NATIONAL GRID USA

ANNUAL REPORT 2010

PRICEWATERHOUSECOOPERS

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Report of Independent Auditors

To the Stockholder and Board of Directors of
National Grid USA:

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 USA and its subsidiaries at March 31, 2010 and March 31, 2009, 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 audit. We conducted our audit 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 audit provides a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

August 23, 2010

NATIONAL GRID USA AND SUBSIDIARY COMPANIES

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NATIONAL GRID USA AND SUBSIDIARY COMPANIES
Consolidated Balance Sheets

(in millions of dollars)	March 31, 2010	2009
ASSETS		
Current assets		
Cash and cash equivalents	**$ 768.5**	$ 424.9
Restricted cash	**233.0**	197.3
Accounts receivable	**2,382.3**	2,523.4
Allowance for doubtful accounts	**(395.4)**	(392.8)
Accounts receivable from affiliates	**51.6**	7.6
Unbilled revenues	**621.3**	718.9
Gas in storage, at average cost	**288.0**	479.4
Materials and supplies, at average cost	**178.5**	199.8
Derivative contracts	**42.2**	51.6
Regulatory assets	**1,102.2**	1,011.9
Prepayments	**274.6**	171.9
Current deferred income taxes	**106.8**	218.5
Prepaid taxes and other	**688.5**	8.0
Discontinued assets held for sale	**-**	30.0
Total current assets	**6,342.1**	5,650.4
Equity investments and other	**555.0**	469.9
Property, plant and equipment, net	**19,336.4**	18,322.9
Deferred charges		
Regulatory assets	**5,639.8**	5,800.8
Goodwill	**7,372.4**	7,372.4
Intangible assets, net	**135.7**	165.5
Derivative contracts	**128.5**	20.1
Other	**189.3**	216.0
Total deferred charges	**13,465.7**	13,574.8
Total assets	**$ 39,699.2**	$ 38,018.0

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

NATIONAL GRID USA AND SUBSIDIARY COMPANIES
Consolidated Balance Sheets

(in millions of dollars)	March 31, 2010	2009
LIABILITIES AND CAPITALIZATION		
Current liabilities		
Accounts payable	**$ 1,329.4**	$ 1,269.8
Current portion of long-term debt	**2,044.1**	471.4
Taxes accrued	**115.9**	543.8
Customer deposits	**101.4**	107.6
Interest accrued	**187.4**	211.2
Regulatory liabilities	**115.4**	261.0
Intercompany money pool	**769.6**	1,975.8
Current portion of accrued Yankee nuclear plant costs	**14.9**	14.8
Derivative contracts	**334.7**	331.3
Discontinued current liabilities held for sale	**-**	12.7
Other	**531.3**	510.2
Total current liabilities	**5,544.1**	5,709.6
Deferred credits and other liabilities		
Regulatory liabilities	**2,775.6**	2,611.6
Asset retirement obligations	**69.7**	67.7
Deferred income taxes	**3,260.8**	2,344.0
Postretirement benefits and other reserves	**3,703.5**	3,776.8
Environmental remediation costs	**1,312.2**	1,382.1
Derivative contracts	**248.7**	252.2
Other	**1,362.6**	1,108.6
Total deferred credits and other liabilities	**12,733.1**	11,543.0
Capitalization		
Common stock ($.10 par value)	-	-
Paid in capital	**13,043.5**	13,043.5
Retained earnings	**2,592.6**	2,351.7
Accumulated other comprehensive income (loss)	**(810.9)**	(1,043.7)
Total common shareholders' equity	**14,825.2**	14,351.5
Non-controlling interest	**15.6**	18.2
Cumulative preferred stock, par value $100 per share	**34.8**	34.8
Total equity	**14,875.6**	14,404.5
Long-term debt	**6,546.4**	5,136.5
Long-term debt to affiliates	**-**	1,224.4
Total capitalization	**21,422.0**	20,765.4
Total liabilities and capitalization	**$ 39,699.2**	$ 38,018.0

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

NATIONAL GRID USA AND SUBSIDIARY COMPANIES
Consolidated Statements of Income

(in millions of dollars)	For the years ended March 31, 2010	2009
Revenues		
Gas distribution	**$ 5,765.5**	$ 7,321.6
Electric services	**7,482.1**	8,194.6
Other	**142.8**	163.2
Total revenues	**13,390.4**	15,679.4
Operating expenses		
Purchased gas for sale	**3,229.5**	4,775.9
Electricity purchased	**2,505.2**	3,544.2
Contract termination charges and nuclear shutdown charges	**20.0**	24.6
Operations and maintenance	**3,930.0**	3,759.3
Depreciation, depletion and amortization	**817.1**	803.0
Amortization of regulatory assets, stranded costs and rate plan deferrals	**657.2**	574.2
Other taxes	**929.0**	905.2
Total operating expenses	**12,088.0**	14,386.4
Operating income	**1,302.4**	1,293.0
Other income and (deductions)		
Interest on long-term debt	**(301.0)**	(312.4)
Other interest, including affiliate interest	**(157.7)**	(246.0)
Other	**120.5**	42.0
Total other income and (deductions)	**(338.2)**	(516.4)
Income taxes	**518.4**	320.5
Dividend on preferred stock of subsidiaries	**1.3**	1.3
Income from continuing operations	**444.5**	454.8
Income from discontinued operations, net of tax expense of $17.5 million	**-**	24.6
Income from discontinued operations, net of tax	**-**	24.6
Net income attributable to non-controlling interest	**(3.5)**	(3.1)
Net income attributable to National Grid shareholders	**$ 441.0**	$ 476.3

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

NATIONAL GRID USA AND SUBSIDIARY COMPANIES
Consolidated Statements of Comprehensive Income

(in millions of dollars)	For the years ended March 31,	
	2010	2009
Net income	**$ 441.0**	$ 476.3
Other comprehensive income (loss), net of taxes:		
Unrealized gains (losses) on investments	**13.1**	(15.4)
Unrealized gains (losses) on hedges	**(6.7)**	2.4
Change in pension and other postretirement obligations	**16.4**	(517.7)
Reclassification adjustment for gains (losses) included in net income	**73.7**	(0.4)
Change in other comprehensive income (loss)	**96.5**	(531.1)
Total comprehensive income (loss)	**$ 537.5**	$ (54.8)
Related tax expense (benefit):		
Unrealized gains (losses) on investments	**8.7**	(10.3)
Unrealized gains (losses) on hedges	**(4.5)**	1.6
Change in pension and other postretirement obligations	**10.9**	(345.3)
Reclassification adjustment for gains (losses) included in net income	**49.2**	(0.3)
Total tax expense (benefit)	**$ 64.4**	$ (354.3)

NATIONAL GRID USA AND SUBSIDIARY COMPANIES
Consolidated Statements of Retained Earnings

(in millions of dollars)	For the years ended March 31,	
	2010	2009
Retained earnings at beginning of period	**$ 2,351.7**	$ 1,875.5
Net income	**441.0**	476.3
Dividends on preferred stock	**(0.1)**	(0.1)
Dividend to Parent	**(200.0)**	-
Retained earnings at end of period	**$ 2,592.6**	$ 2,351.7

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

NATIONAL GRID USA AND SUBSIDIARY COMPANIES
Consolidated Statements of Cash Flows

(in millions of dollars)	For the years ended March 31, 2010	2009
Operating activities:		
Net income	$ **441.0**	$ 476.3
Adjustments to reconcile net income to net cash provided by operating activities:		
Net (income) loss from discontinued operations	**-**	(24.6)
Depreciation and amortization	**817.1**	803.0
Amortization of stranded costs and rate plan deferrals	**657.2**	574.2
Provision for deferred income taxes and investment tax credits	**911.8**	(743.3)
Income from equity investments, net	**2.7**	(21.8)
Other non-cash items	**(14.5)**	109.8
Net prepayments and other amortizations	**(126.9)**	4.4
Net pension and other postretirement expense/cash payment	**(289.9)**	(300.5)
Net environmental payments	**(218.8)**	(129.9)
Changes in operating assets and liabilities:		
Accounts receivable, net	**208.5**	294.6
Materials and supplies	**194.9**	(75.3)
Accounts payable and accrued expenses	**(141.7)**	(515.0)
Prepaid taxes and accruals	**(642.3)**	310.1
Accounts payable affiliates, net	**(44.0)**	(7.1)
Other, net	**(51.9)**	1.1
Net cash (used in)/provided by operating activities	**1,703.2**	756.0
Investing activities:		
Plant expenditures	**(1,586.2)**	(1,457.7)
Net proceeds from sale of subsidiary and assets	**10.1**	2,989.3
Derivative margin calls	**59.0**	(120.3)
Restricted cash	**(58.3)**	(29.4)
Other, including cost of removal	**(135.2)**	(103.9)
Net cash used in investing activities	**(1,710.6)**	1,278.0
Financing activities:		
Dividends paid on common and preferred stock	**(200.1)**	(0.1)
Payment of long-term debt	**(829.1)**	(923.3)
Proceeds from long-term debt	**2,586.4**	160.5
Increase (decrease) in intercompany moneypool	**(1,206.2)**	863.8
Buyback of common stock	**-**	(1,000.0)
Net (decrease) increase in external short-term debt	**-**	(1,412.9)
Net cash provided/(used in) by financing activities	**351.0**	(2,312.0)
Net increase in cash and cash equivalents	**343.6**	(278.0)
Cash flow from discontinued operations - operating activities	**-**	(28.8)
Cash flow from discontinued operations - investing activities	**-**	(13.2)
Cash flow from discontinued operations - financing activities	**-**	(425.0)
Cash and cash equivalents, beginning of period	**424.9**	1,169.9
Cash and cash equivalents, end of period	$ **768.5**	$ 424.9
Supplemental disclosures of cash flow information:		
Interest paid	$ **425.6**	$ 370.3
Taxes paid	$ **414.6**	$ 938.4

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

NATIONAL GRID USA AND SUBSIDIARY COMPANIES
Consolidated Statement of Capitalization

(in millions of dollars)	March 31,			
	2010	2009	**2010**	2009
Common shareholders' equity	**Shares Issued**		**Amounts**	
Common stock, $0.10 par value	1,000	1,000	$ -	$ -
Additional paid in capital			13,043.5	13,043.5
Retained earnings			2,592.6	2,351.7
Accumulated other comprehensive loss			(810.9)	(1,043.7)
Total common shareholders' equity			14,825.2	14,351.5
Non-controlling interest in subsidiaries			15.6	18.2
Cumulative preferred stock, $100 and $50 par value	944	944	34.8	34.8
Long-term debt	**Interest Rates**			
Medium and long-term debt				
European Medium Term Note		1.01%	23.1	93.2
Notes payable		4.65% - 9.75%	4,885.4	2,690.9
Total medium and long-term debt			4,908.5	2,784.1
Gas Facilities Revenue Bonds		Variable	230.0	230.0
		4.70% - 6.95%	410.5	410.5
Total Gas Facilities Revenue Bonds			640.5	640.5
Promissory Notes to LIPA				
Pollution Control Revenue Bonds		5.15%	108.0	108.0
Electric Facility Revenue Bonds		5.30%	47.4	47.4
Total Promissory Notes to LIPA			155.4	155.4
First Mortgage Bonds		6.34% - 9.63%	132.1	133.4
State Authority Financing Bonds		Variable	1,199.7	1,199.7
Industrial Development Revenue Bonds		5.25%	128.3	128.3
Committed Facilities		Variable	550.5	543.0
Inter-Company Notes		5.52%	866.7	1,224.4
Subtotal			8,581.7	6,808.8
Other			8.8	23.5
Less: current maturities			2,044.1	471.4
Total long-term debt			6,546.4	6,360.9
Total capitalization			$ 21,422.0	$ 20,765.4

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

NATIONAL GRID USA AND SUBSIDIARY COMPANIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Nature of Operations

National Grid USA (referred to as "the Company", "NGUSA", "we", "us", and "our") is a public utility holding company with regulated subsidiaries engaged in the transmission, distribution, generation and sale of electricity and the distribution of natural gas. The Company is a wholly-owned subsidiary of National Grid plc (the "Parent"). National Grid plc is a public limited company incorporated under the laws of England and Wales. In 2007, the company acquired KeySpan Corporation ("KeySpan"), a public utility holding company.

The Company's electricity and gas distribution subsidiaries serve over six million customers in New York, Massachusetts, Rhode Island and New Hampshire. The Company's 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 ("Boston Gas") Company, Colonial Gas ("Colonial Gas") Company, Essex Gas Company ("Essex Gas") and EnergyNorth Natural Gas Inc ("EnergyNorth"). The Company's New York subsidiaries include: Niagara Mohawk Power Corporation ("Niagara Mohawk"), National Grid Generation, LLC, The Brooklyn Union Gas Company ("Brooklyn Union") and KeySpan Gas East Corporation ("KeySpan Gas East").

Additionally, Company subsidiaries operate the electric transmission and distribution system owned by the Long Island Power Authority ("LIPA"), in Nassau and Suffolk Counties in Long Island. The Company also owns and provides capacity to and produces energy for LIPA from our generating facilities located on Long Island and manages fuel supplies for LIPA to fuel our Long Island generating facilities. These services are provided in accordance with existing service contracts that expire in 2013.

The Company's other operating subsidiaries are primarily involved in gas production and development, underground gas storage, liquefied natural gas storage, retail electric marketing, service and maintenance of energy systems, and the development of natural gas pipelines and other energy-related projects. Additionally, the Company has an equity ownership interest in two hydro-transmission electric companies as well as a minority ownership interest in three regional nuclear generating companies whose facilities that have been decommissioned.

Pursuant to the Public Utility Holding Company Act of 2005, the Federal Energy Regulatory Commission ("FERC") has jurisdiction over certain of our holding company activities, including (i) regulating certain transactions among our affiliates within our holding company system; (ii) governing the issuance, acquisition and disposition of securities and assets by certain of our public utility subsidiaries; and (iii) approving certain utility mergers and acquisitions.

Moreover, our affiliate transactions also remain subject to certain regulations of the New York State Public Service Commission ("NYPSC"), the Massachusetts Department of Public Utilities ("DPU"), the New Hampshire Public Utilities Commission, and the ("NHPUC") Rhode Island Public Utility

Commission (“RIPUC”) in addition to the FERC.

Under our holding company structure, we have no independent operations or source of income of our own and conduct all of our operations through our subsidiaries 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.

B. Basis of Presentation

The consolidated financial statements for the years ended March 31, 2010 and 2009, 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 (See Item C - “Accounting for the Effects of Rate Regulation”).

The preparation of financial statements in conformity with GAAP requires management to make estimates that affect the reported amounts of assets and liabilities and the disclosures of contingent assets and liabilities as of the date of the balance sheets, and revenues and expenses for the period. These estimates may differ from actual amounts if future circumstances cause a change in the assumptions used to calculate these estimates.

All material intercompany balances and transactions have been eliminated.

The consolidated financial statements include the accounts of the Company, its wholly-owned subsidiaries and other entities in which the Company has a controlling financial interest. The Company adopted accounting guidance for non-controlling interests on March 31, 2010. Accordingly, for consolidated subsidiaries that are less than wholly-owned, the third-party holdings of equity interests are referred to as non-controlling interests. The portion of net income attributable to non-controlling interests for such subsidiaries is presented as “Net income (loss) applicable to non-controlling interests” on the Consolidated Statements of Income, and the portion of the shareholders’ equity of such subsidiaries is presented as “Non-controlling interests” in the Consolidated Balance Sheets and Consolidated Statements of Capitalization.

For entities where (1) the total equity investment at risk is sufficient to enable the entity to finance its activities independently and (2) the equity holders bear the economic residual risks of the entity and have the right to make decisions about the entity’s activities, the Company consolidates those entities it controls through a majority voting interest or otherwise.

The results of operations for companies acquired or disposed of are included in the consolidated financial statements from the effective date of acquisition or up to date of disposal.

The Company has evaluated events or transactions that occurred after March 31, 2010 through August 23, 2010 for potential recognition or disclosure in the financial statements. (See Note 14. “Subsequent Events for additional details”.)

C. Accounting for the Effects of Rate Regulation

The accounting records for our gas and electric regulated utilities are maintained in accordance with the Uniform System of Accounts prescribed by NYPSC, NHPUC, DPU and RIPUC. Our financial statements reflect the ratemaking policies and actions of these regulators in conformity with GAAP for rate-regulated enterprises. Our electric generation subsidiary is not subject to state rate regulation, but is subject to FERC jurisdiction.

All of our transmission and distribution regulated utilities are subject to the provisions of the accounting guidance by the Financial Accounting Standards Board (“FASB”) related to the accounting for the effects of certain types of regulation. This guidance recognizes the ability of regulators, through the ratemaking process, to create future economic benefits and obligations affecting rate-regulated companies. Accordingly, we record these future economic benefits and obligations as regulatory assets and regulatory liabilities. (See Note 2. “Rates and Regulatory”).

D. Revenue Recognition

Electric and Gas Utility Services: The Company’s regulated subsidiaries charge customers for electric and gas service in accordance with rates approved by applicable state regulatory commissions on a monthly basis.

The cost of gas and electricity used is recovered when billed to firm customers included in utility tariffs. Any difference is deferred pending recovery from or refund to firm customers. Further, net revenue from tariff gas balancing services, off-system sales and certain on-system interruptible sales are refunded, for the most part, to firm customers subject to certain sharing provisions.

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, 2010 and 2009 was $621.3 million and $718.9 million, respectively. The distribution subsidiaries normalize the difference between revenue and expenses from energy conservation programs, commodity purchases, transmission service and contract termination charges.

Brooklyn Union, KeySpan Gas East, Niagara Mohawk and Narragansett gas utility tariffs contain weather normalization adjustments that 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. 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.

***LIPA Agreements*:** KeySpan and LIPA are parties to three service agreements that (i) provide to LIPA all operation, maintenance and construction services and significant administrative services relating to the Long Island electric transmission and distribution ("T&D") system pursuant to the Management Services Agreement (the "MSA"); (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"); and (iii) manage certain aspects of the fuel supply for our Long Island generating facilities pursuant to the Energy Management Agreement (the "EMA"). The agreements expire on December 31, 2013, May 28, 2013 and May 28, 2013, respectively. 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 MSA, PSA and EMA all are collectively referred to as the "LIPA Agreements".

The Company's compensation for managing the electric transmission and distribution system owned by LIPA under the MSA consists of two components: a minimum compensation component of $224 million per year and a variable component based on electric sales. The $224 million component will remain unchanged for three years and then increase annually by 1.7%, plus inflation. The variable component, which will comprise no more than 20% of the Company's compensation, is based on electric sales on Long Island exceeding a base amount of 16,558 gigawatt hours, increasing by 1.7% in each year. Above that level, the Company will receive approximately 1.34 cents per kilowatt hour for the first contract year, 1.29 cents per kilowatt hour in the second contract year (plus an annual inflation adjustment), 1.24 cents per kilowatt hour in the third contract year (plus an annual inflation adjustment), with the per kilowatt hour rate thereafter adjusted annually by inflation. At March 31, 2010 the contract is in its 5th year.

Pursuant to the MSA, the Company must meet eighteen (18) performance metrics, one of which is a customer satisfaction metric. Failure to achieve a minimum level of performance under this metric for three consecutive years gives rise to an event of default under the MSA. The 2008 results were released, but LIPA and KeySpan had a dispute as to interpretation. LIPA and KeySpan have settled this dispute and the parties have executed settlement documents which have been approved by the New York State Comptroller and Attorney General. The settlement will not have a material impact on the consolidated financial statements. In addition, the Company met all the performance metrics in year 2009, as a result, no penalty was assessed.

The Company sells to LIPA under the PSA all of the capacity and, to the extent requested, energy conversion services from its existing Long Island based oil and gas-fired generating plants. Sales of capacity and energy conversion services are made under rates approved by the FERC. Rates charged to LIPA include a fixed and variable component. The variable component is billed to LIPA on a monthly per megawatt hour basis and is dependent on the number of megawatt hours dispatched.

The PSA runs for a term of fifteen years through May 28, 2013, with LIPA having the option to renew the PSA for an additional fifteen-year term. On January 30, 2009, our subsidiary, National Grid Generation filed with the FERC for a rate increase for the final five year rate term of the fifteen year contract for the electricity generated and supplied to LIPA under the PSA. The filing sought an increase of $92 million. LIPA and National Grid Generation filed a settlement on October 23, 2009 with a FERC Administrative Law Judge that provides for a revenue requirement of $435.7 million, an annual increase of approximately $65.7 million, an ROE of 10.75% and a capital structure of 50% debt and 50% equity. FERC approved the settlement on January 5, 2010. The order accepting the settlement is no longer subject to rehearing and the settlement became effective on March 1, 2010.

Other Revenues: Revenues earned by our non-regulated subsidiaries 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. We have unearned revenue recorded in "deferred credits and other liabilities - other" on the consolidated balance sheet totaling $23.4 million and $25.3 million as of March 31, 2010 and 2009, respectively. This balance represents primarily unearned revenues for service contracts and is generally amortized to income over a one year period.

E. Property, Plant and Equipment

Property, plant and equipment is stated at original cost. The cost of additions to utility plant and replacements of retired units of property are capitalized. Costs include direct material, labor, overhead and allowance for funds used during construction. Replacement of minor items of utility plant and the cost of current repairs and maintenance are charged to expense. Whenever utility plant is retired, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation.

In addition, included in property, plant and equipment is intangible assets related to software development costs of $370.0 million and $324.8 million at March 31, 2010 and 2009, respectively, and associated amortization of $296.1 million and $270.0 million at March 31, 2010 and 2009, respectively. Common and other plant assets consist largely of land, buildings, office equipment, furniture, vehicles, computer and telecommunications equipment and systems.

	At March 31,	
(in millions of dollars)	**2010**	2009
Property, Plant and Equipment		
Electric plant	**$ 14,061.9**	$ 13,412.9
Gas plant	**9,394.8**	8,799.2
Common and other plant	**823.1**	777.9
Construction work-in-process	**828.5**	638.0
Total utility plant	**25,108.3**	23,628.0
Less: accumulated depreciation and amortization	**(5,806.6)**	(5,341.6)
Net property plant and equipment	**19,301.7**	18,286.4
Gas production	**43.9**	42.2
Less: depletion	**(9.2)**	(5.7)
Net gas production plant	**34.7**	36.5
Total Property, Plant and Equipment	**$ 19,336.4**	$ 18,322.9

Depreciation – Depreciation expense is 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 respective 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, 2010 and 2009, the Company had cumulative costs recovered in excess of costs incurred totaling $1.4 billion. 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:

	Fiscal Years Ended March 31,	
	2010	2009
Asset Category:		
Electric	**33**	32
Gas	**35**	35
Common	**21**	18

Capitalized interest for the years ended March 31, 2010 and 2009 was $5.4 million and $8.3 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.

F. Goodwill and Intangible Assets

Goodwill**:** In accordance with current accounting guidance for goodwill and intangible assets, the Company tests goodwill for impairment on an annual basis and on an interim basis when certain events or circumstances exist. Goodwill impairment is determined by comparing the estimated fair value of a reporting unit with its respective book value. If the estimated fair value exceeds the book value, goodwill at the reporting unit level is not deemed to be impaired. If the estimated fair value is below book value, however, further analysis is required to determine the amount of any impairment.

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 6% and a terminal year growth rate of 3% based upon expected long-term average growth rates. Our forecasts assume long-term recovery and rate of returns that are in line with historical levels within the utility industry.

If the forecasted returns utilized in the analysis are not achieved, an impairment of goodwill may result. For example, within our calculation of forecasted returns, we have made certain assumptions around the amount of pension and environmental costs to be recovered in future periods. Should we not benefit from improved rate relief 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.

The annual analysis of the Company's goodwill determined that no adjustment of the goodwill carrying value was required.

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, an 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. The carrying amount of the intangible asset is not recoverable if it exceeds the sum of the expected undiscounted cash flows.

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, an 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.

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 Excise Taxes

Federal and state income taxes are recorded under the provisions of the FASB accounting guidance for 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 investment tax credits are amortized over the useful life of the underlying property. Additionally, the Company follows the FASB guidance related to the accounting for uncertainty in income taxes which applies to all income tax positions reflected on the Company's Consolidated Balance Sheet that have been included in previous tax returns or are expected to be included in future tax returns.

We report our collections and payments of excise taxes on a gross basis. Gas and electric distribution revenues include the collections of excise taxes, while operating taxes include the related expenses. Excise taxes collected and paid were $95.7 million and $117.4 million, for the years ended March 31, 2010 and 2009, respectively.

J. Derivatives

We employ derivative instruments to hedge a portion of our exposure to commodity price risk and interest rate risk. Whenever hedge positions are in effect, we are exposed to credit risk in the event of nonperformance by counter-parties to derivative contracts, as well as nonperformance by the counter-parties of the transactions against which they are hedged. We believe that the credit risk related to the futures, options and swap 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 and certain power supply contracts were assessed as no longer being exempt from the requirements of the FASB accounting guidance on normal purchases. As such, these contracts are recorded on the Consolidated Balance Sheets at fair market value. However, since such contracts were executed for regulated utility customers, changes in the fair market value of these contracts are recorded as a regulatory asset or regulatory liability on the Consolidated Balance Sheets.

Financially-Settled Commodity Derivative Instruments - Non-regulated. We also employ derivative financial instruments, such as futures, options and swaps, for the purpose of hedging the 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 the FASB accounting guidance on 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. Unrealized gains and losses (on such cash flow hedges) that are recorded as accumulated other comprehensive income are subsequently reclassified into earnings concurrent 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 to variable or variable to fixed. 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.

K. Other Comprehensive Income (Loss)

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 or loss, the other components of comprehensive income relate to transaction changes specified in the FASB accounting guidance related to the accounting for defined benefit pension and postretirement plans, deferred gains and losses associated with hedging activity, and unrealized gains and losses associated with certain investments held as available for sale (See Note 9 "Accumulated Other Comprehensive Income (Loss)").

L. Employee Benefits

The Company follows the provisions of the 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, the Company values its pension and other postretirement assets using the year-end market value of those assets. Benefit obligations are also measured at year-end. (See Note 3. "Employee Benefits" for additional details on the Company's pension and other postretirement plans.)

M. 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 - exit price. The determination of the fair value incorporates various factors required including not only the credit standing of the counterparties involved but also the impact of the Company's nonperformance risk on its liabilities. To increase consistency and comparability in fair value measurements, a fair value hierarchy was established that prioritizes the inputs to valuation techniques used to measure fair value into three levels. The following is a fair value hierarchy:

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 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 need to maximize the use of observable inputs and maximize the use of observable inputs and minimize the use of unobservable inputs.

N. Reclassifications

Certain amounts from prior years have been reclassified on the accompanying consolidated financial statements to conform to the current year presentation.

O. Inventory

Inventory, primarily gas in storage and materials and supplies, is stated primarily at the lower of cost or market value under the average costs method. The company's write-down policy is to write-off obsolete inventory.

P. Equity Investments and Other

Certain subsidiaries own as their principal assets, investments representing ownership interests of 50% or less in energy-related businesses that are accounted for under the equity method. None of these current investments are publicly traded. At March 31, 2010, approximately $314.9 million of equity investments and other property are included in this caption. Additionally, the Company has corporate assets recorded on the consolidated balance sheets representing funds designated for supplemental executive retirement plans. At March 31, 2010 approximately $240.1 million of these investments are included in this caption. These funds are primarily invested in corporate owned life insurance policies. The Company records changes in the value of these assets in accordance with FASB guidance related to the 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 - other income and (deductions) concurrent with the change in the value of the underlying assets.

Q. 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 ("SO2") 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. The Company has an emission allowance credit of $28.6 million and $47.9 million at March 31, 2010 and 2009, respectively, which is recorded in "materials and supplies, at average cost" on the 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. At March 31, 2010, we reduced the inventory value resulting in a $7.2 million charge to the consolidated statements income. In 2009, a charge of $24.6 million was recorded to reduce the inventory balance.

R. Recent Accounting Pronouncements

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. This FASB guidance is effective for financial statements issued for interim and annual periods ending after June 15, 2009.

In June 2009, the FASB issued an amendment to the accounting and disclosure requirements for transfers and servicing of financial assets and extinguishment of liabilities. The objective of the amendment is to improve the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial statements about a transfer of financial assets; and effects of a transfer on its financial position, financial performance and cash flows; and transferor's continuing involvement, if any, in transferred financial assets. The new provisions must be applied as of the beginning of each reporting entity's first annual reporting period that begins after November 15, 2009 and are to be applied to transfers occurring on or after the effective date. The Company will adopt this standard next year.

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 Company will adopt this standard next fiscal year as it has not yet finalized its analyses of the accounting guidance.

In June 2009, the FASB issued the FASB Accounting Standards Codification ("Codification"). The Codification will become the single source for all authoritative GAAP recognized by the FASB to be applied for financial statements issued for periods ending after September 15, 2009. The Codification does not change GAAP and will not have an affect on our financial position, results of operations or liquidity. With the adoption of this new guidance, the Company has eliminated specific references in the notes to its financial statements and other documents and replaced them with more general topical references.

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 statement 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 Company will adopt this standard next fiscal year.

NOTE 2 – RATE AND REGULATORY

The accounting records for the Company's regulated utilities are maintained in accordance with the Uniform System of Accounts prescribed by the NYPSC, NHPUC, RIPUC and DPU. Our electric generation subsidiary is not subject to state rate regulation, but they are subject to FERC oversight. Our consolidated financial statements reflect the ratemaking policies and actions of these regulators in conformity with GAAP for rate-regulated enterprises.

All of the Company's regulated utilities are subject to current accounting guidance for rate regulated enterprises. This statement recognizes the ability of regulators, through the ratemaking process, to create future economic benefits and obligations affecting rate-regulated companies. Accordingly, we record these future economic benefits and obligations as regulatory assets and regulatory liabilities on the consolidated balance sheets, respectively.

For regulatory items for which cash expenditures have been made or for which cash has been collected in advance, we record an appropriate amount of carrying charges. For regulatory items in which cash has not been paid or received, carrying charges are not recorded. We anticipate recovering or refunding those items in our utility rates concurrently with future cash expenditures or collections. If recovery or refund is not concurrent with cash expenditures or collections, the Company will record the appropriate level of carrying charges.

Management believes its rates are based on costs and investments and it should continue to apply the current accounting guidance for rate regulated enterprises. If the Company could no longer apply the guidance, the resulting charge would be material to the Company's reported financial statements.

(in millions of dollars)	March 31, **2010**	2009
Regulatory assets included in accounts receivable:	**$ 95.8**	$ 59.2
Regulatory liabilities included in accounts payable:	**78.6**	182.9
Current portion of regulatory assets:		
Stranded costs	**529.4**	502.5
Derivative contracts	**333.2**	328.5
Pension and post-retirement benefit plans	**84.4**	89.3
Yankee nuclear decommissioning costs	**14.9**	26.2
Other	**140.3**	65.4
	1,102.2	1,011.9
Current portion of regulatory liabilities:		
Rate adjustment mechanisms	**(41.5)**	(166.2)
Derivative contracts	**(28.4)**	(46.0)
Other	**(45.5)**	(48.8)
	(115.4)	(261.0)
Regulatory assets:		
Pension and postretirement benefit plans	**2,189.5**	1,908.7
Deferred environmental restoration costs	**1,819.7**	1,706.2
Stranded costs	**454.0**	981.0
Derivative contracts	**227.5**	231.5
Regulatory tax asset	**117.1**	234.6
Storm cost recoveries	**213.8**	210.3
Yankee nuclear decommissioning costs	**66.7**	80.9
Loss on reacquired debt	**43.8**	51.6
Long-term portion of standard offer under-recovery	**42.9**	53.4
Other	**464.8**	342.6
	5,639.8	5,800.8
Regulatory liabilities:		
Removal costs recovered	**(1,443.0)**	(1,392.2)
Stranded costs	**(169.6)**	(181.9)
Pension and postretirement plans fair value deferred gain	**(139.9)**	(207.9)
Derivative contracts	**(127.3)**	(9.3)
Environmental response fund and insurance recoveries	**(96.3)**	(97.2)
Storm costs reserve	**(18.0)**	(21.4)
Other	**(781.5)**	(701.7)
	(2,775.6)	(2,611.6)
Net regulatory assets	**$ 3,851.0**	$ 3,940.1

The following is a description of the larger regulatory assets and liabilities:

Pension and Postretirement Benefit Plans: Costs of the Company's pension and other postretirement benefits (OPEB) plans over amounts reflected in rates are reflected as a regulatory asset to be recovered in a future period. This regulatory asset includes the deferral of the fair value adjustments to the pension and postretirement benefits plans other than pensions. The Company has also recorded a regulatory asset as an offset to its defined benefit pension and OPEB plans' liability. For the most part, the Company has rate recovery for pension and OPEB costs for its regulated utilities on a dollar for dollar basis. Therefore, it is anticipated that there will not be a material impact on the results of operations as revenues will match the underlying pension and OPEB expenses.

Deferred Environmental Restoration Costs: This regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at hazardous waste sites with which it may be associated. The Company's rate plans provide for specific rate allowances for these costs, with variances deferred for future recovery or pass-back to customers. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates.

Stranded Costs: Certain regulatory assets, referred to as stranded costs, resulted from major fundamental changes that took place in the industry, most notably the divestiture of generation assets pursuant to deregulation. Under deregulation, the generation segment of the utility business was opened to competition in that consumers could choose their generation supplier. Public utilities continued to control the transmission and distribution of electricity and were encouraged to dispose of generation assets such as power plants. The net unrecovered costs from the sale of these generation assets, along with the costs to terminate, restate or amend existing purchase power contracts were deferred for recovery in rates over future periods. A large portion of these stranded costs are being recovered through a special rate being charged to customers. Similarly, the recovery of costs outside of customer rate recovery, but that nevertheless relate to the former generation business, are credited back to customers as well to offset stranded costs. This mechanism is called the contract termination charge and (or) the competitive transition charge (in both cases, these charges are called the CTC).

Management believes that future cash flows from charges for electric service under existing rate plans, including the CTC, will be sufficient to recover the Company's electric regulatory assets over the planned amortization period. This assumes that there will be no unforeseen reduction in demand and no bypass of the CTC or exit fees.

Regulatory Tax Asset: The regulatory tax asset represents the expected future recovery from ratepayers of the tax consequences of temporary differences between the recorded book basis and the tax basis of assets and liabilities. This amount is primarily timing differences related to depreciation. These amounts are recovered and amortized as the related temporary differences reverse.

Storm Costs: The Company is generally allowed to recover from customers the costs of major storms in which the costs and (or) number of customers affected exceed certain specific thresholds as specified in various rate orders. The majority of these deferrals relate to an ice storm in fiscal 2009 in which the Company's electric distribution operations in New York, Massachusetts and New Hampshire incurred significant damage. The Company has either received rate orders supporting recovery of these costs or has filed for recovery of these repairs and is waiting final regulatory resolution.

Yankee Nuclear Decommissioning Costs: This regulatory asset represents the estimated future decommissioning billings related to three nuclear generating utilities (See Note 11 "Commitments and Contingencies"). Under settlement agreements with regulators, the Company is permitted to recover prudently incurred decommissioning costs through CTCs.

Removal Cost Recovered: For the Company's rate regulated utilities the cost of property retired, and the cost of removal less salvage, is charged to accumulated depreciation. The Company's rate regulated utilities recover certain asset retirement costs through rates charged to customers as a portion of depreciation expense. These amounts are reflected as a regulatory liability on the consolidated balance sheets.

Rate Adjustment Mechanism: The revenue requirements of the Company's regulated subsidiaries are set by various state public utility commission in the jurisdictions that the Company operates as the amount each company will need to (1) recover its prudently incurred capital and operating costs and (2) earn an agreed to rate of return on equity. A rate adjustment mechanism that certain subsidiaries have periodically adjusts electric rates, up or down, to account for differences between revenues the companies have been authorized to recover and the revenues the company has actually received. The mechanism covers the fixed costs of distributing electricity including costs for purchased-power costs from electric power generating companies.

The regulatory assets also reflect approximately $33 million of energy efficiency program costs in excess of the current rate agreements. The Company believes these amounts will be recovered pursuant to future rate filings.

Regulatory Developments

The Companies regulated operating companies are involved in several regulatory proceedings, as follows:

New England Power:

New England Power has received authorization from the FERC to recover through contract termination charges (CTC's), substantially all of the costs associated with its former generating business not recovered through their divestiture. Additionally, FERC enables transmission companies to recover their specific costs of providing transmission service. Therefore, substantially all of New England Power's business, including the recovery of its stranded costs, operates under cost-based rate regulation.

Under settlement agreements approved by the appropriate commissions or FERC orders, New England Power 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 New England Power's affiliated former wholesale customers with whom it has settlement agreements through a CTC. New England Power's affiliated former wholesale customers in turn recover the stranded cost charges through delivery charges to their distribution customers. New England Power earns a return on equity ("ROE") of approximately 11% on stranded cost recovery. Most stranded costs will be fully recovered through CTCs by the end of calendar 2010. New England Power's stranded cost obligation related to the above-market cost of purchase power contracts and nuclear decommissioning costs are recovered through the CTC when the costs are actually incurred. New England Power, under certain settlement agreements, earned incentives based on successful mitigation of its stranded costs through December 2009 and these incentives supplement New England Power's ROE.

New England Power 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 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. 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.

Effective on the RTO operations date of February 1, 2005, New England Power'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 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 New England Power's transmission costs are recovered through RNS rates.

New England Power 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, FERC issued an order establishing the ROE for the NETOs, including New England Power. In this order, FERC overturned the Administrative Law Judge's initial decision and approved, over the dissent of two Commissioners, 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 FERC represent an increase from New England Power's last authorized ROE of 10.25%.

The NETOs and opposing parties to the NETOs requested rehearing of various aspects of the Commission's order. On March 24, 2008, FERC issued an order on rehearing increasing New England Power's base ROE for all classes of transmission plant by 24 basis points retroactive to February 1, 2005. The Commission also limited the 1.0% ROE adder it had previously granted so that it only applies to new transmission plant placed in service on or before December 31, 2008. The Commission's order also indicated that any future transmission investment incentives after 2008 must be sought through initiating an incentive proposal under Section 205 of the Federal Power Act.

In December 2008, opposing parties in the underlying FERC proceeding filed appeals 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 NETOs, including New England Power, intervened in this proceeding. On January 29, 2010, the Court issued an order denying the petition and affirming the FERC's decision to award the 1.0% ROE adder for RTO-approved transmission projects placed in service by December 31, 2008.

On September 17, 2008, New England Power, Narragansett, and Northeast Utilities (an unaffiliated company) jointly filed with FERC to recover financial incentives for the New England East-West Solution ("NEEWS"). 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 is estimated to be $474 million and New England Power's share is estimated to be $160 million. Effective as of November 18, 2008, 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 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.

Under the terms of its FERC Electric Tariff No. 1, New England Power operates the transmission facilities of its New England distribution affiliates as a single integrated system and reimburses its affiliates for the cost of those facilities, including a return. New England Power'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, New England Power filed with 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. The result of the proposed rate change would be an overall rate decrease of $1.6 million. On March 29, 2010, 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. New England Power cannot predict the outcome of this filing at this time.

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.

On August 3, 2009, Niagara Mohawk submitted a filing in compliance with the NYPSC's Fourth CTC Reset Filing. This filing complies with Niagara Mohawk's obligations under the MRP to: (i) reset it's CTC in retail delivery rates to reflect changes in the forecast of commodity prices for the coming two years and (ii) adjust delivery rates to reflect deferral recoveries because the deferral account balance exceeded $100 million as of June 30, 2009. On December 21, 2009, the NYPSC issued its order on this matter and directed, among other things, that there would be no change in the deferral recoveries currently reflected in customer rates because of the difficult economic circumstances faced by customers.

On October 22, 2007, Niagara Mohawk made a compliance filing with the NYPSC regarding the implementation of the Follow-on Merger Credit associated with the acquisition of KeySpan in August 2007. In its compliance filing, Niagara Mohawk calculated the share of the KeySpan Follow-on Merger savings allocable to Niagara Mohawk for the period from September 2007 through December 2011 to be approximately $40 million. Niagara Mohawk subsequently agreed, in its comments filed in the Third CTC Reset proceeding on October 31, 2007, to lower rates submitted in its August 1, 2007 CTC Reset filing to reflect a proposal by the parties in that proceeding to apply the KeySpan Follow-on Merger Credit to Niagara Mohawk's electric customers over a two year period instead of over the four remaining years of the MRP, which was approved by the NYPSC in December 2007. On May 29, 2008, the NYPSC issued its decision with respect to Niagara Mohawk's October 22, 2007 compliance filing rejecting Niagara Mohawk's proposed calculation and requiring a Follow-on Merger Credit of $52 million for the August 24, 2007 through December 2011 period. On June 30, 2008, Niagara Mohawk filed a petition for rehearing of the May 29, 2008 order from the NYPSC. The NYPSC denied Niagara Mohawk's rehearing petition in an order dated February 24, 2009, holding that its May 2008 order was consistent with the explicit language of the MRP.

The NYPSC further issued a notice on June 25, 2008 seeking additional comment on Department of Public Service Staff's (Staff) Paper setting forth two Follow-on Merger savings issues that were not addressed in the compliance filing of October 22, 2007. In the notice, the NYPSC asked for comments on Staff's Paper and its two issues that called for Niagara Mohawk to credit an additional $35 million of synergy savings to electric and gas customers. Multiple Interveners (a consortium of large commercial and industrial customers) filed comments in favor of a larger credit. Following settlement negotiations, on January 25, 2010, Niagara Mohawk, Staff, and Multiple Interveners filed a joint proposal that, if adopted by the NYPSC, would resolve the issues raised in Staff's Paper by Niagara Mohawk's crediting an additional $4 million to Niagara Mohawk's electric and gas customers. Statements in support of the joint proposal were filed on February 1, 2010 by Niagara Mohawk, Staff and Multiple Interveners.

Asset Condition and Capital Investment Plan: On October 22, 2007, Niagara Mohawk filed with the NYPSC the first of required annual reports on its asset condition and capital investment plan for its electric transmission and distribution system. Niagara Mohawk's 2007 capital investment plan involved significant investment in capital improvements over the projections initially included in its MRP. On August 15, 2008, the NYPSC issued its order on the compliance filing. The NYPSC affirmed Niagara Mohawk's need to invest a minimum of $1.47 billion during the five year period 2007-2011 (calendar) and stated that further projects and investments "appear to be justified" with the possibility of further expansion over time. On January 29, 2010, Niagara Mohawk filed its capital investment plan with the latest five year projection for capital investment estimated at $2.86 billion for fiscal years 2011 and 2015. On the same date, Niagara Mohawk filed a proposal to revise its electric rates effective January 1, 2011. The rate case filing included a copy of the 2011-2015 capital investment plan. On May 3, 2010, Niagara Mohawk filed in its rate case corrections and updates filing a downward adjustment to the five-year infrastructure investment of approximately $116 million, resulting in a five-year projected capital plan estimated at $2.75 billion.

On December 21, 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 had found 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.

On September 5, 2008, the NYPSC issued its order on Niagara Mohawk's Petition for Special Ratemaking. The NYPSC stated that Niagara Mohawk's investment program could "conceptually" be considered incremental to the level of investment assumed in the MRP and therefore could be eligible for deferral. However, the NYPSC ordered Niagara Mohawk to supplement its petition with actual expense information once results for calendar year 2008 were known. Niagara Mohawk was directed to show in its supplemental filing that Niagara Mohawk will not over earn in 2008 after the deferrals are allowed, that the expenditures on which the deferrals are based are incremental to what was reflected in the MRP forecast, that such expenditures have been offset by all relevant cost savings and related benefits, and to the extent that actual expenditures for 2008 differed from amounts in the budgets that were previously filed with the NYPSC, that the basis for such differences be explained. Finally, the NYPSC ordered a schedule of reporting requirements on the investment program which Niagara Mohawk has been working with the NYPSC to develop. In April 2009, Niagara Mohawk filed for authority to defer 2008 actual incremental capital and associated operating expenditures. The NYPSC has not yet ruled on Niagara Mohawk's petition. In May 2010, Niagara Mohawk filed a request for recovery of incremental investment in 2009 in another Petition for Special Ratemaking to the NYPSC.

Gas Rate Plan Joint Proposal: On May 15, 2009, the NYPSC approved a joint proposal (Joint Proposal) that provides for a two-year rate plan, with an annual increase of $39.4 million in the first year and specific, incremental adjustments in the second year to reflect changes in such costs as postretirement benefit plans other than pensions and environmental site investigation and remediation costs. Among other deferral mechanisms, the Joint Proposal provides for a true up to the actual amount, cost and timing of certain new long-term debt issuance, subject to the actual costs falling outside of a defined range. The Joint Proposal provides for a 10.2% return on equity and a 43.7% equity ratio, and an earnings-sharing mechanism that requires Niagara Mohawk to share earnings with customers to the extent its return on equity exceeds 11.35%. 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. Pursuant to the Joint Proposal, on April 12, 2010, Niagara Mohawk filed for rate adjustments to be effective May 20, 2010 based on increases in certain costs. If approved, the rate adjustments will increase from gas operations by approximately $13.9 million.

Transmission Rate Case: In February 2008, Niagara Mohawk filed with FERC a formula transmission rate for customers that take service under the NYISO tariff. In July 2008, FERC issued an order accepting the proposed formula rate and approved a 50 basis point incentive return on equity applicable to all transmission facilities. This decision marked the first formula rate for a private transmission owner in New York. 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 formula was projected to increase annual revenues by approximately $7.9 million. The settlement provides for an authorized return on equity of 11.5%, including any incentive return. 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. 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. The increase in revenues resulting from the new formula rate are charged to wholesale transmission customers and credited back to retail electric distribution customers through the Transmission Revenue Adjustment Clause mechanism. In November 2009, Niagara Mohawk filed a proposed Stipulation and Agreement modifying the calculation of the Long-Term Debt Cost of Capital Rate so that the amount of Niagara Mohawk's long-term debt used in the calculation of the Capital Rate is based on the average of the beginning-of-the-year and the year-end long-term debt balances. As a result of the proposed change Niagara Mohawk's revenue is estimated to decline by approximately $0.4 million. Niagara Mohawk agreed to give customers the benefit of the change from July 1, 2009 forward. On February 13, 2010, the proposed Stipulation and Agreement was accepted by FERC.

Electric Rate Filing: On January 29, 2010, Niagara Mohawk filed with the NYPSC a new electric base rate case for new rates proposed to go into effect on January 1, 2011, which would terminate the MRP one year early. In its filing, Niagara Mohawk proposed a three year rate plan commencing January 1, 2011 running through December 31, 2013. Niagara Mohawk designed its rate filing to produce, in the aggregate, no net increase in electric delivery rates over the course of the three-year rate plan. To achieve this result, Niagara Mohawk proposed to extend the amortization schedule for recovery of certain fixed stranded costs to offset the total increase in transmission and distribution revenue. In addition to new base rates, Niagara Mohawk's filing proposed mechanisms that would permit it to defer certain costs that vary from the level reflected in Niagara Mohawk's proposed rates, including a mechanism that would reconcile investment in system infrastructure. On May 3, 2010, Niagara Mohawk submitted corrections and updates to its original filing, including a revised capital expenditures forecast. The corrections and updates filing decreases Niagara Mohawk's proposal revenue requirement for 2011 from approximately $391 million to $369 million, an additional $51 million (total of $420 million) in 2012 and a reduction in revenues of $28 million (total of $392 million) in 2013. Niagara Mohawk continues to propose a three-year rate plan with no net increase in the electric delivery rates, as discussed above.

On July 14, NYPSC Staff filed its testimony in the pending rate case and recommended that Niagara Mohawk should reduce electric rates by $14.1 million. The Company and the NYPSC Staff are continuing negotiations and at this point in time the Company can not predict the outcome of this rate proceeding.

Federal Income Tax Refund*:* Niagara Mohawk received federal income tax refunds covering the tax years of 1991 to 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, respectively. As required by NYPSC regulations, 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 agreed with the parties in proceeding on several adjustments to the proposed disposition resulting in an additional $18.7 million credit to its customers**,** including approximately $7.3 million (through December 2009) in carrying charges due to the delay in filing the refund notice and $11.4 million in full settlement of all other outstanding issues. On March 19, 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. On April 16, 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.

Massachusetts Electric:

Rates for services rendered by Massachusetts Electric are subject to approval by the DPU. In March 2000, the DPU approved a long-term rate plan for Massachusetts Electric, which became effective on May 1, 2000. During the period from March 1, 2005 through December 31, 2009, the Rate Index Period, distribution rates were adjusted annually. Massachusetts Electric implemented increases in distribution rates pursuant to this mechanism of 1.90% and 1.54% effective March 1, 2008, and 2009, respectively. The rate plan also included provisions for recovery of major storm costs and recovery or passback to customers for exogenous events.

On May 15, 2009, Massachusetts Electric, together with Nantucket Electric, filed for an increase in base distribution rates effective January 1, 2010. The DPU issued its order on Massachusetts Electric's case on November 30, 2009 which was subsequently modified by an order issued on April 13, 2010 in which the DPU approved an overall increase in base distribution revenue of approximately $42 million as compared to the revenue generated at the old rates and an equity ratio of 49.99% for ratemaking purposes. Approximately $6 million of the increase relates to storm costs associated with restoration of service following an ice storm on December 11 and 12, 2008 that severely damaged parts of the electric distribution system and caused numerous power outages in the central and northeast portions of Massachusetts Electric's service territory. 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, pension, postretirement benefits other than pension costs to our actual costs. The RDM allows for annual adjustments to Massachusetts Electric's distribution rates as a result of incremental capital investment and the reconciliation between allowed revenue and billed revenue.

This rate order also allowed recovery of non-capitalized pension and PBOP costs to occur outside of base rates through a separate factor. Costs of Massachusetts Electric's pension and postretirement benefits plans over or under amounts reflected in rates are deferred to a regulatory asset to be recovered in a future period. As a result 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.

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 customers, all transmission costs, and costs charged by New England Power for stranded costs associated with the affiliate's former electric generation investments.

Nantucket:

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:

Electric segment: On June 1, 2009, Narragansett filed for an increase in base distribution rates. On February 9, 2010 the RIPUC approved an increase in distribution revenue of approximately $23.5 million. Narragansett's proposal for revenue decoupling, a capital addition recovery mechanism and recovery of actual pension and postretirement benefits other than pensions charged to income were not approved. Commodity-related bad debt recovery was approved at a fixed average write-off rate applied to commodity revenue, however, a full reconciliation mechanism was denied. 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 rates to actual revenues received for both the electric and gas businesses. The new law also provides for submission and approval of an annual infrastructure spending plan that would provide for a reconciling allowance for anticipated capital spending on utility infrastructure and other costs related to maintaining system safety and reliability on an annual basis, without having to file a full base rate case. The annual infrastructure spending plan for the electric business also includes the annual costs of vegetation management and system inspection and resulting repairs. The infrastructure spending plans will be filed with the Commission before the end of the calendar year, for effect in the fiscal year commencing April 2011. Narragansett also expects to file separate proposals to implement decoupling for both electric and gas before the end of the calendar year.

In 2009, Rhode Island enacted legislation (the 2009 legislation) promoting the development of renewable energy resources through long-term contracts for the purchase of capacity, energy, and attributes. On March 1, 2010, pursuant to the 2009 legislation and RIPUC rules enacted pursuant to the 2009 legislation, Narragansett filed its proposed timetable and method of execution of annual long-term contract solicitations scheduled to begin July 1, 2010.

The 2009 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.

The 2009 legislation also includes a provision requiring Narragansett to solicit proposals for a smaller scale renewable energy generation project of up to eight wind turbines with aggregate nameplate capacity of up to 30 MW to benefit the Town of New Shoreham (Block Island). In response to Narragansett's request for proposals, Deepwater Wind Block Island LLC (Deepwater) submitted the sole bid for an off-shore wind farm off the coast of Block Island. As required by the legislation, the project includes a transmission cable to be constructed between Block Island and the mainland of Rhode Island. On December 9, 2009, Narragansett filed with RIPUC a signed Power Purchase Agreement (PPA) with Deepwater. On March 30, 2010, the RIPUC voted to reject the PPA indicating that the pricing terms were not commercially reasonable.

During May 2010, Rhode Island enacted legislation that authorized Narragansett to procure a commercially reasonable long-term contract for a renewable energy project fuelled by landfill gas with a gross nameplate capacity of less than thirty-seven megawatts from the central landfill in Johnston, Rhode Island. The legislation provides for Narragansett to recover all costs under the agreement, including administration and implementation costs, and permits Narragansett to recover remuneration equal to 2.75% of the actual annual payments made under the agreement when it is commercially operating. On May 21, 2010, Narragansett entered into a power purchase agreement with Rhode Island LFG Genco LLC. Pursuant to the legislation, the agreement was submitted for approval to certain designated state agencies.

Gas segment: Narragansett is allowed recovery of all of its gas commodity costs through a fully reconciling rate recovery mechanism.

On August 3, 2009, Narragansett made its Distribution Adjustment Charge filing, which proposed a downward adjustment to the approved rate base. The RIPUC approved the adjustment on October 27, 2009 which resulted in a $2 million reduction to the annual revenue requirement.

During May 2010, Rhode Island enacted decoupling legislation that provides for Narragansett proposing a mechanism that reconciles revenue received to an allowed annual revenue level determined on a per-customer basis as is typically employed by gas utilities. The legislation also provides for submission and approval of an annual infrastructure spending plan that would provide for a reconciling allowance for anticipated capital spending on utility infrastructure and other costs related to maintaining system safety and reliability as mutually agreed to with the Division. The legislation also allows for the expansion of gas energy efficiency programs.

Brooklyn Union:

Brooklyn Union is currently subject to a five year rate plan through December 2012. Base delivery rates were increased $5 million annually in rate year one through rate year five. However, the incremental revenue from the increase in base delivery rates will be deferred and used to offset future increases for customers such as environmental investigation and remediation costs or other cost deferrals. The plan is based on a return on equity of 9.6%. Cumulative annual earnings above 10.5% will be shared with customers. There are various reconciliation mechanisms that permit Brooklyn Union to fully or partially true up to established thresholds for such items as real property taxes, special franchise taxes and site investigation and remediation costs. In the case of non growth-related capital, other than city and state construction, Brooklyn Union must return unspent funds below established targets to customers, but may not recover overspending. Brooklyn Union may recover overspending in addition to returning under-spent funds related to city and state construction. Brooklyn Union is permitted to reconcile its actual pension and other post-employment benefit expense to the amount allowed in rates and is subject to affiliate rules and various financial protections for the term of the rate plan.

On December 22, 2009, the NYPSC adopted the terms of a Joint Proposal between NYPSC Staff and Brooklyn Union that provided for a revenue decoupling mechanism to take effect as of January

1, 2010. The revenue decoupling mechanism applies only to Brooklyn Union's firm residential heating sales and transportation customers, and permits Brooklyn Union to reconcile actual revenue per customer to target revenue per customer for the affected customer classes on an annual basis. The revenue decoupling mechanism is designed to eliminate the disincentive for Brooklyn Union to implement energy efficiency programs. The deferred amount was $1.4 million at March 31, 2010.

Pursuant to its current rate plan, on January 29, 2010, Brooklyn Union filed the status of its deferrals so that the NYPSC can determine whether in 2011 Brooklyn Union should adjust the level of revenue it receives under the existing rate plan to minimize outstanding deferrals. Brooklyn Union proposed an increase on 2009 revenues of 1.63% through an existing surcharge to take effect January 1, 2011, subject to NYPSC approval. Brooklyn Union is proposing to recover $31.7 million of regulatory assets that are on the consolidated balance sheets.

KeySpan Gas East:

KeySpan Gas East is currently subject to a five year rate plan through December 2012. Base delivery rates were increased by $60 million on January 1, 2008. In rate years two through five, base delivery rates will be increased by $10 million. However, the incremental revenue from the increase in delivery rates in years two through five will be deferred and used to offset future increases for customers such as environmental investigation and remediation or other cost deferrals. The plan is based on an allowed ROE of 9.6%. Cumulative annual earnings above 10.5% will be shared with customers. There are various reconciliation mechanisms that permit KeySpan Gas East to fully or partially true up to established thresholds for such items as real property taxes, special franchise taxes and site investigation and remediation costs. In the case of non growth-related capital, other than City and State construction, KeySpan Gas East may recover overspending in addition to returning under-spent funds related to City and State construction. KeySpan Gas East is permitted to reconcile its actual pension and other post-employment benefit expense to the amount allowed in rates and remains subject to affiliate rules and various financial protections for the term of the rate plan.

On December 22, 2009, the NYPSC adopted the terms of a Joint Proposal between NYPSC Staff and KeySpan Gas East that provided for a revenue decoupling mechanism to take effect as of January 1, 2010. The revenue decoupling mechanism applies only to KeySpan Gas East's firm residential heating sales and transportation customers, and permits KeySpan Gas East to reconcile actual revenue per customer to target revenue per customer for the affected customer classes on an annual basis. The revenue decoupling mechanism is designed to eliminate the disincentive for KeySpan Gas East to implement energy efficiency programs. The deferred amount was $0.7 million at March 31, 2010.

Pursuant to its current rate plan, on January 29, 2010, KeySpan Gas East filed the status of its deferrals so that the NYPSC can determine whether in 2011 KeySpan Gas East should adjust the level of revenue it receives under the existing rate plan to minimize outstanding deferrals. KeySpan Gas East proposed an increase on 2009 revenues of or 2.48% through an existing surcharge to take effect January 1, 2011, subject to NYPSC approval. KeySpan Gas East is proposing to recover $33.3 million of regulatory assets that are on the consolidated balance sheets.

Boston Gas, Colonial Gas and Essex Gas:

Boston Gas currently has a long-term rate plan in place to 2013, unless terminated earlier. Under the long-term rate plan, rates are adjusted each year with the approval of the DPU based on a price cap formula. The rate plan also provides for a true-up mechanism for pension and other postretirement benefit costs under which variations between actual pension and other postretirement benefit costs and amounts used to establish rates are deferred and collected from or refunded to customers in subsequent periods. This true-up mechanism allows for carrying charges on deferred assets and liabilities at Boston Gas's weighted-average cost of capital. There is also an earnings sharing mechanism. If the ROE is greater than 14.2%, customers share 25% of the excess gain. Conversely, if the ROE is lower than 6.2%, customers bear 25% of the loss. On September 15, 2009, Boston Gas filed its sixth annual request for an increase under the rate plan in the amount of $5.4 million, which was approved by the DPU in October 2009. On April 16, 2010, Boston Gas, jointly with Colonial Gas and Essex Gas, KeySpan subsidiaries, filed a request for an increase in base distribution rates. Boston Gas and Essex Gas are proposing a combined increase of $79.2 million and Colonial Gas is proposing an increase of $26.8 million. The filing includes, among other things, a revenue decoupling proposal. The matter is pending before the DPU. An Order is anticipated on November 1, 2010 with rates to become effective on November 2, 2010.

Colonial Gas and Essex Gas are currently subject to DPU 10 year rate freezes that expired on September 2009 and September 2008 respectively. Those rates stay in effect until the DPU approves a rate change.

Service Quality Penalties:

In connection with various regulatory plans, the Companies regulatory subsidiaries are subject to maintaining certain service quality standards. Service quality measures typically focus on safety targets related to gas operations, electric reliability measures related to outages, residential and business customer satisfaction, meter reads, customer call response times, and administration of the Assistance Program. If a prescribed standard is not satisfied, the Companies may incur a penalty, with the penalty amount applied as a credit or refund to customers. The Companies has not incurred any material penalties for the year ended March 31, 2010.

NOTE 3 - EMPLOYEE BENEFITS

Summary

The Company and its subsidiaries have defined benefit pension plans covering a substantial portion of its employees. The pension plans are noncontributory and tax qualified defined benefit plans which provide employees with a minimum retirement benefit. Benefits are based on compensation and / or years of service.

The Company and its subsidiaries have defined benefit postretirement benefit plans other than pensions ("PBOP") which provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirement and, in most cases, retirees must contribute to the cost of their coverage.

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 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 allocations for the benefit plans at March 31 are:

	Pension Benefits		**Non-Union PBOP**		**Union PBOP**	
	2010	2009	**2010**	2009	**2010**	2009
U.S. equities	**23%**	30%	**38%**	37%	**34%**	49%
Global equities (including U.S.)	**8%**	7%	**0%**	0%	**12%**	0%
Global tactical asset allocation	**12%**	7%	**0%**	0%	**17%**	0%
Non-U.S. equities	**10%**	11%	**17%**	17%	**17%**	21%
Fixed income	**42%**	40%	**44%**	45%	**20%**	28%
Private equity and other	**5%**	5%	**1%**	1%	**0%**	2%
	100%	100%	**100%**	100%	**100%**	100%

The percentage of the fair value of total plan assets at March 31 is:

	Pension Benefits		**Non-Union PBOP**		**Union PBOP**	
	2010	**2009**	**2010**	**2009**	**2010**	**2009**
U.S. equities	**23%**	30%	**38%**	42%	**35%**	48%
Global equities (including U.S.)	**8%**	5%	**0%**	0%	**12%**	0%
Global tactical asset allocation	**12%**	7%	**0%**	0%	**17%**	0%
Non-U.S. equities	**10%**	10%	**17%**	12%	**17%**	20%
Fixed income	**42%**	41%	**44%**	44%	**18%**	30%
Private equity and other	**5%**	7%	**1%**	2%	**1%**	2%
	100%	100%	**100%**	100%	**100%**	100%

The Company manages benefit plan investments to minimize the long-term cost of operating the plans, with a reasonable level of risk. Risk tolerance is determined as a result of a periodic asset/liability study which analyzes plan liabilities and plan funded status and results in the determination of the allocation of assets across equity and fixed income securities. During the past year, the Company lowered its overall targeted equity allocation for its pension assets which resulted in a shift from U.S. equities to 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. Assets held in global tactical asset allocation strategies are managed by investment managers who use both top-down and bottom-up valuation methodologies to value assets classes, countries, industrial sectors, and individual securities in order to allocate assets opportunistically. Investments are also held in private equity funds with the objective of enhancing long-term returns while improving portfolio diversification. For the PBOP plans, since the earnings on a portion of the assets are taxable, those investments are managed to maximize after tax returns consistent with the broad asset class parameters established by the asset allocation study. Investment risk and return are reviewed by the Company's investment committee.

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 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. The rates of return for each asset class are then weighted in accordance with the plans' year end target asset allocation, and the resulting long-term return on asset rate is then applied to the market-related value of assets.

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.

	Pension benefits			
	Benefit obligation		**Net periodic benefit costs**	
	2010	2009	**2010**	2009
Discount rate	**6.10%**	7.30%	**7.30%**	6.50%
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	3.50% - 4.00%
Expected long-term rate of return on assets	**n/a**	n/a	**8.00%**	8.00%

	PBOP			
	Benefit obligation		**Net periodic benefit costs**	
	2010	**2009**	**2010**	2009
Discount rate	**6.10%**	7.30%	**7.30%**	6.50%
Expected long-term rate of return on assets	**n/a**	n/a	**6.00% - 8.25%**	6.75% - 8.25%
Health care cost trend rate				
Initial - pre 65	**8.50%**	8.50%	**8.50%**	9.00%
Initial - post 65	**8.50%**	9.50%	**9.50%**	10.00%
Prescription drugs	**9.25%**	n/a	**n/a**	n/a
Ultimate	**5.00%**	5.00%	**5.00%**	5.00%
Year ultimate rate reached - pre 65	**2017**	2015	**2015**	2014
Year ultimate rate reached - post 65	**2017**	2016	**2016**	2015
Prescription drugs	**2019**	n/a	**n/a**	n/a

The expected contributions to the Company's pension and PBOP plans during the year ended March 31, 2011 are $597 million.

Pension Benefits

The Company's net periodic benefit cost for the years ended March 31, 2010 and 2009 included the following components:

(in millions of dollars)		**2010**		2009
Service cost	**$**	**97.5**	$	111.8
Interest cost		**365.5**		351.0
Expected return on plan assets		**(335.8)**		(417.0)
Amortization of prior service cost		**7.4**		5.6
Amortization of loss		**169.2**		67.0
Net period benefit costs before settlements and curtailments		**303.8**		118.4
Settlement and curtailment loss		**2.8**		-
Special termination benefits		**36.3**		75.7
Net periodic benefit cost	**$**	**342.9**	$	194.1

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

(in millions of dollars)		**2010**		2009
Accumulated benefit obligation	**$**	**(5,708.3)**	$	(4,794.9)
Reconciliation of benefit obligation:				
Benefit obligation at beginning of period		**(5,224.4)**		(5,530.0)
Service cost		**(97.5)**		(111.8)
Interest cost		**(365.5)**		(351.0)
Actuarial gain (loss)		**(827.2)**		379.2
Benefits paid		**404.9**		442.3
Plan amendments		**(31.0)**		-
Settlements and special termination benefits		**(23.8)**		(53.1)
Benefit obligation at end of period		**(6,164.5)**		(5,224.4)
Fair value of plan assets at beginning of period		**3,755.5**		5,077.4
Actual return on plan assets		**1,203.8**		(1,331.7)
Company contributions		**477.7**		478.4
Benefits paid		**(404.9)**		(442.3)
Settlements		**(12.6)**		(26.3)
Fair value of plan assets at end of period		**5,019.5**		3,755.5
Funded status	**$**	**(1,145.0)**	$	(1,468.9)

As of March 31, amounts recognized on the Consolidated Balance Sheets consist of:

(in millions of dollars)	**2010**	2009
Current pension liability	**$ (24.8)**	$ (32.7)
Non-current pension liability	**(1,120.2)**	(1,436.2)
Net amount recognized	**$ (1,145.0)**	$ (1,468.9)

(in millions of dollars)	**2010**	2009
Amounts recognized in AOCI consist of:		
Net actuarial loss	**$ 1,876.4**	$ 2,083.3
Prior service cost	**65.5**	41.9
Net amount recognized	**$ 1,941.9** *	$ 2,125.2 *

*As a result of deferral accounting treatment mandated by various state regulatory authorities, $1.0 billion and $889.6 million is reflected in regulatory assets on the consolidated balance sheets at March 31, 2010 and 2009, 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, 2011 are $195 million and $8 million, respectively.

The following pension benefit payments are expected to be paid:

(in millions of dollars)	**Pension benefits**
2011	$ 381.4
2012	$ 384.5
2013	$ 404.9
2014	$ 412.9
2015	$ 427.5
2016-2020	$ 2,285.5

Defined Contribution Plan

The Company also has several defined contribution pension plans (primarily section 401(k) employee savings fund plans) that cover substantially all employees. Employer matching contributions of approximately $30 million were expensed in the years ended March 31, 2010 and 2009.

Postretirement Benefits Other than Pensions

The Company's total net periodic benefit cost of PBOPs for the years ended March 31, 2010 and 2009 included the following components:

(in millions of dollars)		**2010**		2009
Service cost	**$**	**40.9**	$	49.3
Interest cost		**226.0**		220.2
Expected return on plan assets		**(85.9)**		(113.9)
Amortization of prior service cost		**11.7**		13.3
Amortization of net loss		**60.8**		50.4
Net periodic benefit cost before special termination benefits		**253.5**		219.3
Special termination benefits		**1.0**		1.6
Net periodic benefit cost	**$**	**254.5**	$	220.9

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

(in millions of dollars)		**2010**		2009
Change in benefit obligation:				
Benefit obligation at beginning of period	**$**	**(3,302.8)**	$	(3,540.2)
Service cost		**(40.9)**		(49.3)
Interest cost		**(226.0)**		(220.2)
Actuarial (gain)/loss		**(568.6)**		331.2
Benefits paid		**208.8**		177.8
Medicare subsidy		**(12.7)**		(0.5)
Plan amendments		**17.2**		-
Healthcare reform amendment		**(19.0)**		-
Special termination benefits		**(1.0)**		(1.6)
Other		**(5.5)**		-
Benefit obligation at end of period		**(3,950.5)**		(3,302.8)
Change in plan assets:				
Fair value of plan assets at beginning of period		**1,037.3**		1,474.2
Actual return on plan assets		**394.7**		(401.1)
Company contributions		**219.3**		142.0
Benefits paid		**(208.8)**		(177.8)
Other		**0.9**		-
Fair value of plan assets at end of period		**1,443.4**		1,037.3
Funded status	**$**	**(2,507.1)**	$	(2,265.5)

As of March 31, amounts recognized on the Consolidated Balance Sheets consist of:

(in millions of dollars)		**2010**		2009
Noncurrent assets	**$**	**2.6**	$	-
Current liabilities		**(14.0)**		(10.0)
Noncurrent liabilities		**(2,495.7)**		(2,255.5)
Net amount recognized	**$**	**(2,507.1)**	$	(2,265.5)

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

(in millions of dollars)		**2010**			**2009**	
Amount recognized in AOCI consist of:						
Net actuarial loss	**$**	**922.5**		**$**	**726.6**	
Prior service cost		**70.1**			**79.9**	
Net amount recognized	**$**	**992.6**	*	**$**	**806.5**	*

*As a result of deferral accounting treatment mandated by various state regulatory authorities, $571.7 million and $394.3 million is reflected in regulatory assets on the consolidated balance sheets at March 31, 2010 and 2009.

The estimated net actuarial loss and prior service cost for the PBOP plans that will be amortized during the year ended March 31, 2011 are estimated to be $91 million and $12 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**
2011	$	206.1	$	12.8
2012	$	218.0	$	14.1
2013	$	228.5	$	15.5
2014	$	239.7	$	16.8
2015	$	250.5	$	18.1
2016-2020	$	1,401.9	$	109.2

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)		2010
Increase 1%		
Total of service cost plus interest cost	$	39.1
Postretirement benefit obligation	$	528.1
Decrease 1%		
Total of service cost plus interest cost	$	(32.9)
Postretirement benefit obligation	$	(451.9)

Special Termination Benefits (Voluntary Early Retirement Offer)

In connection with National Grid plc's acquisition of KeySpan, which was completed on August 24, 2007, National Grid plc and KeySpan offered certain non-union employees voluntary early retirement offer ("VERO") packages in June 2007 in an effort to achieve necessary staff reduction through voluntary means; 560 employees enrolled in the VERO. Employees enrolled in the early retirement program will retire between October 1, 2007 and October 1, 2010. The cost of the VERO program is expected to be $147 million. The Company recorded $30 million and $69 million of VERO costs for the years ended March 31, 2010 and 2009, respectively. At March 31, 2010 the costs associated with this VERO program have been fully accrued.

Additional VERO packages were offered to 205 employees in 2009. Of the eligible employees, 134 enrolled in these VEROs. Employees enrolled in the early retirement program will retire by between October 1, 2008 and December 1, 2010. The Company recorded costs of approximately $16 million related to these voluntary plans, most of which has been expensed.

Fair Value Measurements

As discussed in Note 1 Summary of Significant Accounting Policies, current accounting guidance on fair value measurements establishes a framework for measuring fair value. That framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements).

Following is a description of the valuation methodologies used at March 31, 2010 for pension and other postretirement benefit assets measured at fair value. The pension and other postretirement benefit assets can be invested in any of the following categories.

Cash and cash equivalent:
Interest bearing cash is 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 Plans at year end.

Equity and preferred securities:
Common stocks, preferred stocks, and real estate investment trusts are valued using the official close (for NASDAQ only), last trade, bid of the ask offer price reported on the active market on which the individual securities are traded.

Fixed income securities and future contracts:
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 which are in turn comprised of government agency securities, government mortgage-backed securities, index linked government bonds, and state and local bonds), 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.

Private equity and real estate:
Commingled equity funds, commingled special equity funds, limited partnerships, real estate, venture capital and other investments are valued using evaluations (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.

The asset classes listed in the tables below may also be held in the following investment vehicles:

Mutual funds, common and collective trusts, and pooled separate accounts are valued at the net asset value of shares held by the Plan at year end.

103-12 investment entities (entities whose legal structure is in the form of a financial services product such as a collective trust or a limited partnership and whose underlying assets include "plan assets" of two or more plans that are not members of a related group of employee benefit plans in accordance with Department of Labor Regulation 2520.103-12) are valued using financial information received from the investment trustee, advisor and/or general partner. This information is received monthly and is based on the value of underlying securities. For some 103-12 investments, the financial information is provided in the quarterly statements that are typically provided more than 30 days after quarter end. Because of this time lag, investment units for these 103-12 investment entities are valued as of the Plan year end using the available statement from the prior quarter 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, 2010:

(in millions of dollars)				
Asset Type	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ 34.8	$ 102.8	$ -	$ 137.6
Equity	1,111.6	1,170.0	99.3	2,380.9
Fixed income securities	564.6	1,396.8	40.7	2,002.1
Futures contracts	1.6	-	-	1.6
Preferred securities	8.6	-	-	8.6
Private equity	-	45.8	441.7	487.5
Real estate	-	-	1.2	1.2
Net assets at fair value	$ 1,721.2	$ 2,715.4	$ 582.9	$ 5,019.5

The table depicted below sets forth by level, within the fair value hierarchy, the National Grid USA Master Union Trust Plan retirement benefits other than pension investments at fair value as of March 31, 2010:

(in millions of dollars)				
Asset Type	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ 64.1	$ 19.1	$ -	$ 83.2
Equity	341.2	451.7	32.5	825.4
Fixed income securities	217.4	220.7	-	438.1
Preferred securities	0.9	-	-	0.9
Private equity	-	27.7	68.1	95.8
Net assets at fair value	$ 623.6	$ 719.2	$ 100.6	$ 1,443.4

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, 2010:

(in millions of dollars)	Equity	Fixed Income Securities	Preferred Securities	Private Equity	Real Estate	Total
Balance, beginning of year	$ 144.4	$ 48.5	$ 0.9	$ 342.0	$ 1.2	$ 537.0
Realized gains/(losses)	21.5	(0.1)	(0.8)	56.5	-	77.1
Unrealized gains/(losses) at reporting date	30.9	1.8	-	(23.0)	-	9.7
Purchases, sales, issuance and settlements (net)	(97.5)	(9.5)	(0.1)	66.2	-	(40.9)
Balance, end of year	$ 99.3	$ 40.7	$ -	$ 441.7	$ 1.2	$ 582.9

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, 2010:

(in millions of dollars)	Equity	Fixed Income Securities	Preferred Securities	Private Equity	Total
Balance, beginning of year	$ 43.1	$ 0.1	$ 0.3	$ 20.5	$ 64.0
Realized gains/(losses)	2.6	(0.3)	(0.3)	0.8	2.8
Unrealized gains/(losses) at reporting date	9.0	0.3	-	0.5	9.8
Purchases, sales, issuance, and settlements (net)	(22.2)	(0.1)	-	46.3	24.0
Balance, end of year	$ 32.5	$ -	$ -	$ 68.1	$ 100.6

NOTE 4 –DEBT

***European Medium Term Note Program*:**
At March 31, 2010, 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 Euro. At March 31, 2010, $23.1 million of these notes were issued and outstanding, including the impact of interest rate and currency swaps. The interest rate at March 31, 2010 was 1.01%. During the year-ended March 31, 2010, the Company repaid $70.1 million of Euro Medium Term Notes at maturity. At March 31, 2009, $93.2 million of these notes were outstanding with interest rates ranging from 0.40% - 4.61%.

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 ("US") or to a US 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, 2010, the Company was in compliance with all covenants.

Notes Payable:
At March 31, 2010, the Company had outstanding $1.1 billion of secured medium and long-term notes with interest rates ranging from 6.80% to 9.75% and maturity dates ranging from 2010 through 2030. During the year-ended March 31, 2010, the Company repaid $400 million of 7.875% medium-term notes at maturity.

Additionally, the Company had outstanding $3.8 billion of unsecured medium and long-term notes at March 31, 2010. Between August 2009 and March 2010, the Company issued debt in five tranches totaling $2.6 billion. The interest rates on the unsecured notes range from 3.55% to 9.41% and maturity dates extend from 2013 through 2040. 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, 2010, the total long-term debt was 18% of total capitalization. Additionally, some of these bonds have a sinking fund requirement which totaled $5.5 million during the year ended March 31, 2010.

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 $10.6 million loss on the “treasury lock” settlement will be amortized over the life of the bonds to match the corresponding rate treatment.

At March 31, 2009, the Company had $2.7 billion of secured and unsecured medium and long-term notes outstanding with interest rates ranging between 4.65% and 9.75%.

Gas Facilities Revenue Bonds:
At March 31, 2010 and 2009, the Company had outstanding $640.5 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 $640.5 million, $230.0 million is variable rate series due through July 1, 2026. The interest rate is reset weekly and ranged from 0.4% to 4.00% for the year ended March 31, 2010. For the year ended March 31, 2009, the interest rates ranged from 0.83% to 11.0%. The variable-rate auction bonds are currently in the auction rate mode and are backed by bond insurance. In the case of a failed auction, the resulting interest rate on the bonds would revert to the maximum rate which depends on the current commercial paper rates and the senior unsecured rating of the bonds.

***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, 2010 and 2009, $155.4 million of promissory notes remained outstanding with maturity dates between 2016 and 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, 2010, the Company was in compliance with this requirement.

First Mortgage Bonds:
At March 31, 2010, the Company had outstanding $132.1 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 $1.6 million and, (iv) the payment of dividends from retained earnings. At March 31, 2010, 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, 2009, $133.4 million of first mortgage bonds were outstanding with interest rates ranging from 6.34% to 9.63%. The Company repaid $1.4 million of First Mortgage Bonds on their maturity dates during the year-ended March 31, 2010.

State Authority Financing Bonds:
At March 31, 2010, the Company had outstanding $1.2 billion of State Authority Financing Bonds. Of the $1.2 billion outstanding at March 31, 2010, $716.1 million of these bonds were issued

through NYSERDA and the remaining $483.4 million were issued through various other state agencies.

Approximately $575 million of the Company's NYSERDA first mortgage bonds were issued to secure a like amount of tax-exempt revenue bonds and bear interest at short-term adjustable interest rates (with an option to convert to other rates, including a fixed interest rate) which range from 0.57% to 1.39% for the year ended March 31, 2010. The NYSERDA bonds are currently in the auction rate mode and are backed by bond insurance. In the case of a failed auction, the resulting interest rate on the bonds would revert to the maximum rate which depends on the current commercial paper rates and the senior secured rating of the bonds.

The Company also has $75.0 million of 5.15% fixed rate pollution control revenue bonds issued through NYSERDA which are callable at 101% through November 1, 2010 and at par thereafter. 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 $41.1 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 0.45% to 18.00% during the year ended March 31, 2010, at which time the rate was 2.00%. The second Series A bond is a $24.9 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 0.18% to 0.55%.for the year ended March 31, 2010, at which time the rate was 0.30%.

At March 31, 2010, the Company had outstanding $430.3 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 1.00% for the year ended March 31, 2010. There are no payments or sinking fund requirements due in 2011 through 2015. The Company has Standby Bond Purchase Agreements and Credit Agreements to provide liquidity support for these bonds. (See "Standby Bond Purchase Agreement" below).

At March 31, 2010, the Company had $53.1 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 1.85% during the year ended March 31, 2010. The bonds were issued by the Massachusetts Development Finance Agency in connection with the Company's financing of its first and second underground and submarine cable projects. Sinking fund payments of $0.2 million were made during the year ended March 31, 2010. The Company has Standby Bond Purchase Agreements to provide liquidity support for these bonds. See "Standby Bond Purchase Agreement" below.

At March 31, 2009, the Company had outstanding $1.2 billion of State Authority Financing Bonds. Interest rates on the variable rate series ranged from 1.10% to 17.75% in fiscal 2009.

Industrial Development Revenue Bonds
At March 31, 2010 and 2009, the Company had outstanding $128.3 million of tax-exempt Industrial Development Revenue bonds. Of these bonds, $53.3 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, 2010, NGUSA had five committed bank loans outstanding totaling $550.5 million which mature from 2010 to 2014. These loans are in various currencies and are used to provide funds for working capital needs. The interest rates on these bank loans are reset periodically and ranged from 0.40% to 0.90% over issued currency LIBOR rates in both years. At March 31, 2009, $543 million was outstanding.

Inter-Company Notes Payable:
At March 31, 2010 and 2009, the Company had outstanding $866.7 million and $1.2 billion of an inter-company note due to the Parent. This note has an interest rate of 5.52% and matures in November 2010. During the year ended March 31, 2010 $334 million was repaid.

Debt Maturity:
The following table reflects the maturity schedule for our debt repayment requirements, including capitalized leases and related maturities, at March 31, 2010:

(in millions of dollars)	Long-Term Debt
Repayment for fiscal years:	
2011	$ 2,044.1
2012	17.4
2013	17.2
2014	235.9
2015	629.6
Thereafter	5,637.5
	$ 8,581.7

The following table depicts the sinking fund requirements.

(in millions of dollars)	Sinking Fund
Repayment for fiscal years:	
2011	$ 7.1
2012	7.1
2013	7.2
2014	7.2
2015	7.2
Thereafter	16.2
	$ 52.0

Standby Bond Purchase Agreement:

At March 31, 2010, three of the Company's subsidiaries had a Standby Bond Purchase facility with banks totaling $455 million, which is available to provide liquidity support for certain tax-exempt State Authority Bonds. The fees for the facility are based on each subsidiary's credit rating and are increased or decreased based on a change in the entity's rating.

The facility contains certain financial covenants that require the Company's subsidiaries to maintain a debt to total capitalization ratio of no more than 65% at the last day of each fiscal quarter. At March 31, 2010, the Company's subsidiaries named in the facility were in compliance with this covenant. The agreement expires in November 2011. There were no borrowings under the standby bond purchase agreement at March 31, 2010 or 2009.

Credit Facilities:

At March 31, 2010 one of the Company's subsidiaries had two Credit Agreements with banks totaling $75 million, which is available to provide liquidity support for certain tax-exempt State Authority Bonds.

Commercial Paper and Revolving Credit Agreements

Commercial Paper

At March 31, 2010, the Company has a commercial paper program totaling $2.0 billion. In support of this program, the Company was a named borrower under a National Grid plc credit facility totaling $810 million, with the full amount of the facility being available to the Company. This facility supports both the Parent's and the Company's commercial paper programs for ongoing working capital needs. The facility expires in November 2010.

The credit facility allows both the Parent and the Company to borrow in Sterling or US Dollars at the appropriate LIBOR rate plus a margin of 0.85%. The current annual fee is 0.30%. We do not anticipate borrowing against this facility; 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 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, 2010, the Company was in compliance with all covenants.

Subject to certain conditions set forth in the credit facility, the Parent and the Company have the right to "Term Out" the facility, whereby they may borrow in total up to the full facility amount of $810 million and this borrowing may remain outstanding for a further year beyond the expiration date of the facility. In addition, the Parent has the right to request that the termination date be extended for an additional period of 364 days prior to each anniversary of the closing date. This extension option requires the approval of lenders holding more than 50% of the total commitments to such extension request and only the lenders that consent will have their commitment extended. Under the agreements, the Parent has the ability to replace non-consenting lenders with other banks or financial institutions.

At March 31, 2010, there were no borrowings on the NGUSA commercial paper program.

KeySpan's Commercial Paper Program

At March 31, 2009, KeySpan had two credit facilities totaling $1.5 billion - $580 million through 2009, which has expired, and $920 million, which was terminated in November 2009. These credit facilities were used to support KeySpan's commercial paper program for working capital needs. KeySpan's commercial paper program has been terminated and all commercial paper was repaid in fiscal year 2009.

Uncommitted Facility Agreements

At March 31, 2010, the Company had uncommitted loan facilities totaling $480 million available from five banks. There were no borrowings at March 31, 2010. These facilities provide liquidity for ongoing working capital needs by allowing the Company to borrow at very short notice. However, the lenders are not obliged to make a loan under the facilities at any time. The interest rates are set at the time of issuance and range from 20 basis points to 45 basis points over LIBOR. Maturities are also set at the time of issuance and differ from lender to lender.

Inter-company Money Pool

The Company and subsidiaries operate regulated and unregulated money pools to more effectively utilize cash resources and to reduce outside short-term borrowings. The money pool is an arrangement among NGUSA and its wholly-owned subsidiaries that allows for short term borrowings and investments of available cash balances. Short-term borrowing needs are met first by available funds of the money pool participants. Borrowing companies pay interest at a rate designed to approximate the cost of third-party short-term borrowings. Companies that invest in the money pool share the interest earned on a basis proportionate to their average monthly investment in the money pool. Funds may be withdrawn from or repaid to the pool at any time without prior notice. The Company has the ability to borrow up to $3 billion from the Parent for working capital needs, including for the purpose of funding the money pool, if necessary. At March 31, 2010, the Company did not have any outstanding borrowings under this arrangement, but does have a $769.6 million outstanding borrowing from National Grid Holdings Inc. ("NGHI"), a National Grid plc subsidiary.

NOTE 5 – INCOME TAXES

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

	Fiscal Year Ended March 31,	
(In millions of dollars)	**2010**	2009
Components of federal and state income taxes:		
Current tax expense (benefit):		
Federal	**$ (376.2)**	$ 791.2
State	**(17.1)**	272.6
Total current tax expense (benefit)	**(393.3)**	1,063.8
Deferred tax expense (benefit):		
Federal	**725.6**	(548.9)
Investment Tax Credits (1)	**(6.9)**	(6.8)
State	**193.1**	(187.6)
Total deferred tax expense (benefit)	**$ 911.8**	$ (743.3)
Total income tax expense	**$ 518.4**	$ 320.5

(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 2010 and 2009 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 percent, to the Company's actual income tax expense for 2010 and 2009 is presented in the following table:

	Fiscal Year Ended March 31,	
(In millions of dollars)	**2010**	2009
Computed tax	**$ 337.4**	$ 270.7
Increase (reduction) including those attributable to flow-through of certain tax adjustments:		
State income tax, net of federal benefit	**88.2**	54.7
Change in cash surrender value	**(11.4)**	13.2
Medicare subsidy, including Patient Protection & Affordable Care Act effect, net	**112.7**	(14.5)
Investment tax credit	**(6.9)**	(6.8)
Intercompany tax allocation	**(9.6)**	(2.3)
Provision to return adjustments	**6.3**	(7.0)
Audit and related reserve movements	**(2.7)**	10.8
Temporary differences flowed through	**5.2**	8.8
Other items - net	**(0.8)**	(7.1)
Total	**$ 181.0**	$ 49.8
Federal and state income taxes	**$ 518.4**	$ 320.5

Significant components of the Company's net deferred tax assets and liabilities at March 31, 2010 and 2009 are presented in the following table:

(In millions of dollars)	**At March 31, 2010**	At March 31, 2009
Allowance for uncollectible accounts	**$ 168.2**	$ 111.0
Pensions, OPEB and other employee benefits	**1,654.3**	1,638.0
Regulatory Liabilities - Other	**106.4**	382.0
Reserve - Environmental	**526.0**	259.0
Unbilled revenue	**17.9**	32.0
Other items	**504.7**	473.0
Total deferred tax assets (1)	**$ 2,977.5**	$ 2,895.0
Property related differences	**$ (3,703.0)**	$ (3,426.0)
Regulatory Assets - Merger rate plan stranded costs	**(349.5)**	(546.0)
Regulatory Assets - Pension and OPEB	**(946.4)**	(585.0)
Regulatory Assets - Environmental	**(681.1)**	(324.0)
Investment tax credit	**(52.8)**	(59.7)
Other items	**(398.7)**	(79.8)
Total deferred tax liabilities	**$ (6,131.5)**	$ (5,020.5)
Net accumulated deferred income tax liability	**$ (3,154.0)**	$ (2,125.5)
Current portion of net deferred tax asset (liability)	**106.8**	218.5
Non-current portion of net deferred income tax liability	**$ (3,260.8)**	$ (2,344.0)

As of March 31, 2010, the Company has approximately $685 million of net operating losses in the state of Massachusetts that are being carried forward to offset the future earnings of the company. Valuation allowances have been established for the full amount of these loss carry forwards as the Company believes that the losses will not be utilized in the foreseeable future. As of March 31, 2010, these state net operating losses will expire between 2011 and 2015. As of March 31, 2010, the Company generated approximately $303.5 million of New York State net operating losses which it expects to use to offset future years earnings. This net operating loss has a 20 year carryforward utilization period,

The Company is a member of the NGHI and subsidiaries consolidated federal income tax return. The Company has joint and several liability for any potential assessments against the consolidated group. In December 2009, NGHI made an income tax accounting method change (in accordance with Internal Revenue Code Section 481(a)) to deduct routine repair and maintenance of network assets pursuant to Internal Revenue Code Section 162 and Treasury Regulation §1.162-4 in its consolidated federal income tax return for the tax year ended March 31, 2009 which resulted in a current tax benefit recognized during the fiscal year ended March 31, 2010.

ASC 740 clarifies the accounting for uncertain tax positions. ASC 740-10-25-6 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.

Due to the application of ASC 740, as of March 31, 2010 and 2009, the Company's unrecognized tax benefits totaled $849.1 million and $539.4 million, respectively, of which $ 197.0 million and $158.5 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, 2010 and 2009:

Reconciliation of Unrecognized Tax Benefits	**As at March 31,**	
(In millions of dollars)	**2010**	2009
Beginning balance	**$ 539.4**	$ 474.7
Gross increases (decreases) related to prior period	**-**	54.9
Gross increases (decreases) related to current period	**366.0**	18.9
Settlements with tax authorities	**(56.1)**	(9.1)
Reductions due to lapse of statute of limitations	-	-
Ending balance	**$ 849.3**	$ 539.4

As of March 31, 2010 and March 31, 2009, the Company has accrued for total interest of $61.6 million and $96.4 million, respectively. During fiscal years ended March 31, 2010 and March 31 2009, the Company recorded interest benefit $15.8 million and expense of $42.2 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 fiscal years ended March 31, 2010 and March 31, 2009.

The Company is a member of a federal consolidated return with its parent, National Grid Holdings, Inc. ("NGHI"). Subsequent to the KeySpan acquisition on August 24, 2007, KeySpan is also a member in the NGHI consolidated return. 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 fiscal year ended March 31, 2009, the NGHI consolidated group, excluding KeySpan, settled all outstanding IRS audit adjustments related to fiscal years ending March 31, 2003 and March 31, 2004 with the IRS Office of Appeals and made a payment of $41.7 million to the IRS. As a result of the settlement of the IRS audits for fiscal years ended March 31, 2003 and March 31, 2004, the Company filed amended state returns in New York and New Hampshire, and made payments of $9.4 million to New York and $0.3 million to New Hampshire.

The IRS is currently auditing the federal NGHI consolidated income tax returns, excluding KeySpan, for March 31, 2005 through March 31, 2007. The Company expects to make a cash tax payment to the IRS within the next twelve months related to the 2005-2007 settlement. At that time, the Company expects to decrease its total gross unrecognized tax benefits by $9.4 million. The fiscal years ended March 31, 2008 and March 31, 2009, which includes KeySpan, remain subject to examination.

The IRS is in the process of examining KeySpan's consolidated income tax returns for the years ended December 31, 2000 through 2006. The Company expects to conclude the examination in fiscal year ended March 31, 2011. At that time, the Company expects to decrease its total gross unrecognized tax benefits by $215.4 million. Tax returns for the short year ended August 24, 2007, remain subject to examination.

The Company and its subsidiaries file a unitary or separate returns with various state authorities including New York, Massachusetts, New Hampshire, Connecticut, Vermont, Maine, West Virginia, and South Carolina. These returns are subject to examination for the years open under the statute of limitations.

During the fiscal year ended March 31, 2009, the State of New York completed its audit of fiscal years ending March 31, 2003 through March 31, 2005 for Niagara Mohawk. As a result of the federal and state audits, the Company paid $4.8 million of its total gross unrecognized tax benefits in fiscal year March 31, 2009. During the fiscal year ended March 31, 2009 the State of New York began a new audit cycle covering the fiscal years ended March 31, 2006 though March 31, 2008. The fiscal years ended March 31, 2009 remains subject to examination by New York State.

In addition, the Massachusetts Department of Revenue is conducting a field audit of the Company's Combined Returns for March 31, 2003 through March 31, 2005. The Company is also in the process of appealing adjustments made by the Massachusetts Department of Revenue in a previous audit of its Massachusetts Combined Returns for January 1, 2000 through March 31, 2002. The fiscal years ending March 31, 2006 through March 31, 2009 remain subject to examination by Massachusetts.

The Company's, excluding the KeySpan acquired companies, fiscal years ended prior to March 31, 2004 are no longer subject to examination by federal or state authorities in the major jurisdictions in which the Company operates. The following table indicates the earliest KeySpan tax years subject to examination for each major jurisdiction:

Jurisdiction	Tax Year
Federal	2000
New York State	2000
California	2004
Massachusetts	2005
New Hampshire	2005
West Virginia	2005

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. This change does not have a material effect on the 2010 or 2009 financial statements.

During the period ending March 31, 2009, The State of New York concluded its audit of calendar years ending December 31, 2005 through December 31, 2006 for Brooklyn Union Gas with no changes proposed. The periods ended August 24, 2007, March 31, 2008, March 31, 2009 and March 31, 2010 remain subject to examination. No other state income tax audits are currently in progress. State income tax returns remain open subject to the statute of limitations of each respective state. Brooklyn Union Gas has filed 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 protest.

KeySpan Corporation combined New York State tax returns for calendar years December 31, 2003 through December 31, 2006, the period ended August 24, 2007, and fiscal years ended March 31, 2008, and March 31, 2009 remain subject to examination.

The State of New York is currently auditing calendar years ending December 31, 2002 through December 31, 2004 for Boston Gas Company. The tax returns for calendar years ended December 31, 2005 through December 31, 2006, the period ended August 24, 2007, and fiscal years ended March 31, 2008 and March 31, 2009 remain subject to examination.

The State of New York is in the process of examining tax returns for calendar years ending December 31, 2000 through December 31, 2002 for KeySpan Energy Delivery Long Island. The tax returns for the calendar years ended December 31, 2003 through December 31, 2006, the period ended August 24, 2007 and fiscal years ended March 31, 2008 and March 31, 2009 remain subject to examination. KeySpan Energy Delivery Long Island has 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 protest.

Health Care Reform

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 income statement of approximately $138.0 million.

This was partially offset by the reversal of regulatory liabilities, net of related taxes, which reduced the net impact by approximately $62.4 million for a net charge to the Consolidated Statements of Income of $75.6 million.

NOTE 6 – 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. A substantial portion of the Company’s commodity supply contracts qualify for the normal purchase 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 FASB 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 Sheet. 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 utilize 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 has entered into a Revenue Sharing Arrangement ("RSA") with Constellation, covering a period of 10 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 now been determined to be a financial derivative instrument since a futures market has now been established in upstate New York and although trading is relatively shallow, there is now a trend of market prices that can be used for modeling purposes. The value of this derivative at March 31, 2010 is $78.0 million. Since the power purchased under the RSA will be used to supply rate regulated electric sales customer, the accounting for this derivative follows the current accounting guidance for rate regulated enterprises noted above.

At March 31, 2010 the net fair value of natural gas derivative instruments was a liability of $141.0 million. The net fair value of the electric derivative instruments, including the RSA contract above, was an asset of $4.5 million. At March 31, 2009 the net fair value of natural gas derivative instruments was a liability of $274.9 million. The net fair value of the electric derivative instruments was a liability of $42.5 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, 2010 and 2009, the net fair value of these derivatives was a liability of $77.1 million and a liability of $13.5 million, respectively.

As a result of the Usage bankruptcy settlement agreement ("Bankruptcy Settlement"), New England Power resumed the performance and payment obligations under power supply contracts that had been transferred to Usage when the Company divested its generating business. The fair value of these derivative instruments at March 31, 2010 was a liability of $191.5 million. The fair value of these derivative instruments at March 31, 2009 was a liability of $174.5 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, 2010, Seneca-Upshur has hedge positions in place for approximately 66% of its estimated 2010 gas production, net of gathering costs. We use market quoted forward prices to value these swap positions. The maximum length of time over which Seneca-Upshur has hedged such cash flow variability is through March 2011. The fair value of these derivative instruments at March 31, 2010 was $1.3 million. The amount of gains/losses currently included in accumulated other comprehensive income and expected to be reclassified to earnings in the next twelve months is $1.3 million. There was no ineffectiveness associated with these outstanding derivative financial instruments for the year ended March 31, 2010. The fair value of these derivative instruments at March 31, 2009 was $4.2 million.

These derivative financial instruments are designated as cash flow hedges and are not considered held for trading purposes as defined by current accounting literature. 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, 2010 was $2.7 million. We use market quoted forward prices to value these contracts. The fair value of these contracts at March 31, 2009 was a liability of $0.2 million.

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 income statement. 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 income statement as a yield adjustment over the remainder of the hedging period.

At March 31, 2010, the Company had a net hedged liability position of $11.6 million on $265.5 million of debt. At March 31, 2009, the Company had a net hedged liability position of $10.4 million on $571.9 million of debt. Net losses on the derivative financial instruments were $11.4 million and $19.2 million for the twelve months ended March 31, 2010 and 2009, respectively.

The following are commodity volumes associated with commodity derivative contracts:

As of March 31, 2010		
('000)		Total
	Gas (dths)	171,635
Physicals	Electric (Mwhs)	3,883
	Gas swaps (dths)	94,679
	Gas options (dths)	-
	Gas futures (dths)	13,840
	Electric futures (Mwhs)	69
	Electric swaps (Mwhs)	3,072
Financials	Electric options (Mwhs)	30,294
	Gas (dths)	**280,154**
Total	**Electric (Mwhs)**	**37,318**

The following are balance sheet and income statement tables under different accounting treatments for various commodities.

Fair Values of Derivative Instruments					
	Asset Derivatives			Liability Derivatives	
(in millions of dollars)	March 31, 2010	March 31, 2009		March 31, 2010	March 31, 2009
Regulated contracts					
Gas contracts:					
Gas futures contract - current asset	$ -	$ 3.5	Gas futures contract - current liability	$ (17.4)	$ (78.1)
Gas swaps contract - current asset	0.4	14.8	Gas swaps contract - current liability	(112.9)	(192.1)
Gas options contract -current asset	-	0.1	Gas options contract -current liability	-	(1.4)
Gas purchase contract - current asset	27.5	27.6	Gas purchase contract - current liability	(122.4)	(13.1)
Current asset	***27.9***	***46.0***	*Current liability*	***(252.7)***	***(284.7)***
Gas futures contract - deferred asset	0.1	-	Gas futures contract - deferred liability	(4.3)	(7.2)
Gas swaps contract - deferred asset	0.0	0.8	Gas swaps contract - deferred liability	(6.9)	(15.3)
Gas purchase contract - deferred asset	48.6	9.2	Gas purchase contract - deferred liability	(30.8)	(37.3)
Deferred asset	***48.7***	***10.0***	*Deferred liability*	***(42.0)***	***(59.8)***
Electric contracts:					
Electric futures contract - current asset	-	-	Electric futures contract - current liability	(0.9)	(0.1)
Electric options contract - current asset	-	-	Electric swaps contract - current liability	(48.1)	(15.5)
Electric purchase contract - current asset	0.5		Electric purchase contract - current liability	(31.5)	(29.5)
Current asset	***0.5***	-	*Current liability*	***(80.5)***	***(45.1)***
Electric options contract - deferred asset	78.0		Electric swaps contract - deferred liability	(24.4)	(26.9)
Electric purchase contract - deferred asset	0.6		Electric purchase contract - deferred liability	(161.1)	(145.0)
Deferred asset	***78.6***	-	*Deferred liability*	***(185.5)***	***(171.9)***
Subtotal	***155.7***	***56.0***		***(560.7)***	***(561.5)***
Non-regulated contracts					
Cash-flow hedges					
Gas contracts:					
Gas swaps contract - current asset	-	4.2	Gas swaps contract - current liability	-	-
Gas swaps contract - deferred asset	1.2	-	Gas swaps contract - deferred liability	-	-
Non-hedged transactions					
Gas contracts:					
Gas swaps contract - current asset	3.2	0.3	Gas swaps contract - current liability	(1.4)	(0.1)
Gas purchase contract - current asset	1.1	1.0	Gas purchase contract - current liability	(0.1)	-
Oil contracts:					
Oil swaps contract - current asset	-	-	Oil swaps contract - current liability	-	(0.8)
Subtotal	***5.5***	***5.5***	***Subtotal***	***(1.5)***	***(0.9)***
Total Commodity Derivatives	**161.2**	**61.5**		**(562.2)**	**(562.4)**
Interest rates and currency swap:					
Current assets	9.5	-	Current liability	-	-
Deferred assets	-	10.1	Deferred liability	(21.2)	(20.5)
Total derivatives	**$ 170.7**	**71.6**		**$ (583.4)**	**$ (582.9)**

Fair Values of Derivative Instruments

(in millions of dollars)	**YTD movement**	March 31, 2010	March 31, 2009
Regulated contracts			
Gas contracts:			
Gas futures contract - regulatory asset	$ 63.6	$ (21.7)	$ (85.3)
Gas swap contract - regulatory asset	87.5	(119.8)	(207.3)
Gas option contract - regulatory asset	1.4	-	(1.4)
Gas purchase contract - regulatory asset	(102.9)	(153.2)	(50.3)
Gas futures contract - regulatory liability	(3.4)	0.1	3.5
Gas swap contract - regulatory liability	(15.1)	0.4	15.5
Gas option contract - regulatory liability	(0.1)	-	0.1
Gas purchase contract - regulatory liability	39.3	76.1	36.8
Gas subtotal	**70.3**	**(218.1)**	**(288.4)**
Electric contracts:			
Electric futures contract - regulatory asset	(0.8)	(0.9)	(0.1)
Electric swap contract - regulatory asset	(30.0)	(72.5)	(42.5)
Electric purchase contract -regulatory asset	(17.1)	(191.5)	(174.4)
Electric swap contract - regulatory liability	78.0	78.0	-
Electric subtotal	**30.1**	**(186.9)**	**(217.0)**
Subtotal	**100.4**	**(405.0)**	**(505.4)**
Unregulated contracts			
Gas contracts:			
Gas swap - other income (deduction)	0.2	(0.3)	(0.5)
Gas swap - other revenues	1.9	2.0	0.1
Gas purchase - other income (deduction)	(0.1)	1.0	1.1
Gas purchase contract - other revenues	-	-	-
Gas subtotal	2.0	2.7	0.7
Oil contracts:			
Oil swap - other income (deduction)	0.9	-	(0.9)
Oil subtotal	0.9	-	(0.9)
Subtotal	**2.9**	**2.7**	**(0.2)**
Total	**$ 103.3**	**$ (402.3)**	**$ (505.6)**

Movements in the fair value of regulatory contracts are recorded as a regulatory asset or liability, rather than through the Statements of Income. Movements in the fair value of non-regulatory contracts are recorded through the Statements of Income.

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 Negus'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, 2010 is $ 222.0 million for which the Company has posted collateral of $ 7.4 million in the normal course of business. If the Company's credit rating were to downgrade by one notch, it would be required to post $ 2.4 million additional collateral. If the Company's credit rating were to downgrade by three notches, it would be required to post $ 215.1 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 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, 2010, the Company paid $70.0 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 7. FAIR VALUE MEASUREMENTS

As discussed in Note 1. Summary of Significant Accounting Policies, 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 - exit price. The determination of the fair value incorporates various factors required including not only the credit standing of the counterparties involved but also the impact of the Company's nonperformance risk on its liabilities.

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 OTC gas swaps and forward physical gas deals where market data for pricing inputs is observable. Level 2 pricing inputs are obtained from NYMEX and Platts M2M (industry standard, non-exchange-based editorial commodity forward curves) when it can be verified by available market data from Intercontinental Exchange. 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.

The Company's 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 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 and municipal and corporate bonds based on quoted prices of similar traded assets in open markets.

Available for sale securities are primarily equity investments based on quoted market prices and municipal and corporate bonds based on quoted prices of similar traded assets in open markets.

The following table presents assets and liabilities measured and recorded at fair value on the Company's consolidated balance sheets on a recurring basis and their level within the fair value hierarchy during the year ended March 31, 2010:

Recurring Fair Value Measurements

(In millions of dollars)	Level 1	Level 2	Level 3	March 31, 2010
Assets				
Derivative contracts	$ 0.1	$ 4.6	$ 156.5	$ 161.2
Available for sale securities	120.2	110.6	-	230.8
Interest rate and currency swaps	-	9.5	-	9.5
Total Assets	$ 120.3	$ 124.7	$ 156.5	$ 401.5
Liabilities				
Derivative contracts	$ 21.7	$ 194.7	$ 345.8	$ 562.2
Interest rate and currency swaps	-	21.2	-	$ 21.2
Total Liabilities	$ 21.7	$ 215.9	$ 345.8	$ 583.4

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, 2010:

(In millions of dollars)	Total
Beginning balance at March 31, 2009	$ (185.8)
Transfers into Level 3	(5.1)
Transfers out of Level 3	(0.8)
Total gains or losses	
included in earnings (or changes in net assets)	0.6
included in other comprehensive income	0.5
included in regulatory assets and liabilities	(54.7)
Purchases	58.0
Sales	(2.0)
Ending balance at March 31, 2010	$ (189.3)
The amount of total gains or losses for the period included in earnings (or changes in net assets) attribute to the change in unrealized gains or losses relating to assets still held at March 31, 2010	$ 1.1

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.

Fair value of 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 fair value of the Company's debt is $8.0 billion at March 31, 2010.

NOTE 8 – GOODWILL AND OTHER INTANGIBLE ASSETS

National Grid plc's acquisitions include the acquisitions by the Company of New England Electric System, Eastern Utilities Associates ("EUA"), Niagara Mohawk, the Rhode Island gas assets of New England Gas Company and KeySpan. All of these acquisitions were accounted for by the acquisition method of accounting, the application of which includes the recognition of goodwill.

Changes in the carrying amount of the Company's goodwill, net of accumulated impairment losses for years ended March 31, 2010 and 2009 were as follows:

(In millions of dollars)		**Total**
Goodwill at March 31, 2008	$	7,326.5
Additions		-
Disposals		-
Adjustments associated with acquisition		45.9
Impairment		-
Goodwill at March 31, 2009		7,372.4
Additions		-
Disposals		-
Adjustments		-
Goodwill at March 31, 2010	$	7,372.4

During the year ended March 31, 2009, including the post acquisition period through August 2008, the provisional fair values applied to certain balance sheet accounts were reviewed and a number of adjustments were made to those provisional values as a result of better information being available resulting in an adjustment to goodwill of $45.9 million.

Other Intangible Assets:

Changes in the carrying amount of the Company's intangible assets for the years ended March 31, 2010 and 2009 were as follows:

(In millions of dollars)	LIPA Contracts	Licensing	Other	Total
Balance at March 31, 2008	$ 142.1	$ 35.4	$ -	$ 177.5
Reclassifications	(1.5)	(2.3)	0.5	(3.3)
Amortization	(6.9)	(1.7)	(0.1)	(8.7)
Balance at March 31, 2009	$ 133.7	$ 31.4	$ 0.4	$ 165.5
Impairment	-	(18.3)	-	(18.3)
Amortization	(9.8)	(1.7)	-	(11.5)
Balance at March 31, 2010	$ 123.9	$ 11.4	$ 0.4	$ 135.7

The Company has recognized an impairment of $18.3 million for the year ended March 31, 2010 in relation to a plumbing license which is used to support a subsidiary business acquired as part of the KeySpan acquisition. The Company is planning to sell this license during 2010. The fair value was measured using management's estimate based upon the current market for similar assets. This impairment is reported in operating expenses in the Company's consolidated statements of income.

NOTE 9 – ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The following table details the components of accumulated other comprehensive income (loss) for the years ended March 31, 2010, 2009 and 2008:

(in millions of dollars)	Unrealized Gains (Losses) on investments	Postretirement Benefit Liabilities	Cash Flow Hedges	Total Accumulated Other Comprehensive Income (Loss)
March 31, 2008	$ (1.3)	$ (511.3)	$ -	$ (512.6)
Other comprehensive income (loss), net of taxes:				
Unrealized gains (losses) on securities	(15.4)	-	-	(15.4)
Unrealized gains (losses) on hedges	-	-	2.4	2.4
Change in pension and other postretirement provisions	-	(517.7)	-	(517.7)
Reclassification adjustment for (gain)/ loss included in net income	(0.4)	-	-	(0.4)
March 31, 2009	$ (17.1)	$ (1,029.0)	$ 2.4	$ (1,043.7)
Other comprehensive income (loss), net of taxes:				
Unrealized gains (losses) on investments	13.1	-	-	13.1
Unrealized gains (losses) on hedging	-	-	(6.7)	(6.7)
Change in pension and other postretirement provisions	-	16.4	-	16.4
Reclassification adjustment for (gain) included in net income	-	73.7	-	73.7
Subtotal	13.1	90.1	(6.7)	96.5
Adjustment to accumulated other comprehensive income	-	136.3	-	136.3
March 31, 2010	$ (4.0)	$ (802.6)	$ (4.3)	$ (810.9)

The adjustment to the accumulated other comprehensive income is the result of the new tracking mechanism that was implemented at certain regulated subsidiaries.

NOTE 10 – COMMITMENTS AND CONTINGENCIES

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 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 NOx boiler combustion modifications, the use of natural gas firing systems at our steam electric generating stations, and the compliance flexibility available under cap and trade programs have enabled the Company to achieve its prior emission reductions in a cost-effective manner. Future investments will include the installation of enhanced NOx controls and efficiency improvement projects at certain of our Long Island based electric generating facilities. The cost of these improvements is estimated to be approximately $100 million; a mechanism for recovery from LIPA of these investments has been established. We are currently developing a compliance strategy to address anticipated future requirements. At this time, we are unable to predict what effect, if any, these future requirements will have on our financial condition, results of 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. Draft permits that have been issued by the DEC propose to require the installation of significant capital equipment, including cooling towers to mitigate the plants' alleged cooling water system impacts to aquatic organisms. We are currently conducting additional studies as directed by the DEC to determine the impacts of our discharges on aquatic resources and are engaged in discussions with the DEC regarding the nature of capital upgrades or other mitigation measures necessary to reduce any impacts. It is expected that the determination of required capital improvements and the issuance of final renewal permits for these plants will involve adjudicatory hearings among the Company, the agency, and the environmental groups. Costs associated with the development of studies and analyses necessary to defend our positions are reimbursable from LIPA. Capital costs for expected mitigation requirements at the five plants had been estimated at 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 years, ultimate costs could be substantially higher. Costs associated with any finally ordered capital improvements would also be reimbursable from LIPA.

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. Other subsidiaries do not discount the liability.

During the year, the Company completed additional investigations at a legacy environmental site in Massachusetts. The Company is developing remedial alternatives to address contamination on a portion of this site. The Company estimates that the cost to remediate this portion of the site could be $20 million higher than previously estimated and has increased its environmental reserves by such amount during 2010. It is uncertain when these costs will be incurred; however at this point in time we anticipate that the costs will be equally incurred in fiscal year 2012 and 2013.

Utility Sites: At March 31, 2010, the Company's total reserve for estimated manufactured gas plant ("MGP") related environmental activities are approximately $1.3 billion. The potential high end of the range at March 31, 2010 is presently estimated at approximately $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 approximately $24.0 million, which has been accrued at March 31, 2010 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.

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 millions of dollars)	The Company's Investment as of March 31, 2010			Future Estimated Billings to the Company
Unit	%	Amount	Date Retired	Amount
Yankee Atomic	34.5	$ 0.5	Feb 1992	$ 19.2
Connecticut Yankee	19.5	$ 0.6	Dec 1996	$ 51.4
Maine Yankee	24.0	$ 0.6	Aug 1997	$ 11.0

With respect to each of the units, at March 31, 2010 New England Power has a $81.6 million liability and a regulatory asset 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 approximately $143 million for spent fuel storage costs that had been incurred through 2001 and 2002. The Yankees had requested $176.3 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. A decision has not yet been issued. 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. On December 14, 2007, the Yankees brought further litigation in the Claims Court to recover damages incurred subsequent to 2001 and 2002. The parties are negotiating a discovery schedule in that litigation. 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, 2010 and 2009, Niagara Mohawk has a liability of $167 million 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 2010 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)	Estimated Payments	
2011	$	1,149.7
2012		179.5
2013		59.8
2014		59.6
2015		59.1
2016 and thereafter		104.6
Total	$	1,612.3

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. Table below summarized the estimated commitments as of March 31, 2010.

(In millions of dollars)	Estimated Payments	
2011	$	1,228.3
2012		811.4
2013		564.2
2014		461.9
2015		372.2
2016 and thereafter		317.2
Total	$	3,755.2

Legal Matters

Town of Norwood:

From 1983 until 1998, New England Power was the wholesale power supplier for Norwood, Massachusetts. In April 1998, Norwood began taking power from another supplier, although its contract term with New England Power ran to 2008. Pursuant to a tariff amendment approved by the FERC in May 1998, New England Power began charging Norwood a monthly CTC of $0.6 million, plus interest on unpaid balances at 18% per year. New England Power and Norwood have been engaged in litigation at the FERC and in the Massachusetts State Court, as follows.

December 20, 2003, Norwood filed a complaint with FERC under Section 206 of the Federal Power Act, contending that FERC did not approve the application of New England Power's 1998 amended CTC to Norwood, and that the CTC amount is too high in any event. The FERC held that it did approve the CTC and that the CTC amount is correctly calculated. The First Circuit upheld FERC, and the US Supreme Court denied Norwood's petition for certiorari. However, FERC ruled on May 17, 2007 that the interest to be paid by Norwood on unpaid monthly CTC bills should be calculated at the prime rate from the beginning of the CTC and not at 1.5% per month, as provided in the tariff. New England Power appealed this interest ruling to the First Circuit on the grounds that it goes beyond FERC's authority to award retroactive relief under Section 206 of the Federal Power Act, and violates the filed rate doctrine. On July 16, 2008, the First Circuit again remanded the case to FERC for further consideration of exactly when the reduced interest rate should apply to calculate the payment due from Norwood. On January 15, 2009, FERC issued an order on remand leaving, in effect the tariff's 1.5% interest rate applicable to Norwood's unpaid monthly CTC bills for the period from the 1998 inception of the CTC through February 20, 2004 and from May 22, 2004 through June 29, 2006. Interest on unpaid CTC bills for the remaining periods is to be calculated in accordance with the interest rates set by Section 35.19a of the Commission's regulations. On February 13, 2009 Norwood filed a rehearing request at FERC seeking an expansion of the time period in which the reduced interest rates are applicable, and seeking an order directing that the interest rates not be subject to compounding.

On July 2, 2009, New England Power and Norwood filed a settlement agreement at FERC that provided for Norwood to make an additional payment of $20 million by no later than August 31, 2009, following FERC acceptance of the settlement. The FERC approved the settlement and Norwood remitted the final $20 million payment on August 31, 2009.

MPG Sites:
Since July 12, 2006, several lawsuits have been filed which allege damages resulting from contamination associated with the historic operations of former manufactured gas plants located in Bay Shore, New York. KeySpan has been conducting site investigations and remediations at these locations pursuant to Administrative Orders on Consent (ACO) with the New York State DEC. There is one lawsuit pending related to the former Clifton manufactured gas plant on Staten Island. KeySpan intends to contest each of 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 will work cooperatively with the DEC and AG to address environmental conditions associated with the remainder of the properties. KeySpan has entered into an ACO for one of the land-based sites. The DEC and AG recently determined that the New York State did not have the financial resources to continue oversight of this project and sent a letter to the United States Environmental Protection Agency ("USEPA") requesting evaluation of the site for possible inclusion on its list of superfund sites. We are currently in negotiations with the USEPA. On September 23, 2009, the USEPA proposed this site for listing on its National Priorities List of Superfund sites. 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 National Grid'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. 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 CID. The proposed terms of the settlement contain no admission of wrongdoing by KeySpan and remains subject to court approval, which is anticipated later in 2010.The amount is reflected in pension benefits and other reserves on the Consolidated Balance Sheet. The agreement contains no admissions of liability by KeySpan and remains subject to court approval which is currently anticipated later in 2010.

Lease Obligations
The Company has various operating leases which include leases for buildings, office equipment, vehicles and power operating equipment. Average future minimum cash lease payments under various leases are $132.2 million per year over the next five years and $604.6 million, in the aggregate, for all years thereafter.

Financial Guarantees
The Company has guaranteed the principal and interest payments on certain outstanding debt as discussed in Note 4, "Long-Term Debt". Additionally, the Company has issued financial guarantees in the normal course of business, on behalf of its subsidiaries, to various third party creditors. At March 31, 2010, 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	Dates
Guarantees for subsidiaries				
Industrial Development Revenue Bonds	(i)	$	128,275	2027
KeySpan Ravenswood LLC lease	(ii)		572,288	2040
Reservoir Woods	(iii)		293,373	2029
Surety Bonds	(iv)		110,666	Revolving
Commodity Guarantees and Other	(v)		64,967	2009-2027
Letters of Credit	(vi)		157,838	2009-2011

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 $128.3 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 2039. The cash consideration from the buyer of the facility included the remaining lease payments on a net present value basis. At March 31, 2010, the Company's obligation related to the lease was $291 million and is reflected in deferred credits and other liabilities – other.

(iii) The Company has fully and unconditionally guaranteed approximately $293.3 million in lease payments through 2029 related to the lease of office facilities at Reservoir Woods in Waltham, MA.

(iv) The Company has agreed to indemnify the issuers of various surety and performance bonds associated with certain construction projects being performed by certain current and former subsidiaries. In the event that the subsidiaries fail to perform their obligations under contracts, the injured party may demand that the surety make payments or provide services under the bond. 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) The Company has guaranteed commodity-related payments for certain subsidiaries. These guarantees are provided to third parties to facilitate physical and financial transactions involved in the purchase and transportation of natural gas, oil and other petroleum products for electric production and marketing activities. The guarantees cover actual purchases by these subsidiaries that are still outstanding as of March 31, 2010.

(vi) The Company has arranged for stand-by letters of credit to be issued to third parties that have extended credit to certain subsidiaries. Certain vendors require 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, the Company 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.

The Company owns a 26.25% ownership interest in the Millennium Pipeline Company LLC ("Millennium"), the developer of the Millennium Pipeline project. The Company has guaranteed $210 million of an $800 million Millennium Pipeline construction loan. The $210 million represents the Company's proportionate share of the $800 million loan based on the Company's 26.25% ownership interest in the Millennium Pipeline project. This guarantee has been accounted for in accordance with the FASB guidance related to a guarantor's accounting and disclosure requirements for guarantees, including indirect guarantees of indebtedness of others and is reflected in equity investments and other, with an offsetting position in deferred credits and other liabilities.

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, 2010 and 2009 was $69.7 million and $67.7 million respectively.

NOTE 11 – 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, 2010 and 2009 is as follows (in thousands except for share data and call price):

		Shares Outstanding		Amount *(in millions of dollars)*		
		March 31,		**March 31,**		Call
Series	Company	**2010**	2009	**2010**	2009	Price
$100 par value -						
3.40% Series	Niagara Mohawk	57,524	57,524	$ 5.7	$ 5.7	$ 103.500
3.60% Series	Niagara Mohawk	137,152	137,152	13.7	13.7	104.850
3.90% Series	Niagara Mohawk	95,171	95,171	9.5	9.5	106.000
4.44% Series	Mass Electric	22,585	22,585	2.3	2.3	104.068
6.00% Series	New England Power	11,117	11,117	1.1	1.1	Noncallable
$50 par value -						
4.50% Series	Narragansett	49,089	49,089	2.5	2.5	55.000
Total		**372,638**	372,638	**$ 34.8**	$ 34.8	

NOTE 12 - PARENT COMPANY CHARGES

For the year ended March 31, 2010, NGUSA received 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. The estimated effect on net income are approximately $29.0 million before tax, and $18.9 million after tax.

NOTE 13 – DISCONTINUED OPERATIONS AND OTHER DISPOSITIONS

In April 2009, KeySpan sold its remaining two engineering companies that were classified as discontinued operations at March 31, 2009 and prior interim periods. The assets and liabilities of these companies were fair valued at August 24, 2007 as required by the current accounting guidance for business combinations. As a result, the aforementioned sales transaction did not result in any material gain or loss recognition.

The information below highlights the major classes of assets and liabilities and expenses of the discontinued operations.

(In millions of dollars)	March 31, 2009	
Property	$	3.2
Current assets		15.1
Deferred charges		11.7
Current liabilities		12.7
Deferred credits and other Liabilities		-

(In millions of dollars)	For the Year Ended March 31, 2009	
Revenues	$	154.5
Operating expenses:		
Fuel and purchase power		23.9
Operations and maintenance		90.3
Depreciation and amortization		2.6
Operating taxes		(5.6)
Operating Income		43.3
Other income (deductions)		(1.2)
Income taxes		17.5
Income from discontinued operations	$	24.6

In January 2010, the company sold its investment in a gas storage facility for $10.1 million and recognized a gain of $8.5 million which is reflected in other income and (deductions) – other on the Consolidated Statements of Income.

NOTE 14 – SUBSEQUENT EVENTS

On April 13, 2010, a purchase agreement was signed between KeySpan and Home Service USA Corp. ("HSUSA") pertaining to the Company's sale of the service contracts portion of its National Grid Energy Services LLC (NGES) business. Under terms of the agreement, HSUSA has agreed to acquire the service contract business for approximately $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.

We are in negotiations to sell our 52% interest in a further gas storage field, Honeoye Storage Corporation. We currently anticipate the sale to be completed during August or September 2010.

During August 2010, we agreed to invest an additional $35 million in Millennium Pipeline Company LLC, a joint venture in which we hold a 26% interest, in connection with the refinancing of its external borrowings.

Subsequent to the end of the fiscal year, we announced that we are evaluating our options concerning our New Hampshire businesses – EnergyNorth Natural Gas, Inc. and Granite State Electric Company which represent approximately 2.0% of our consolidated revenues. These options could include a potential disposal; however, at this point in time no decision has been made by management or the Board regarding either company.