Boston Gas Company
d/b/a
National Grid

Financial Statements

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

BOSTON GAS COMPANY

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Report of Independent Auditors

To the Stockholder and Board of Directors of
Boston Gas Company:

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

PricewaterhouseCoopers LLP

June 28, 2011

PricewaterhouseCoopers LLP, PricewaterhouseCoopers Center, 300 Madison Avenue, New York, NY 10017
T: (646) 471 3000, F: (813) 286 6000, www.pwc.com/us

BOSTON GAS COMPANY
BALANCE SHEETS

(in thousands of dollars, except per share and number of shares data)	March 31, 2011	March 31, 2010 Restated
ASSETS		
Current assets		
Cash and cash equivalents	$ 228	$ 194
Restricted cash	270	6,650
Intercompany moneypool	74,719	57,426
Accounts receivable	297,511	277,929
Allowance for doubtful accounts	(20,214)	(20,409)
Unbilled revenues	73,246	69,884
Gas in storage, at average cost	55,374	81,633
Materials and supplies, at average cost	10,093	4,719
Derivative contracts	1,291	4,150
Regulatory assets	41,231	62,705
Prepaid and other current assets	6,039	2,397
Total current assets	539,788	547,278
Property, plant, and equipment, net	1,725,952	1,629,068
Deferred charges		
Regulatory assets	155,339	204,444
Goodwill	396,322	396,322
Derivative contracts	898	234
Other deferred charges	3,910	3,727
Total deferred charges	556,469	604,727
Total assets	$ 2,822,209	$ 2,781,073

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

BOSTON GAS COMPANY
BALANCE SHEETS

(in thousands of dollars, except per share and number of shares data)	March 31,			
		2011		2010 Restated
LIABILITIES AND CAPITALIZATION				
Current liabilities				
Accounts payable	**$**	**35,372**	$	30,802
Accounts payable to affiliates, net		**175,442**		178,488
Current portion of long-term debt		**10,000**		20,000
Taxes accrued		**1,202**		936
Interest accrued		**2,230**		17,720
Regulatory liabilities		**6,940**		4,449
Derivative contracts		**6,677**		25,264
Customer deposits		**3,450**		2,671
Current portion of deferred income taxes		**20,382**		17,958
Other current liabilities		**10,619**		9,453
Total current liabilities		**272,314**		307,741
Deferred credits and other liabilities				
Regulatory liabilities		**411,898**		393,142
Asset retirement obligations		**13,027**		12,290
Deferred income tax liabilities		**262,547**		238,131
Postretirement benefits and other reserve		**101,057**		119,367
Environmental remediation costs		**42,252**		36,904
Derivative contracts		**1,110**		1,394
Other deferred liabilities		**8,958**		7,007
Total deferred credits and other liabilities		**840,849**		808,235
Capitalization				
Common stock, par value $100 per share, issued and outstanding 514,184 shares		**51,418**		51,418
Additional paid-in capital		**960,663**		960,663
Retained earnings		**63,889**		90,016
Accumulated other comprehensive income		**76**		-
Total stockholder's equity		**1,076,046**		1,102,097
Long-term debt		**153,000**		163,000
Advance from affiliates		**480,000**		400,000
Total capitalization		**1,709,046**		1,665,097
Total liabilities and capitalization	**$**	**2,822,209**	$	2,781,073

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

BOSTON GAS COMPANY
STATEMENTS OF INCOME

(in thousands of dollars)	Years Ended March 31,	
	2011	2010 Restated
Operating revenues	**$ 1,186,880**	$ 1,109,262
Operating expenses		
Gas purchased for resale	**695,094**	682,363
Operations and maintenance	**232,649**	220,589
Depreciation and amortization	**110,876**	108,855
Other taxes	**33,677**	29,687
Total operating expenses	**1,072,296**	1,041,494
Operating income	**114,584**	67,768
Other income and (deductions)		
Interest on long-term debt	**(14,338)**	(14,722)
Other interest, including affiliate interest	**(9,409)**	(22,372)
Other (deductions) income	**(16,387)**	2,360
Total other deductions	**(40,134)**	(34,734)
Income taxes		
Current	**(9,915)**	(75,511)
Deferred	**30,492**	96,035
Total income taxes	**20,577**	20,524
Net income	**$ 53,873**	$ 12,510

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

BOSTON GAS COMPANY
STATEMENTS OF CASH FLOWS

(in thousands of dollars)	Years Ended March 31, 2011	2010 Restated
Operating activities:		
Net income	**$ 53,873**	$ 12,510
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**110,876**	108,855
Provision for deferred income taxes	**30,492**	96,035
Other non-cash items	**41,261**	10,389
Net prepayments and other amortizations	**254**	256
Net pension and other postretirement expense	**(39)**	(19,700)
Net environmental payment	**(1,645)**	(4,509)
Changes in operating assets and liabilities:		
Accounts receivable, net	**(23,139)**	23,422
Gas in storage	**26,259**	7,744
Materials and supplies	**(5,374)**	(354)
Accounts payable and accrued expenses	**(19,254)**	(5,472)
Prepaid taxes and accruals	**(3,376)**	(2,835)
Other, net	**18,554**	4,998
Net cash provided by operating activities	**228,742**	231,339
Investing activities:		
Capital expenditures	**(173,857)**	(170,518)
Derivative margin calls	**6,380**	14,150
Other, including cost of removal	**(20,160)**	(14,361)
Net cash used in investing activities	**(187,637)**	(170,729)
Financing activities:		
Payments of capital lease obligation	**(1,308)**	(1,233)
Payments on long-term debt obligation	**(20,000)**	-
Affiliate moneypool borrowing and other	**(19,763)**	(59,583)
Net cash used in financing activities	**(41,071)**	(60,816)
Net increase (decrease) in cash and cash equivalents	**34**	(206)
Cash and cash equivalents, beginning of year	**194**	400
Cash and cash equivalents, end of year	**$ 228**	$ 194
Supplemental information:		
Interest paid	**$ 59,801**	$ 39,883
Taxes refunded from Parent	**$ (8,227)**	$ (4,626)
Capital-related accruals included in accounts payable	**$ 8,334**	$ 541
Non-cash transaction:		
Capital contribution from KeySpan New England, LLC	**$ -**	$ 490,000
Increase (decrease) in advance from affiliates	**$ 80,000**	$ (100,000)
Changes in intercompany moneypool	**$ -**	$ (390,000)
Dividend paid to KeySpan New England, LLC	**$ (80,000)**	$ -

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

BOSTON GAS COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

(in thousands of dollars)	Years Ended March 31,	
	2011	2010 Restated
Net income	**$ 53,873**	$ 12,510
Other comprehensive income (loss), net of taxes:		
Unrealized gains on investments	**76**	-
Change in other comprehensive income	**76**	-
Total comprehensive income	**53,949**	12,510
Related tax (expense) benefit:		
Unrealized gains on investments	**(51)**	-
Total tax expense	**$ (51)**	$ -

STATEMENTS OF RETAINED EARNINGS

(in thousands of dollars)	Years Ended March 31,	
	2011	2010 Restated
Retained earnings, beginning of year	**$ 90,016**	$ 77,506
Net income	**53,873**	12,510
Dividend paid to KeySpan New England, LLC	**(80,000)**	-
Retained earnings, end of year	**$ 63,889**	$ 90,016

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

BOSTON GAS COMPANY
STATEMENTS OF CAPITALIZATION

(in thousands of dollars, except per share and number of shares data)	**March 31**			
	2011	2010 Restated	**2011**	2010 Restated
Stockholder's equity	**Shares Issued and Outstanding**		**Amounts**	
Common stock, $100 par value	**514,184**	514,184	**$ 51,418**	$ 51,418
Additional paid-in capital			**960,663**	960,663
Retained earnings			**63,889**	90,016
Accumulated other comprehensive income			**76**	-
Total stockholder's equity			**$ 1,076,046**	$ 1,102,097

Long-term debt	**Interest Rate**	**Maturity Date**	**Amounts**	
Notes payable				
MTN Series 1990 A	9.68%	December 15, 2010	**$ -**	$ 10,000
MTN Series 1990 A	9.00%	February 22, 2011	**-**	10,000
MTN Series 1989 A	8.95%	June 1, 2011	**10,000**	10,000
MTN Series 1995 C	6.80%	November 30, 2012	**10,000**	10,000
MTN Series 1995 C	6.80%	December 2, 2013	**5,000**	5,000
MTN Series 1994 B	6.93%	January 15, 2014	**5,000**	5,000
MTN Series 1994 B	8.50%	October 24, 2014	**2,000**	2,000
MTN Series 1995 C	7.10%	October 15, 2015	**5,000**	5,000
MTN Series 1994 B	6.93%	January 15, 2016	**5,000**	5,000
MTN Series 1994 B	6.93%	April 1, 2016	**10,000**	10,000
MTN Series 1992 A	8.33%	July 10, 2017	**8,000**	8,000
MTN Series 1992 A	8.33%	July 10, 2018	**10,000**	10,000
MTN Series 1994 B	6.93%	January 15, 2019	**10,000**	10,000
MTN Series 1989 A	8.97%	December 15, 2019	**7,000**	7,000
MTN Series 1990 A	9.75%	December 1, 2020	**5,000**	5,000
MTN Series 1990 A	9.05%	September 1, 2021	**15,000**	15,000
MTN Series 1992 A	8.33%	July 5, 2022	**10,000**	10,000
MTN Series 1995 C	6.95%	December 1, 2023	**10,000**	10,000
MTN Series 1994 B	6.98%	January 15, 2024	**6,000**	6,000
MTN Series 1995 C	6.95%	December 1, 2024	**5,000**	5,000
MTN Series 1995 C	7.25%	October 1, 2025	**20,000**	20,000
MTN Series 1995 C	7.25%	October 1, 2025	**5,000**	5,000
Total long-term debt			**163,000**	183,000
Long-term debt due within a year			**10,000**	20,000
Total long-term debt excluding current portion			**153,000**	163,000
Advance from affiliates			**480,000**	400,000
Total capitalization			**$ 1,709,046**	$ 1,665,097

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

NOTES TO FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

A. *Nature of Operations*

Boston Gas Company d/b/a National Grid (the "Company", "we", "us" and "our") is a gas distribution company engaged in the transportation and sale of natural gas to approximately 658,000 residential, commercial and industrial customers in the City of Boston ("the city"), Essex County, and other communities in eastern and central Massachusetts.

The Company is a wholly-owned subsidiary of KeySpan New England, LLC ("KNE LLC") and an indirectly-owned subsidiary of KeySpan Corporation ("KeySpan"). KeySpan is a wholly-owned subsidiary of National Grid USA ("NGUSA"), a public utility holding company with regulated subsidiaries engaged in the generation of electricity and the transmission, distribution and sale of both natural gas and electricity. NGUSA is an indirectly-owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales.

B. *Basis of Presentation*

The Company's accounting policies conform to accounting principles generally accepted in the United States of America ("GAAP"), including the accounting principles for rate-regulated entities, and are in accordance with the accounting requirements and ratemaking practices of the applicable regulatory authorities.

The accounts of the Company are maintained in accordance with the Uniform System of Accounts prescribed by the regulatory bodies having jurisdiction.

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

On December 16, 2009, the Company and Essex Gas, an affiliate, filed a joint petition with the Massachusetts Department of Public Utilities ("DPU") for authorization for legal consolidation. The companies requested that the DPU confirm that the Company, as the surviving corporation of the consolidation, will continue to have all of the franchise rights and obligations that were previously held by the Company and Essex Gas. On September 3, 2010, the legal consolidation of the Company and Essex Gas was approved by the DPU, which became effective November 1, 2010, with the Company as the sole surviving entity. The current year and historical financial statements are presented on a pooling of interests basis. This method involves addition of the historical financial information of the component firms to form a new balance sheet, statement of income and related financial statements of the surviving entity. As a result, the Company's result of operations and cash flows were restated for the year ended March 31, 2010.

C. *Regulatory Accounting*

The Federal Energy Regulatory Commission ("FERC") and the DPU provide the final determination of the rates the Company charges our customers. In certain cases, the actions of the FERC or the DPU would result in an accounting treatment different from that used by non-regulated companies to determine the rates the Company charges our customers. In this case, the Company is required to defer the recognition of costs (a regulatory asset) or the recognition of obligations (a regulatory liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates.

In the event the Company determines that its net regulatory assets are not probable of recovery, the Company would be required to record an after-tax, non-cash charge against income for any remaining regulatory assets and liabilities. The impact could be material to the Company's reported financial condition and results of operations.

D. Revenue Recognition

Customers are generally billed on a monthly basis. Revenues include unbilled amounts related to the estimated gas usage that occurred from the most recent meter reading to the end of each month.

The Cost of Gas Adjustment Factor ("CGAF") requires the Company to semi-annually adjust rates or, based on certain criteria, monthly adjust rates for firm gas sales in order to track changes in the cost of gas distributed, with an annual adjustment of subsequent rates made for any over or under recovery of actual costs incurred. As a result, the cost of firm gas that has been distributed, but is unbilled at the end of a period, is deferred to the period in which the gas is billed to customers. The Company recovers the gas cost portion of bad debt write-offs through the CGAF. In addition, through a Local Distribution Adjustment Factor ("LDAF"), the Company is allowed to recover the amortization of environmental response costs associated with former manufactured gas plant ("MGP") sites, costs related to the Company's various energy efficiency programs and other specified costs from the Company's sales and transportation customers. The Company record amounts recoverable under LDAF as revenue when billed to customers.

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

During the years ended March 31, 2011 and March 31, 2010, 62% and 63% of the Company's revenue from the sale and delivery of gas was derived from residential customers, 24% and 23% from commercial customers, and 14% from industrial customers, respectively.

E. Property, Plant and Equipment

Property, plant, and equipment are stated at original cost. The cost of additions to property, plant, and equipment and replacements of retired units of property are capitalized. Costs include direct material, labor, overhead and allowance for funds used during construction ("AFUDC"), which represents capitalized interest and an equity return, if applicable. Replacement of minor items of property, plant, and equipment and the cost of current repairs and maintenance are charged to expense. Whenever property, plant, and equipment is retired, its original cost, together with cost of removal, less salvage, is charged to accumulated depreciation.

F. Goodwill

Goodwill represents the excess of the purchases price of a business combination over the fair value of the tangible and intangible assets acquired, net of the fair value of liabilities assumed and the fair value of any non-controlling interest in the acquisition. The Company tests goodwill for impairment on an annual basis and on an interim basis when certain events or circumstances exist.

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

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

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

Our goodwill review indicated that there is a risk that goodwill could be impaired if the assumptions for future growth and our expectation that we will achieve allowed rates of return in the future are not delivered. In particular, a reduction in the assumed long-term growth rate of more than 0.3% could potentially result in an impairment being required, although this would be dependent in a number of other factors.

G. Cash and Cash Equivalents

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

H. Restricted Cash

Restricted cash consists of collateral requirement to the Company's counterparties for outstanding derivative contracts.

I. Income Taxes

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

Deferred income taxes reflect the tax effect of net operating losses, capital losses and general business credit carryforwards and the net tax effects of temporary differences between the carrying amount of assets and liabilities for financial statement and income tax purposes, as determined under enacted tax laws and rates. The financial effect of changes in tax laws or rates is accounted for in the period of enactment. Deferred investment tax credits are amortized over the useful life of the underlying property. Additionally, the Company follows the current accounting guidance relating to uncertainty in income taxes which applies to all income tax positions reflected on the Company's balance sheets that have been included in previous tax returns or are expected to be included in future tax returns.

J. Comprehensive Income (Loss)

Comprehensive income (loss) is the change in the equity of a company, not including those changes that result from stockholder transactions. The primary component of comprehensive income (loss) is reported net income or loss, the other component of comprehensive income (loss) consists of unrealized gains and losses associated with certain investments held as available for sales.

K. Derivatives

The Company employ derivative instruments to hedge a portion of the Company's exposure to commodity price risk. Whenever hedge positions are in effect, the Company is exposed to credit risks in the event of non-performance by counterparties to derivative contracts, as well as non-performance by the counterparties of the transactions against which they are hedged.

Firm Gas Sales Derivative Instruments
The Company utilizes derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases. The Company's strategy is to minimize fluctuations in firm gas sales prices to the Company's regulated firm gas sales customers. Because these derivative instruments are being employed to reduce the variability of the purchase price of natural gas to be sold to regulated firm gas sales customers, the accounting for these derivative instruments is subject to the current accounting guidance on accounting for the effects of rate regulation. Therefore, changes in the market value of these derivatives have been recorded as a regulatory asset or regulatory liability on the balance sheets. Gains or losses on the settlement of these contracts are initially deferred and then refunded to or collected from the Company's firm gas sales customers during the appropriate winter heating season consistent with regulatory requirements.

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

Other Financially-Settled Commodity Derivative Instruments
The Company also employs a limited number of derivative financial instruments that are accounted for pursuant to the requirements of the Financial Accounting Standards Board ("FASB") guidance on the accounting for derivative instruments and hedging activities. The change in fair market value of those contracts would be recorded in "other (deduction) income" on the statements of income.

L. Employee Benefits

The Company's employees are members of a consolidated defined benefit pension and postretirement benefits other than pension ("PBOP") plan sponsored by KeySpan. The Company receives an allocation from KeySpan for the Company's portion of pension and other postretirement benefits costs which results in an intercompany payable. Consistent with past practice and as required by current guidance, KeySpan values its pension and other postretirement assets using the year-end market value of those assets. Benefit obligations are also measured at year-end.

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. The following is the fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

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

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

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

N. Gas in Storage and Materials

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

Per current accounting guidance, the Company is required to re-value storage and materials at the lower of cost or market. However, per rate orders in effect as issued by the DPU, the Company is permitted to pass through the cost of gas purchased for resale directly to the rate payers along with any applicable authorized delivery surcharge adjustments. Therefore, the value of gas in storage never falls below the cost to the Company. Gas costs passed through to the rate payers are subject to periodic regulatory approval and are regularly reported to the DPU. The Company files reports to DPU on a semi-annual basis for the peak season (Nov – April) and off-peak season (May – October).

O. Change in Accounting Estimates

The Company calculates its bad debt reserve on its customer accounts receivable (including purchased receivables) based on the bad debt write-offs compared to actual billed sales and transportation revenues (with a six month lag). All receivables over 360 days past due are 80% reserved. Certain identified "at risk" customers are 100% reserved. As of March 31, 2011, there were no "at risk" customers identified. Economic conditions and other factors are considered in addition to the historic write-off rate. The Company reduced the write-off rate for the year ended March 31, 2011, for improved economic conditions which were evidenced by improved collection patterns for overdue receivables. The aggregate effect of these changes in the methodology for calculating the bad debt reserve resulted in a pre-tax benefit of $2.2 million.

P. Recent Accounting Pronouncements

In the preceding twelve months, the FASB has issued numerous updates to GAAP. The Company has evaluated various guidelines and has either deemed them as not applicable based on its nature of operations or has implemented the new standards. A discussion of the more significant and relevant updates is as follows:

Prospective Accounting Pronouncements

In June 2011, the FASB issued accounting guidance that eliminated the option to present the components of other comprehensive income as part of the statement of changes in stockholders' equity. This update seeks to improve financial statement users' ability to understand the causes of an entity's change in financial position and results of operations. The Company is now required to consecutively present the statement of income and statement of comprehensive income and also present reclassification adjustments from other comprehensive income to net income on the face of the financial statements. This update does not change the items that are reported in other comprehensive income or any reclassification of items to net income. Additionally, the update does not change an entity's option to present components of other comprehensive income net of or before related tax effects. This guidance is effective for public companies for fiscal years, and interim periods within that year, beginning after December 15, 2011, and it is to be applied retrospectively. Early adoption is permitted. The Company does not expect adoption of this guidance to have an impact on the Company's financial position, results of operations or cash flows.

In April 2011, the FASB issued accounting guidance that substantially amended existing guidance with respect to the fair value measurement topic ("the Topic"). The guidance seeks to amend the Topic in order to achieve common fair value measurement and disclosure requirements in GAAP and International Financial Reporting Standards. Consequently, the guidance changes the wording used to describe many of the requirements in GAAP for measuring fair value and for disclosing information about fair value measurements as well as changing specific applications of the Topic. Some of the amendments clarify the FASB's intent about the application of existing fair value measurement requirements. Other amendments change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements including, but not limited to, fair value measurement of a portfolio of financial instruments, fair value measurement of premiums and discounts and additional disclosures about fair value measurements. This guidance is effective for financial statements issued for interim and annual periods beginning after December 15, 2011. The early adoption of this guidance is not permitted and can only be applied prospectively. The Company is currently determining the potential impact of the guidance on its financial position, results of operations and cash flows.

In March 2011, the FASB issued updated guidance over the agreements between two entities to transfer financial assets. Prior to this update, an entity could recognize this transfer when it was deemed that the transferee had effective control over the transferred asset, specifically whether the entity has the ability to repurchase substantially the same asset based on the transferor's collateral. This accounting update evaluates the effectiveness of the entity's control by focusing on the transferor's contractual rights and obligations as opposed to the entity's ability to perform on those rights and obligations. This update also eliminates the requirement to demonstrate that the transferor possesses adequate collateral to fund substantially all the cost of purchasing replacement financial assets. This guidance is treated prospectively and effective for annual or interim reporting periods beginning on or after December 15, 2011. The Company does not expect adoption of this guidance to have an impact on the Company's financial position, results of operations or cash flows.

In December 2010, the FASB issued an accounting update to address inconsistencies in the application of accounting guidance related to reporting pro forma revenue and earnings of business combinations. This update is effective for entities who entered into an acquisition and whose acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. This disclosure requires revenue and earnings of the combined entity to be disclosed as though the combination had occurred at the beginning of the prior reporting period. The supplemental disclosure related to this activity now is required to provide a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination. The Company does not expect the adoption of this guidance to have an impact on the Company's financial position, results of operations or cash flows.

In December 2010, the FASB issued an accounting update that modified the goodwill impairment procedures necessary for entities with zero or negative carrying value. The FASB created this guidance to require entities to complete Step 2 of the impairment test, which requires the entity to assess whether or not it was likely that impairment existed throughout the period. To do this, an entity should consider whether there were adverse qualitative factors throughout the period that would contribute to impairment. This update is effective for fiscal years and interim periods beginning after December 15, 2011. The Company does not expect the adoption of this guidance to have an impact on the Company's financial position, results of operations or cash flows.

Recently Adopted Accounting Pronouncements

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

In February 2010, the FASB issued an amendment to certain recognition and disclosure requirements for events that occur after the balance sheet date but before the financial statements are issued or are available to be issued. The amendment applies to both issued financial statements and financial statements revised as a result of either a correction of an error or retrospective application of GAAP. The new provisions require non-public entities to disclose both the date that the financial statements were issued, or available to be issued, and the date the revised financial statements were issued or available to be issued. The amendment is effective for interim or annual periods ending after June 15, 2010. The adoption of this guidance did not have an impact on the Company's financial position, results of operations or cash flows.

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

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 beginning after November 15, 2009 and are to be applied to transfers occurring on or after the date of adoption. The adoption of this guidance did not have an impact on the Company's financial position, results of operations or cash flows.

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 evaluated its variable interest and investments, and the adoption of this guidance did not have an impact on the Company's financial position, results of operations or cash flows.

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

Note 2. Rates and Regulatory

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

(in thousands of dollars)	March 31, 2011	March 31, 2010
Regulatory assets – current		
Postretirement benefit costs	**$ 27,292**	$ 24,158
Environmental costs	**3,209**	3,209
Derivative contracts	**5,492**	24,417
Other	**5,238**	10,921
Total current regulatory assets	**41,231**	62,705
Regulatory liabilities – current		
Miscellaneous liability	**(5,926)**	(3,108)
Derivative contracts	**(1,014)**	(1,341)
Total current regulatory liabilities	**(6,940)**	(4,449)
Total current assets, net	**34,291**	58,256
Regulatory assets – non-current		
Postretirement benefit costs	**100,801**	144,482
Environmental costs	**49,618**	45,928
Derivative contracts	**1,110**	1,394
Regulatory tax assets	**378**	151
Other	**3,432**	12,489
Total non-current regulatory assets	**155,339**	204,444
Regulatory liabilities - non-current		
Miscellaneous liability	**(4,749)**	(3,310)
Derivative contracts	**(898)**	(234)
Cost of removal	**(406,251)**	(389,598)
Total non-current regulatory liabilities	**(411,898)**	(393,142)
Total non-current regulatory liabilities, net	**(256,559)**	(188,698)
Net regulatory liabilities	**$ (222,268)**	$ (130,442)

The regulatory items above are not included in the utility rate base. The Company record carrying charges, as appropriate, on the regulatory items for which cash expenditures have been made and are subject to recovery or for which cash has been collected and is subject to refund. Carrying charges are not recorded on items for which expenditures have not yet been made. The Company anticipates recovering these costs in the gas rates concurrently with future cash expenditures. If recovery is not concurrent wit the cash expenditures, the Company will record the appropriate level of carrying charges. Deferred gas costs of approximately $73.9 million and $79.6 million as of March 31, 2011 and March 31, 2010 are reflected against accounts receivable on the balance sheets.

Rate Matters

In April 2010, the Company with its affiliate, Colonial Gas Company ("Colonial Gas"), filed an initial request with DPU for a rate increase of $79.2 million, which was revised to $77.8 million in September, 2010. In November 2010, the DPU issued an order approving a revenue increase of $41.5 million based upon a 9.75% rate of return on equity and a 50% equity ratio. In May 2011, the Company made its first filing with the DPU for recovery of capital costs related to infrastructure replacement. The reported revenue requirement associated with these capital costs are approximately $10 million. Since this amount is below the ordered cap of 1% of the Company's prior year total revenues, the entire amount is eligible for recovery.

The DPU order also provided for a revenue decoupling mechanism to take effect as of November 1, 2010. The revenue decoupling mechanism applies to the Company's firm rate classes, excluding gas lamps and negotiated contracts and permits the Company to reconcile actual revenue per customer to target revenue per customer for the affected customer classes on a seasonal basis. The revenue decoupling mechanism is designed to eliminate the disincentive for the Company to implement energy efficiency programs. At March 31, 2011, the deferred amount under the decouple mechanism was a payable of $13.0 million which is fully refundable to the affected customer classes.

In November 2010, the Company filed two motions in response to the DPU order (1) in its motion for recalculation, the Company has requested that the DPU recalculate certain adjustments that it made in determining the $41.5 million increases approved in its order. If approved, the rate increase for the Company would increase by an additional $4.9 million to a total of $46.4 million (2) in its motion for reconsideration and clarification; the Company is seeking reconsideration of the DPU's disposition of four issues it believes were based on legal error or lack of substantial evidence, and clarification on three non-financial matters. The most significant of the four items for reconsideration involves that DPU's disallowance of $11.3 million from rate base related to certain of the Company's fixed asset additions from calendar years 1996 to 1998 as well as disallowance of depreciation expenses of approximately $0.8 million per year associated with those assets. If the Company is unsuccessful with its request for reconsideration, it could appeal the matter to the Massachusetts Supreme Judicial Court. The motions remain pending at the DPU.

Other Regulatory Matters

In November 2008, the Company, together with Colonial Gas, filed a combined request for approval of a three year gas portfolio optimization agreement with ConocoPhillips, which was approved in April 2009 but limited the term to a one year period. This agreement was extended for one additional year upon the approval of DPU in April 2010. In November 2010, a combined request was filed for approval of a new gas portfolio optimization co-management agreement with BG Energy Merchants, LLC for a term of two years commencing in April 2011, which was rejected by DPU in May 2011. Since the former ConocoPhillips agreement terminated as of Mach 31, 2011, the Company has been managing and optimizing its assets on its own while the DPU proceeding was pending. The Company is presently evaluating its options with respect to portfolio management in light of the DPU's rejection of the proposed co-management agreement.

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

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

Green Communities Act

The Company's Energy Efficiency ("EE") plan is run as a single combined plan with Colonial Gas. For the calendar years 2010 through 2012, the plan significantly expands EE programs for customers with a concomitant increase in spending. The budget for the gas companies in Massachusetts, exclusive of lost base revenue (revenues reduced as a result of installed EE measures) for the calendar years 2010 through 2012 is $203.4 million. In addition to cost recovery, the Company has the opportunity to earn a performance incentive. On March 31, 2011, the DPU approved a combined performance incentive for 2009 of $1.0 million, net of taxes. The DPU also approved an increase to the 2009 EE budget of approximately $8.8 million. The Company's request for recovery of lost base revenue for 2008 and 2009 is pending before the DPU.

Note 3. Employee Benefits

Summary
The Company participates with certain other KeySpan subsidiaries in a non-contributory defined benefit plan and a PBOP plan.

The pension plan is a defined benefit plan which provides union employees with a retirement benefit and non-union employees hired before January 1, 2011 with a retirement benefit.

Supplemental nonqualified, non-contributory executive programs provide additional defined pension benefits for certain executives.

PBOPs provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and in most cases, retirees must contribute to the cost of their coverage.

Pension Plans

The Company participates in the pension plans with certain other KeySpan subsidiaries. Pension plan assets are commingled and cannot be allocated to an individual company. Pension costs are allocated to the Company. The pension plans have a net underfunded obligation of $643.9 million and $740.2 million at March 31, 2011 and March 31, 2010, respectively.

Certain current year changes in the funded status of the KeySpan plan are allocated to the Company through an intercompany payable account. The Company is subject to certain deferral accounting requirements mandated by the DPU for pension expense and other postretirement health care costs. Any variation between actual costs and amounts used to establish rates are deferred and collected from or refunded to customers in subsequent periods. Any deferral is recorded as either a regulatory asset or regulatory liability on the balance sheets. Gross actuarial pension expense allocated to the Company was $11.0 million and $12.4 million for the years ended March 31, 2011 and March 31, 2010, respectively.

Postretirement Health Care Benefits

The PBOP plan has not been merged with other KeySpan plans and therefore, continues to remain a separate plan of the Company.

The Company is subject to deferral accounting requirements, as previously ordered by the DPU, for postretirement health care costs. Any variation between actual postretirement health care costs and amounts used to establish rates are deferred and collected from or refunded to customers in subsequent periods through an adjustment clause. Any deferral is recorded as either a regulatory asset or regulatory liability on the balance sheet.

The net costs for postretirement health care costs charged to expense for the years ended March 31, 2011 and March 31, 2010 are as follows:

(in thousands of dollars)	Years Ended March 31, **2011**	2010
Service cost-benefits earned during the year	**$ 2,207**	$ 1,676
Interest cost on benefit obligation	**8,033**	8,404
Expected return on plan assets	**(2,073)**	(1,384)
Amortization of PSC	**71**	-
Amortization of net actuarial gain	**(216)**	(714)
Special termination benefits	**-**	175
Total	**$ 8,022**	$ 8,157

The following table sets forth the change in benefit obligation and plan assets and reconciliation of funded status of the Company's health care plans and amounts recorded on the balance sheets as of March 31, 2011 and March 31, 2010:

(in thousands of dollars)	Years Ended March 31, **2011**	2010
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ (142,813)**	$ (113,642)
Service cost	**(2,207)**	(1,676)
Interest cost	**(8,033)**	(8,404)
Amendments	**252**	(796)
Actuarial gain (loss)	**2,903**	(23,690)
Benefits paid	**6,682**	8,541
Actual Medicare Part D subsidy received	**(193)**	(447)
Special termination benefits	**-**	(174)
Other	**-**	(2,525)
Benefit obligation at end of year	**(143,409)**	(142,813)
Change in plan assets:		
Fair value of plan assets at beginning of year	**22,480**	13,489
Actual return on plan assets	**4,232**	5,850
Employer contributions	**11,379**	11,682
Benefits paid	**(6,682)**	(8,541)
Fair value of plan assets at end of year	**31,409**	22,480
Funded status	**(112,000)**	(120,333)
Amounts recognized in the balance sheets consist of:		
Current liabilities	**(2,885)**	(2,806)
Noncurrent liabilities	**(109,115)**	(117,527)
Total	**(112,000)**	(120,333)
Amounts recognized in regulatory assets consist of:		
Net losses	**(643)**	(5,490)
Prior service cost	**(473)**	(796)
Total	**(1,116)**	(6,286)

Estimated amount of regulatory assets to be recognized in next fiscal year through net periodic postretirement cost:				
Net gain		**195**		150
Prior service cost		**(35)**		(95)
Total	**$**	**160**	$	55

A one-percentage-point increase or decrease in the assumed health care trend rate would have the following effects:

(in thousands of dollars)		**One-Percentage-Point Increase**		**One-Percentage-Point Decrease**
Net periodic healthcare expense	$	702	$	(612)
Postretirement benefit obligation	$	8,718	$	(7,688)

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid in the years indicated:

(in thousands of dollars)		**Gross Benefit Payments**		**Subsidy Receipts Expected ***
2012	$	10,303	$	493
2013		10,600		497
2014		10,961		496
2015		11,154		489
2016		11,450		478
Thereafter		58,028		2,076

* Rebates are based on calendar year in which prescription drug costs are incurred.
Actual receipt of rebates may occur in the following year.

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 that 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 statement of income of $2 million for the year ended March 31, 2010.

No regulatory asset has been established with respect to this charge as any potential future recovery from customers of the increased cost of the Company's retiree health plans that results from the loss of this tax deduction has not been agreed under the terms of the Company's then existing rate plans which predated the passage of the legislation.

Workforce Reduction Program
In connection with National Grid plc’s acquisition of KeySpan, National Grid plc and KeySpan offered 673 non-union employees a voluntary early retirement offer (“VERO”) in an effort to reduce the workforce. Eligible employees must have been working in a targeted area as of April 13, 2007 and be at least 52 years of age with seven or more years of service as of September 30, 2007. For eligible employees who have elected to accept the VERO offer, National Grid plc and KeySpan have the right to retain that employee for up to three years before VERO payments are made. An employee who accepts the VERO offer but elects to terminate employment with National Grid plc or KeySpan prior to the three year period, without consent of National Grid plc or KeySpan, forfeits all rights to VERO payments. The VERO is completed and the Company has accrued $11.2 million.

Note 4. Debt

Advance from Affiliates

At March 31, 2011 and March 31, 2010 the Company had a $400 million advance payable due to KNE LLC with an interest rate of 4.65% and 7.625% respectively. During the year ended March 31, 2011, the Company borrowed an additional $80 million from KeySpan with an interest rate at 4.65%, leaving a total intercompany borrowing balance of $480 million at March 31, 2011. The Company treats the $400 million advance from KNE LLC and the $80 million advance from KeySpan as long-term obligations. There are no covenants or fixed maturity dates associated with the advance.

Recapitalization

During the year ended March 31, 2010, the Company restructured its total capitalization. Additional paid-in capital was increased by $490 million and concurrently the outstanding advance from KeySpan was reduced by $100 million and outstanding moneypool borrowings were reduced by $390 million. The recapitalization resulted in a more optimal and cost efficient capital structure for the Company. Interest rates associated with the moneypool are designed to approximate the cost of third-party short-term borrowings.

During the year ended March 31, 2011, the Company restructured its capital structure to a 50% debt and 50% equity structure. The Company borrowed additional $80 million from KNE LLC and concurrently pays off as form of dividend.

Notes Payable

At March 31, 2011, the Company had an outstanding balance of $163 million of secured medium and long-term notes with interest rates ranging from 6.80% to 9.75% and maturity dates ranging from 2011 through 2025.

Maturity schedule
The following table reflects the maturity schedule for the Company's debt repayment requirement at March 31, 2011:

March 31,		
(in thousands of dollars)	**Long-term debt**	
2012	$	10,000
2013		10,000
2014		10,000
2015		2,000
2016		10,000
Thereafter		121,000
	$	163,000

Capital Lease

In April 1999, the Company entered into a 15-year capital lease for liquefied natural gas ("LNG") facilities located in Massachusetts. A summary of the property held under the capital lease as of March 31, 2011 and March 31, 2010 is as follows:

	March 31,	
(in thousands of dollars)	**2011**	2010
LNG facilities	**$ 14,835**	$ 14,835
Less: accumulated depreciation	**(10,434)**	(9,126)
Net capital lease	**$ 4,401**	$ 5,709

Under the terms of certain accounting standards, the timing of expense recognition on capitalized leases conforms to regulatory rate treatment. The Company has included the rental payments on its capital leases in its cost of service for rate purposes. The current and non-current portions of the capital lease obligation are recorded as a component at "other current liabilities" and "other deferred liabilities" on the Company's balance sheets.

Maturity Schedule
The following table reflects the maturity schedule for the Company's capital lease requirement at March 31, 2011:

(in thousands of dollars)	
2012	$ 1,388
2013	1,473
2014	1,540
Total	$ 4,401

Note 5. Property, Plant and Equipment

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

(in thousands of dollars)	March 31,	
	2011	2010
Plant and machinery	**$ 2,230,019**	$ 2,062,712
Land and buildings	**59,567**	58,889
Assets in construction	**26,226**	31,304
Software and othe intangibles	**75,715**	77,553
Total	**2,391,527**	2,230,458
Accumulated depreciation and amortization	**(665,575)**	(601,390)
Property, plant and equipment, net	**$ 1,725,952**	$ 1,629,068

AFUDC

The Company capitalizes AFUDC as part of construction costs. AFUDC represents an allowance for the cost of funds used to finance construction and, includes a debt and equity component. AFUDC is capitalized in "property, plant and equipment" with offsetting credits to "other interest, including affiliate interest" for the debt component and "other (deductions) income" for the equity component. The Company is permitted to recover prudently incurred capital costs through their ultimate inclusion in rate base and in the provision for depreciation. The composite AFUDC rate for March 31, 2011 and March 31, 2010 was 4.9% and 3.9%, respectively. AFUDC capitalized during the years ended March 31, 2011 and March 31, 2010 was $1.2 million and $1.7 million, respectively

Depreciation

Depreciation expense is determined using the straight-line method. The depreciation rates 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 uses composite depreciation rates that are approved by the applicable federal and state utility commissions. The composite depreciation rate, expressed as a percentage of the average depreciable property in service, at March 31, 2011 and March 31, 2010 is 4.5%. The cost of repair and minor replacement and renewal of property is charged to maintenance expense.

Plant Disallowances

On October 31, 2010, the DPU issued docket no. 10-55 ("10-55"). The DPU determined that the Company did not meet the requisite standards of documentation for plant additions made in 1996 through 1998. These additions were specifically disallowed by the DPU. The Company calculated the effect of the disallowances through March 31, 2011 to be $11.3 million, net of accumulated depreciation. In addition the Company was required to reverse a deferred tax benefit of approximately $2.8 million. The depreciation related to the disallowed plant was calculated by applying a composite rate to the gross amount of plant disallowed and was estimated to be $0.8 million. NGUSA, on behalf of the Company, has entered into a Motion for Reconsideration regarding the disallowances discussed herein. Any recovery of disallowances granted by the DPU in the future would equate to a gain contingency and would be recognized only when realized. The disallowances amounts are included in "other (deduction) income" on the statements of income.

Note 6. Income Taxes

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

	Years Ended March 31,	
(in thousands of dollars)	**2011**	2010
Components of federal and state income taxes:		
Current tax benefit:		
Federal	**$ (5,032)**	$ (69,514)
State	**(4,883)**	(5,997)
Total current tax benefit	**(9,915)**	(75,511)
Deferred tax expense (benefit):		
Federal	**32,884**	80,093
State	**(2,321)**	16,085
Total deferred tax expense	**30,563**	96,178
Investment tax credits*	**(71)**	(143)
Total income tax expense	**$ 20,577**	$ 20,524

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

Income tax expense for the years ended March 31, 2011 and March 31, 2010 varied from the amount computed by applying the statutory rate to income before income taxes. A reconciliation of expected federal income tax expense, using the federal statutory rate of 35%, to the Company's actual income tax expense for the years ended March 31, 2011 and March 31, 2010 is presented in the following table:

	Years Ended March 31,	
(in thousands of dollars)	**2011**	2010
Computed tax	**$ 26,058**	$ 11,561
Increase (reduction) including those attributable to flow-through of certain tax adjustments:		
State income taxes (including reserve changes), net of federal benefit	**(4,683)**	6,557
Intercompany tax allocation	**(1,345)**	-
Audit and related reserve movements	**561**	1
Allowance for equity funds used during construction	**(121)**	(80)
Investment tax credit	**(71)**	(143)
Provision to return adjustments	**7**	590
Medicare subsidy, including Patient Protection & Affordable Care Act effect, net	**-**	1,874
Other items - net	**171**	164
Total	**(5,481)**	8,963
Federal and state income taxes	**$ 20,577**	$ 20,524

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

	March 31,	
(in thousands of dollars)	**2011**	2010
Pensions, other post employment benefits ("OPEB") and other employee benefits	**$ 65,778**	$ 73,404
Reserve - environmental	**16,338**	12,745
Future federal benefit on state taxes	**11,981**	12,253
Allowance for uncollectible accounts	**8,389**	8,595
Reserves not currently deducted	**4,794**	-
Regulatory liabilities / assets - other	**2,796**	(5,071)
Other items	**685**	4,227
Total deferred tax assets [1]	**110,761**	106,153
Property related differences	**(286,812)**	(241,098)
Regulatory assets - pension and OPEB	**(53,616)**	(68,047)
Deferred gas cost	**(31,262)**	(33,714)
Regulatory assets - environmental	**(20,599)**	(15,042)
Unamortized debt discount or premium	**(666)**	(754)
Unbilled revenue	**(513)**	(3,294)
Total deferred tax liabilities	**(393,468)**	(361,949)
Net accumulated deferred income tax liability	**(282,707)**	(255,796)
Investment tax credit	**(222)**	(293)
Net accumulated deferred income tax liability and investment tax credit	**(282,929)**	(256,089)
Current portion of net deferred tax liability	**(20,382)**	(17,958)
Non-current portion of net deferred income tax liability and investment tax credit	**(262,547)**	(238,131)
Net accumulated deferred income tax liability and investment tax credit	**$ (282,929)**	$ (256,089)

[1] There were no valuation allowances for deferred tax assets at March 31, 2011 or March 31, 2010.

Subsequent to the KeySpan acquisition by NGUSA on August 24, 2007, KeySpan and its subsidiaries became members of the National Grid Holdings, Inc. ("NGHI") and subsidiaries consolidated federal income tax return. The

Company is a member of this consolidated group. The Company has joint and several liability for any potential assessments against the consolidated group.

As of March 31, 2011 and March 31, 2010, the Company's current federal income taxes balances payable to its parent are $35.7 million and $27.9 million, respectively.

The Company adopted the provisions of the current accounting guidance which clarifies the accounting and disclosure of uncertain tax positions in the financial statements. The guidance provides that the financial effects of a tax position shall initially be recognized when it is more likely than not, based on the technical merits, that the position will be sustained upon examination, assuming the position will be audited and the taxing authority has full knowledge of all relevant information.

As of March 31, 2011 and March 31, 2010, the Company's unrecognized tax benefits totaled $44.1 million and $71.7 million, respectively, of which none and $3.8 million would affect the effective tax rate, if recognized.

The following table reconciles the changes to the Company's unrecognized tax benefits for the years ended March 31, 2011 and March 31, 2010:

Reconciliation of Unrecognized Tax Benefits	**Years Ended March 31,**	
(in thousands of dollars)	**2011**	2010
Beginning balance	**$ 71,738**	$ 44,462
Gross decreases related to prior years	**(20,936)**	-
Gross increases related to current year	**6,494**	27,276
Settlements with tax authorities	**(7,267)**	-
Reductions due to lapse of statute of limitations	**(5,901)**	-
Ending balance	**$ 44,128**	$ 71,738

As of March 31, 2011 and March 31, 2010, the Company has accrued for interest related to unrecognized tax benefits of $1.9 million and $10.3 million, respectively. During the years ended March 31, 2011 and March 31, 2010, the Company recorded interest income of $6.4 million and interest expense of $1.0 million, respectively. The Company recognizes accrued interest related to unrecognized tax benefits in interest expense or interest income and related penalties, if applicable, in operating expenses. No penalties were recognized during the years ended March 31, 2011 and March 31, 2010.

During the year ended March 31, 2011, KeySpan and its subsidiaries reached a settlement with the Internal Revenue Service ("IRS") on outstanding tax matters for the calendar tax years 2000 through 2006. The Company was a member of the KeySpan and its subsidiaries consolidated federal income tax return for these years and were obligated to pay $6.4 million to KeySpan for its share of the settlement pursuant to the tax sharing agreement. In connection with the settlement, the Company incurred a $0.6 million tax charge for the differences between the amounts settled upon with the IRS and the tax positions previously accrued. Resolution of tax matters for these years with state and local tax authorities is outstanding. The tax returns for the short year ended August 24, 2007, as well as the years ended March 31, 2008 through March 31, 2011 remains subject to examination by the IRS.

The State of New York is in the process of examining the Company's income tax returns for the calendar years ended December 31, 2002 through December 31, 2004. The tax returns for calendar years ended December 31, 2005 through December 31, 2006, the short year ended August 24, 2007, and years ended March 31, 2008 through March 31, 2011 remain subject to examination by the State of New York.

For the years ended March 31, 2011 and March 31, 2010 the Company is a member of the NGUSA service company Massachusetts unitary group. The tax returns for these years remain subject to examination by the State of Massachusetts. Prior to filings as a member of this unitary group, the Company filed on a separate basis. The separate tax returns for the years ended March 31, 2008 and March 31, 2009 remain subject to the examination by the State of Massachusetts.

Note 7. Derivative Contracts

Physical Derivatives

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 purchased option contract to qualify as normal purchase and normal sales. Certain contracts for the physical purchase of natural gas do not qualify for this exception. Because these contracts are for the purchase of natural gas sold to regulated firm gas sales customers, the accounting for these contracts follows the accounting guidance for rate-regulated enterprises. Additionally, the Company has gas transportation service agreements with large generating facilities that contain embedded derivatives. These contracts and related embedded derivatives also follow the accounting guidance for rate-regulated enterprises. The fair value of these derivatives at March 31, 2011 and March 31, 2010 was a liability of $0.5 million and $1.5 million, respectively.

Financial Derivatives

The Company uses derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases. The Company's strategy is to minimize fluctuations in firm gas sales prices to regulated firm gas sales customers in the Company's service territory. The accounting for these derivative instruments follows the accounting guidance for rate-regulated enterprises. Therefore, the fair value of these derivatives is recorded as a current or deferred asset and liability, with offsetting positions recorded as regulatory assets or regulatory liabilities on the balance sheets. As these derivative contracts are eligible for rate-regulated accounting treatment, changes in fair value have no income statement impact. Gains or losses upon settlement of these contracts are initially deferred and then refunded to or collected from the Company's gas sales customers consistent with regulatory requirements. The fair value of these derivative instruments was a liability of $4.2 million and $22.7 million as of March 31, 2011 and March 31, 2010, respectively.

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

(in thousands)		
Physicals	Gas (dths)	13,629
Financials	Gas swaps (dths)	22,221
	Gas futures (dths)	-
Total	**Gas (dths)**	**35,850**

Other Derivative Instruments

Additionally, the Company employs a limited number of derivative instruments to hedge a small portion of its risk associated with storage optimization. These financial derivative instruments do not qualify for hedge accounting treatment or the accounting guidance for rate-regulated enterprises. The fair value of these contracts was a liability of $0.9 million at March 31, 2011 and an asset of $2.0 million at March 31, 2010. The Company use market quoted forward prices to value these contracts.

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

Fair Values of Derivative Instruments - Balance Sheets					
	Asset Derivatives			Liability Derivatives	
(in thousands of dollars)	March 31, 2011	March 31, 2010		March 31, 2011	March 31, 2010
Regulated contracts					
Gas contracts					
Current assets			Current liabilities		
Gas purchase contract	$ 130	$ 1,330	Gas purchase contract	$ (707)	$ (1,662)
Gas swaps contract	884	11	Gas swaps contract	(4,785)	(22,755)
Subtotal current assets	1,014	1,341	Subtotal current liabilities	(5,492)	(24,417)
Deferred asset			Deferred liabilities		
Gas purchase contract	773	234	Gas purchase contract	(698)	(1,394)
Gas swaps contract	125	-	Gas swaps contract	(412)	-
Subtotal deferred assets	898	234	Subtotal deferred liabilities	(1,110)	(1,394)
Subtotal regulated contracts	1,912	1,575	Subtotal regulated contracts	(6,602)	(25,811)
Non-regulated contracts					
Gas contracts					
Current assets			Current liabilities		
Gas purchase contract	-	18	Gas purchase contract	-	(55)
Gas swaps contract	277	2,791	Gas swap contract	(1,185)	(792)
Subtotal non-regulated contracts	277	2,809	Subtotal non-regulated contracts	(1,185)	(847)
Total	$ 2,189	$ 4,384	Total	$ (7,787)	$ (26,658)

The following table presents the change in value and the asset and (liability) balances of the Company’s derivative contracts. The change in fair value of the regulated contracts exactly corresponds to offsetting regulatory assets and liabilities. As a result, the changes in fair value of derivative contracts and their offsetting regulatory assets and liabilities had no impact on the statements of income. The change in value of the non-regulated contracts had an impact on Statements of income, and is included in “other (deductions) income”.

(in thouands of dollars)	**YTD Movement**	**March 31, 2011**	March 31, 2010
Regulated contracts			
Gas Contracts			
Gas Purchase Contract - Regulatory Asset	**$ 1,651**	**$ (1,405)**	$ (3,056)
Gas Swaps Contract - Regulatory Asset	**17,558**	**(5,197)**	(22,755)
Gas Purchase Contract - Regulatory Liability	**(661)**	**903**	1,564
Gas Swaps Contract - Regulatory Liability	**998**	**1,009**	11
Subtotal	**19,546**	**(4,690)**	(24,236)
Non-regulated contracts			
Gas Contracts			
Gas Purchase Contract - Other Revenues	**37**	**-**	(37)
Gas Swaps Contract - Other Revenues	**(2,907)**	**(908)**	1,999
Subtotal	**(2,870)**	**(908)**	1,962
Total	**$ 16,676**	**$ (5,598)**	$ (22,274)

Credit and Collateral

Derivative contracts are primarily used to manage exposure to market risk arising from changes in commodity prices and interest rates. In the event of non-performance by a counterparty to a derivative contract, the desired impact may not be achieved. The risk of counterparty non-performance is generally considered a credit risk and is actively managed by assessing each counterparty credit profile and negotiating appropriate levels of collateral and credit support. In instances where the counterparties' credit quality has declined, or credit exposure exceeds certain levels, the Company may limit its credit exposure by restricting new transactions with counterparties, requiring additional collateral or credit support and negotiating the early termination of certain agreements. At March 31, 2011 and March 31, 2010, the Company paid \$0.3 million and \$6.7 million, respectively, to its counterparties as collateral associated with outstanding derivative contracts. This amount has been recorded as restricted cash, with offsetting positions on the balance sheet.

The aggregate fair value of the Company's derivative instruments with credit-risk-related contingent features that are in a liability position at March 31, 2011, is \$5.7 million for which the Company has posted collateral of \$0.3 million in the normal course of business. If the Company's credit rating were to be downgraded by one notch, it would not be required to post any additional collateral. If the Company's credit rating were to be downgraded by three notches, it would be required to post \$5.7 million additional collateral to its counterparties.

Note 8. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The following is the fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

The Company currently has no Level 1 assets or liabilities for its derivative contracts. The Level 1 available for sale securities are primarily in equities and are investments based on quoted market prices and municipal and corporate bonds based on quoted prices of similar traded assets in open markets.

The Company's Level 2 fair value derivative instruments primarily consist of over-the-counter ("OTC") gas swaps and forward physical gas deals where market data for pricing inputs is observable. Derivative assets and liabilities utilizing Level 2 inputs include non-exchanged-based financial contracts (e.g. OTC gas financial swap) and standard North American Energy Standards Board physical gas supply contracts. Level 2 pricing inputs are obtained from the New York Mercantile Exchange ("NYMEX") and Intercontinental Exchange ("ICE"), except cases when ICE publishes seasonal averages or there were no transactions within the last seven days. During periods prior to December 31, 2010 Level 2 pricing inputs were obtained from the NYMEX and Platts M2M (industry standard, non-exchange-based editorial commodity forward curves) when it can be verified by available market data from ICE based on transactions within the last seven days. Level 2 derivative instruments may utilize discounting based on quoted interest rate curve as well as have a liquidity reserve calculated based on a bid/ask spread. Substantially all of these price curves are observable in the marketplace throughout at least 95% of the remaining contractual quantity, or they could be constructed from market observable curves with correlation coefficients of 0.95 or higher.

Level 3 fair value derivative instruments primarily consist of the Company's gas OTC forwards, options, and physical gas transactions where pricing inputs are unobservable, as well as other complex and structured transactions. Complex or structured transactions can introduce the need for internally-developed models based on reasonable assumptions. Industry-standard valuation techniques, such as the Black-Scholes pricing model, Monte Carlo simulation, and Financial Engineering Associates libraries, are used for valuing such instruments. The value is categorized as Level 3. Level 3 is also applied in cases when forward curves are internally developed, extrapolated or derived from market observable curve with correlation coefficients less than 0.95, or optionality is present, or non-economical assumptions are made. The internally developed forward curves have a high level of correlation with Platts M2M curves.

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

(in thousands of dollars)	Balance at March 31, 2011			
Derivative contracts	Level 1	Level 2	Level 3	Total
Assets	$ -	$ 1,286	$ 903	$ 2,189
Liabilities	-	(6,382)	(1,405)	(7,787)
Total derivative liabilities, net	-	(5,096)	(502)	(5,598)
Available for sale securities	Level 1	Level 2	Level 3	Total
Assets	674	-	-	674
Available for sale securities	$ 674	$ -	$ -	$ 674

Year to Date Level 3 Movement Table

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

(in thousands of dollars)	
Balance at March 31, 2010	$ (1,543)
Total gains or losses	
included in earnings (or changes in net assets)	(201)
included in regulatory assets and liabilties	3,665
Purchase	(2,423)
Balance at March 31, 2011	$ (502)
The amount of realized gains and (losses) included in net income attributed to the change in unrealized gains and (losses) related to derivative assets and liabilities at March 31, 2011	$ (5)

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

Long-term debt is based on quoted market prices where available or calculated prices based on the remaining cash flows of the underlying bond discounted at the Company's incremental borrowing rate. The Company's balance sheets reflect the long-term debt at carrying value. The fair value of this debt at March 31, 2011 and March 31, 2010 was $184.7 million and $218.4 million, respectively.

Note 9. Commitments and Contingencies

Legal Matters

The Company provides gas service to most of the City and owns equipment in the City to provide such service. That equipment is taxable as personal property in Massachusetts and the various municipalities set the assessment value which should reflect fair value. The Company applied for an abatement of its fiscal year 2004 assessment with the Assessing Department of the City of Boston ("the Assessors") disputing the methodology applied in determining fair value. On July 22, 2004, after being denied abatements by the Assessors, the Company filed an appeal with the Appellate Tax Board ("ATB"). On December 16, 2009, the ATB issued its decision finding for the City. The Company appealed this ruling to the Supreme Judicial Court ("SJC") on May 3, 2010. On January 20, 2011, the SJC issued its decision which affirmed much of the ATB decision. The tax amounts are included in "other taxes" on the statements of income.

Environmental Matters

Within the Commonwealth of Massachusetts, the Company is aware of numerous former MGP sites and related facilities within the existing or former service territories of the Company. Agreements with other utilities are in place to share environmental cleanup costs on numerous of these sites.

The Company estimates the remaining cost of these MGP-related environmental cleanup activities will be $42.2 million and $36.9 million at March 31, 2011 and March 31, 2010, respectively, which have been accrued by the Company a reasonable estimate of cost for known sites. However, remediation costs for each site may be materially higher than estimated, depending upon changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered.

By rate orders, the DPU provided for the recovery of site investigation and remediation costs and accordingly, at March 31, 2011 and March 31, 2010, the Company has reflected a regulatory asset of $52.8 million and $49.1 million, respectively, for the MGP sites.

Asset Retirement Obligations

The Company has various asset retirement obligations associated with its gas distribution facilities. These obligations have remained substantially unchanged from March 31, 2010, except for normal accretion adjustments and costs incurred. 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 the Company's 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. These obligations total $13 million and $12.3 million at March 31, 2011 and March 31, 2010, respectively.

At March 31, the following asset retirement obligations were recorded on the balance sheets at their estimated present values:

(in thousands of dollars)	**March 31, 2011**	March 31, 2010
Asbestos removal	**$ 128**	$ 121
Tanks removal and cleaning	**13**	13
Main cutting, purging and capping	**12,885**	12,156
Total asset retirement obligations	**$ 13,027**	$ 12,290

The Company recorded $0.9 million and $0.7 million of asset retirement obligation accretion expense for the years ended March 31, 2011 and March 31, 2010, respectively.

Fixed Charges under Firm Contracts

The Company has entered into various contracts for gas delivery, storage and supply services. The Company is liable for these payments regardless of the level of service it requires from third parties. Such charges are currently recovered from utility customers as gas costs.

(in thousands of dollars)		
Years ended March 31,		
2012	$	128,460
2013		101,417
2014		61,599
2015		44,403
2016		39,882
Thereafter		366,020
Total	**$**	**741,781**

Note 10. Related Party Transactions

Moneypool

The Company is engaged in various transactions with KeySpan, NGUSA and certain affiliates. For the most part, the various affiliates of KeySpan do not maintain separate cash balances. Financing for the Company's working capital and gas inventory needs are obtained through participation in the KeySpan moneypool for regulated entities. The Company is limited in its participation in the moneypool and is authorized to borrow funds as needed.

The moneypool is funded by operating funds from moneypool participants. In addition, KeySpan and NGUSA collectively have the ability to borrow up to $3 billion from National Grid plc for working capital needs including funding of the moneypool, if necessary. The Company had a short-term moneypool investment of $74.7 million and $57.4 million at March 31, 2011 and March 31, 2010, respectively. Interest rates associated with the moneypool are designed to approximate the cost of third-party short-term borrowings. Lenders to the moneypool earn interest while borrowers are charged interest. The average interest rate for moneypool was 1.20% and 0.91% for the years ended March 31, 2011 and March 31, 2010, respectively. All costs related to the borrowings related to gas inventory transactions are recoverable from customers.

Advances to/from Affiliates

NGUSA and its affiliates also provide us with various services, including executive and administrative, customer services, financial (including accounting, auditing, risk management, tax, treasury/finance), human resources, information technology, legal, and strategic planning. The costs of these services are charged to the Company via intercompany billings and generally settled through the moneypool on a monthly basis. At March 31, 2011 and March 31, 2010, the total affiliate payable was $175.4 million and $178.5 million, respectively, for those services.

Service Company Charges

The affiliated service companies of NGUSA provide certain services to the Company at their cost. The service company costs are generally allocated to associated companies through a tiered approach. First and foremost, costs are directly charged to the benefited company whenever practicable. Secondly, in cases where direct charging cannot be readily determined, costs are typically allocated using cost/causation principles linked to the relationship of that type of service, such as meters, square footage, number of employees, etc. Lastly, all other costs are allocated based on a general allocator. These costs include operating and capital expenditures of $121.4 million and $43.4 million for the year ended March 31, 2011, and $109.4 million and $39.1 million for the year ended March 31, 2010, respectively.

Holding Company Charges

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. These charges, which are recorded on the books of NGUSA, have not been reflected on these financial statements. Were these amounts allocated to this subsidiary, the estimated effect on net income would be $3.7 million and $1.9 million before taxes, and $2.4 million and $1.2 million after taxes, for the years ended March 31, 2011 and March 31, 2010, respectively.

Organization Restructuring

On January 31, 2011, National Grid plc announced substantial changes to the organization, including new global, US and UK operating models, and changes to the leadership team. The announced structure seeks to create a leaner, more-efficient business backed by streamlined operations that will help meet, more efficiently, the needs of regulators, customers and shareholders. The implementation of the new U.S. business structure commences on April 4, 2011 and targets annualized savings of $200 million by March 2012 primarily through the reduction of up to 1,200 positions. As of March 31, 2011, NGUSA had recorded approximately $66.8 million reserve for one-time employment termination benefits related to severance, payroll taxes, healthcare continuation, outplacement services as well as consulting fees related to the restructuring program. These charges have been recorded by NGUSA and none have been allocated to the Company as of March 31, 2011. Subsequently in June 2011, we offered a voluntary severance plan to certain individuals which are expected to cost up to an additional $20 million across all entities affiliated with NGUSA.

Note 11. Restrictions on Payment of Dividends

Pursuant to the provisions of the long-term note agreement, payment of dividends on common stock would not be permitted if, after giving effect to such payment of dividends, common equity becomes less than 30% of total capitalization. At March 31, 2011 and March 31, 2010 common equity was 63% and 66%, respectively, of total capitalization. Under these provisions, none of the Company’s retained earnings at March 31, 2011 and March 31, 2010 were restricted as to common dividends.

Note 12. Subsequent Events

In accordance with current authoritative accounting guidance, the Company has evaluated for disclosure subsequent events that have occurred up through June 28, 2011, the date of issuance of these financial statements. As of June 28, 2011, there were no subsequent events which required recognition or disclosure.