings, beginning of year	**$ 1,082**	$ 833
Net income attributable to NGHI	**340**	249
Retained earnings, end of year	**$ 1,422**	$ 1,082

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

NATIONAL GRID HOLDINGS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
(in millions of dollars, except per share and number of shares data)

			March 31, 2011	March 31, 2010
Shareholders' equity	**Shares Issued and Outstanding**		**Amounts**	
Common stock, par value $.10 per share	**1,353**		**$ -**	$ -
Cumulative preferred stock (see Note 13)	**372,638**		**35**	35
Additional paid-in capital			**7,098**	7,098
Retained earnings			**1,422**	1,082
Accumulated other comprehensive loss			**(857)**	(949)
Total shareholders' equity			**7,698**	7,266
Non-controlling interest in subsidiaries			**10**	16
Long-term debt	**Interest Rate**	**Maturity Date**		
Medium and long-term debt:				
European Medium Term Note	1.10%	May 2012 - Jan 2016	**181**	23
Notes payable	3.55% - 9.75%	June 2011 - Apr 2041	**4,645**	4,870
Total medium and long-term debt			**4,826**	4,893
Gas Facilities Revenue Bonds	Variable	Dec 2020 - July 2026	**230**	230
	4.7% - 6.95%	Apr 2020 - July 2026	**411**	411
Total Gas Facilities Revenue Bonds			**641**	641
Promissory Notes to LIPA:				
Pollution Control Revenue Bonds	5.15%	March 2016	**108**	108
Electric Facility Revenue Bonds	5.30%	Nov 2023 - Aug 2025	**47**	47
Total Promissory Notes to LIPA			**155**	155
First Mortgage Bonds	6.34% - 9.63%	Apr 2018 - Apr 2028	**130**	132
State Authority Financing Bonds	Variable	Oct 2013 - Aug 2042	**1,200**	1,200
Industrial Development Revenue Bonds	5.25%	June 2027	**128**	128
Committed Facilities	Variable	October 2029	**500**	550
Intercompany Notes	Variable	Aug 2011 - Aug 2027	**7,503**	8,470
Subtotal			**15,083**	16,169
Other			**1**	9
Less: current maturities			**1,717**	2,694
Total long-term debt			**13,367**	13,484
Total capitalization			**$ 21,075**	$ 20,766

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

NATIONAL GRID HOLDINGS INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

A. *Nature of Operations*

National Grid Holdings Inc. (referred to as "NGHI", the "Company", "we", "us", and "our") 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. NGUSA delivers electricity to approximately 3.3 million customers in Massachusetts, New Hampshire, New York and Rhode Island, and manages the electricity network on Long Island under an agreement with the Long Island Power Authority ("LIPA") which expires in 2013. NGUSA also owns over 4,000 megawatts ("MW") of contracted electricity generation that provides power to over 1.0 million LIPA customers. NGUSA is also the largest distributor of natural gas in the northeastern US, serving approximately 3.4 million customers in New York, Massachusetts, New Hampshire and Rhode Island.

NGUSA's other operating subsidiaries are primarily involved in gas production and development; underground gas storage; and liquefied natural gas storage. We also invest and participate in the development of natural gas pipelines and other energy-related projects. Additionally, NGUSA has an equity ownership interest in two hydro-transmission electric companies.

NGUSA's wholly-owned New England subsidiaries include: New England Power Company ("New England Power"), The Narragansett Electric Company ("Narragansett"), Massachusetts Electric Company ("Massachusetts Electric"), Nantucket Electric Company ("Nantucket"), Granite State Electric Company ("Granite State"), Boston Gas Company ("Boston Gas"), Colonial Gas Company ("Colonial Gas"), and EnergyNorth Natural Gas Inc ("EnergyNorth"). 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").

The Company's consolidated financial statements also include a 26.25% interest in Millennium Pipeline Company LLC 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".

At March 31, 2011 and March 31, 2010, the assets and liabilities of EnergyNorth and Granite State are classified as held for sale in the accompanying consolidated balance sheets pending regulatory approvals of its sale to a third party as discussed in Note 14. "Discontinued Operations and Other Dispositions". In addition, in September 2010, the Company's indirectly wholly-owned subsidiary, National Grid Development Holdings sold it's 52.14% interest in Honeoye Storage Corporation, as discussed in Note 14.

The Company has no independent operations or source of income and conducts all of its operations through its subsidiaries and, 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 us is subject to regulation by state regulatory authorities.

The Company has evaluated subsequent events and transactions through October 26, 2011, and concluded that except for what is disclosed in Note 16, there were no events or transactions that require adjustment to, or disclosure in the note to, the consolidated financial statements.

B. Basis of Presentation

The consolidated financial statements for the years ended March 31, 2011 and March 31, 2010, are prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"), including accounting principles for rate-regulated entities with respect to the Company's subsidiaries engaged in the transmission and distribution of gas and electricity (regulated subsidiaries), and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities having jurisdiction over such entities.

The preparation of 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 financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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

The Company uses the equity method of accounting for its investments in affiliates, which are 50% or less owned, as the Company has the ability to exercise significant influence over the operating and financial policies of the affiliates but does not control the affiliate. The Company's share of the earnings or losses of the affiliates is included as equity income in subsidiaries in the consolidated statements of income.

C. Regulatory Accounting

The Federal Energy Regulatory Commission ("FERC") in addition to the New York State Public Service Commission ("NYPSC"), the Massachusetts Department of Public Utilities ("DPU"), the New Hampshire Public Utilities Commission ("NHPUC"), and the Rhode Island Public Utility Commission ("RIPUC") provide the final determination of the rates we charge our customers. In certain cases, the actions of the federal and state regulatory bodies would result in an accounting treatment different from that used by non-regulated companies to determine the rates we charge our customers. In this case, the Company is required to recognize costs (a regulatory asset) or to recognize obligations (a regulatory liability) if it is probable that these amounts will be recovered or refunded through the rate-making process, which would result in a corresponding increase or decrease in future rates. The Company believes its rates are based on its costs and investments and it should continue to apply the current guidance for rate-regulated enterprises.

In the event the Company determines that its net regulatory assets are not probable of recovery, it would no longer apply the principles of the current accounting guidance for rate-regulated enterprises and would be required to record an after-tax, non-cash charge against income for any remaining regulatory assets and liabilities. The impact could be material to the Company's reported financial condition and results of operations.

D. Revenue Recognition

Gas Distribution and Electric Services
The Company bills its customers on a monthly cycle and 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. The unbilled revenue at March 31, 2011 and March 31, 2010 was $701 million and $614 million, respectively.

The cost of gas and electricity used is recovered when billed to customers through the operation of commodity cost recovery mechanisms. Any difference is deferred pending recovery from or refund to customers.

Brooklyn Union, KeySpan Gas East, Niagara Mohawk and Narragansett gas utility tariffs contain weather normalization adjustments which largely offset shortfalls or excesses of firm net revenues (revenues less gas costs and revenue taxes) during a heating season due to variations from normal weather as measured by heating degree days. 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 their 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.

Additionally, certain of our gas and electric distribution utilities have revenue decoupling mechanisms that permit each utility company to reconcile actual revenue per customer to target revenue per customer for certain customer classes on an annual basis. The revenue decoupling mechanism is designed to eliminate the disincentive to implement energy efficiency programs.

The gas distribution business is influenced by seasonal weather conditions. Annual revenues are principally realized during the heating season (November through April) as a result of the large proportion of heating sales in these months. Accordingly, results of operations are most favorable in the first calendar quarter of the year, followed by the fourth calendar quarter. Operating losses are generally incurred in the second and third calendar quarters.

Included in electric services are revenues associated with our three contracts with LIPA, as discussed in Note 11. "Commitments and Contingencies" under "Power Supply Agreement"**.**

Other Revenues
Revenues earned for service and maintenance contracts associated with small commercial and residential appliances 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 an allowance for funds used during construction ("AFUDC"). Replacement of minor items of property, plant, and equipment and the cost of current repairs and maintenance are charged to expense. Whenever property, plant, and equipment is retired, its original cost, together with cost of removal, less salvage, is charged to accumulated depreciation.

F. Goodwill and Intangible Assets

Goodwill
Goodwill represents the excess of the purchase price of a business combination over the fair value of 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 on an annual basis and, on an interim basis, when certain events or circumstances exist.

The goodwill impairment analysis is comprised of two steps. In the first step, the Company compares the fair value of each reporting unit to its carrying value. The Company can consider both an income-based approach using projected discounted cash flows and a market-based approach using valuation multiples of comparable companies to determine fair value. The Company's estimate of fair value of each reporting unit is based on a number of subjective factors, including: (i) the appropriate weighting of valuation approaches (income-based approach and market-based approach), (ii) estimates of the future revenue and cash flows, (iii) discount rate for estimated cash flows, (iv) selection of peer group companies for the market-based approach, (v) required levels of working capital, (vi) assumed terminal value, (vii) the time horizon of cash flow forecasts; and (viii) control premium.

If the fair value of the reporting unit exceeds the carrying value of the net assets assigned to that unit, goodwill is not considered impaired and no further analysis is required to be performed. If the carrying value of the net assets assigned to the reporting unit exceeds the fair value, then a second step is performed to determine the implied fair value of the reporting unit's goodwill. If the carrying value of a reporting unit's goodwill exceeds its implied fair value, then an impairment charge equal to the difference is recorded.

The Company utilizes a discounted cash flow approach incorporating its most recent business plan forecasts together with a projected terminal year calculation in the performance of the annual goodwill impairment test. Critical assumptions used in the Company's analysis include a discount rate of 5.9% and a terminal year growth rate of 2.4% based upon expected long-term average growth rates. Within its calculation of forecasted returns, the Company made certain assumptions with respect to the amount of pension and environmental costs to be recovered in future periods. Should the Company not continue to receive the same level of recovery in these areas, the result could be a reduction in fair value of the Company, which in turn could give rise to an impairment of goodwill. Our forecasts assume long-term recovery and rate of returns that are in line with historical levels within the utility industry. The resulting fair value of the annual analyses determined that, except for the adjustment to regulatory approval (discussed in Note 6.), no adjustment of the goodwill carrying value was required for our continuing operations at March 31, 2011 and March 31, 2010.

Intangible Assets
Amortizable intangible assets are amortized over their estimated useful lives and reviewed for impairment when certain events or circumstances exist. For amortizable intangible assets, impairment exists when the carrying amount of the intangible asset exceeds its fair value. An impairment loss will be recognized only if the carrying amount of the intangible asset is not recoverable and exceeds its fair value.

Indefinite-lived intangible assets are not amortized but are reviewed annually (or more frequently when certain events or circumstances exist) for impairment. For indefinite-lived intangible assets, impairment exists when the carrying amount exceeds its fair value.

G. Cash and Cash Equivalents

The Company classifies short-term investments with an original maturity of three months or less as cash equivalents. These short-term investments are carried at cost which approximates fair value.

H. Restricted Cash

Restricted cash consists of margin accounts for commodity hedging activity, health care claims deposits, New York State Department of Conservation securitization for certain site cleanup, and workers' compensation premium deposits.

I. Income and Other Taxes

Federal and state income taxes are recorded under the current accounting provisions for the accounting and reporting of income taxes. Income taxes have been computed utilizing the asset and liability approach that requires the recognition of deferred tax assets and liabilities for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities.

Deferred income taxes 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 amount of assets and liabilities for 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 on the Company's consolidated balance sheets that have been included in previous tax returns or are expected to be included in future tax returns.

Other taxes in the accompanying consolidated statements of income primarily include excise tax, property tax and payroll tax. We report our collections and payments of excise taxes on a gross basis.

J. Comprehensive Income

Comprehensive income is the change in the equity of a company, not including those changes that result from shareholder transactions. While the primary component of comprehensive income is reported as net income, the other components include amounts related to foreign currency translation, defined benefit pension and postretirement plans, deferred gains and losses on derivative contracts associated with hedging activity, and unrealized gains and losses associated with certain investments held as available for sale.

K. Employee Benefits

The Company follows the provisions of the Financial Accounting Standards Board ("FASB") accounting guidance related to the accounting for defined benefit pension and postretirement plans which requires employers to fully recognize all postretirement plans' funded status on the balance sheet as a net liability or asset and required an offsetting adjustment to accumulated other comprehensive income in shareholders' equity upon implementation or, in the case of regulated enterprises, to regulatory assets or liabilities. Consistent with past practice, and as required by the guidance, the Company values its pension and postretirement benefits other than pensions ("PBOP") assets using the year-end market value of those assets. Benefit obligations are also measured at year-end.

L. Supplemental Executive Retirement Plans

The Company has corporate assets recorded on the consolidated balance sheets representing funds designated for Supplemental Executive Retirement Plans. These funds are invested in corporate owned life insurance policies. The Company records changes in the value of these assets in accordance with Accounting for the Purchase of Life Insurance. As such, increases and decreases in the value of these assets are recorded through earnings in the consolidated statements of income concurrent with the change in the value of the underlying assets.

M. Derivatives

We employ derivative instruments to hedge a portion of our exposure to commodity price risk. Whenever hedge positions are in effect, we are exposed to credit risks in the event of non-performance by counterparties to derivative contracts, as well as non-performance by the counterparties of the transactions against which they are hedged. We believe the credit risk related to derivative instruments is no greater than that associated with the primary commodity contracts which they hedge.

Commodity Derivative Instruments – Regulated Utilities
We use derivative financial instruments to reduce cash flow variability associated with the purchase price for a portion of future natural gas and electricity purchases associated with our gas and electric distribution operations. Our strategy is to minimize fluctuations in firm gas and electricity sales prices to our regulated customers. The accounting for these derivative instruments is subject to the FASB accounting guidance applicable to entities subject to the certain types of regulation. 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 on the consolidated balance sheets. Gains or losses on the settlement of these contracts are initially deferred and then refunded to or collected from our firm gas sales customers consistent with regulatory requirements.

Certain of our contracts for the physical purchase of natural gas are derivatives as defined by current accounting literature. As such, these contracts are recorded on the consolidated balance sheets at fair market value. However, since such contracts were executed for the purchases of natural gas that is sold to regulated firm gas sales customers, and pursuant to the requirements for accounting for the effects of rate regulation, changes in the fair market value of these contracts are recorded as a regulatory asset or regulatory liability on the consolidated balance sheets.

Commodity Derivative Instruments – Hedge Accounting
We also use derivative financial instruments, such as futures, options and swaps, for the purpose of hedging cash flow variability associated with forecasted purchases and sales of various energy-related commodities. All such derivative instruments are accounted for pursuant to the requirements of current accounting guidance for derivative instruments and hedging activities. With respect to those commodity derivative instruments that are designated and accounted for as cash flow hedges, the effective portion of periodic changes in the fair market value of cash flow hedges is recorded as accumulated other comprehensive income on the consolidated balance sheets, while the ineffective portion of such changes in fair value is recognized in earnings. For the year ended March 31, 2011 there was no ineffective portion. Unrealized gains and losses (on such cash flow hedges) that are recorded as accumulated other comprehensive income are subsequently reclassified into earnings concurrent to when hedged transactions impact earnings. With respect to those commodity derivative instruments that are not designated as hedging instruments, such derivatives are accounted for on the consolidated balance sheets at fair value, with all changes in fair value reported in earnings.

Treasury Financial Instruments
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 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. Hedging transactions that effectively convert the terms of underlying debt obligations from fixed to variable are designated and accounted for as fair-value hedges pursuant to the requirements of the FASB accounting guidance on derivative instruments and hedging

activities. Hedging transactions that effectively convert the terms of underlying debt obligations from variable to fixed are considered cash flow hedges.

N. Fair Value Measurements

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 into three levels as follows:

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

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

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

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. Valuation techniques used maximize the use of observable inputs and minimize the use of unobservable inputs.

O. Storage and Materials

Storage and materials is comprised primarily of gas in storage and materials and supplies. Gas in storage is recorded initially at average weighted cost and is expensed when delivered to customers as gas purchased for resale. Materials and supplies are recorded when purchased and expensed as used or capitalized into specific capital additions as utilized. The Company's policy is to write off obsolete materials and supplies.

The Company evaluates the value of storage and materials at the lower of cost or market. Existing rate orders allow the Company to pass through the cost of gas purchased for resale directly to the rate payers 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 the rate payers are subject to periodic regulatory approval and are reported periodically to the relevant regulatory authorities.

P. Emission Allowance Credit

The US Environmental Protection Agency issued the Clean Air Interstate Rule ("CAIR") which was intended to permanently cap emission of sulfur dioxide and nitrogen oxide ("NOx") in 28 eastern states and the District of Columbia. The CAIR requirements were supplemental to the existing emission reductions required under the Clean Air Act. On July 7, 2011, the EPA issued the Cross-State Air Pollution Rule ("CSAPR") which replaces the CAIR effective January 1, 2012. The CSAPR contains new emissions trading programs for sulfur dioxide and NOx emissions as well as more stringent overall emissions targets in 27 states. Additionally, the Regional Greenhouse Gas Initiative is a cooperative effort by ten northeastern states to reduce emissions of carbon dioxide. The Company has an emission allowance credit of $26 million and $29 million at March 31, 2011 and March 31, 2010, respectively, which is recorded in "materials and supplies, at average cost" in the accompanying consolidated balance sheets. On a periodic basis, the emission allowance credit is reviewed for impairment at the balance sheet date the allowance could have been traded or sold in an active market. For the years ended March 31, 2011 and March 31, 2010, we reduced the inventory value resulting in a charge to "operations and maintenance" in the accompanying consolidated statements of income of $3 million and $7 million, respectively.

R. Recent Accounting Pronouncements

Prospective Accounting Pronouncements

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 update seeks to improve financial statement users' ability to understand the causes of an entity's change in financial position and results of operations. The Company is now 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 on the face of the financial statements. This update does not change the items that are reported in other comprehensive income or any reclassification of items to net income. Additionally, the update does not change an entity's option to present components of other comprehensive income net of or before related tax effects. This guidance is 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. Early adoption is permitted. The Company does not expect adoption of this guidance to have an impact on the Company's consolidated financial position, results of operations or cash flows.

Fair Value Measurements

In April 2011, the FASB issued accounting guidance that substantially amended existing guidance with respect to the fair value measurement topic ("the Topic"). The guidance seeks to amend the Topic in order to achieve 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 and for disclosing information about fair value measurements as well as changing specific applications of the Topic. 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 is effective for financial statements issued for annual periods beginning after December 15, 2011. The early adoption of this guidance for non-public companies is permitted but only for interim periods beginning after December 15, 2011. The Company is currently determining the potential impact of the guidance on its consolidated financial position, results of operations and cash flows.

Goodwill Impairment

In December 2010, the FASB issued an accounting update that modified the goodwill impairment procedures necessary for entities with zero or negative carrying value. The FASB created this guidance to require entities to complete Step 2 of the impairment test, which requires the entity to assess whether or not it was likely that impairment existed throughout the period. To do this, an entity should consider whether there were adverse qualitative factors throughout the period that would contribute to impairment.

In September 2011, the FASB amended its previous guidance issued in December 2010 regarding goodwill impairment testing. Under this amendment, an entity is not required to calculate the fair value of a reporting unit and 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.

The original and amended guidance on goodwill impairment is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. Early adoption is permitted. The Company does not expect adoption of this guidance to have an impact on the Company's consolidated financial position, results of operations, or cash flows.

Recently Adopted Accounting Pronouncements

Embedded Credit Derivative

In March 2010, the FASB issued updated guidance that provides for scope exceptions applicable to financial instrument contracts with embedded credit derivative features. This FASB guidance is effective for financial statements issued for interim periods beginning after June 15, 2010. On an ongoing basis, the Company evaluates new and existing transactions and agreements to determine whether they are derivatives, or have provisions that meet the characteristics of embedded derivatives. Those transactions designated for any of the elective accounting treatments for derivatives must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis. None of the financial instrument contracts or credit agreements the Company has entered were identified and designated as meeting the criteria for derivative or embedded derivative treatment. The adoption of this guidance did not have an impact on the Company's consolidated financial statements.

Fair Value Measurements

In January 2010, the FASB issued an amendment to the accounting guidance for fair value measurements that will provide for additional disclosures about (a) the different classes of assets and liabilities measured at fair value, (b) the valuation techniques and inputs used, (c) the activity in Level 3 fair value measurements, and (d) the transfers between Levels 1, 2, and 3. This FASB guidance is effective for financial statements issued for interim and annual periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. The adoption of this guidance did not have an impact on the Company's consolidated financial statements.

Consolidation of Variable Interest Entities

In June 2009, the FASB issued an amendment to the accounting and disclosure requirements for the consolidation of variable interest entities. The objective of the amendment is to improve financial reporting by enterprises involved with variable interest entities and to provide more relevant and reliable information to users of financial statements. The amendment requires an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a variable interest entity. The new requirements shall be effective as of the beginning of each reporting entity's first annual reporting period that begins after November 15, 2009. The adoption of this guidance did not have an impact on the Company's consolidated financial statements.

Subsequent Events

In May 2009, the FASB issued accounting guidance establishing the general standards of accounting for the disclosure of events that occur after the balance sheet date but before the financial statements are issued or are available to be issued. In particular, this FASB guidance requires enhanced disclosures about (a) events or transactions that may occur for potential recognition or disclosure in the financial statements in the period after the balance sheet date, (b) circumstances under which an entity should recognize such events, and (c) date through which an entity has evaluated subsequent events, including the basis for that date, and whether that date represents the date the financial statements were issued or available to be issued. The FASB guidance is effective for financial statements issued for interim and annual periods ending after June 15, 2009. The Company adopted this standard for the reporting period beginning April 1, 2010 and noted no impact on the Company's consolidated financial statements due to the adoption of this standard.

Note 2. Rates and Regulatory

The following table presents the Company's regulatory assets and regulatory liabilities at March 31, 2011 and March 31, 2010:

(in millions of dollars)	March 31, 2011	March 31, 2010
Regulatory assets included in accounts receivable:	**$ 12**	$ 92
Regulatory liabilities included in accounts payable:	**(54)**	(67)
Regulatory assets – current		
Stranded costs	**455**	529
Derivative instruments	**115**	218
Pension and postretirement benefit plans	**90**	82
Yankee nuclear decommissioning costs	**15**	15
Other	**104**	142
Total current regulatory assets	**779**	986
Regulatory assets – non-current		
Pension and postretirement benefit plans	**1,553**	2,176
Deferred environmental restoration costs	**1,909**	1,820
Stranded costs	**-**	454
Derivative contracts	**161**	218
Regulatory tax asset	**118**	114
Storm cost recoveries	**212**	211
Yankee nuclear decommissioning costs	**73**	67
Loss on reacquired debt	**35**	40
Long-term portion of standard offer under-recovery	**-**	43
Merger savings	**228**	-
Transportation marketer credit	**117**	113
Other	**379**	291
Total non-current regulatory assets	**4,785**	5,547
Total regulatory assets	**5,564**	6,533
Regulatory liabilities – current		
Rate adjustment mechanisms	**(124)**	(42)
Derivative contracts	**(26)**	(29)
Other	**(62)**	(79)
Total current regulatory liabilities	**(212)**	(150)
Regulatory liabilities – non-current		
Removal costs recovered	**(1,453)**	(1,409)
Stranded costs	**(130)**	(170)
Pension and postretirement plans fair value deferred gain	**(150)**	(138)
Derivative contracts	**(138)**	(127)
Environmental response fund and insurance recoveries	**(164)**	(96)
Storm costs reserve	**(22)**	(18)
Other	**(836)**	(778)
Total non-current regulatory liabilities	**(2,893)**	(2,736)
Total regulatory liabilities	**(3,105)**	(2,886)
Net regulatory assets	**$ 2,459**	$ 3,647

The regulatory items above are not included in the utility rate base. The Company record carrying charges, as appropriate, on the regulatory items for which cash expenditures have been made and are subject to recovery or for which cash has been collected and is subject to refund. Carrying charges are not recorded on items for which expenditures have not yet been made. The Company anticipates recovering these costs in the gas 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.

Rate Matters

The Company's regulated operating companies are involved in several regulatory rate cases, as follows:

New England Power

New England Power ("NEP") has received authorization from the FERC to recover through contract termination charges ("CTCs"), substantially all of the costs associated with its former generating business not recovered through their divestiture. Additionally, the FERC enables transmission companies to recover their specific costs of providing transmission service. 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 return on equity ("ROE") of approximately 11% on stranded cost recovery. Most stranded costs have been fully recovered through CTCs by the end of 2010 and NEP intends to recover remaining stranded costs through 2020.

NEP is a Participating Transmission Owner ("PTO") in the New England Regional Transmission Organization ("RTO") which commenced operations effective February 1, 2005. The Independent System Operator for New England ("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 and resolved certain issues concerning the New England Transmission Owners ("NETOs"). Other ROE issues were set for hearing in the 2004 order.

Effective on the RTO operations date of February 1, 2005, NEP's transmission rates began to reflect a proposed base ROE of 12.8%, subject to refund, plus an additional 0.5% incentive return on regional network service ("RNS") rates that the FERC approved in March 2004. An additional 1.0% incentive adder was also applicable to new RNS transmission investment, subject to refund. Approximately 70% of NEP's transmission costs are recovered through RNS rates.

NEP and other NETOs participated in FERC proceedings to resolve outstanding ROE issues, including base ROE and the proposed 1.0% ROE incentive for new transmission investment. On October 31, 2006, the FERC issued an order approving the proposed 1.0% ROE adder for all new transmission investment approved through the regional system planning process as an incentive to build new transmission infrastructure. The resulting ROE varied depending on whether costs are recovered through RNS rates or local network service ("LNS") rates, and whether the costs are for existing or new facilities. For the locked-in period (February 2005 to October 2006), the resulting ROEs were 10.7% (including a 0.5% RTO participation adder) for recovery of existing transmission through RNS rates; 11.7% (including 0.5% and 1.0% adders) for new transmission costs recovered through RNS; and 10.2% (base ROE only) for LNS. For the prospective period beginning November 1, 2006, those ROEs increased to 11.4%, 12.4% and 10.9%, respectively, as a result of a FERC adjustment to reflect updated bond data. Overall, the ROEs approved by the FERC increased NEP's last authorized ROE of 10.25%.

On rehearing, the FERC issued an order in March 2008 increasing NEP's base ROE for all classes of transmission plant by 24 basis points retroactive to February 1, 2005 and limiting the 1.0% ROE adder to new transmission plant placed in service on or before December 31, 2008. In December 2008, certain parties in the underlying FERC proceeding filed an appeal of the Commission's orders with the US Court of Appeals for the District of Columbia Circuit arguing that the Commission's approval of the 1.0% ROE adder was unjustified. The appeal was denied by the Court in January 2010.

On September 30, 2011, several state and municipal parties in New England, including the Massachusetts Attorney General's Office, the Connecticut Public Utilities Regulatory Authority and the DPU, filed with the FERC a complaint under Section 206 of the Federal Power Act against certain Transmission Owners, including NEP, to lower the base ROE for RNS and LNS from the FERC approved rate of 11.14% to 9.2%. At this time, NEP cannot predict the outcome of the complaint.

In September 2008, NEP, The Narragansett Electric Company, 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, estimated to cost a total of $2.1 billion, 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. The Narragansett Electric Company's share is estimated to be approximately $0.5 billion and NEP's share is estimated to be approximately $0.1 billion. Effective November 2008, the FERC granted (1) an incentive ROE of 12.89% (125 basis points above the approved base ROE of 11.64%), (2) 100% construction work in progress in rate base and (3) recovery of plant abandoned for reasons beyond the companies' control. Parties opposing the NEEWS incentives have sought rehearing of the FERC order. On June 28, 2011, the FERC denied all requests for rehearing.

At March 31, 2011, NEP's NEEWS-related CWIP and in-service investment related to NEEWS totaled $31.2 million and $15.9 million, respectively. In April 2011 NEP and Northeast Utilities jointly filed with the FERC to transfer the recovery of 100% of NEEWS-related CWIP from its LNS rate to RNS rate under section II of the ISO-NE OATT. The Massachusetts Attorney General has filed a Motion to Intervene, Partial Protest and Request for Relief. On May 27, 2011, NEP received approval from the FERC to begin recovery of NEEWS CWIP through the RNS rate effective June 2011.

Under the terms of its FERC Electric Tariff No. 1, NEP operates its transmission facilities and those of its New England affiliates as a single integrated system and reimburses its affiliates for the cost of those facilities, including a return. NEP's costs under Tariff No. 1 are then allocated among transmission customers in New England in accordance with the terms of the ISO-NE OATT. On December 30, 2009, NEP filed with the FERC a proposed amendment to Tariff No.1 (1) to adjust depreciation rates and postretirement benefits other than pensions ("PBOPs") according to recent depreciation and actuarial studies updating such costs, and (2) to update rate formulas applicable to Massachusetts Electric Company. The result of the proposed rate change would be an overall rate decrease of $1.6 million. In March 2010, the FERC issued an order establishing hearing and settlement procedures for this filing and made the new rates effective January 1, 2010, subject to refund, pending the outcome of the proceeding. In March 2011, NEP filed an uncontested settlement agreement with the FERC resolving all issues raised by the Massachusetts Attorney General in this proceeding. On July 8, 2011, the FERC accepted the settlement without modification.

Niagara Mohawk

Niagara Mohawk's key regulatory agreements include the Master Restructuring Agreement ("MRA") initiated under the Master Restructuring Plan ("MRP") and the Gas Rate Plan Joint Proposal. This MRP was initiated in January 2002 to affect the restructuring of Niagara Mohawk's integrated electric power and delivery business. Under the MRP and MRA, Niagara Mohawk divested its electric generation assets and related contracts and is permitted to recover any "stranded" unrecovered costs from its distribution customers. Recovery of these stranded costs will take several years lasting through 2015. The MRA requires several rate filings and other proceedings to address changes and adjustments to estimates or stranded costs from restructuring.

Electric Rate Case Filing

In January 2010, Niagara Mohawk filed an application with the New York Public Service Commission ("NYPSC") for new electricity base rates, effective January 2011, which would terminate the Merger Rate Plan ("MRP") one year early. Niagara Mohawk filed for an increase in the base transmission and distribution revenue of $361.2 million based on a return on equity of 11.1% and equity ratio of 50.01% for rate year 2011. While Niagara Mohawk filed for a three-year rate case commencing January 1, 2011 through December 31, 2013, Department of Public Service ("DPS") Staff responded to a one-year rate case and Niagara Mohawk adopted the one-year rate case in this proceeding. In January 2011, the NYPSC granted the request for an increase in revenue of approximately $112 million, including recovery of $40 million in competitive transition charges, with a 9.1% return on equity. The NYPSC gave Niagara Mohawk the option of receiving a 9.3% return on equity, which would result in a revenue requirement increase of approximately $119 million, if it agreed not to file another general rate case prior to January 1, 2012. In correspondence dated January 31, 2011, Niagara Mohawk advised the DPS Staff that it was accepting the option and filing tariffs to reflect a 9.3% return on equity. Of the increase granted, $50 million in revenue is due to temporary rates and is subject to the results of the NYPSC's audit of service company costs allocated to Niagara Mohawk. The NYPSC also established a fixed level of $29.8 million per year for Niagara Mohawk's costs associated with the site investigation and remediation ("SIR") of former manufactured gas plants ("MGPs") and other environmental sites. While Niagara Mohawk had previously recovered all prudently incurred SIR costs, for any annual spend above the fixed level, 80% will now be placed into a deferral account for recovery in a future rate case and the other 20% will be the responsibility of Niagara Mohawk. For any annual spend below the fixed level, a credit will be applied to the deferral account.

The NYPSC adopted the capital expenditures stipulation entered into between Niagara Mohawk, DPS Staff, and Multiple Intervenors in the rate case, which addresses, among other things, Niagara Mohawk's capital budget and investments for fiscal years 2011 and 2012. The amount of capital reflected in Niagara Mohawk's rates for calendar year 2011 is subject to refund to customers if Niagara Mohawk fails to invest at the levels agreed in the stipulation. In addition, the NYPSC approved the revenue decoupling stipulation entered into between Niagara Mohawk, DPS Staff, the New York Power Authority, and Pace/NRDC which allows for the implementation of a revenue decoupling mechanism whereby Niagara Mohawk's base rates are adjusted annually as a result of the reconciliation between allowed revenue and billed revenue.

Gas Rate Case Filing

In May 2009, the NYPSC approved a joint proposal that provides for a two-year rate plan, with an annual increase of $39.4 million with incremental adjustments in the second year to reflect changes in certain expenses based on an allowed return on equity of 10.2% and a equity ratio of 43.7%. The joint proposal also includes a revenue decoupling mechanism, negative revenue adjustments for failure to meet certain service quality performance metrics and a commodity-related bad debt recovery mechanism that adjusts for fluctuations in commodity prices. The new rates went into effect on May 20, 2009. In April 2010, Niagara Mohawk filed to increase rates by approximately $13.9 million effective May 20, 2010 based on increases in certain costs. The NYPSC ordered the new rates to go into effect on a temporary basis and, in August 2010, the NYPSC approved the rates on a permanent basis effective with the date of such order.

Transmission Rate Case Filing

In February 2008, Niagara Mohawk filed with the FERC a formula transmission rate for customers that take service under the New York Independent System Operator ("NYISO") tariff. The rate took effect on October 1, 2008 subject to refund. The FERC directed hearing and settlement judge proceedings to resolve the remaining contested issues in the proceeding. On April 6, 2009, Niagara Mohawk filed a settlement agreement which was accepted by the FERC by its order issued on June 22, 2009, and which resolved all issues in the proceeding. The settlement provided for an authorized return on equity of 11.5%. The effective date for the settlement was January 30, 2009 with a phase-in of the settlement rate over the period January 30 through June 30, 2009. In July 2009, Niagara Mohawk refunded to customers a total of $7.1 million, inclusive of FERC required interest, for amounts collected in excess of the settlement rates for the period of October 2008 through June 2009. Under the tariff, Niagara Mohawk is required to provide an annual informational filing to the FERC. Annual Update filings have been made in June of 2009 and 2010. In response thereto, certain parties raised issues with Niagara Mohawk's 2009 and 2010 filings. In February 2010, the FERC accepted a proposed Stipulation and Agreement modifying the calculation of the Long-Term Debt Cost of Capital Rate. In January 2011, the FERC accepted in an unpublished letter order Niagara Mohawk's negotiated settlement of the limited issues raised by the parties on the 2010 Annual Update filing, including removal from the formula rate a component reflecting the Temporary State Assessment under Section 18-a of the New York Public Service Law to prevent duplicate charging of that 18-a assessment to entities who are directly assessed or are otherwise exempt from such assessment. The 2011 Annual Update was filed in June 2011. The revenues resulting from the formula rate are charged to wholesale transmission customers and credited back to retail electric distribution customers through the Transmission Revenue Adjustment Clause mechanism.

Other Regulatory Matters

In February 2011, the NYPSC instituted a statewide proceeding to review its policies regarding the funding mechanisms supporting SIR expenditures and directing the New York State's utilities to assist in developing a comprehensive record of: (1) the current and future scope of utility SIR programs; (2) the current cost controls in place by utilities and opportunities to improve such cost controls; (3) the appropriate allocation of costs among customers and, potentially, shareholders; and (4) methods for recovering SIR costs appropriately borne by customers in a way that minimizes the impact. The NYPSC has requested that the Administrative Law Judge provide a presentation of recommendations before the end of 2011.

In November 2010, the FERC commenced an audit of Niagara Mohawk for the period from January 1, 2009 through December 31, 2009 to evaluate Niagara Mohawk's compliance with the FERC's: (1) Uniform System of Accounts for public utilities; (2) Form No. 1 Annual report requirements of major electric utilities; and (3) Form No. 3–Q, Quarterly financial report of electric utilities. The audit is currently ongoing. No formal findings have been communicated by the FERC to date.

In its September 12, 2007, "Order Authorizing Acquisition subject to Conditions and Making Some Revenue Requirement Determinations for KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island", issued in Case 06-M-0878, the NYPSC authorized the merger of KeySpan Corporation and National Grid subject to the adoption of various financial and other conditions. One of the conditions was the requirement that Niagara Mohawk issue a class of preferred stock having one share (the "Golden Share"), subordinate to any existing preferred stock, the holder of which would have voting rights that limit Niagara Mohawk's right to commence any voluntary bankruptcy, liquidation, receivership or similar proceeding without the consent of the holder of such share of stock. 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. The Golden Share was issued by Niagara Mohawk on July 8, 2011.

Niagara Mohawk received federal income tax refunds covering the tax years of 1991 through 1995 in the amount of $25.6 million, inclusive of $13.3 million of interest, from the Internal Revenue Service ("IRS") in March 2003 and August 2004. Niagara Mohawk made a filing with the NYPSC and proposed to credit $7.2 million to its customers and recorded the resulting regulatory liability and earnings impact in March 2009. Niagara Mohawk subsequently entered into a settlement with the parties in connection with certain adjustments which resulted in an additional $18.7 million credit to its customers**,** including approximately $7.3 million in carrying charges (through December 2009) due to the delay in filing the refund notice and $11.4 million in full settlement of all other outstanding issues. In March 2010, Niagara Mohawk made a supplemental filing to provide procedures put in place by Niagara Mohawk to ensure that all future income tax refunds would be timely noticed. In April 2010, the NYPSC issued an order adopting the submitted joint proposal. Niagara Mohawk will continue to accrue carrying charges for gas customers until such time as the deferred amounts are passed back to gas customers.

In October 2007, Niagara Mohawk filed a preliminary application with the NYPSC regarding the implementation of the Follow-on Merger Credit associated with the KeySpan merger. Niagara Mohawk indicated that the merger would result in the savings allocable to Niagara Mohawk of approximately $40 million for the period from September 2007 through December 2011. In the second quarter of 2008, the NYPSC issued its decision requiring a Follow-on Merger Credit of approximately $56 million, including $4 million of additional credit based on settlement between Multiple Intervenors, Niagara Mohawk and the NYPSC. In July 2010, the NYPSC adopted the terms of the joint proposal and directed Niagara Mohawk to record the proposed credits accordingly. The deferred gas credit will be in Niagara Mohawk's next general gas rate proceeding.

Capital Investment

In December 2007, Niagara Mohawk filed with the NYPSC a Petition for Special Ratemaking seeking authorization to defer for later rate recovery 50% of the revenue requirement impact during calendar year 2008 of specified capital programs and operating expenses that are directly associated with these programs. In the order approving the KeySpan merger, the NYPSC held that the rate impacts associated with certain incremental investments during the remaining period of the MRP would be limited to not more than 50% of the total rate impact as ultimately determined by the NYPSC.

In September 2008, the NYPSC issued its order on Niagara Mohawk's December 2007 Petition for Special Ratemaking. The NYPSC stated that Niagara Mohawk's multi-year capital program should satisfy the materiality requirement to qualify for deferral. However, the NYPSC concluded that Niagara Mohawk's petition was premature because it was based on a forecast of capital investments. The NYPSC instructed Niagara Mohawk to supplement its petition using actual information once known. In April 2009, Niagara Mohawk filed a supplemental petition containing the actual expenditures for 2008 pursuant to the NYPSC's order. In May 2010, Niagara Mohawk filed a request for recovery of incremental investment in 2009 in another Petition for Special Ratemaking to the NYPSC. In May 2011, Niagara

Mohawk filed a request for recovery of incremental investment in 2010 in another Petition for Special Ratemaking to the NYPSC. The NYPSC has not yet ruled on these petitions.

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 revenues required for payment of the Temporary State Assessment, including carrying charges, subject to reconciliation over five years, July 1, 2009 through June 30, 2014. In subsequent compliance filings in June 2010 and 2011, Niagara Mohawk noted that it intends to maintain its gas and electric Temporary State Assessment surcharges for the July 1, 2010 through June 30, 2011 and July 1, 2011 through June 30, 2012 recovery periods. At March 31, 2011, $11.7 million was deferred pending recovery; $30.0 million was recorded at March 31, 2010.

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 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. The NYPSC is expected to rule on Niagara Mohawk's filing by the end of 2011.

Massachusetts Electric and Nantucket

Rates for services rendered by Massachusetts Electric are subject to approval by the DPU. In May 2009, Massachusetts Electric, together with its affiliate Nantucket, filed an application for an increase of $111.3 million in electric base distribution rates. Following its initial order issued November 2009, in April 2010, the DPU issued its final order in the case approving an overall increase in base distribution revenue of approximately $43.9 million based upon a 10.35% rate of return on equity and a 49.99% equity ratio. Approximately $6.0 million of the increase relates to storm costs associated with restoration of service following an ice storm in December 2008. New rates went into effect January 1, 2010.

In addition, the DPU approved, with modification, the revenue decoupling mechanism ("RDM") proposed by Massachusetts Electric, as well as the reconciliation of commodity-related bad debt and working capital, and pension and postretirement benefits other than pensions ("PBOP") costs to actual costs. In November 2010 and subsequently revised in February 2011, Massachusetts Electric and Nantucket Electric filed an application for approval under its RDM to refund $3.4 million to customers. The DPU approved the rates to go into effect subject to further investigation, and in March 2011, the DPU opened a proceeding, as requested by the Massachusetts Attorney General's Office, for an independent audit of Massachusetts Electric's 2009 capital investments which, in part, formed the basis for Massachusetts Electric's RDM rate adjustment. On July 7, 2011, the DPU issued an order on the scope of the audit and directed Massachusetts Electric to engage an independent auditor to provide audit services consistent with the requirements of its order.

The rate case order also allowed for the recovery of non-capitalized pension and PBOP costs outside of base rates through a separate factor. As a result, Massachusetts Electric is authorized to recover all pension and PBOP expenses from its customers. The difference in the costs of Massachusetts Electric's pension and PBOP plans from the amounts billed through this separate factor is deferred to a regulatory asset to be recovered or refunded over the following three years. Consequently in 2010, Massachusetts Electric reclassified accumulated other comprehensive income of $195.4 million and related accumulated deferred income taxes of $129.1 million to regulatory assets of $324.5 million.

NEP operates the transmission facilities of its New England affiliates as a single integrated system and reimburses Massachusetts Electric for the cost of its transmission facilities in Massachusetts, including a return on those facilities. In turn, these costs are allocated among transmission customers in New England in accordance with the tariff agreement. In December 2009, NEP filed with the FERC a proposed amendment to Massachusetts Electric's formula rate revenue requirements which decreased Massachusetts Electric's compensation for its electric transmission facilities by approximately $1.7 million. In March 2010, the FERC issued an order establishing hearing and settlement procedures for this filing and made the new rates effective January 1, 2010. In March 2011, NEP filed an uncontested settlement agreement with the FERC resolving all issues raised by the Massachusetts Attorney General in this proceeding.

Other Regulatory Matters
In the general rate case involving Massachusetts Electric's Massachusetts gas distribution affiliates, the DPU opened an investigation to address the allocation and assignment of costs to the gas affiliates by the National Grid service companies. In June 2011, the Attorney General's Office requested that the DPU expand the scope of the audit to address the allocation and assignment of costs to Massachusetts Electric by the NGUSA service companies and to review NGUSA's cost allocation practices. Massachusetts Electric has agreed to expand the scope of the audit to its Massachusetts electric distribution companies. As of the date of this report, DPU has not established the full scope of the audit.

In January 2011, the DPU opened an investigation into Massachusetts Electric and Nantucket Electric's 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. The maximum fine may not exceed $20 million for any related series of violations. On June 7, 2011, Massachusetts Electric and the Attorney General's Office filed a proposed settlement with a total value of approximately $1.0 million. The DPU informed Massachusetts Electric and the Attorney General that it would not rule on the settlement but will proceed with its initial investigation. Subsequently, on July 19, 2011, Massachusetts Electric and the Attorney General's Office filed an amended settlement increasing the value of the original settlement by $1.2 million. Massachusetts Electric also filed a Motion to Stay the proceeding that was granted by the DPU. The DPU approved the settlement on September 22, 2011.

In addition to the rates and tariffs put into effect following the 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.

Green Communities Act
Pursuant to the 2008 Green Communities Act ("GCA"), the Massachusetts Legislature mandated large scale and innovative ideas for implementing renewable and alternative energy sources, as well as increased energy efficiency spending. Massachusetts Electric's first three-year energy efficiency plan, offered as a single combined program with Nantucket Electric, covers calendar years 2010 through 2012 and significantly expands energy efficiency programs for customers with a concomitant increase in spending. The budget for the two electric companies in Massachusetts for the calendar years 2010 through 2012, is $572.8 million. In addition to cost recovery, Massachusetts Electric has the opportunity to earn a performance incentive. Massachusetts Electric also has requested recovery of lost base revenues for calendar year 2009.

In October 2009 the DPU approved Massachusetts Electric and Nantucket Electric's proposal to construct, own, and operate approximately 5 MW of solar generation on five separate properties owned by Massachusetts Electric and/or its affiliates in Dorchester, Everett, Haverhill, Revere, and a location on the Sutton/Northbridge border. The estimated total capital cost of the projects is approximately $31 million. As each unit goes into service, Massachusetts Electric and Nantucket Electric are allowed to recover the costs of each site with a return equal to the weighted average cost of capital approved by the DPU in Massachusetts Electric's most recent rate proceeding. Massachusetts Electric and Nantucket Electric 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 each instance, the DPU issued an order approving recovery subject to its ongoing review and further investigation and reconciliation of Massachusetts Electric's costs for the sites. The DPU has not yet issued a final order approving recovery for any of the sites. Construction of the Dorchester site is expected to be completed by the end of 2011.

In May 2010, Massachusetts Electric and Nantucket Electric announced that they entered into a 15-year power purchase agreement ("PPA") with Cape Wind Associates, LLC to purchase half of the energy, capacity and renewable energy credits generated by the proposed 468 MW offshore wind project at an adjusted price of 18.7 cents per kilowatt hour beginning in 2013 (escalated for inflation by 3.5% thereafter). In November 2010, the DPU approved the PPA including Massachusetts Electric's proposed cost recovery mechanism. The DPU's decision to approve the PPA has been appealed to the Supreme Judicial Court of Massachusetts. Oral Arguments were held in September 2011.

Rates for services rendered by Nantucket are the same as those approved by the DPU for Massachusetts Electric, with the addition of a cable facilities surcharge to cover the costs associated with two 46 kilovolt submarine cables owned by Nantucket that deliver electricity from the mainland to the island of Nantucket.

Narragansett

In June 2009, Narragansett filed an application for an increase of $75.3 million in electric base distribution rates, which it later adjusted to $57.8 million. In February 2010, RIPUC approved an overall increase in base distribution revenue of approximately $23.5 million based upon a 9.8% rate of return on equity ("ROE") and a 42.75% equity ratio. Narragansett's new rates went into effect on March 1, 2010 retroactive to January 1, 2010. The RIPUC approved recovery of the increase in revenue generated by the new rates for January and February 2010 over a 13 month period. On April 21, 2010 Narragansett filed a petition for writ of certiorari with the Rhode Island Supreme Court appealing the RIPUC's decision.

During May 2010, Rhode Island enacted decoupling legislation 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. Narragansett filed a proposal to implement revenue decoupling for both electric and gas in October 2010. At an open meeting held on July 26, 2011, the RIPUC approved both the electric and gas decoupling mechanisms as proposed by Narragansett, effective retroactively to April 1, 2011. The new law also provides for submission and approval of an annual infrastructure spending plan without having to file a full general rate case. In December 2010, Narragansett filed with RIPUC both the electric and gas plans, subsequently revised in the first quarter of 2011, both plans were approved by the RIPUC in March 2011. The electric plan includes 2012 capital investment and other maintenance costs resulting in a revenue requirement of approximately $3.4 million and the gas plan includes capital investment resulting in a revenue requirement of $1.8 million.

Narragansett's affiliate, New England Power ("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 December 2009, NEP filed with the FERC a proposed amendment to the Tariff NO. 1 formula rate revenue requirements which decreased Narragansett's compensation for its electric transmission facilities by approximately $0.1 million. In March 2010, the FERC issued an order establishing hearing and settlement procedures for this filing and made the new rates effective January 1, 2010. In March 2011, NEP filed an uncontested settlement agreement with the FERC resolving all issues raised by the Massachusetts Attorney General in this proceeding. On July 8, 2011, the FERC accepted the settlement without modification.

In September 2008, Narragansett, NEP, 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, estimated to cost a total of $2.1 billion, 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. Narragansett's share of the NEEWS-related transmission investment is approximately $0.5 billion and NEP's share is approximately $0.1 billion. Narragansett is fully reimbursed for its transmission revenue requirements on a monthly basis by NEP through NEP's Tariff No. 1. Effective as of November 18, 2008, the FERC granted for NEEWS (1) an incentive ROE of 12.89% (125 basis points above the approved base ROE of 11.64%), (2) 100% construction work in progress ("CWIP") in rate base and (3) recovery of plant abandoned for reasons beyond the companies' control. Parties opposing the NEEWS incentives sought rehearing of the FERC order. On June 28, 2011, the FERC denied all requests for rehearing.

On September 30, 2011, the Massachusetts Attorney General's Office, the Connecticut Public Utilities Regulatory Authority and the DPU filed a complaint against New England Power at the FERC under Section 206 of the Federal Power Act to lower the base ROE for RNS and LNS from the FERC approved rate of 11.14% to 9.2%. This complaint would impact Narragansett's base transmission rate as well. At this time, Narragansett cannot predict the outcome of the compliant.

In August 2011, 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. The prior DAC rate recovered approximately $3.2

million from customers. The proposed DAC rate would result in recovery of approximately $2.2 million from customers for the period November 2011 through October 2012.

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.

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. In March 2010, Narragansett filed its proposed timetable and method of execution of annual long-term contract solicitations, which was approved by RIPUC in June 2010, with some modifications. 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 Division of Public Utilities and Carriers issued a certification on July 1, 2010, and filed the contract with the RIPUC in July 2010.

The 2009 legislation 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 includes a transmission cable to be constructed between Block Island and the mainland of Rhode Island. In October 2009, Narragansett entered into a 20 year Power Purchase Agreement ("PPA") with Deepwater Wind Block Island LLC ("Deepwater") and in December 2009, Narragansett filed the PPA with the RIPUC. In March 2010, the RIPUC voted to reject the PPA due to pricing issues. As a result, the legislature amended the law to specifically authorize Narragansett to enter into an amended PPA with Deepwater, to establish a new standard of review, and to provide for a reduction in the initial fixed price under the prior PPA if certain cost savings could be achieved. In August 2010, the RIPUC approved the amended PPA. Certain parties have appealed the RIPUC's decision. In May 2011, the Rhode Island Supreme Court heard oral arguments of the Deepwater appeal and on July 1, 2011, the Court issued its decision approving the PPA with Deepwater. On September 29, 2011, Narragansett filed with the RIPUC for approval of a waiver of the one-year termination provision regarding appeals resolution contained in the PPA.

On July 28, 2011, the RIPUC unanimously approved a 15 year PPA with Orbit Energy Rhode Island, LLC for a 3.2 MW anaerobic digester biogas project. This is the first PPA 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. Once constructed, the Orbit Energy project will bring Narragansett's total contract capacity to 46% of the 90 MW minimum long-term contract capacity requirement under the long-term contracting statute.

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 ("DG") projects over a four year period from 2011 through 2014.

The Rhode Island long-term contracting and DG contracting legislation permits Narragansett to recover all costs incurred under such contracts and permits Narragansett to recover remuneration equal to 2.75% of the actual annual payments made under the long-term contracts for those projects that are commercially operating.

In November 2010, Narragansett filed a settlement reached on its 2011 Energy Efficiency ("EE") plan with the Energy Efficiency Resources Management Council ("Council"). The EE plan, endorsed by the Council, includes the portfolio of electric and gas energy efficiency programs to be approved by the RIPUC along with the associated budgets and the electric and gas EE program charges, effective January 1, 2011. In December 2010, the RIPUC approved the electric energy efficiency program and the proposed EE budget of approximately $54 million. The RIPUC denied the proposed gas EE program charge and in January 2011, Narragansett filed a revised gas EE program plan conforming to the statutory cap on gas EE program charges based on a budget of approximately $4.5 million, which was approved by the RIPUC in February 2011. Pursuant to 2011 legislation which eliminated the cap on gas EE program charges, on June 15, 2011, Narragansett requested an increase in its gas EE program charge to allow for the expansion of its gas energy efficiency programs for the remainder of the calendar year. This request was approved by RIPUC on July 25, 2011.

On September 9, 2011, Narragansett filed its second three-year plan under the least cost procurement legislation, as amended, with the RIPUC for 2012-2014 program years. The three-year plan, endorsed by the Council, provides the framework for the detailed annual EE Plan and System Reliability Annual Report, which are will be filed with the RIPUC on November 1.

Other Regulatory Matters
In June 2009, Narragansett filed an initial application seeking authorization to issue and sell one or more series of new long-term debt. In December 2009, the Division approved a settlement with NGUSA authorizing an issuance of $550 million in new long-term debt by March 2010. Narragansett issued this debt on March 22, 2010 in two tranches. In March 2011 Narragansett notified the Division of its intent to seek permission for an additional issuance in an amount of $290 million.

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

In June 2009, the 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. In a second compliance filing in June 2010, the Companies increased its combined Temporary State Assessment surcharge to $70.8 million for the period from July 1, 2010 through June 30, 2011. On June 15, 2011, the Companies submitted another compliance filing in which it once again proposed to maintain the surcharge for the July 1, 2011 through June 30, 2012 recovery period. At March 31, 2011, a combined $11.4 million was deferred pending recovery; a combined $15 million was recorded at March 31, 2010.

The Companies are currently subject to a five-year rate plan through December 2012. Base delivery rates were increased by $60 million in January 2008 and are based on an allowed ROE of 9.8%. A combined $15 million annual surcharge for the recovery of regulatory assets ("Delivery Rate Surcharge") was implemented in January 2009. The Delivery Rate Surcharge increases each year by a combined $15 million, resulting in an aggregate recovery of approximately $175 million over the five-year term of the rate plan. Revenues collected from the delivery rate surcharge will be deferred and used to offset deferred special franchise taxes with incremental revenue above that level deferred and used to offset future increases in rates for costs such as environmental investigation and remediation or other cost deferrals. An earnings sharing mechanism in the rate plan is triggered if cumulative annual earnings result in an ROE that exceeds 10.5%. Earnings above this threshold are shared with customers on a tiered basis. During the year ended March 31, 2011, the Companies recorded a combined excess earnings of $34 million related to the rate year 2010. The Companies are not eligible to submit a new rate plan until January 2012 for rates to take effect January 2013.

In January 2010, the Companies filed the status of its regulatory deferrals so that the NYPSC could determine if the Companies should adjust its 2011 revenue levels under the existing rate plan so as to minimize outstanding deferral balances. The Companies proposed an increase to 2009 revenues of 1.7% and 2.3%, respectively, through an existing surcharge, to take effect January 1, 2011, subject to NYPSC approval. The Companies are proposing to recover a combined $65.0 million of regulatory assets, which is comprised of a combined annual amortization of deferral balances on the balance sheet at December 31, 2009 of $55.4 million, and a half year annual amortization of the 2010 forecasted deferral balances of $9.7 million. The discovery phase of the proceeding remains ongoing at the NYPSC and a completion date can not be predicted at this time.

In April 2008, Brooklyn Union filed with the NYPSC to recover an incentive earned in 2002-2007 relating to lost and unaccounted for ("LAUF") gas. Brooklyn Union was entitled to earn an incentive during that period by reducing LAUF below an amount specified in a prior rate case. Due to an error in the methodology that had been used to calculate LAUF for the years 2002-2007, the incentive amount earned and recovered in rates was understated by approximately $27 million. The 2008 petition sought recovery of the understated amount. The gain contingency is not reflected in the consolidated financial statements. In April 2011, the NYPSC issued a ruling denying Brooklyn Union's request.

Other Regulatory Matters
In February 2011, the NYPSC instituted a proceeding to review its policies regarding the funding mechanisms supporting SIR expenditures and directing the New York State's utilities to assist in developing a comprehensive record of: (1) the current and future scope of utility site investigation SIR programs; (2) the current cost controls in place by utilities and opportunities to improve such cost controls; (3) the appropriate allocation of costs among customers and potentially shareholders; and (4) methods for recovering SIR costs appropriately borne by customers in a way that minimizes the impact. The NYPSC has requested that the Administrative Law Judge provide a presentation of recommendations before the end of 2011.

In its September 12, 2007, "Order Authorizing Acquisition subject to Conditions and Making Some Revenue Requirement Determinations for KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island", issued in Case 06-M-0878, the NYPSC authorized the merger of KeySpan Corporation and National Grid subject to the adoption of various financial and other conditions. One of the conditions was the requirement that the Company issue a class of preferred stock having one share (the "Golden Share"), subordinate to any existing preferred stock, the holder of which 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 such share of stock. 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. The Golden Share was issued by the Company on July 8, 2011.

In August 2010, KeySpan Gas East filed a petition with the NYPSC seeking multi-year authority to issue, prior to March 31, 2014, up to $1.1 billion in new long-term debt securities (revised to $1.0 billion in February 2011). In March 2011, the NYPSC granted this authority and KeySpan Gas East issued $500 million in long term debt. The proceeds will be used for general corporate purposes.

On December 22, 2009, the NYPSC adopted the terms of a Joint Proposal between Staff of the Department of Public Service and the Companies that provided for a RDM to take effect as of January 1, 2010. The revenue decoupling mechanism applies only to the Companies' firm residential heating sales and transportation customers, and permits the 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 Companies to implement energy efficiency programs by breaking the link between sales and revenues and/or profits. The Companies had a combined deferred payable balances related to the RDM in the amount of $12.8 million and $2.1 million at March 31, 2011 and March 31, 2010. These payable balances are fully refundable to the affected customer class.

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

In April 2010, the Gas Companies filed an initial request with the DPU for a combined rate increase of $106 million, which was revised to $104.1 million in September, 2010. In November 2010, the DPU issued an order approving a combined revenue increase of $58 million based upon a 9.75% rate of return on equity and a 50% equity ratio. In May 2011, the Gas Companies made their first filing with the DPU for recovery of capital costs related to infrastructure replacement. The reported combined revenue requirement associated with these capital costs are approximately $10.4 million. Since this amount is below the ordered cap of 1% of the Gas Companies' prior year total revenues, the entire amount is eligible for recovery.

The DPU order also provided for a RDM to take effect as of November 1, 2010. The RDM applies to the Gas Companies' firm rate classes, excluding gas lamps and negotiated contracts and permits the Gas Companies to reconcile actual revenue per customer to target revenue per customer for the affected customer classes on a seasonal basis. The RDM is designed to eliminate the disincentive for the Gas Companies to continue to aggressively implement energy efficiency programs. As of March 31, 2011, the combined deferred amount under the RDM was a liability to customers of $17.9 million. On August 1, 2011, the Gas Companies submitted its first RDM filing with the DPU proposing to refund a combined $17.1 million to its customers.

In November 2010, the Gas Companies' filed two motions in response to the DPU order (1) in its motion for recalculation, the Gas Companies have requested that the DPU recalculate certain adjustments that it made in determining the $58 million increases approved in its order. If approved, the rate increase for the Gas Companies would increase by an additional $10.4 million to a total of approximately $68.4 million (2) in its motion for reconsideration and clarification, the Gas Companies are seeking reconsideration of the DPU's disposition of four issues they believe were based on legal error or lack of substantial evidence, and clarification on three non-financial matters. The most significant of the four items for reconsideration involves the DPU's disallowance of $11.3 million from Boston Gas rate base related to certain fixed asset additions from calendar years 1996 to 1998 as well as disallowance of depreciation expenses of approximately $0.8 million per year associated with those assets. These assets have been impaired in the accompanying financial statements. If the Gas Companies are unsuccessful with their request for reconsideration, they could appeal the matter to the Massachusetts Supreme Judicial Court. The motions remain pending at the DPU.

Associated with its general rate case, the DPU opened an investigation to address the allocation and assignment of costs to the Gas Companies by the National Grid service companies. In June 2011, the Attorney General's Office requested the DPU to expand the scope of the audit to address the allocation and assignment of costs to the Company's electric distribution affiliates by the National Grid service companies and to review National Grid's cost allocation practices. The Company has agreed to expand the scope of the audit to its Massachusetts electric distribution affiliates. As of the date of this report, the DPU has not established the full scope of the audit.

Other Regulatory Matters

In November 2008, the Gas Companies filed a combined request for approval of a three year gas portfolio optimization agreement with ConocoPhillips, which was approved in April 2009 but limited the term to a one year period. This agreement was extended for one additional year upon the approval of DPU in April 2010. Since the former ConocoPhillips agreement terminated as of March 31, 2011, and the Gas Companies' request for a subsequent co-management agreement with BG Energy Merchants, LLC (which was intended to commence April, 2011), was rejected by the DPU in May, 2011, the Gas Companies have been managing and optimizing their assets on their own . In August, 2011, the Companies sought approval for six natural gas asset management services agreements between the Gas Companies and one of five counterparties. The DPU approved the agreements on October 17, 2011 and they will commence on November 1, 2011 and expire on March 31, 2012. Under these agreements, the Gas Companies will be eligible to share in 25% of only the portions 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 D.P.U. 93-141-A. These potential earnings will not be determined until the end of the peak season. One hundred percent of the commodity-related fees will be returned to firm sales customers.

On June 1, 2011, in conjunction with the DPU's annual investigation of Boston Gas's calendar year 2009 pension and PBOP rate reconciliation mechanism, the Massachusetts Attorney General argued that the Company 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 DPU is expected to decide this matter during the second half of 2011.

Green Communities Act

The Gas Companies' EE plan is run as a single combined plan. For the calendar years 2010 through 2012, the plan significantly expands EE programs for customers with a concomitant increase in spending. The budget for the gas companies in Massachusetts, exclusive of lost base revenues ("LBR") (revenues reduced as a result of installed EE measures) for the calendar years 2010 through 2012 is $203.4 million. In addition to cost recovery, the Company has the opportunity to earn a performance incentive. On March 31, 2011, the DPU approved a combined performance incentive for 2009 of $1.0 million, net of taxes. The DPU also approved an increase to the 2009 EE budget of approximately $8.8 million. On July 27, 2011, the DPU approved the recovery of 2008 and 2009 LBR and associated carrying costs of $2.6 million. The Company will begin recovering this amount in November 2011. On August 16, 2011 the Gas Companies filed for recovery of its 2010 LBR and associated carrying costs of $2.9 million.

National Grid Generation

In January 2009, our indirectly-owned subsidiary, National Grid Generation filed an application with the FERC for a rate increase of $92 million for the final five year rate term of the fifteen year contract under the power supply agreement. 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, an 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.

Service Company Audit

In November 2008, the FERC commenced an audit of NGUSA, including its service companies and other affiliates in the National Grid holding company system. The audit evaluated our compliance with: 1) cross-subsidization restrictions on affiliate transactions; 2) accounting, recordkeeping and reporting requirements; 3) preservation of records requirements for holding companies and service companies; and 4) Uniform System of Accounts for centralized service companies. The final audit report from the FERC was received in February 2011. In April 2011, NGUSA replied to the FERC and outlined its plan to address the findings in the report, which we are currently in the process of implementing. None of the findings had a material impact on the consolidated financial statements of the Company.

In February 2011, the NYPSC selected Overland Consulting Inc., a management consulting firm, to perform a management audit of National Grid's affiliate cost allocation, policies and procedures. The audit of these service company charges seeks to determine if any service company transactions have resulted in unreasonable costs to New York customers for the provision of delivery service. If potentially material levels of misallocated or inappropriate service company costs are discovered, at the direction of the NYPSC, the investigation will be expanded to prior years to determine if a material amount of misallocated or inappropriate costs under these service company contracts have been charged to the New York utilities. A report of this review to the NYPSC is anticipated in Spring 2012. At the present time we are not aware of any material misallocation of costs among our affiliates and we do not expect the audit to result in any material adjustment to our financial statements.

Note 3. Employee Benefits

Summary

The Company and its subsidiaries have defined benefit pension plans which provides union employees with a retirement benefit and non-union employees hired before January 1, 2011 with a retirement benefit.

Supplemental nonqualified, noncontributory executive retirement programs provide additional defined pension benefits for certain executives. A similar retirement program is provided to non-executive employees who have compensation or benefits in excess of the qualified plan limits.

The Company and its subsidiaries have defined PBOP plans which provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must contribute to the cost of their coverage.

The Company and its subsidiaries also offer employees a defined contribution plan. Plans are available to all eligible employees. Eligible employees contributing to the plans may receive certain employer contributions including matching contributions.

Funding Policy

The pension contribution for any one year will not be less than the minimum amount required under the Pension Protection Act of 2006 and is expected to exceed the minimum required contribution amounts. For PBOP plans, funding is made in accordance with the requirements of the various regulatory jurisdictions within which the Company operates.

Plan Assets

The target asset allocation for the benefit plans at March 31, 2011 and March 31, 2010 are:

	Pension Benefits		**Non-union PBOPs**		**Union PBOPs**	
	2011	2010	**2011**	2010	**2011**	2010
U.S. equities	**20%**	20%	**45%**	38%	**34%**	34%
Global equities (including US equities)	**7%**	7%	**-**	-	**12%**	12%
Global tactical asset allocation	**10%**	10%	**-**	-	**17%**	17%
Non-U.S. equities	**10%**	10%	**25%**	17%	**17%**	17%
Fixed income	**40%**	40%	**30%**	44%	**20%**	19%
Private equity	**5%**	5%	**-**	1%	**-**	1%
Real estate	**5%**	5%	**-**	-	**-**	-
Infrastructure	**3%**	3%	**-**	-	**-**	-
	100%	100%	**100%**	100%	**100%**	100%

The percentage of the fair value of total plan assets at March 31, 2011 and March 31, 2010 is:

	Pension Benefits		**Non-union PBOPs**		**Union PBOPs**	
	2011	2010	**2011**	2010	**2011**	2010
U.S. equities	**21%**	23%	**44%**	36%	**34%**	35%
Global equities (including US equities)	**8%**	8%	**-**	-	**12%**	12%
Global tactical asset allocation	**12%**	12%	**-**	-	**16%**	16%
Non-U.S. equities	**11%**	10%	**25%**	17%	**17%**	17%
Fixed income	**40%**	41%	**30%**	46%	**20%**	19%
Private equity	**6%**	6%	**1%**	1%	**1%**	1%
Real estate	**2%**	**-**	**-**	-		-
	100%	100%	**100%**	100%	**100%**	100%

The Company manages the pension and PBOP plans' investments to minimize the long-term cost of operating the pension and PBOP Plan, with a reasonable level of risk. Risk tolerance is determined as a result of a periodic asset/liability study which analyzes the pension and PBOP plans' liabilities and funded status and results in the determination of the allocation of assets across equity and fixed income securities. Equity investments are broadly diversified across U.S. and non-U.S. stocks, as well as across growth, value, and small and large capitalization stocks. Likewise, the fixed income portfolio is broadly diversified across the various fixed income 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. Investment risk and return is reviewed by an investment committee on a quarterly basis.

The discount rate is the rate at which plan obligations can be settled. The discount rate assumption is based on rates of return on high quality fixed income investments in the market place as of each measurement date (typically March 31). Specifically, the Company uses the Aon Hewitt Top Quartile Discount Curve along with the expected future cash flows from the retirement plans to determine the weighted average discount rate assumption.

The estimated rate of return for various passive asset classes is based on both 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 assumption. A small premium is added for active management and rebalancing 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.

Assumptions Used for Benefits Accounting

The following weighted average assumptions were used to determine the pension and PBOP benefit obligations and net periodic benefit costs for the years ending March 31, 2011 and March 31, 2010:

	Pension Benefits			
	Benefit obligation		**Net periodic benefit cost**	
	2011	2010	**2011**	**2010**
Discount rate	**5.90%**	6.10%	**6.10%**	**7.30%**
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	**3.50%**
Expected long-term rate of return on assets	**7.75%**	8.00%	**8.00%**	**8.00%**

	PBOP			
	Benefit obligation		**Net periodic benefit cost**	
	2011	2010	**2011**	**2010**
Discount rate	**5.90%**	6.10%	**6.10%**	7.30%
Expected long-term rate of return on asset				
Union	**7.75%**	8.00%	**8.00%**	8.25%
Non-union	**7.83%**	7.00%	**7.00%**	6.75%
Health care cost trend rate				
Medical trend rate				
Pre-65	**8.50%**	8.50%	**8.50%**	8.50%
Post-65	**8.00%**	8.50%	**8.50%**	9.50%
Prescription drug trend rate	**8.75%**	9.25%	**9.25%**	n/a
Ultimate rate	**5.00%**	5.00%	**5.00%**	5.00%
Year ultimate rate is reached - medical				
Pre-65	**2018**	2017	**2017**	2015
Post-65	**2017**	2017	**2017**	2016
Year ultimate rate is reached - prescription	**2019**	2019	**2019**	n/a

The expected contributions to the Company's pension and PBOP plans during the year ended March 31, 2012 are $344 million and $321 million, respectively.

Several assumptions affect the pension and other postretirement benefit expense and measurement of their respective obligations. The following is a description of some of those assumptions:

Benefit plan investments
The Company manages the pension and PBOP plans' investments to minimize the long-term cost of operating the pension and PBOP plans, with a reasonable level of risk. Risk tolerance is determined as a result of a periodic asset/liability study which analyzes the pension and PBOP plans' liabilities and funded status and results in the determination of the allocation of assets across equity and fixed income. Equity investments are broadly diversified across U.S. and non-U.S. stocks, as well as across growth, value, and small and large capitalization stocks. Likewise, the fixed income portfolio is broadly diversified across the various fixed income 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. Investment risk and return is reviewed by an investment committee on a quarterly basis.

Expected return on assets
The estimated 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 assumption. 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.

Discount rate
The Company selects its discount rate assumption based upon rates of return on high quality corporate bond yields in the marketplace as of each measurement date (typically each March 31st). Specifically, the Company uses the Hewitt Top Quartile Discount Curve along with the expected future cash flows from the KeySpan retirement plans to determine the weighted average discount rate assumption.

Pension Benefits

The Company's net periodic benefit cost for the years ended March 31, 2011 and March 31, 2010 included the following components:

(in millions of dollars)		**2011**		2010
Service cost	**$**	**119**	$	98
Interest cost		**367**		366
Expected return on plan assets		**(398)**		(336)
Amortization of prior service cost		**8**		7
Amortization of loss		**199**		169
Net periodic benefit costs before settlements and curtailments		**295**		304
Settlement and curtailment loss		**2**		3
Special termination benefits		**15**		36
Net periodic benefit cost	**$**	**312**	$	343

The following tables provide the accumulated benefit obligation and the changes in the funded status of the pension plans at March 31, 2011 and March 31, 2010:

(in millions of dollars)		**2011**		2010
Accumulated benefit obligation	**$**	**(5,993)**	$	(5,708)
Reconciliation of benefit obligation:				
Benefit obligation at beginning of year		**(6,164)**		(5,224)
Service cost		**(119)**		(98)
Interest cost		**(367)**		(366)
Actuarial loss		**(183)**		(827)
Benefits paid		**391**		405
Curtailments/settlements		**1**		13
Plan amendments		**(3)**		(31)
Special termination benefits		**(15)**		(36)
Benefit obligation at end of year	**$**	**(6,459)**	$	(6,164)
Fair value of plan assets at beginning of year		**5,019**	$	3,756
Actual return on plan assets		**675**		1,203
Company contributions		**405**		478
Benefits paid		**(391)**		(417)
Settlements		**(3)**		(1)
Fair value of plan assets at end of year	**$**	**5,705**	$	5,019
Funded status	**$**	**(754)**	$	(1,145)

As of March 31, 2011 and March 31, 2010, amounts recognized on the consolidated balance sheets consist of:

(in millions of dollars)		**2011**		2010
Current pension liability	**$**	**(23)**	$	(25)
Noncurrent pension liability		**(731)**		(1,120)
	$	**(754)**	$	(1,145)

As of March 31, 2011 and March 31, 2010, amounts recognized in regulatory assets and accumulated other comprehensive income consist of:

(in millions of dollars)		**2011**		2010
Net actuarial loss	**$**	**1,585**	$	1,876
Prior service cost		**61**		65
Net amount recognized	**$**	**1,646**	$	1,941

As a result of deferral accounting requirements mandated by the regulators, $836 million and $1 billion of the net amount recognized has been recorded in regulatory assets on the consolidated balance sheets for the years ended March 31, 2011 and March 31, 2010, respectively.

The estimated net actuarial loss and prior service cost for the defined benefit pension plans that will be amortized during the year ended March 31, 2012 are $197 million and $8 million, respectively.

The following pension benefit payments are expected to be paid:

(in millions of dollars)		Pension Benefits
2012	$	394
2013		412
2014		423
2015		440
2016		455
Thereafter		2,462

Defined Contribution Plan

The Company also has several defined contribution pension plans (primarily 401(k) employee savings fund plans) that cover substantially all employees. Employer matching contributions of approximately $32 million and $30 million were expensed in the years ended March 31, 2011 and March 31, 2010.

Postretirement Benefits Other than Pensions

The Company's total net periodic benefit cost of PBOPs for the years ended March 31, 2011 and March 31, 2010 included the following components:

(in millions of dollars)		**2011**		2010
Service cost	**$**	**58**	$	41
Interest cost		**231**		226
Expected return on plan assets		**(110)**		(86)
Amortization of prior service cost		**12**		12
Amortization of net loss		**94**		61
Net periodic benefit cost before special termination benefits		**285**		254
Special termination benefits		**-**		1
Net periodic benefit cost	**$**	**285**	$	255

The following tables provide the changes in the funded status of the PBOP plans at March 31, 2011 and March 31, 2010:

(in millions of dollars)		**2011**		2010
Benefit obligation at beginning of period	**$**	**(3,951)**	$	(3,303)
Service cost		**(58)**		(41)
Interest cost		**(231)**		(226)
Actuarial gain/(loss)		**42**		(569)
Benefits paid		**183**		209
Medicare subsidy		**(8)**		(13)
Plan amendments		**23**		13
Special termination benefits		**-**		(1)
Healthcare Reform Amendment		**-**		(15)
Other		**-**		(5)
Benefit obligation at end of period	**$**	**(4,000)**	$	(3,951)
Fair value of plan assets at beginning of period	**$**	**1,444**	$	1,037
Actual return on plan assets		**206**		396
Company contributions		**247**		219
Benefits paid		**(183)**		(209)
Other		**-**		1
Fair value of plan assets at end of period	**$**	**1,714**	$	1,444
Funded status	**$**	**(2,286)**	$	(2,507)

As of March 31, 2011 and March 31, 2010, amounts recognized on the consolidated balance sheets consist of:

(in millions of dollars)		**2011**		2010
Current assets	**$**	**5**	$	3
Current liabilities		**(30)**		(14)
Noncurrent liabilities		**(2,261)**		(2,496)
Net amount recognized		**(2,286)**		(2,507)

As of March 31, 2011 and March 31, 2010, amounts recognized in regulatory assets and accumulated other comprehensive income (loss), before taxes, consist of:

(in millions of dollars)		**2011**		2010
Net actuarial loss	**$**	**689**	$	923
Prior service cost		**35**		70
Net amount recognized *	**$**	**724**	$	993

* The above amounts are before adjustments for regulatory deferrals and deferred taxes.

As a result of deferral accounting requirements mandated by the regulators, $395 million and $613 million of the net amount recognized has been recorded in regulatory assets on the consolidated balance sheets for the years ended March 31, 2011 and March 31, 2010, respectively.

The estimated net actuarial loss and prior service cost for the PBOP plans that will be amortized during the year ended March 31, 2012 are $89 million and $10 million, respectively.

The following PBOP benefit payments expected to be paid and subsidies expected to be received from the U.S. Federal Government, which reflect expected future services as appropriate are:

(in millions of dollars)	Payments	Subsidies
2012	$ 207	$ 14
2013	218	15
2014	229	16
2015	239	17
2016	248	19
2017-2021	1,366	110

The assumptions used in health care cost trends have a significant effect on the amounts reported. A 1% change in the assumed rates would have the following effects:

(in millions of dollars)	
Increase 1%	
Total of service cost plus interest cost	44
Postretirement benefit obligation	540
Decrease 1%	
Total of service cost plus interest cost	(37)
Postretirement benefit obligation	(461)

Health Care Reform Act

In March 2010, the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 became law. These laws included provisions which resulted in the repeal, with effect from 2012, of the deduction for federal income tax purposes of the portion of the cost of an employer's retiree prescription drug coverage for which the employer received a benefit under the Medicare Prescription Drug Improvement and Modernization Act of 2003. The consequential reduction in the deferred tax asset balance resulted in a net charge to the consolidated statement of income of approximately $138 million for the year ended March 31, 2010.

This was partially offset by the reversal of regulatory liabilities, net of related taxes, which reduced the net impact by approximately $62 million for a net charge to the consolidated statement of income of $76 million for the year ended March 31, 2010.

Workforce Reduction Program

In connection with National Grid plc's acquisition of KeySpan, National Grid plc and KeySpan offered 673 non-union employees a voluntary early retirement offer ("VERO") in an effort to reduce the workforce. Eligible employees must have been working in a targeted area as of April 13, 2007 and be at least 52 years of age with seven or more years of service as of September 30, 2007. For eligible employees who have elected to accept the VERO offer, National Grid plc and KeySpan had the right to retain that employee for up to three years before VERO payments are made. An employee who accepted the VERO offer but elects to terminate employment with National Grid plc or KeySpan prior to the three year period, without consent of National Grid plc or KeySpan, forfeits all rights to VERO payments. The VERO is completed and the Company has accrued approximately $158 million of which a portion has been deferred for recovery from customers as part of the synergy savings and cost to achieve calculations.

In connection with the renewal of the collective bargaining agreement with NGUSA employees that are part of Local 101, National Grid plc offered 284 Local 101 union employees a VERO in an effort to reduce the workforce. Eligible employees must have been working in a targeted area as of October 15, 2010 and be retirement age eligible in accordance with the pension plan each employee participates in as of May 1, 2011. For eligible employees who have elected to accept the VERO offer, NGUSA has the right to retain that employee for up to one year before VERO payments are made. An employee who accepts the VERO offer, but elects to terminate employment with National Grid plc prior to the one year period without consent of National Grid plc, forfeits all rights to VERO payments. The Company recorded $5 million in accrued cost associated with this VERO package.

Fair Value Measurements of Plan Assets

Investments are reported at fair value. Fair value is the price that would be received to sell the asset or paid to transfer the liability (an exit price) in an orderly transaction between market participants at the measurement date, not the price that would be paid to acquire the asset or received to assume the liability (an entry price). The company used valuation which maximized the use of observable inputs and minimized the use of unobservable inputs.

Following is a description of the valuation methodologies used at March 31, 2011 for plan assets measured at fair value:

Cash equivalents are valued at the investment principal plus all accrued interest. Temporary cash investment and short-term investments are valued at either the investment principal plus all accrued interest or the net asset value of shares held by the Plan at year end.

Common and preferred stocks, and real estate investment trusts are valued using the official close for the National Association of Securities Dealers Automated Quotations ("NASDAQ"), the last trade, or bid of the ask offer price reported on the active market on which the individual securities are traded.

Fixed income securities, convertible securities, collateral received from securities lending (which include corporate debt securities, municipal fixed income securities, US Government and Government agency securities) are comprised of government agency securities, government mortgage-backed securities, index linked government bonds, and state and local bonds. Fixed income securities are valued with an institutional bid valuation or an institutional mid evaluation. A bid evaluation is an estimated price at which a dealer would pay for a security (typically in an institutional round lot). A mid evaluation is the average of the estimated price at which a dealer would sell a security and the 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 used when primary price vendors do not supply prices.

Derivatives (except certain options traded on an exchange) and forward foreign exchange contracts (comprised of interest rate swaps, credit default swaps, index swaps, financial futures, and other derivatives), and investment of securities lending collateral (comprised of repurchase agreements, asset-backed securities, floating rate notes and time deposits) are valued with an institutional bid valuation or an institutional mid evaluation. A bid evaluation is an estimated price at which a dealer would pay for a security (typically in an institutional round lot). A mid evaluation is the average of the estimated price at which a dealer would sell a security and the 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 used when primary price vendors do not supply prices.

Mutual funds are valued at the net asset value of shares held by the Plan at year end. Commingled equity funds, commingled special equity funds, limited partnerships, real estate, venture capital and other investments are valued using evaluations (a good faith opinion as to what a buyer in the marketplace would pay for a security– typically in an institutional round lot-in a current sale), based on proprietary models, or based on the net asset value. Index funds include investments that seek to match the return performance and characteristics of a specified index. The index funds are controlled by investment managers, which balance the funds to track the specified index. Non-US equity funds are typically invested in at least 80% foreign equity securities. Registered investment companies and common and collective trusts, and pooled separate accounts are valued at the net asset value of shares held by the Plans at year end.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, 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 certain financial instruments could result in a different fair value measurement at the reporting date.

The table depicted below sets forth by level, within the fair value hierarchy, the NGUSA Master Union Trust Plan pension investments at fair value as of March 31, 2011 and March 31, 2010.

(in millions of dollars)	March 31, 2011			
Asset type	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ 2	$ 160	$ -	$ 162
Equity	1,225	1,325	419	2,969
Fixed income securities	474	1,639	340	2,453
Preferred securities	6	-	-	6
Real estate	-	-	115	115
Total	$ 1,707	$ 3,124	$ 874	$ 5,705

(in millions of dollars)	March 31, 2010			
Asset type	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ 35	$ 103	$ -	$ 138
Equity	1,111	1,196	351	2,658
Fixed income securities	565	1,416	224	2,205
Futures contracts	2	-	-	2
Preferred securities	8	-	-	8
Real estate	-	-	1	1
Total	$ 1,721	$ 2,715	$ 576	$ 5,012

The table depicted below sets forth by level, within the fair value hierarchy, the NGUSA Master Union Trust Plan retirement benefits other than pension investments at fair value as of March 31, 2011 and March 31, 2010.

(in millions of dollars)	March 31, 2011			
Asset type	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ 4	$ 31	$ -	$ 35
Equity	447	649	41	1,137
Fixed income securities	254	225	62	541
Preferred securities	1	-	-	1
Total	$ 706	$ 905	$ 103	$ 1,714

(in millions of dollars)	March 31, 2010			
Asset type	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ 64	$ 19	$ -	$ 83
Equity	341	454	40	835
Fixed income securities	217	246	61	524
Preferred securities	1	-	-	1
Total	$ 623	$ 719	$ 101	$ 1,443

The following table sets forth a summary of changes in the fair value of the pension plan's Level 3 investments for the year ended March 31, 2011:

(in millions of dollars)	Equity	Fixed Income Securities	Real Estate	Total
Balance, beginning of year	$ 351	$ 224	$ 1	$ 576
Realized gains	22	-	-	22
Unrealized gains at reporting date	48	23	12	83
Purchases, sales, issuance and settlements (net)	(2)	93	102	193
Balance, end of year	$ 419	$ 340	$ 115	$ 874

The following table sets forth a summary of changes in the fair value of the retirement benefits other than pension plan's Level 3 investments for the year ended March 31, 2011:

(in millions of dollars)	Equity	Fixed Income Securities	Total
Balance, beginning of year	$ 40	$ 61	$ 101
Realized gains	3	1	4
Unrealized gains at reporting date	3	6	9
Purchases, sales, issuance and settlements (net)	(5)	(6)	(11)
Balance, end of year	$ 41	$ 62	$ 103

Note 4. Debt

European Medium Term Note Program

At March 31, 2011, 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. At March 31, 2011, $181 million of these notes were issued and outstanding, including the impact of interest rate and currency swaps. At March 31, 2010, $23 million of these notes were outstanding.

Instruments issued under the Program are admitted to trading on the London Stock Exchange. The Program commenced in December 2007 and is expected to be renewed annually for the foreseeable future. The funds raised under the Program may be used for general corporate purposes. Instruments may be issued in bearer form in any currency, with maturities ranging from one month to perpetuity. Instruments may not be offered, sold or delivered within the United States or to a U.S. person except in certain limited circumstances permitted by US regulations. Any fees associated with issuing instruments under the Program are negotiated with the bank(s) managing the issuance at the time. Instruments issued under the Program rank pari passu with each other and with all other unsecured debt obligations of the Company, except to the extent that the other debt obligations may be subordinated. Instruments carry certain positive 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, 2011, the Company was in compliance with all covenants.

Notes Payable

At March 31, 2011, the Company had outstanding $4.6 billion of unsecured medium and long-term notes. Between August 2009 and March 2011, the Company issued debt in six tranches totaling $3.1 billion. The interest rates on the unsecured notes range from 3.55% to 9.75% and maturity dates range from 2011 through 2041. The unsecured notes include $15 million of long-term debt, issued at a subsidiary, which has certain restrictive covenants and acceleration clauses. These covenants stipulate that note-holders may declare the debt to be due and payable if total debt becomes greater than 70% of total capitalization at the subsidiary. At March 31, 2011, the total long-term debt was 35% of total capitalization. Additionally, some of these bonds have a sinking fund requirement which totaled $7 million during the year ended March 31, 2011.

On March 18, 2010, the Company settled a derivative financial instrument that it had entered into in connection with two of the fiscal 2010 bond issuances for the purpose of locking-in the risk-free interest rate element of the bond issues. The $11 million loss on the "treasury lock" settlement will be amortized over the life of the bonds to match the corresponding rate treatment.

Gas Facilities Revenue Bonds

At March 31, 2011 and March 31, 2010, the Company had outstanding $641 million of tax exempt gas utility revenue bonds. The Company can issue tax-exempt bonds through the New York State Energy Research and Development Authority ("NYSERDA"). Whenever bonds are issued for new gas facilities projects, proceeds are deposited in trust and subsequently withdrawn to finance qualified expenditures. There are no sinking fund requirements on any of our Gas Facilities Revenue Bonds ("GFRBs"). Of the $641 million, $230 million are variable rate securities due through July 1, 2026. The interest rate is reset weekly and ranged from 0.455% to 2.433% during the year ended March 31, 2011. For the year ended March 31, 2010, the interest rates ranged from 0.4% to 4.00%. The variable-rate auction bonds are currently in the auction rate mode and are backed by bond insurance.

Promissory Notes to LIPA

Certain of the Company's subsidiaries issued promissory notes to LIPA to support certain debt obligations assumed by LIPA in May 1998. At March 31, 2011 and March 31, 2010, $155 million of promissory notes remained outstanding with maturity dates ranging from 2016 to 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 statistical rating agencies. At March 31, 2011, the Company was in compliance with this requirement.

First Mortgage Bonds

At March 31, 2011, the Company had outstanding $130 million of first mortgage bonds. Certain of the first mortgage bond indentures include, among other provisions, limitations/requirements on: (i) the issuance of long-term debt; (ii) engaging in additional lease obligations; (iii) annual sinking fund requirements of $1 million and, (iv) the payment of dividends from retained earnings. At March 31, 2011, these bonds remain outstanding and have interest rates ranging from 6.34% to 9.63% and maturity ranging from 2018 to 2028. At March 31, 2010, $132 million of first mortgage bonds were outstanding with interest rates ranging from 6.82% to 9.63%.

State Authority Financing Bonds

At March 31, 2011, the Company had outstanding $1.2 billion of State Authority Financing Bonds. Of the $1.2 billion outstanding at March 31, 2011, $716 million of these bonds were issued through NYSERDA and the remaining $483 million were issued through various other state agencies.

Approximately $650 million of first mortgage bonds were issued to secure a like amount of tax-exempt revenue bonds, of which $575 million bear interest at short-term variable rates (with an option to convert to other rates, including a fixed interest rate) and ranged from 0.575% to 0.885% for the year ended March 31, 2011. The NYSERDA bonds are currently in the auction rate mode and are backed by bond insurance.

The remaining $75 million of first mortgage bonds are 5.15% fixed rate pollution control revenue bonds issued through NYSERDA which are callable at par. Pursuant to agreements between NYSERDA and the Company's subsidiary, 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 was subsequently sold) or to refund outstanding tax-exempt bonds and notes.

Additionally, the Company has $41 million of Authority Financing Notes 1999 Series A Pollution Control Revenue Bonds due October 1, 2028. The interest rate on these notes is reset based on an auction procedure. The interest rate ranged from 0.50% to 2.00% for the year ended March 31, 2011, at which time the rate was 1.60%. The second Series A bond is a $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 0.24% to 0.34% for the year ended March 31, 2011, at which time the rate was 0.26%.

At March 31, 2011, the Company had outstanding $430 million of the Pollution Control Revenue Bonds in tax exempt commercial paper mode. These bonds were issued through Business Finance Authority of the State of New Hampshire, the Massachusetts Industrial Finance Agency, and the Connecticut Development Authority. Interest rates ranged from 0.50% to 1.05% for the year ended March 31, 2011. There are no payments or sinking fund requirements due in 2012 through 2016. The Company has Standby Bond Purchase Agreements and Credit Agreements to provide liquidity support for these bonds.

At March 31, 2011, the Company had $53 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 0.70% to 1.00% during the year ended March 31, 2011. 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 $230 thousand were made during the year ended March 31, 2011. The Company has Standby Bond Purchase Agreements to provide liquidity support for these bonds.

Industrial Development Revenue Bonds

At March 31, 2011 and March 31, 2010, the Company had outstanding $128 million of tax-exempt Industrial Development Revenue bonds. Of these bonds, $53 million 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 $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.

Committed Facility Agreements

At March 31, 2011, NGUSA had three committed bank loans outstanding totaling $500 million which mature in 2014. These loans are used to provide funds for working capital needs. The interest rates on these bank loans are reset periodically and are set at 0.90% over the London Interbank Offered Rate ("LIBOR").

Intercompany Notes Payable

As of March 31, 2011 and March 31, 2010, the Company'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 Company had no public debt since all public debt was held at the subsidiary level. The intercompany loans are paid back by the Company from the dividends it receives from NGUSA.

The following table summarizes the terms of the Company's intercompany loans as of March 31, 2011 and March 31, 2010:

(in millions of dollars)			**March 31,**	
			2011	2010
Due to:	**Interest Rate**	**Maturity Date**	**Amounts**	
National Grid plc	5.69%	August 22, 2011	**$ 500**	500
National Grid Investments Ltd. ("NGLI")	0.53% to 2.2% over LIBOR	Aug 2011 - Aug 2027	**4,372**	5,022
National Grid Luxembourg 5 Sarl	1.7% to 2.3% over LIBOR	Aug 2011 - Aug 2018	**2,081**	2,081
NGUSA due to National Grid plc	0.2% to 0.9% over LIBOR	Nov 2011 - Nov 2015	**550**	867
Total			**$ 7,503**	$8,470

At March 31, 2010, NGUSA had an outstanding balance due to the Parent of $867 million, at 5.52% which was repaid in November 2010, the date of its maturity.

Debt Maturity

The following table reflects the maturity schedule for our debt repayment requirements at March 31, 2011:

(in millions of dollars)		
Years Ended March 31,		
2012	$	1,717
2013		588
2014		758
2015		1,237
2016		1,126
Thereafter		9,658
Total	$	15,084

The following table depicts the sinking fund requirements at March 31, 2011:

(in millions of dollars)		
Years Ended March 31,		**Amount**
2012	$	7
2013		7
2014		7
2015		4
2016		5
Thereafter		12
Total	$	42

Standby Bond Purchase Agreement

At March 31, 2011, three of the Company's subsidiaries had a Standby Bond Purchase facility of $455 million, expiring in November 2011. At March 31, 2011 and March 31, 2010, there were no bond purchases by the banks under this agreement. The Company is in the process of evaluating all its liquidity support options available in addition to renewing the agreement to support certain tax-exempt State Authority Bonds after the current agreement expires.

Credit Facilities

At March 31, 2011 and March 31, 2010 one of the Company's subsidiaries had two Credit Agreements with banks totaling $75 million, which are available to provide liquidity support for certain tax-exempt State Authority Bonds. There were no borrowings under these facilities at March 31, 2011 and March 31, 2010.

***Commercial Paper and Revolving Credit Agreem*ents**

Commercial Paper
At March 31, 2011, 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 $1.5 billion of the facilities being 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 2012-2015.

The credit facilities allow both the Parent and the Company to borrow in Pounds Sterling or US Dollars. The current annual fees range from 0.21% to 0.30%. We do not anticipate borrowing against these facilities; however, if for any reason we were not able to issue sufficient commercial paper or source funds from other sources, this facility could be drawn upon to meet cash requirements. The facility contains 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, 2011, the Company was in compliance with all covenants.

At March 31, 2011, there was $735 million of borrowings outstanding on the US commercial paper program and no borrowings outstanding on the Euro commercial paper program. At March 31, 2010, there were no borrowings outstanding on either program.

Intercompany Moneypool
NGUSA and subsidiaries are participants in a moneypool to more effectively utilize cash resources and to reduce outside short-term borrowings. The Company can borrow from its Parent for working capital needs on a short-term basis. The moneypool is administered by the NGUSA service company as the agent for the participants. Interest rates associated with the moneypool are designed to approximate the cost of third-party short-term borrowings. Funds may be withdrawn from or repaid to the moneypool at any time without prior notice. NGUSA and KeySpan, collectively, have the ability to borrow up to $3 billion from the Parent for working capital needs, including for the purpose of funding the moneypool, if necessary. At March 31, 2011, the Company had $500 million due to its Parent under this arrangement . At March 31, 2010, the Company had no amounts outstanding.

Note 5. Property, Plant and Equipment

At March 31, 2011 and March 31, 2010, property, plant and equipment at cost and accumulated depreciation are as follows:

(in millions of dollars)	**March 31,**	
	2011	2010
Plant and machinery	**$ 21,690**	$ 20,398
Land and buildings	**3,237**	3,111
Assets in construction	**984**	843
Software	**515**	507
Total	**26,426**	24,859
Accumulated depreciation and amortization	**(6,300)**	(5,801)
Property, plant and equipment, net	**$ 20,126**	$ 19,058

AFUDC

The Company capitalizes AFUDC as part of construction costs. AFUDC represents an allowance for the cost of funds used to finance construction includes a debt component and an equity component. AFUDC is capitalized in “property, plant and equipment” with offsetting credits to “other interest, including affiliates interest” for the debt component and “other income” for the equity component. This method is in accordance with an established rate-making practice under which the Company is permitted to recover prudently incurred capital costs through its ultimate inclusion in rate base and in the provision for depreciation. AFUDC capitalized during the years ended March 31, 2011 and March 31, 2010 was $21.0 million and $11 million, respectively.

Depreciation

Depreciation expense is generally determined using the straight-line method. The depreciation rates for the Company’s gas and electric subsidiaries are based on periodic studies of the estimated useful lives of the assets and the estimated cost to remove them, net of salvage value. The Company’s gas and electric subsidiaries use composite depreciation rates that are approved by the applicable federal and state utility commissions. The cost of property retired is charged to accumulated depreciation in accordance with regulatory accounting guidance. The Company recovers cost of removal through rates charged to customers as a portion of depreciation expense. At March 31, 2011 and March 31, 2010, the Company had cumulative costs recovered in excess of costs incurred totaling $1.5 billion and $1.4 billion, respectively. This amount is reflected as a regulatory liability.

The weighted average service life, in years, for each asset category is presented in the table below:

	Years Ended March 31,	
	2011	2010
Asset Category:		
Electric	**35**	33
Gas	**36**	35
Common	**19**	21

Capitalized interest for the years ended March 31, 2011 and March 31, 2010 was $6 million and $5 million, respectively, and is reflected as a reduction to interest expense.

The Company's repair and maintenance costs, including planned major maintenance for turbine and generator overhauls, are expensed as incurred unless they represent replacement of property to be capitalized. Planned major maintenance cycles primarily range from seven to eight years. Smaller periodic overhauls are performed approximately every 18 months.

Impairment

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 current 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, the Company 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 generating units located at the Far Rockaway and Glenwood, New York generating facilities ("the Facilities"). The effectiveness of the Ramp Down Amendment is subject to receipt of certain regulatory approvals, including (i) the approval of the New York State Comptroller and the New York State Attorney General; and (ii) acceptance of the Ramp Down Amendment by the Federal Energy Regulatory Commission. Under the Ramp Down Amendment, the Ramp Down of Glenwood and Far Rockaway will be deemed to have occurred for purpose of calculating the economic impact (the net of items (a) and (b) above) on May 27, 2011 (the "Ramp Down Date"). Notwithstanding, the Company will continue to provide capacity, energy and ancillary services from Glenwood and Far Rockaway to LIPA until such time as the units become eligible for retirement, pending completion of certain transmission projects in the area currently served by these facilities. The Company believes that the Facilities will be deemed retirement eligible by LIPA during the summer of 2012.

In anticipation of the Ramp Down of Glenwood and Far Rockaway, as of March 31, 2011, the Company recorded estimated charges for impairment to long-lived assets of $31 million. The recorded impairment charges reduced the carrying value of the power generating units located in Glenwood and Far Rockaway to their net recoverable value as determined by use of discounted cash flows and estimated salvage value.

As of September 30, 2011, the Company has a legal obligation to remediate/demolish the facilities following retirement and for the related costs. Pursuant to the existence of this legal obligation, the Company recorded a reserve of $48.1 million subsequent to the balance sheet date.

In January 2010, NGUSA initiated an implementation program of SAP AG's enterprise resource planning ("ERP") program for NGUSA and its wholly-owned subsidiaries. This implementation program included a planning phase and implementation phase. After progressing through the planning phase and into a portion of the implementation phase, the Company identified various program costs and estimated what percentages of those costs were due to transition issues, re-working due to new specifications and other costs that should not be capitalized as a part of the program. In addition, the Company's timeline and date of completion has been significantly delayed. The Company's consideration of these and other factors caused it to reserve approximately $30 million of capitalized software development costs for the year ended March 31, 2011.

The Company applies the full cost method of accounting for its oil and gas production activities. In applying the full cost method, the Company performs an impairment test ("ceiling test") at each reporting date. The ceiling test compares the carrying value of capitalized costs related to oil and gas production activities to the cost center ceiling. The cost center ceiling is the sum of the following four components: the estimated present value of proved reserves, cost of properties not being amortized, the lower of cost or fair market value of unproved properties less the income tax effects related to differences in the book and tax bases of properties. The estimated present value of proved reserves is the sum of future net revenues, based on current economic and operating conditions as of March 31, 2011, discounted at 10%. As of the report date the Company had no unproved reserves or properties not being amortized. If capitalized costs exceed the cost center ceiling, an impairment charge is recorded to the results of operations. The Company recorded impairment charges related to the ceiling test of $9 million for the year ended March 31, 2011.

Note 6. Goodwill and Other Intangible Assets

Changes in the carrying amount of the Company's goodwill, net of accumulated impairment losses for years ended March 31, 2011 and March 31, 2010 were as follows:

	March 31,	
(in millions of dollars)	**2011**	2010
Goodwill, beginning of year	**$ 7,275**	$ 7,275
Regulatory recovery	**(142)**	-
Goodwill, end of year	**$ 7,133**	$ 7,275

Colonial Gas was acquired by Eastern Enterprises, Inc. ("Eastern") in 1998 pursuant to a business combination transaction ("the Eastern Merger"). Subsequent to the Eastern Merger, Colonial Gas and Eastern entered into business combinations with KeySpan in 2000 and then with NGUSA in 2007. In 1998, Eastern and Colonial Gas applied for recovery from the Massachusetts DPU of acquisition premium paid pursuant to the Eastern Merger of $224 million, net of tax. Colonial Gas and Eastern agreed to a ten-year rate freeze as well as reduction of the price of burner-tip gas for rate-payers for recovery of certain costs including the recovery of $369 million of acquisition premium, pre-tax. On November 1, 2010 ("the Effective Date") the DPU issued DPU 10-55 which authorized recovery of $235 million of acquisition premium, pre-tax. Colonial Gas recorded a regulatory asset of that amount and recorded corresponding credits to a newly created deferred tax liability of $93 million and a reclassification of $142 million to reduce goodwill. Colonial Gas will amortize this amount over 30 years as prescribed by DPU 10-55. Colonial Gas recorded a catch-up adjustment at March 31, 2011, for $3 million to reflect amortization from the Effective Date through March 31, 2011.

Other Intangible Assets

The carrying amount of the Company's intangible assets for the years ended March 31, 2011 and March 31, 2010 were as follows:

	March 31,	
(in millions of dollars)	**2011**	2010
LIPA Contracts	**$ 114**	$ 124
Licensing and other	**4**	12
Total	**$ 118**	$ 136

In July 2010, the Company sold its plumbing license business, as discussed in Note 14. The Company has recognized an impairment of $18 million for the year ended March 31, 2010 in relation to this license which was used to support the National Grid Energy Services ("NGES") installation business. The fair value was measured using management's estimate based upon the current market for similar assets.

Note 7. Income Taxes

Following is a summary of the components of federal and state income tax expense (benefit):

(in millions of dollars)	**Years Ended March 31, 2011**	2010
Components of federal and state income taxes:		
Current tax expense (benefit):		
Federal	**$ 149**	$ (383)
State	**28**	(9)
Total current tax expense (benefit)	**177**	(392)
Deferred tax expense:		
Federal	**35**	$ 696
State	**54**	182
Total deferred tax expense	**89**	878
Investment tax credits [1]	**(6)**	(7)
Total income tax expense	**$ 260**	$ 479

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

Income tax expense for the years ended March 31, 2011 and March 31, 2010 varied from the amount computed by applying the statutory rate to income before income taxes. A reconciliation of 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, 2011 and March 31, 2010 is presented in the following table:

(in millions of dollars)	**Years Ended March 31, 2011**	2010
Computed tax	**$ 233**	$ 251
Increase (reduction) including those attributable to flow-through of certain tax adjustments:		
State income tax (including reserve movements), net of federal benefit	**53**	86
Federal audit and related reserve movements	**3**	35
Outside basis differential in investment in subsidiary	**(17)**	-
Investment tax credit	**(6)**	(7)
Change in cash surrender value	**(5)**	(11)
Medicare charge attributable to the Patient Protection and Affordable Care Act	**-**	112
Other items - net	**(1)**	13
Total	**27**	228
Federal and state income taxes	**$ 260**	$ 479

Significant components of the Company's net deferred tax assets and liabilities at March 31, 2011 and March 31, 2010 are presented in the following table:

	March 31,	
(in millions of dollars)	**2011**	2010
Pensions, OPEB, and other employee benefits	**$ 1,392**	$ 1,643
Reserve - environmental	**553**	513
Regulatory liabilities - other	**416**	325
Allowance for uncollectible accounts	**171**	168
Other items	**334**	336
Total deferred tax assets [1]	**2,866**	2,985
Property related differences	**(4,119)**	(3,646)
Regulatory assets - pension and OPEB	**(859)**	(931)
Regulatory assets - environmental	**(748)**	(677)
Regulatory assets - merger rate plan stranded costs	**(155)**	(349)
Other items	**(195)**	(398)
Total deferred tax liabilities	**(6,076)**	(6,001)
Net accumulated deferred income tax liability	**(3,210)**	(3,016)
Deferred investment tax credit	**(46)**	(52)
Net accumulated deferred income tax liability and investment tax credit	**(3,256)**	(3,068)
Current portion of net deferred tax asset	**216**	115
Non-current portion of net deferred income tax liability and investment tax credit	**(3,472)**	(3,183)
Net accumulated deferred income tax liability and investment tax credit	**$ (3,256)**	$ (3,068)

(1) As of March 31, 2011 and March 31, 2010, the Company has approximately $293 million and $343 million of net operating losses in the state of Massachusetts that are being carried forward. A valuation allowance has been established for the full amount of these loss carryforwards as the Company believes that the losses will not be utilized in the foreseeable future. These state net operating losses will expire between 2012 and 2014. As of March 31, 2011 and March 31, 2010, the Company has approximately $198 million and $252 million, respectively, of New York state net operating losses which will expire between 2012 and 2019. As of March 31, 2011 a valuation allowance has been established for the full amount of these loss carryforwards as the Company believes that the losses will not be utilized in the foreseeable future.

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. Subsequent to the Company's acquisition of KeySpan and subsidiaries on August 24, 2007, KeySpan and subsidiaries are also members in the NGHI consolidated group.

The Company adopted the provisions of the FASB guidance which clarifies the accounting and disclosures of uncertain tax positions in the financial statements. The guidance provides that the financial effects of a tax position shall initially be recognized 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.

As of March 31, 2011 and March 31, 2010, the Company’s unrecognized tax benefits totaled $1,142 million and $1,134 million, respectively, of which $364 million and $408 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, 2011 and March 31, 2010:

Reconciliation of Unrecognized Tax Benefits	**Years Ended March 31,**	
(in millions of dollars)	**2011**	2010
Beginning balance	**$ 1,134**	$ 788
Gross increases related to prior period	**(3)**	(2)
Gross increases related to current period	**143**	404
Settlements with tax authorities	**(122)**	(56)
Reductions due to lapse of statute of limitations	**(10)**	-
Ending balance	**$ 1,142**	$ 1,134

As of March 31, 2011 and March 31, 2010, the Company has accrued for interest related to unrecognized tax benefits of $91 million and $84 million, respectively. During the years ended March 31, 2011 and March 31, 2010, the Company recorded interest income of $30 million and interest expense of $32 million, respectively. The Company recognizes accrued interest related to unrecognized tax benefits in interest expense or interest income and related penalties, if applicable, in operating expenses. No penalties were recognized during the years ended March 31, 2011 and March 31, 2010.

Federal income tax returns have been examined and all appeals and issues have been agreed with the Internal Revenue Service ("IRS") and the NGHI consolidated filing group, excluding KeySpan, through March 31, 2004. During the year ended March 31, 2011, the NGHI consolidated group, excluding KeySpan, reached an agreement with the IRS that contained a settlement of the majority of the income tax issues related to the years ended March 31, 2005 through March 31, 2007 as well as an acknowledgment that certain discrete items remained disputed. 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 the appeals. The years ended March 31, 2008 through March 31, 2011 remain subject to examination by the IRS.

In November 2010, KeySpan and its subsidiaries reached a settlement agreement with the IRS on outstanding tax matters for calendar tax years 2000 through 2006. In connection with the settlement, the Company recognized a $53 million tax benefit for the differences between the amounts settled upon with the IRS and the tax positions previously accrued. Resolution of tax matters for these years with state and local tax authorities is outstanding. KeySpan's preacquisition tax returns for the short year ended August 24, 2007 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	January 31, 2000
New York	December 31, 2000
New Hampshire	March 31, 2008

On July 2, 2008, the state of Massachusetts changed the state filing requirements that eliminate the previous separate reporting filing rules and implemented a unitary group filing requirement. The new combined reporting rules are effective for tax years beginning on or after January 1, 2009. The Company's first unitary filing begins for the year ended March 31, 2010.

During the year ended March 31, 2011, the Massachusetts Department of Revenue ("MADOR") completed its field audit of the Company's combined returns for March 31, 2003 through March 31, 2005. The Company is in the process of appealing adjustments made by the MADOR for the years ended March 31, 2002 through March 31, 2005, as well as adjustments from the previous audit of its Massachusetts combined returns for January 1, 2000 through March 31, 2002.

KeySpan's subsidiaries have filed NY ITC claims for tax years ended December 31, 2000 through December 31, 2006. These claims have been denied by the State of New York and are currently under appeal.

Note 8. Derivative Contracts

In the normal course of business, the Company's subsidiaries are party to derivative instruments, such as futures, options, swaps, and physical forwards that are principally used to manage commodity prices associated with its natural gas and electric 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.

Current accounting guidance for derivative instruments establishes criteria that must be satisfied in order for option contracts, forward contracts with optionality features, or contracts that combine a forward contract and a purchase option contract to qualify for the normal purchases and sales exception. However, certain contracts for the physical purchase of natural gas associated with our regulated gas service territories do not qualify for normal purchases under this guidance.

Certain derivative instruments employed by the Company are accounted for as cash-flow hedges and receive hedge accounting treatment under the current accounting guidance for derivative instruments and hedging activities. The change in fair value of instruments that qualify for hedge accounting is deferred in accumulated other comprehensive income and will be reclassified through revenue commensurate with the timing of the forecasted transactions.

The Company also employs derivative instruments that do not qualify for hedge accounting treatment. Most of the derivative instruments utilized by the Company are subject to the accounting guidance for rate-regulation entities since the Company's rate agreements allow for the pass-through of the commodity costs of electricity and natural gas and the costs related to hedging.

Commodity Derivative Instruments - Regulated Utilities

We use derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas and electric purchases associated with our gas and electric distribution operations. Our strategy is to minimize fluctuations in gas and electric sales prices to our regulated firm gas and electric sales customers. The accounting for these derivative instruments is subject to current 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 on the consolidated balance sheets. Gains or losses on the settlement of these contracts are initially deferred and then refunded to or collected from firm gas and electric sales customers consistent with regulatory requirements.

Prior to 2001 Niagara Mohawk owned 41% of the Nine Mile Point 2 nuclear power generation plant in upstate New York. As part of regulatory reform, Niagara Mohawk was required to divest its power generation assets in 2001 and Constellation Energy Group, Inc ("Constellation") acquired Niagara Mohawk's share of the Nine Mile Point 2 nuclear power generation plant.

Pursuant to this divestiture, Niagara Mohawk agreed to purchase physical energy and capacity from the Nine Mile Point 2 nuclear generating station for a period of ten years, terminating in December 2011 (the "Nine Mile physical purchase contract"). The purchased power from this facility has been utilized to satisfy Niagara Mohawk's electricity customers in the upstate New York area for the duration of this contract. Upon expiration of the Nine Mile physical purchase contract, Niagara Mohawk will buy power from the New York Independent System Operator ("NYISO") as a replacement for the power previously purchased directly from the Nine Mile Point 2 nuclear power generation plant.

Niagara Mohawk also entered into a Revenue Sharing Arrangement ("RSA") in 2001 with Constellation, covering a period of ten years from the expiration of the Nine Mile physical purchase contract. Pursuant to the RSA, Niagara Mohawk and Constellation will share in the revenue that Constellation earns on sales to the NYISO in proportion to the electric volumes that Niagara Mohawk had purchased under the Nine Mile physical purchase contract.

This contract has been determined to be a financial derivative instrument since a futures market exists in upstate New York and although trading is relatively shallow. The value of this derivative at March 31, 2011 and March 31, 2010 is $100 million and $78 million, respectively. Since the power purchased under the RSA will be used to supply rate-regulated electric sales customers, the accounting for this derivative follows the current accounting guidance for rate-regulated enterprises noted above.

At March 31, 2011 the net fair value of natural gas derivative instruments was a liability of $43 million. The net fair value of the electric derivative instruments, including the RSA contract above, was an asset of $78 million. At March 31, 2010 the net fair value of natural gas derivative instruments was a liability of $135 million. The net fair value of the electric derivative instruments was an asset of $5 million.

As noted previously, certain contracts for the physical purchase of natural gas associated with our regulated gas service territories do not qualify for normal purchases under current accounting guidance. These derivatives are also subject to the accounting treatment applicable to rate-regulated entities. At March 31, 2011 and March 31, 2010, the net fair value of these derivatives was an asset of $13 million and $43 million, respectively.

As a result of the USGen bankruptcy settlement agreement, New England Power resumed the performance and payment obligations under power supply contracts that had been transferred to USGen when the Company divested its generating business. The fair value of these derivative instruments at March 31, 2011 was a liability of $160 million. The fair value of these derivative instruments at March 31, 2010 was a liability of $192 million.

The Company continues to record this derivative liability which is the above-market portion of the power supply contracts with an equal offset to a corresponding regulatory asset. The performance and payment obligations will not affect the results of operations, as the Company will recover the above-market cost of the power supply contracts from customers through the CTC.

Financially-Settled Commodity Derivatives – Non-regulated

Our energy investments subsidiary, Seneca-Upshur, utilizes over the counter ("OTC") natural gas swaps to hedge the cash flow variability associated with the forecasted sales of a portion of its natural gas production. At March 31, 2011, Seneca-Upshur did not have any hedge positions in place for its estimated 2011 gas production. We use market quoted forward prices to value these swap positions. The fair value of these derivative instruments at March 31, 2010 was $1 million.

These derivative financial instruments are designated as cash flow hedges and are not considered held for trading purposes as defined by current accounting guidance. Accordingly, we carry the fair value of these derivative instruments on the consolidated balance sheet as either a current or deferred asset or liability, as appropriate, and record the effective portion of unrealized gains or losses in accumulated other comprehensive income. Gains and losses are reclassified from accumulated other comprehensive income to the consolidated statement of income in the period the hedged transaction affects earnings. Gains and losses on settled transactions are reflected as a component of revenue. Any hedge ineffectiveness that results from changes during the period in the price differentials between the index price of the derivative contract and the price of the purchase or sale for the cash flow that is being hedged is recorded directly to earnings.

Additionally the company employs a small number of derivative instruments related to storage optimization, and a limited number of natural gas swaps to hedge the risk associated with fixed price natural gas sales contracts for certain large gas sales customers. These financial derivative instruments do not qualify for hedge accounting treatment. The fair value of these contracts at March 31, 2011 was a liability of $1 million. We use market quoted forward prices to value these contracts. The fair value of these contracts at March 31, 2010 was a liability of $3 million.

The following are commodity volumes associated with commodity derivative contracts as of March 31, 2011:

(in thousands)		
Physicals	Gas (dths)	95,995
	Electric (Mwhs)	3,222
Financials	Gas swaps (dths)	75,119
	Gas options (dths)	12,670
	Gas futures (dths)	18,240
	Electric swaps (Mwhs)	2,559
	Electric options (Mwhs)	30,248
Total	**Gas (dths)**	**202,024**
	Electric (Mwhs)	**36,029**

Treasury Financial Instruments

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. At present, the Company uses fair value hedges, consisting of 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. 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 statement 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 statement of income as a yield adjustment over the remainder of the hedging period.

At March 31, 2011, the Company had a net hedged asset position of $4 million on $52 million of debt. At March 31, 2010, the Company had a net hedged liability position of $12 million on $239 million of debt. Net gains on the derivative financial instruments were $2 million for the year ended March 31, 2011 and a net loss of $2 million for the year ended March 31, 2010.

The following table presents the Company's derivative contract assets and (liabilities) on the consolidated balance sheets:

Fair Values of Derivative Instruments - Consolidated Balance Sheets

	Asset Derivatives			Liability Derivatives	
(in millions of dollars)	**March 31, 2011**	March 31, 2010		**March 31, 2011**	March 31, 2010
Regulated Contracts					
Gas Contracts:					
Gas futures contract - current asset	**$ -**	$ -	Gas futures contract - current liability	**$ (10)**	$ (17)
Gas swaps contract - current asset	**2**	-	Gas swaps contract - current liability	**(33)**	(107)
Gas options contract - current asset	**-**	-	Gas options contract - current liability	**(1)**	-
Gas purchase contract - current asset	**16**	28	Gas purchase contract - current liability	**(16)**	(12)
Current asset	***18***	*28*	*Current liability*	***(60)***	***(136)***
Gas futures contract - deferred asset	**1**	-	Gas futures contract - deferred liability	**(1)**	(4)
Gas swaps contract - deferred asset	**1**	-	Gas swaps contract - deferred liability	**(2)**	(7)
Gas purchase contract - deferred asset	**38**	48	Gas purchase contract - deferred liability	**(25)**	(21)
Deferred asset	***40***	*48*	*Deferred liability*	***(28)***	***(32)***
Electric contracts:					
Electric futures contract - current asset	**-**	-	Electric futures contract - current liability	**-**	(1)
Electric swaps contract - current asset	**3**	-	Electric swaps contract - current liability	**(28)**	(48)
Electric options contract - current asset	**5**	-	Electric options contract - current liability	**-**	-
Electric purchase contract - current asset	**-**	1	Electric purchase contract - current liability	**(28)**	(32)
Current asset	***8***	*1*	*Current liability*	***(56)***	***(81)***
Electric swaps contract - deferred asset	**3**	-	Electric swaps contract - current liability	**(1)**	(25)
Electric options contract - deferred asset	**96**	78	Electric options contract - deferred liability	**-**	-
Electric purchase contract - deferred asset	**-**	1	Electric purchase contract - deferred liability	**(132)**	(161)
Deferred asset	***99***	*79*	*Deferred liability*	***(133)***	***(186)***
Regulated subtotal	***165***	***156***		***(277)***	***(435)***
Unregulated Contracts					
Gas Contracts:					
Gas swaps contract - current asset	**-**	3	Gas swaps contract - current liability	**(1)**	(1)
Gas purchase contract - current asset	**-**	1	Gas purchase contract - current liability	**-**	-
Unregulated subtotal	***-***	***4***		***(1)***	***(1)***
Total derivatives not designated as hedging instruments	**165**	160		**(278)**	(436)
Derivative designated as hedging instruments					
Cash Flow Hedge					
Gas Contracts:					
Gas swaps contract - deferred asset	**-**	1	Gas swaps contract - deferred liability	**-**	-
Deferred asset	***-***	*1*	*Deferred liability*	**-**	-
Total derivatives designated as hedging instruments	**-**	1		**-**	-
Total Commodity Derivatives	**165**	161		**(278)**	(436)
Interest rates and currency swaps:					
Current asset	**-**	7	Current liability	**-**	-
Deferred asset	**4**	2	Deferred liability	**-**	(21)
Total derivatives	**$ 169**	$ 170		**$ (278)**	$ (457)

The change in fair value of the regulated contracts exactly corresponds to offsetting regulatory assets and liabilities. As a result, the changes in fair value of derivative contracts and their offsetting regulatory assets and liabilities had no statement of income impact. The change in value of the non-regulated contracts had a statement of income impact, and is included in "other income (deductions)" or "other revenues". The following table presents the change in value and the asset and (liability) balances of the Company's derivative contracts:

Fair Values of Derivative Instruments - Statements of Income

(in millions of dollars)	Year to Date Movement	**March 31, 2011**	March 31, 2010
Regulated Contracts			
Gas Contracts:			
Gas futures contract - regulatory asset	$ 10	**$ (11)**	$ (21)
Gas swaps contract - regulatory asset	79	**(35)**	(114)
Gas purchase contract - regulatory asset	(7)	**(41)**	(34)
Gas futures contract - regulatory liability	1	**1**	-
Gas swaps contract - regulatory liability	1	**2**	1
Gas purchase contract - regulatory liability	(22)	**54**	76
Gas subtotal	*62*	***(30)***	*(92)*
Electric Contracts:			
Electric futures contract - regulatory asset	1	**-**	(1)
Electric swaps contract - regulatory asset	43	**(29)**	(72)
Electric purchase contract - regulatory asset	31	**(160)**	(191)
Electric swaps contract - regulatory liability	6	**6**	-
Electric options contract - regulatory liability	22	**100**	78
Electric purchase contract - regulatory liability	1	**1**	-
Electric subtotal	104	***(82)***	*(186)*
Regulated subtotal	*166*	***(112)***	*(278)*
Unregulated Contracts			
Gas Contracts:			
Gas swaps contract - other revenues	(3)	**(1)**	2
Gas purchase contract - other income (deductions)	(1)	**-**	1
Gas subtotal	(4)	***(1)***	*3*
Total Commodity Derivatives	162	**(113)**	(275)
Interest rates and currency swaps contract - other income (deductions)	16	**4**	(12)
Total	$ 178	**$ (109)**	$ (287)

Certain of the Company's derivative instruments contain provisions that require its debt to maintain an investment grade credit rating from each of the major credit rating agencies. If NGUSA's credit rating were to fall below a certain level, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all of the Company's derivative instruments with credit-risk-related contingent features that are in a liability position on March 31, 2011 is $52 million for which the Company has posted collateral of $300 thousand in the normal course of business. If the Company's credit rating were to be downgraded by one notch, it would not be required to post any additional collateral. If the Company's credit rating were to be downgraded by three notches, it would be required to post $53 million additional collateral to its counterparties.

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 a 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 managed by assessing each counterparty credit profile and negotiating appropriate levels of collateral and credit support. In instances where the counterparties' credit quality has declined, or credit exposure exceeds certain levels, we may limit our credit exposure by restricting new transactions with counterparties, requiring additional collateral or credit support and negotiating the early termination of certain agreements. At March 31, 2011, the Company paid $20 million to its counterparties as collateral associated with outstanding derivative contracts. This amount has been recorded as restricted cash, with offsetting positions on the consolidated balance sheets.

Note 9. Fair Value Measurements

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 a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

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 New York Mercantile Exchange ("NYMEX").

The Company's Level 2 fair value derivative instruments primarily consist of over-the-counter ("OTC") gas 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 when ICE publishes seasonal averages or there were no transactions within last seven days. During periods prior to March 31, 2011, Level 2 pricing inputs were obtained from the NYMEX and Platts M2M (industry standard, non-exchange-based editorial commodity forward curves) when it can be verified by available market data from ICE based on transactions within last seven days. Level 2 derivative instruments may utilize discounting based on quoted interest rate curve as well as have 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 Black-Scholes pricing model, Monte Carlo simulation, and FEA libraries are used for valuing such instruments. Level 3 is also applied in cases when forward curve is internally developed, extrapolated or derived from market observable curve with correlation coefficients less than 0.95, or optionality is present, or non-economical assumptions are made.

Available for sale securities are primarily equity investments based on quoted market prices (Level 1) and municipal and corporate bonds based on quoted prices of similar traded assets in open markets (Levels 2 and 3).

The following table presents assets and liabilities measured and recorded at fair value on the Company's consolidated balance sheet on a recurring basis and their level within the fair value hierarchy as of March 31, 2011 and March 31, 2010:

Fair Value Measurement Level Summary Table
March 31, 2011

(in millions of dollars)	Level 1	Level 2	Level 3	Total
Assets				
Derivative contracts	$ 1	$ 14	$ 154	$ 169
Available for sale securities	114	221	3	338
Total assets	115	235	157	507
Liabilities				
Derivative contracts	(11)	(66)	(201)	(278)
Total liabilities	(11)	(66)	(201)	(278)
Net asset (liability) balance	$ 104	$ 169	$ (44)	$ 229

Fair Value Measurement Level Summary Table
March 31, 2010

(in millions of dollars)	Level 1	Level 2	Level 3	Total
Assets				
Derivative contracts	$ -	$ 13	$ 157	$ 170
Available for sale securities	120	111	-	231
Total assets	120	124	157	401
Liabilities				
Derivative contracts	(22)	(209)	(226)	(457)
Total liabilities	(22)	(209)	(226)	(457)
Net asset (liability) balance	$ 98	$ (85)	$ (69)	$ (56)

Year to Date Level 3 Movement Table

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the year ended March 31, 2011:

(in millions of dollars)		
Balance at March 31, 2009	$	(183)
Transfers out of Level 3		(2)
Total gains and losses:		
included in regulatory assets and liabilities		39
Purchases		79
Sales		(2)
Balance at March 31, 2010	$	(69)
Transfers out of Level 3		(1)
Total gains and losses:		
included in earnings (or changes in net assets)		(1)
included in regulatory assets and liabilities		30
Purchases		(3)
Balance at March 31, 2011	$	(44)
The amount of realized gains and (losses) included in net income attributed to the change in unrealized gains and (losses) related to derivative assets and liabilities at March 31, 2011	$	-

The Company transfers amounts from Level 2 to Level 3 as of the beginning of each period and amounts from Level 3 to Level 2 as of the end of each period.

Long-term debt is based on quoted market prices where available or calculated prices based on the remaining cash flows of the underlying bond discounted at the Company's incremental borrowing rate. The Company's consolidated balance sheets reflect the long-term debt at carrying value. The fair value of this debt at March 31, 2011 and March 31, 2010 is $14.5 billion.

Note 10. Accumulated Other Comprehensive Income (Loss)

The following table details the components of accumulated other comprehensive income (loss) for the years ended March 31, 2011 and March 31, 2010:

(in millions of dollars)	Foreign Currency Translation	Unrealized Gains (Losses) On Available for Sale Securities	Pension and Other Postretirement Benefit Liabilities	Cash Flow Hedges	Total Accumulated Other Comprehensive Income (Loss)
March 31, 2009 balance, net of tax	$ (106)	$ (17)	$ (1,029)	$ 2	$ (1,150)
Unrealized gain on securities	-	13	-	-	13
Unrealized losses on hedges	-	-	-	(7)	(7)
Foreign currency translation	(32)				(32)
Change in pension and other postretirement obligations	-	-	17	-	17
Reclassification adjustment for gain included in net income	-	-	74	-	74
Subtotal	(138)	(4)	(938)	(5)	(1,085)
Adjustment to accumulated other comprehensive income (1)	-	-	136	-	136
March 31, 2010 balance, net of tax	$ (138)	$ (4)	$ (802)	$ (5)	$ (949)
Unrealized losses on securities	-	(5)	-	-	(5)
Foreign currency translation	(3)	-	-	-	(3)
Change in pension and other postretirement obligations	-	-	(18)	-	(18)
Reclassification adjustment for gain included in net income	-	-	118	-	118
March 31, 2011 balance, net of tax	$ (141)	$ (9)	$ (702)	$ (5)	$ (857)

(1) The adjustment to the accumulated other comprehensive income is the result of the new tracking mechanism that was implemented as part of the rate case filed on May 19, 2009.

Note 11. Commitments and Contingencies

Legal Matters

MGP Sites

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 Office of the Attorney General for the State of New York ("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 entered into an ACO with the DEC for its 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. The group of 5 companies and the City of New York signed a consent decree with the EPA on July 7, 2011. 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 operation and cash flows.

Civil Investigation

In May 2007, KeySpan received a Civil Investigative Demand ("CID") from the United States Department of Justice, Antitrust Division, requesting the production of documents and information relating to its investigation of competitive issues in the New York City electric energy capacity market prior to NGUSA's acquisition of KeySpan. The CID is a request for information in the course of an investigation and does not constitute the commencement of legal proceedings, and no specific allegations have been made against KeySpan. In April 2008, KeySpan received a second CID in connection with this matter. KeySpan believes that its activity in the capacity market has been consistent with all applicable laws and regulations and it continued to cooperate fully with this investigation. On February 22, 2010, the United States Department of Justice ("DOJ") filed a civil complaint, joint stipulation and proposed final judgment under which the DOJ and KeySpan have agreed that KeySpan will pay $12 million in full and final resolution of the DOJ's Civil Investigative Demands from May 2007 and April 2008. The agreement contains no admissions of liability by KeySpan and was subject to court approval which was subsequently received. On February 9, 2011, the Company wire transferred $12 million to the DOJ in full and final settlement of this matter and this matter is closed.

Boston Property Tax Ruling
The Company provides gas service to most of the City of Boston (“the City”) and owns equipment in the City to provide such service. That equipment is taxable as personal property in Massachusetts and the various municipalities set the assessment value which should reflect fair value. The Company applied for an abatement of its fiscal year 2004 assessment with the Assessing Department of the City of Boston (“the Assessors”) disputing the methodology applied in determining fair value. On July 22, 2004, after being denied abatements by the Assessors, the Company filed an appeal with the Appellate Tax Board ("ATB"). On December 16, 2009, the ATB issued its decision finding for the City. The Company appealed this ruling to the Supreme Judicial Court ("SJC") on May 3, 2010. On January 20, 2011, the SJC issued its decision which affirmed much of the ATB decision. The tax amounts are included in “other taxes” on the statements of income. The assessment does not have a material impact on the Company’s consolidated financial statements.

Environmental Matters

The normal ongoing operations and historic activities of the Company are subject to various federal, state and local environmental laws and regulations. Like most other industrial companies, the Company’s historic and current gas, electric transmission and distribution and electric generation businesses use or generate some hazardous and potentially hazardous wastes and by-products. Under federal and state Superfund laws, potential liability for the historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred.

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 New York State Department of Environmental Conservation (“DEC”). In addition to efforts to improve both ozone and particulate matter air quality, there has been an increased focus on greenhouse gas emissions in recent years. Our previous investments in low NO_X 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 NO_X 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 $100 million; a mechanism for recovery from LIPA of these investments through fuel savings 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 operation, 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 lead 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 take twelve or more months, 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 manufactured gas plant, or 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.

The Company uses the "Expected Value" method for measuring its environmental liabilities. The Expected Value method applies a weighting to potential future expenditures based on the probability of these costs being incurred. A liability is recognized for all potential costs based on this probability. Costs considered to be 100% probable of being incurred are recognized in full, with costs below a 100% probability recognized in proportion to their probability. KeySpan discounted its environmental reserves at the time of acquisition by National Grid plc using an appropriate fair value methodology. Our other subsidiaries do not discount the liability.

Utility Sites
At March 31, 2011, the Company's total reserve for estimated MGP related environmental activities is $1.3 billion. The potential high end of the range at March 31, 2011 is presently estimated at $2.0 billion on an undiscounted basis. Management believes that obligations imposed on the Company because of the environmental laws will not have a material adverse effect on its operations, financial condition or cash flows. Through various rate orders issued by the NYPSC, DPU, NHPUC 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 $1.8 billion.

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. The Company presently estimates the remaining cost of the environmental cleanup activities for these two non-utility sites will be $23 million, which has been accrued at March 31, 2011 as 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 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.

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 Management Services Agreement (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 Power Supply Agreement (the "PSA"), expiring on May 27, 2013, the rates of which are approved by FERC; and (iii) manage all aspects of the fuel supply for our Long Island generating facilities, pursuant to the Energy Management Agreement (the "EMA"), expiring on May 27, 2013. On June 3, 2010, LIPA issued a Request for Proposal ("RFP") for an operating and maintenance services provider to furnish the services currently provided under the MSA after the MSA expires. The Company submitted a bid in response to the RFP and has since been actively engaged in contract negotiations with LIPA as part of the RFP process. In June 2010, LIPA announced that the Company was one of three finalists for the award. LIPA has expressed its intent to announce the successful bidder in October 2011. As of the date of this report, no announcement has been made by the LIPA Board.

The Company and LIPA have recently initiated negotiations for an extension of the PSA that is scheduled to expire on May 27, 2013. The Company believes a new PSA will be executed prior to its expiration that will allow the Company to recover its investment in property, plant, and equipment and other assets used in operations of $726 million. In June 2010, LIPA and the Company executed an amendment to the current PSA pursuant to which the parties agreed that LIPA would reduce purchases of capacity from specified generating facilities, specifically the Far Rockaway and Glenwood Landing, New York steam facilities. The Company intends to retire and demolish these generating facilities upon their removal from the PSA, currently anticipated in the Summer 2012.

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 and thereafter increases annually by 1.7%, plus inflation. The variable component is based on electric sales adjusted for inflation.

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.

Lease Obligations

The Company has various operating leases which include leases for buildings, office equipment, vehicles and power operating equipment. The Company's future minimum lease payments under various leases are summarized in the table below.

(in millions of dollars)		
Year Ended March 31,		**Amount**
2012	$	117
2013		120
2014		148
2015		119
2016		121
Thereafter		565
Total	$	1,190

Financial Guarantees

NGUSA has guaranteed the principal and interest payments on certain outstanding debt. 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, 2011, the following amounts would have to be paid by us in the event of non-payment by the primary obligor at the time payment is due:

Nature of Guarantee *(in millions of dollars)*			Amount	Expiration Dates
Guarantees for subsidiaries:				
Industrial Development Revenue Bonds	(i)	$	128	2027
KeySpan Ravenswood LLC Lease	(ii)		528	2040
Reservoir Woods	(iii)		277	2029
Surety Bonds	(iv)		109	Revolving
Commodity Guarantees and Other	(v)		141	2011-2042
Letters of Credit	(vi)		106	2011

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

(i) The Company 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. The face value of these notes is included in long-term debt on the consolidated balance sheet.

(ii) The Company had guaranteed all payment and performance obligations of a former subsidiary (KeySpan Ravenswood LLC) associated with a merchant electric generating facility leased by that subsidiary under a sale/leaseback arrangement. The subsidiary and the facility were sold in 2008. However, the original lease remains in place and we will continue to make the required payments under the lease through 2040. The cash consideration from the buyer of the facility included the remaining lease payments on a net present value basis. At March 31, 2011, the Company's obligation related to the lease was $291 million and is reflected in "other deferred liabilities".

(iii) NGUSA has fully and unconditionally guaranteed $293 million in lease payments through 2029 related to the lease of office facilities at Reservoir Woods in Waltham, MA.

(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. We 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 electric production and marketing activities. The guarantees cover actual purchases by these subsidiaries that are still outstanding as of March 31, 2011.

(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 us to post letters of credit to guarantee subsidiary performance under our 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.

To date, NGUSA has not had a claim made against it for any of the above guarantees and we have no reason to believe that our 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 condition and cash flows.

Asset Retirement Obligations

The Company has various asset retirement obligations primarily associated with its gas distribution and electric generation 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. The asset retirement obligation at March 31, 2011 and March 31, 2010 was $69 million and $70 million respectively.

Decommissioning Nuclear Units

New England Power 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 that have been permanently retired. Physical decommissioning of the units is complete. Spent nuclear fuel remains on each site, awaiting fulfillment by the U.S. Department of Energy ("DOE") of its statutory obligation to remove it. In addition, groundwater monitoring is ongoing at each site. Investment information and future estimated billing which are included in miscellaneous current or accrued liabilities and other deferred credits are as follows:

(in thousands of dollars)	The Company's Investment as of March 31, 2011			Future Estimated Billings to the Company
Unit	%	Amount	Date Retired	Amount
Yankee Atomic	34.5	$ 539	Feb 1992	$ 24,927
Connecticut Yankee	19.5	423	Dec 1996	43,527
Maine Yankee	24.0	497	Aug 1997	18,941

With respect to each of the units, at March 31, 2011 and March 31, 2010, New England Power has a liability and a regulatory asset of $87 million and $82 million, respectively, reflecting the estimated future decommissioning billings from the Yankees. In a 1993 decision, the FERC allowed Yankee Atomic to recover its undepreciated investment in the plant, including a return on that investment, as well as unfunded nuclear decommissioning costs and other costs. Maine Yankee and Connecticut Yankee recover their prudently incurred costs, including a return, in accordance with settlement agreements approved by the FERC in May 1999 and July 2000, respectively. The Yankees collect the approved costs from their purchasers, including New England Power. New England Power's share of the decommissioning costs is accounted for in purchased electric energy on the consolidated statements of income. Under settlement agreements, New England Power is permitted to recover prudently incurred decommissioning costs through CTCs.

The Yankees are periodically required to file rate cases for FERC approval, 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.

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 U.S. Court of Federal Claims ("Claims Court") to determine the level of damages, on October 4, 2006, the Claims Court awarded the three companies an aggregate of $143 million for spent fuel storage costs that had been incurred through 2001 and 2002. The Yankees had requested $176 million. On December 4, 2006, the DOE filed a notice of appeal with the U. S. Court of Appeals for the Federal Circuit. The Court of Appeals rendered an opinion generally supporting the trial court's decision and has remanded the matter to the trial court for further proceedings. A Claims Court trial in the remanded cases was held in August, 2009. On September 7, 2010, the Court again awarded the three companies an aggregate of approximately $143 million. On November 8, 2010, the DOE again filed a notice of appeal with the same Court of Appeals. On November 19, 2010, the Yankees filed notices of cross-appeal. If the Yankees are successful in the litigation, the damages received by the Yankees, net of litigation expenses and taxes, will be applied to reduce the decommissioning and other costs collected from their purchasers including New England Power. The Company cannot predict the outcome of the pending decisions for trial, appeal or the potential subsequent complaints. On December 14, 2007, the Yankees brought further litigation in the Claims Court to recover damages incurred subsequent to 2001 and 2002. Discovery in the further litigation is ongoing and a trial in the Claims Court is expected in October 2011. The DOE has severely curtailed budgetary support for the proposed long-term spent fuel storage facility at Yucca Mountain in Nevada and taken actions designed to prevent its construction and appointed a Blue Ribbon Commission charged with advising it regarding alternatives to disposal at Yucca Mountain. As a result, 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 exceed the estimated amounts, perhaps substantially.

Nuclear Contingencies

As of March 31, 2011 and March 31, 2010, Niagara Mohawk has a liability of $168 million and $167 million, respectively, in non-current liabilities for the disposal of nuclear fuel irradiated prior to 1983 – for a nuclear power plant that was sold to Constellation Energy Group, Inc ("Constellation") in 2001. In January 1983 the Nuclear Waste Policy Act of 1982 (the "Nuclear Waste Act") established a cost of $.001 per kilowatt-hour ("kWh") of net generation for current disposal of nuclear fuel and provides for a determination of the liability to the DOE for the disposal of nuclear fuel irradiated prior to 1983. The Nuclear Waste Act also provides three payment options for liquidating such liability and the Company has elected to delay payment, with interest, until the year in which Constellation which purchased Niagara Mohawk's nuclear assets, initially plans to ship irradiated fuel to an approved DOE disposal facility. Progress in developing the DOE facility has been delayed beyond 2011 and we are unable to predict when it will be able to accept deliveries.

Long-term Contracts for the Purchase of Electric Power

The Company's subsidiaries have several types of long-term contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment. The Company's commitments under these long-term contracts are summarized in the table below.

(in millions of dollars)	
Years Ended March 31,	
2012	$ 1,012
2013	146
2014	70
2015	65
2016	54
Thereafter	53
Total	$ 1,400

The Company's subsidiaries can purchase additional energy to meet load requirements from other independent power producers ("IPPs"), other utilities, energy merchants or on the open market through the New York Independent System Operator ("NYISO") or the ISO-NE at market prices.

Gas Supply, Storage and Pipeline Commitments

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 and its 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. The table below summarizes the estimated commitments as of March 31, 2011.

(in millions of dollars)	
Year Ended March 31,	
2012	$ 1,027
2013	700
2014	526
2015	437
2016	388
Thereafter	1,833
Total	$ 4,911

Sales and Use Tax Contingencies

The Company's subsidiaries are subject to periodic tax audits by federal and state authorities. Niagara Mohawk was subject to a sales and use tax audit conducted by the State of New York for the audit period June 2001 through November 2005. Niagara Mohawk's sales and use tax for 2006 and subsequent years remain subject to examination by the state authorities. In June 2010, the State of New York completed its audit and Niagara Mohawk received an assessment based on which Niagara Mohawk reserved $24 million as other deferred liabilities at March 31, 2010. Niagara Mohawk actively disputed the findings of the audit report and has reached an agreement which resulted in a decrease of $15 million in other deferred liabilities at March 31, 2011. The total reserve on the accompanying consolidated balance sheet as of March 31, 2011 and 2010 is $29 million and $43 million, respectively.

Note 12. Related Party Transactions

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, 2011 and March 31, 2010, the estimated effect on net income was $39 million and $29 million before tax and $25 million and $19 million after tax, respectively.

Note 13. Cumulative Preferred Stock

The Company's subsidiaries have certain issues of non-participating preferred stock which provide for redemption at the option of the Company. A summary of cumulative preferred stock at March 31, 2011 and March 31, 2010 is as follows:

(in millions of dollars, except per share and number of shares data)		Shares Outstanding		Amount		
		March 31,		**March 31,**		Call
Series	Company	**2011**	2010	**2011**	2010	Price
$100 par value -						
3.40% Series	Niagara Mohawk	**57,524**	57,524	**$ 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	Mass Electric	**22,585**	22,585	**2**	2	104.068
6.00% Series	New England Power	**11,117**	11,117	**1**	1	Noncallable
$50 par value -						
4.50% Series	Narragansett	**49,089**	49,089	**3**	3	55.000
Total		**372,638**	372,638	**$ 35**	$ 35	

On October 1, 2010, the Company converted 267 shares of common stock to various classes of non-voting cumulative, fixed-rate, preferred stock (Class A – 51 shares, Class B – 40 shares, Class C – 96 shares, Class D – 79 shares, Class E – 1 share), having par value of $0.10.

Note 14. Discontinued Operations and Other Dispositions

On April 13, 2010, a purchase agreement was signed between KeySpan and Home Service USA Corp. ("HSUSA") pertaining to KeySpan's sale of the service contracts portion of its NGES business. Under terms of the agreement, HSUSA has agreed to acquire the service contract business for $74 million, with $30 million (net of working capital) paid at closing and an additional $44 million ("NPV") of estimated royalties earned and paid over a ten year period. Projected royalties represent 10% of revenues that HSUSA achieves through the sale of its products, subject to adjustment, in years two through ten following the closing. This transaction was completed on August 11, 2010. The installation business of NGES has not been sold. Instead, we are in the process of discontinuing the installation portion of the business after completing all currently contracted work.

In addition, in September 2010, the Company sold National Grid Development Holding's 52.1% interest in Honeoye Storage Corporation for $15 million to Consolidated Edison Development Inc. A gain of $11 million is reflected as gain on disposal of assets in the accompanying consolidated statements of income.

On December 8, 2010, NGUSA, on the behalf of Granite State and EnergyNorth, entered into a stock purchase agreement with Liberty Energy Utilities Co., a subsidiary of Algonquin Power & Utilities Corp., whereby NGUSA will sell, and Liberty Energy will purchase, all of the common stock of EnergyNorth and Granite State for a combined purchase price of $285 million. The parties have filed for the necessary federal and state regulatory approvals that will be required to consummate the transaction. The regulatory approval process is expected to be completed during the year ended March 31, 2012. The assets and liabilities of EnergyNorth and Granite are classified as held for sale at March 31, 2011 and March 31, 2010.

The information below highlights the major classes of assets, liabilities, revenues and expenses of the Granite State and EnergyNorth:

(in millions of dollars)	March 31, 2011	March 31, 2010
Current assets	**$ 67**	$ 59
Property, plant and equipment	**332**	323
Deferred charges	**106**	194
Total assets	**505**	576
Current liabilities	**22**	31
Deferred credits and other liabilities	**202**	185
Total liabilities	**224**	216

(in millions of dollars)	For the Year Ended March 31, 2011	2010
Revenues	**$ 222**	$ 222
Operating expenses:		
Fuel and purchase power	**131**	139
Operations and maintenance	**37**	40
Impairment of intangibles and property, plant and equipment	**78**	-
Depreciation and amortization	**14**	14
Operating taxes	**9**	8
Operating (loss) income	**(47)**	21
Other deductions	**(1)**	(1)
Income taxes	**12**	8
(Loss) income from discontinued operations	**$ (60)**	$ 12

Note 15. Restructuring

On January 31, 2011, National Grid plc announced substantial changes to the organization, including new global, US and UK operating models, and changes to the leadership team. The announced structure seeks to create a leaner, more-efficient business backed by streamlined operations that will help meet, more efficiently, the needs of regulators, customers and shareholders. The implementation of the new U.S. business structure commences on April 4, 2011 and targets annualized savings of $200 million by March 2012 primarily through the reduction of up to 1,200 positions. As of March 31, 2011, NGUSA had recorded a $66.8 million reserve for one-time employment termination benefits related to severance, payroll taxes, healthcare continuation, outplacement services as well as consulting fees related to the restructuring program, which is included within “operations and maintenance” on the consolidated statement of income. As of the date of this report, approximately $57.8 million in termination benefits have been paid. Subsequently in June 2011, we offered a voluntary severance plan to certain individuals which is expected to cost up to an additional $20 million across all entities affiliated with NGUSA.

Note 16. Subsequent Events

On September 30, 2011, several state and municipal parties in New England filed with the FERC a complaint under Section 206 of the Federal Power Act against certain Transmission Owners, including NEP, to lower the base ROE for RNS and LNS from the FERC approved rate of 11.14% to 9.2% (as discussed in Note 2).

On April 28, 2011, NGUSA converted an additional 648 shares of common stock to non-voting cumulative, fixed-rate, preferred stock (Class F), having par value of $0.10.

On June 3, 2011, NGUSA raised an additional $705 million through the Euro Medium Term Note program. These notes are due June 3, 2015 with a weighted average interest rate of 2.604%.

In August 2011, the Company made scheduled payments on its intercompany notes payable in accordance with the terms of their respective agreements as follows: $400 million to National Grid Luxembourg 5 Sarl on August 12, 2011 plus accrued interest of $47.1 million, $500 million to National Grid plc on August 22, 2011 plus accrued interest of $14.3 million and $750 million to NGLI on August 24, 2011 plus accrued interest of $29.8 million. In order to fund these payment obligations, the Company entered into the following agreements:

(i) 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;

(ii) 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 and;

(iii) on August 22, 2011, the Company entered into an intercompany loan agreement with National Grid (US) Partner 1 Limited for $400 million with maturity dates ranging from February 22, 2012 to August 22, 2016 and with interest rates ranging from 1.05% to 1.56% over LIBOR.

Hurricane Irene on August 28, 2011 caused significant damage to both the Company's and the Long Island Power Authority's electric transmission and distribution networks, resulting in approximately 1.4 million customers being without power, some for as much as a week. Storm restoration efforts to repair and replace damaged equipment are estimated to have cost in the order of $289 million, including repairs to the Long Island Power Authority system of $177 million at September 30, 2011. The Company believes it has the ability to recover the majority of these costs through rates or from the Long Island Power Authority as appropriate.

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-Upshur Petroleum, LLC to PDC Mountaineer, LLC. The sale was completed on October 3, 2011 for proceeds of $153 million. The final proceeds are subject to adjustment for working capital and related matters.

In September 2011, the Company increased its environmental reserves by approximately $117 million after receiving new information concerning the proposed remediation plans for an environmental site in downstate New York. After recording an offsetting increase in regulatory assets relating to environmental remediation, there was no impact to the net assets of the Company.